OPEC

World Oil Outlook

2011

Organization of the Petroleum Exporting Countries

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OPEC is a permanent, intergovernmental organization, established in Baghdad, Iraq, 10–14 September 1960. The Organization comprises 12 Members: Algeria, Angola, Ecuador, Islamic Republic of Iran, Iraq, Kuwait, Libya, 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

Deepened global macroeconomic uncertainties, heightened risks surrounding the international financial system, the sovereign debt crisis in the euro-zone, social unrest in many parts of the world, the natural disasters and ensuing nuclear catastrophe in Japan earlier this year, excessive oil price volatility, and increased speculator activity on the main commodity exchanges. It has been another challenging year.

The global economy continues to present the main challenge, for policymakers, industries, businesses and people across the world. While the massive fiscal and monetary support put in place by major economies after the Great Recession helped the global economy to recover more quickly than predicted in last year's World Oil Outlook (WOO), the positive effects of this support are now receding. Today, expanding fiscal deficits and ballooning sovereign debts are the most pressing concerns in many industrialized countries, particularly in the euro-zone. Two opposing factors are at play: the need for additional monetary and fiscal support and the need for fiscal consolidation.

All this has led to heightened downside risks for the world economy and the appearance of potentially damaging weaknesses in the banking system; something that may spread to the international financial system.

Moreover, the large emerging economies that witnessed strong growth rates over the past year or so are showing signs that they are not immune to the worsening economic conditions in the OECD region. They could be adversely affected through multiple channels; the main ones being trade and risks associated with the global financial system.

This year, two unforeseen events also had an impact on oil markets. Well-documented developments in parts of North Africa and the Middle East led to an interruption in the supply of high-quality crude. But to a large extent, the oil market promptly accommodated this situation. Moreover, events in Libya over the past month or two have given cause for optimism that there will be a speedy return to normal supply conditions. The country has excellent technical expertise and production is gradually being restored. It could be back up to 2010 levels in around 15 months or less.

The second unforeseen event was the result of the triple disaster that struck Japan in March, in the form of an earthquake, tsunami and nuclear catastrophe. This had an immediate effect on the oil market, as shut-in nuclear capacity was replaced by both oil- and gas-fired power generation. For oil markets, however, this was only a short-term impact.

These events are just some of the multiple challenges that the market has faced. It is important to stress, however, that the oil market has quickly adjusted to and been able to rapidly mitigate the resulting market disturbances. Once again, this demonstrates the resilience of oil markets, and the fact that oil is a reliable source of energy for meeting the world's energy needs. In this regard, the positive role that OPEC plays has again been amply demonstrated.

This year's WOO highlights that OPEC's role will be even more important in the future. Its Member Countries' daily efforts to provide adequate petroleum supplies to the market, coupled with the huge investments being made to maintain existing fields and infrastructure, develop new capacity, build pipelines and terminals, construct refineries and expand sea transportation fleets, are illustrations of the Organization's commitment to the market and consumers. The efforts will help satisfy demand for OPEC crude and provide a comfortable cushion of spare capacity, estimated to approach a level of 8 mb/d over the medium-term.

The WOO also shows that the world has enough oil resources to meet demand and satisfy consumer needs for decades to come. Estimates of ultimately recoverable resources continue to rise. Technology continues to extend its reach, with new areas and plays being opened to exploration and new countries becoming producers. There will be no shortage of oil for the foreseeable future.

Nevertheless, this year's publication emphasizes a number of challenges and uncertainties, in both the upstream and downstream, that could have implications for the industry.

Such challenges include the energy and environmental policies of consuming countries, many of which offer a hazy picture of their impact on future oil consumption, supply levels and overall energy demand. It is essential that predictability is enhanced. A better comprehension of what is feasible and realistic is vital. This will provide a better understanding of future oil demand and supply patterns, which, in turn, will allow investors to better plan future investments. Confidence is key. It is important to invest in a timely manner to meet future demand. It would be a damaging waste of resources to invest in capacity that is not needed.

Another challenge relates to the functioning of financial markets. Excessive volatility and excessive speculation remain a concern. Financial markets fulfil critical price discovery and risk transfer roles. But they can be distorted, so that they become detached from supply and demand fundamentals. This was seen in the early part of the year, when large price fluctuations were driven by speculative activity.

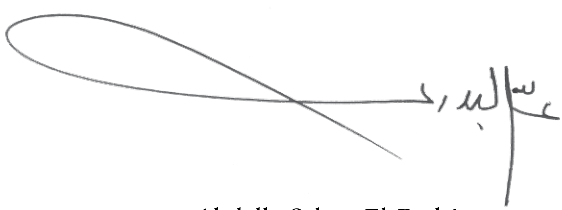
In addition, the WOO highlights continued concerns about the availability of skilled labour and trained manpower; an essential cog in driving the industry's innovation and future growth. And in the downstream, following the economic downturn, there is much talk about possible future capacity closures in certain regions of the world.

There is also the pressing issue of climate change, with the next United Nations Climate Change Conference set to take place in Durban, South Africa, in December 2011. This meeting comes at a crucial time; one year before the expiry of the first commitment period of the Kyoto Protocol. There are concerns about the willingness of developed countries to engage in a second commitment period, which means there are fears about the survival of the Kyoto Protocol itself.

If these negotiations are to succeed, it is important that the principles and provisions of the United Nations Framework Convention on Climate Change are fully taken into account; in particular, those principles relating to equity and common but differentiated responsibilities, with economic and social development and poverty eradication the first and overriding priorities of developing countries, as stipulated in the Convention. It is also essential that developed country commitments to minimize the adverse effects of mitigation response measures on developing countries are honoured. The establishment of a permanent forum to focus on the adverse impacts of response measures could be a move in the right direction.

Next year also sees the Rio+20 UN Conference on Sustainable Development in Brazil. It is vital that we look to reinforce the world's commitments to the UN Millennium Development Goals (MDGs). These shall be met. In line with this, it is important to emphasize that energy poverty remains widespread. It is imperative that the world finds sustainable and durable solutions to energy poverty; solutions that help move the poor up the energy ladder so that they may earn a sustainable income and escape the poverty trap. Improved access to energy, therefore, can facilitate the attainment of the MDGs.

The WOO 2011 illustrates OPEC's constantly-evolving analysis of the global oil market, over all timeframes, and further reinforces its commitment to market stability. The publication is not about making predictions. No-one has a crystal ball, and the evolution of the energy scene over the last decade has underlined the need for greater caution when looking into the future. Nevertheless, we believe that the publication is an important reference tool, offering insights into trends and possible developments in the years ahead. And we hope it makes a useful and positive contribution to global debate and understanding concerning the world's energy future.



Abdalla Salem El-Badri
Secretary General

Executive summary

Price assumption in the Reference Case: $85–95/b for this decade

This year's World Oil Outlook (WOO) sees a revision to last year's nominal OPEC Reference Basket price assumption in the Reference Case due to: the behaviour of prices since the publication of the WOO 2010; a slight reassessment of how upstream costs might evolve; the impact of dollar exchange rate movements on recent prices and potential future developments; and signals from the futures price. It is important to note, however, that the role of speculation has continued to be a major price driver in 2011, with speculator activity on the Nymex surging to record highs in the first quarter of 2011. As such, the most recent price behaviour should not directly feed into assumptions for prices over the medium- and long-term. The WOO 2011 Reference Case oil price assumption has been increased from last year. It is assumed that, in nominal terms, prices stay in the range of $85–95/b for this decade, compared to $75–85/b in last year's WOO, reaching $133/b by 2035. Last year, the timeframe was to 2030 and it was assumed that prices rose to $106/b. It should be emphasized, however, that these figures are only an assumption. They do not reflect, in any way, a projection of likely or desirable prices.

Marginal costs are important in making long-term price assumptions

It is generally accepted that long-term oil price assumptions should involve an assessment of marginal costs. It is evident that the WOO 2010 nominal price assumption may be too low. For example, coal-to-liquids (CTLs) backstop prices could be in the range of $74–85/b, and the price needed to support Canadian oil sands projects at internal rates of return above 10% suggest higher prices than previously assumed. Cost curves also show that at high prices, vast amounts of non-conventional oil would be economic.

Stronger recovery from the Great Recession in 2010 than expected…

A major change from last year's report is the more rapid recovery from the Great Recession than was assumed in the WOO 2010, with global growth in 2010 now estimated to have been 4.6%, compared to the 3.9% assumed last year. Medium-term economic growth rates are largely unchanged from the previous WOO's assumptions. Average global growth over the period 2010–2015 is 3.9% per annum (p.a.). The recovery has been driven by stimulus packages and monetary policy, as well as the fact that developing countries have been a major factor supporting global economic growth, and this is assumed to continue to be the case over the medium-term.

…but the global economic recovery continues to be fragile

However, the global economic recovery is increasingly showing signs of weakness. Two developments seem possible from here. The first is that the global economy will be marked by below average trend growth, in combination with high unemployment in developed economies and continuing global growth imbalances. And the second is the potential failure of the current support schemes and mechanisms, which would shock the global economy and push it back into decline. At present, this seems the less likely scenario, but it cannot be ruled out altogether. There are three main areas of concern. The first, and most pressing issue, are the widening deficits and ballooning sovereign debts in euro-zone countries. If not cooperatively managed, and resolved in a timely manner, they could lead to a worrisome banking crisis with potentially damaging systemic risk. The second major issue relates to the US economy. Of significant concern is the relatively muted recovery in private household demand. After the economic crisis of 2008 and 2009, a revival in consumer consumption was greatly supported by government-led stimulus. However, the economic recovery has recently decelerated considerably after the fiscal stimulus and the major 'extraordinary' monetary supply measures came to an end. The third major issue is the recent slow-down, albeit moderate, in developing countries, particularly the deceleration in China and India whose economies remain largely dependent on either capital inflows from, or exports to, developed countries. Recent significant increases in inflation have forced the countries to make provisions to avoid their economies overheating. The question remains as to whether this represents a well-managed soft landing or the early indication of future economic difficulties. In summary, given that stimulus packages and monetary policy have been the main driving force behind the recovery since the financial crisis began in 2007, the recovery cannot be deemed to be self-sustaining. Medium-term prospects will depend on the ability of governments to maintain their various support measures for as long as it takes to solve their economic issues.

Demographic trends are a determinant of future energy patterns

Demographic trends are important for determining long-term economic growth potential and energy demand. This year's extension of the WOO's timeframe to 2035 means that the impacts of population dynamics are even more pronounced. There will be a slowing of population growth, or even a contraction in some regions, and other demographic features are now being observed, such as rising urbanization and a generally ageing population. The world population increases from just over 6.9 billion in 2010 to almost 8.6 billion in 2035. Only 110 million of the increase over the period 2010–2035 is in the Organisation for Economic Co-operation and Development (OECD) countries, while close to 1.6 billion more people will be living in developing countries.

Reference Case only includes policies that are already passed into law

The Reference Case retains the principle that only policies already in place or widely anticipated are allowed to influence supply and demand patterns. The two key policies already factored in are the European Union (EU) package of measures for climate change and renewable objectives and the US Energy Independence and Security Act.

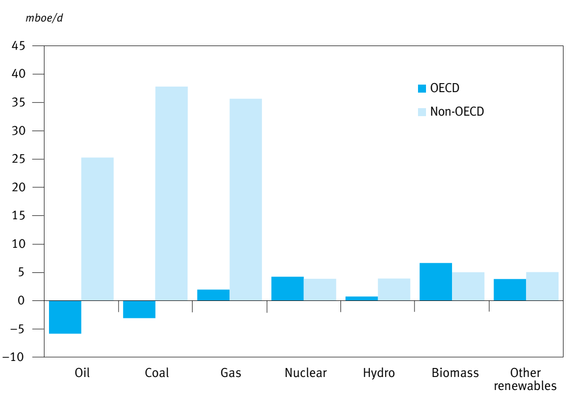
China's latest Five Year Plan: a consolidation of previous ones?

China's recently announced 12th Five Year Plan for the period 2011–2015 includes a focus upon increasing energy efficiency, decreasing carbon intensities, reducing the share of fossil fuels in the energy mix, pushing battery cell technology development, as well as sustaining economic growth at an average of 7% p.a. over the next five years. The Plan contains an energy consumption target of no more than 2,800 million tonnes of oil equivalent p.a. by 2015. This is a challenging target considering that it is only 8.5% above 2010 levels. In the previous five-year period, China's energy consumption actually increased by around 39%. A new carbon intensity reduction concept is also included; in terms of CO_2 emissions per unit of gross domestic product, the Plan states that the country will look to reduce this by 17% by 2015 compared to 2010 levels.

Energy demand increases by 51% by 2035

Over the period 2010–2035, commercial primary energy demand in the Reference Case increases by 51%. Fossil fuels, currently accounting for 87% of primary commercial energy supply, will still make up 82% of the global total by 2035. For most of the projection period, oil will remain the energy type with the largest share. However, by 2035 it will have been overtaken by coal use in the Reference Case, which will represent 29% of total energy, similar to today, while oil's share falls from 34% to 28%. Gas use will rise at faster rates than both coal or oil, in percentage terms and volumes, with its overall share rising from 23% to 25%.

Increase in energy demand 2010–2035, by fuel type



Nuclear prospects affected by Fukushima

The prospects for nuclear energy have clearly been affected by this year's devastating accident at the Fukushima nuclear plant in Japan. The Reference Case reflects the immediate aftermath of the nuclear accident, when shut-in nuclear power was replaced by other fuels. Moreover, moving forward, it is assumed that the long-term prospects for nuclear power have been negatively affected. Possible adverse impacts can be expected elsewhere too. In the Reference Case, nuclear energy still expands at an average rate of 1.7% p.a., although its long-term contribution has been slightly revised down, by under 0.5 million barrels of oil equivalent per day (mboe/d), from estimates in last year's WOO.

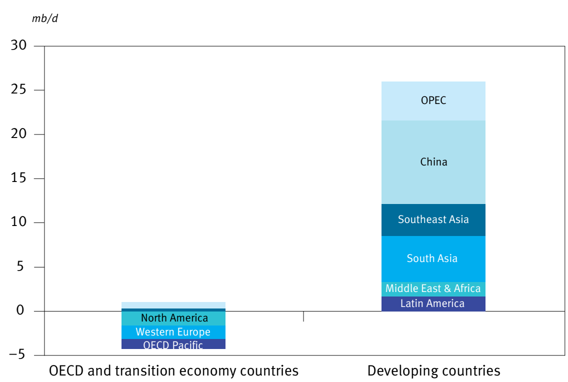
Medium-term oil demand up to 93 mb/d by 2015

In terms of oil demand, the Great Recession had enormous implications for projections in both the short- and medium-term. However, with the initial recovery swifter than expected, although risks now appear rather skewed towards the downside given the widening global macroeconomic uncertainties, the medium-term oil demand outlook reflects an upward revision from last year's assessment. The Reference Case now foresees demand reaching 92.9 mb/d by 2015, an upward revision of 1.9 mb/d.

Oil demand reaches 110 mb/d by 2035

While the central driver for medium-term oil demand is the economy, in the long-term other important drivers come in to play. The impact of policies, technologies, demographics and, to a lesser extent, oil price developments, will increasingly influence long-term demand patterns. In the Reference Case, demand increases by close to 23 mb/d over the period 2010–2035, reaching almost 110 mb/d by 2035. OECD demand actually seems to have peaked in 2005, and the Reference Case sees a steady demand decline in all OECD regions. Fully 80% of the increase in global demand is in developing Asia, where demand reaches almost 90% of that in the OECD by 2035.

Growth in oil demand 2010–2035



World oil demand outlook in the Reference Case *mb/d*

	2010	2015	2020	2035
OECD	46.1	46.0	45.2	41.9
Developing countries	35.9	41.8	47.2	61.9
Transition economies	4.8	5.1	5.3	5.9
World	86.8	92.9	97.8	109.7

Transportation sector key to future oil demand growth

Transportation in non-OECD countries is central to future global demand growth, accounting for close to 90% of the increase over the period to 2035. Developing countries are also expected to see some rise in oil use in other sectors, particularly in industry and the household/commercial/agriculture sector. Globally, the small amount of oil that is still used for electricity generation is expected to fall. In OECD countries, the declining use of oil is dominated by the demand fall in road transportation, as vehicle fuel economies improve and the rate of increase for car ownership slows.

Transportation technology: a major source of efficiency gains

Conventional powertrain technology is expected to continue to act as a source of substantial future efficiency gains. This is true for diesel engines and probably even more for gasoline engines. Hybrid and plug-in vehicles will also begin to have an impact on the vehicle sales mix. In these areas, however, technology and infrastructure are still in their infancy and customer habits will need time to change. With regard to heavy-duty vehicles, the focus is turning to fuel consumption targets, with Japan leading the way, although steps towards implementing fuel efficiency standards in other markets are gradually emerging. Alternative technologies, especially hybrids, are expected to face some commercial and technical challenges in this heavy-duty vehicle segment. Conventional technology improvements and the take-up of new powertrain technologies are therefore anticipated to affect the average fuel consumption for all vehicles. The effects will be lower for trucks than for passenger cars, due to lower levels of hybridization, limited opportunities for plug-ins and constraints to improvements in mainstream diesel engine technology.

Non-OPEC and OPEC supply rise over the medium-term…

Total non-OPEC supply increases steadily over the medium-term, rising by 3 mb/d over the period 2010–2015. The key drivers of this growth are the Caspian region, Brazil and Canada. Biofuels, mainly in Europe and the US, also make some

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

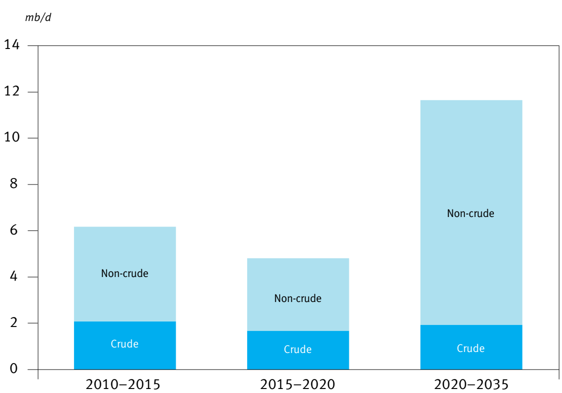
	2010	2015	2020	2035
OECD	19.9	20.3	20.4	22.2
Developing countries, excl. OPEC	16.9	18.4	19.4	19.3
Transition economies	13.4	14.3	14.9	16.1
Total non-OPEC	52.3	55.3	57.3	60.5
OPEC NGLs	4.8	6.2	7.2	9.4
OPEC GTLs	0.1	0.3	0.4	0.6
OPEC crude	29.3	31.3	33.2	39.3

contribution. These supply increases more than compensate for expected conventional oil declines in North America and the North Sea. An increase in OPEC natural gas liquids (NGLs) is also expected over the medium-term, rising from 4.8 mb/d in 2010 to more than 6 mb/d in 2015. The required amount of OPEC crude will rise gradually, from 29.3 mb/d in 2010 to just over 31 mb/d by 2015.

…and long-term too, driven by more non-conventional oil

Over the long-term, increases in conventional oil supply from the Caspian and Brazil, as well as steady increases in non-conventional oil, mainly from biofuels, oil sands and shale oil, will more than compensate for expected decreases in mature regions. Total non-OPEC non-conventional oil supply thereby rises by more than 11 mb/d over the years 2010–2035. On top of this, total NGLs supply, from OPEC and non-OPEC, increases by 6 mb/d over the same period, from 10.5 mb/d in 2010 to almost 17 mb/d by 2035. The total increase of non-crude liquids supply will satisfy more than three quarters of the demand increase to 2035. Crude supply in the Reference Case only increases to 74 mb/d by 2025, and then stops rising. There is then no need for additional crude supply. Finally, OPEC crude supply in the Reference Case rises throughout the period to 2035, reaching just over 39 mb/d by 2035, including additional supply necessary for stocks. The share of OPEC crude in total supply by 2035 is 36%, not markedly different from current levels.

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



Scenarios underscore feasible alternatives to Reference Case

Beyond the Reference Case, it is important to explore developments that could feasibly emerge under realistic alternative assumptions to the drivers of supply and demand. Indeed, the question arises whether the Reference Case is a 'most-likely' scenario. In reality, it is not to be interpreted as such: it is essentially a 'dynamics-as-usual' world, but these dynamics are clearly subject to a variety of influences and bring with them a wide range of potential qualitative and quantitative impacts on supply and demand. These influences include technologies, particularly in transportation, policies, the environment and what evolves to combat the threat of climate change and perceived concerns over energy security.

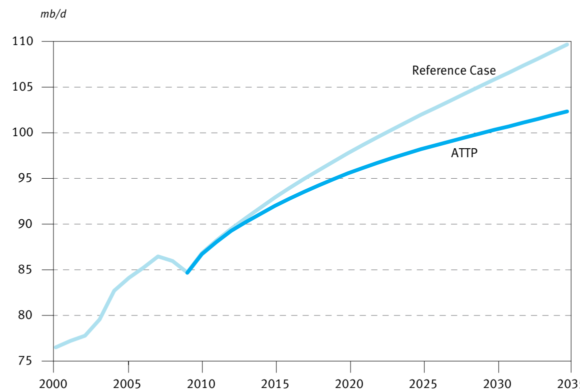
The Alternative Transportation Technologies and Policies scenario

An Accelerated Transportation Technology and Policy (ATTP) scenario has been developed. This assumes higher efficiency improvements to internal combustion engines; an accelerated shift to hybrids, and in some parts of the world, electric vehicles; a more rapid penetration in some regions of natural gas in the transportation sector; and an accelerated move to regulate efficiencies in commercial vehicles. It also includes a more aggressive support for alternative fuels, in particular biofuels, CTLs, biomass-to-liquids, gas-to-liquids and compressed natural gas and the assumption that international marine bunker regulations lead to more efficient fuel use in this sector.

Major impacts on OPEC investment requirements in ATTP scenario

In the ATTP Scenario, more than 7 mb/d is removed from global oil use by 2035, when volumes reach around 102 mb/d. Non-OPEC supply is 3 mb/d higher by 2035, compared to the Reference Case. Consequently, the call on OPEC crude by 2035 is a reduction of more than 10 mb/d when set alongside the Reference Case. Thus, in the ATTP scenario, there will effectively be little room for additional future OPEC crude supply. Indeed, by 2035, the amount of OPEC crude needed will be less than current levels. This means that OPEC upstream investment requirements are subject to huge uncertainties. While the Reference Case in 2025 sees upstream investment requirements of $480 billion (2010 prices), the ATTP scenario points to requirements of just $290 billion. This demonstrates the genuine concerns over security of demand. These estimates do not include investments required in the mid- and downstream industries of OPEC Member Countries.

World oil demand in the ATTP scenario



Future economic growth: important implications for oil demand

A further scenario in the WOO examines the global economy, documenting how uncertainties over economic growth, in the short-, medium- and long-term, have very important implications for the evolution of oil demand. This further complicates the challenge of making appropriate investment decisions along the oil supply chain. Uncertainties over economic growth have been brought to the fore by the recent Great Recession. Looking ahead, countries burdened by heavy government debt will be hampered in their growth prospects if fiscal consolidation is not properly managed. In addition, there are increasingly longer term questions being raised over economic growth rates in the face of a possible retreat of globalization. However, economic growth uncertainties could also point to upside potential as, for example, emerging markets are not as financially constrained as major OECD regions and may increasingly become the motor of world growth.

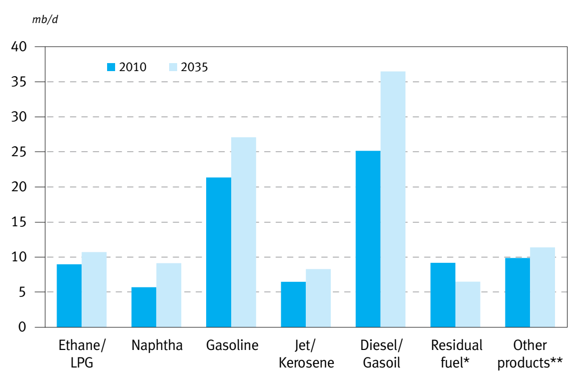
Higher and lower growth have major impacts upon demand for OPEC crude

Scenarios have been developed with both higher and lower economic growth rates of 0.5% p.a. In the lower growth scenario, oil demand by 2035 reaches slightly over 100 mb/d, or about 9 mb/d lower than in the Reference Case. Because of slightly softer oil prices, non-OPEC oil supply is about 2 mb/d lower than in the Reference Case by 2035. This means that the call on OPEC crude oil by 2035 is 7 mb/d lower than in the Reference Case. In this scenario, OPEC crude oil rises slowly, to around 32 mb/d by the mid-2020s, where it stays approximately constant. In the higher economic growth scenario, global oil demand inevitably rises more swiftly, to reach over 112 mb/d by 2030 and almost 119 mb/d by 2035. This further demonstrates the uncertainty over future oil demand due to economic growth, from both the upside and downside. Economic growth uncertainties are therefore probably at least as big a concern with regards to security of demand as the development of policies and technologies, especially over the short- to medium-term.

Middle distillates and light products will dominate product demand growth

Growth in the road transport sector, which is steering demand for gasoline and diesel, is projected to sustain the gasoline-diesel imbalance that has emerged in the past decade. This is clearly evident in the fact that, out of 23 mb/d of additional demand by 2035 compared to the 2010 level, around 57% is for middle distillates and another 40% is for gasoline and naphtha. For the remaining products, a decline in residual fuel is broadly offset by an increase in ethane/LPG and the group of 'other products'. A consequence of these demand trends is a progressive change in the make-up of the future product demand slate. Middle distillates will not only record the biggest volume

Global product demand, 2010 and 2035



* Includes refinery fuel oil.

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

increase, they will also raise their share in the overall slate from the current 36%, to 41% by 2035.

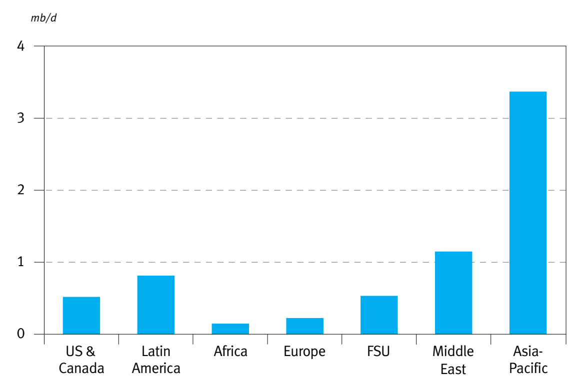
New regulations will further impact demand growth for diesel oil and gasoline

This year's WOO incorporates two new regulations that impact demand growth trends for both diesel oil and gasoline. The first is the European Commission's proposal for Council Directive amending Directive 2003/96/EC to change the taxation policy for refined products (including biofuels), which can be viewed as a signal to EU member states to reverse unwarranted tax advantages for diesel and to steer long-term demand patterns in a balanced and sustainable manner for the refining industry. The second, and the more important, is the adoption of more stringent regulations for marine bunkers by the International Maritime Organization (IMO). While the long-term effect of the first factor will mean a reduction in gasoil/diesel and an increase in gasoline demand over time, the expected effect of the IMO regulations more than offsets the diesel reduction, and leads to a net increase for this product.

New refining capacity moves to developing countries

Recent assessments indicate that around 6.8 mb/d of new crude distillation capacity will be added to the global refining system in the period to 2015. The highest portion of this new capacity is expected to materialize in the Asia-Pacific region, mainly in China and India, accounting for 50% of additional capacity, or 3.4 mb/d. While investments in refining capacity in the Asia-Pacific are predominantly driven by domestic demand, in the other two regions with the highest capacity additions to 2015, the Middle East and Latin America, the incentive is a combination of local demand and, given their increasing supplies of domestic heavier crude streams, the 'value added' benefits of refining 'at home'. Of the global 6.8 mb/d of new refining capacity by 2015, the world's developing regions will account for almost 5.5 mb/d. The scale of new refining capacity in developing countries stands in stark contrast to that assessed to come on stream in developed countries. North America and Europe combined, show an increase of 0.7 mb/d for the period to 2015 and this does not take into account any planned or potential capacity closures. In addition to crude distillation capacity, a relatively

Distillation capacity additions from existing projects 2011–2015

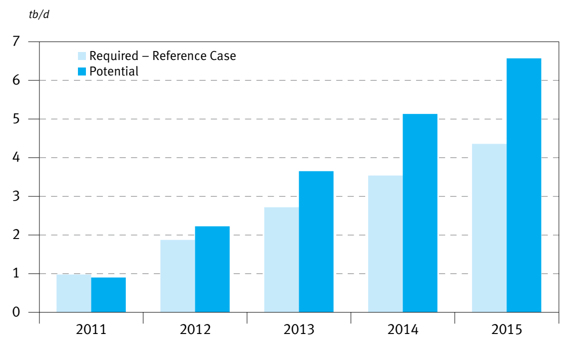


high proportion of secondary process units will be added to the global refining system in the medium-term. Additions to conversion units are estimated at 4.4 mb/d, driven by strong demand for light products, especially middle distillates. Desulphurization capacity additions exceed those for new distillation capacity, reflecting the continued worldwide trend to low and ultra-low sulphur fuels.

Crude distillation capacity additions are projected to exceed requirements in the medium-term

The net effect of assessed 'firm' projects is that excess refinery capacity is anticipated to grow by 2.5 mb/d by 2015 compared to current levels, assuming no refinery closures. This reinforces the expectation of a challenging period for the industry, with lower refinery utilizations and weak margins. Moreover, strong regional differences will apply, notably between the continuing growth requirements in non-OECD regions, especially Asia, and surpluses in the US, Europe and Japan.

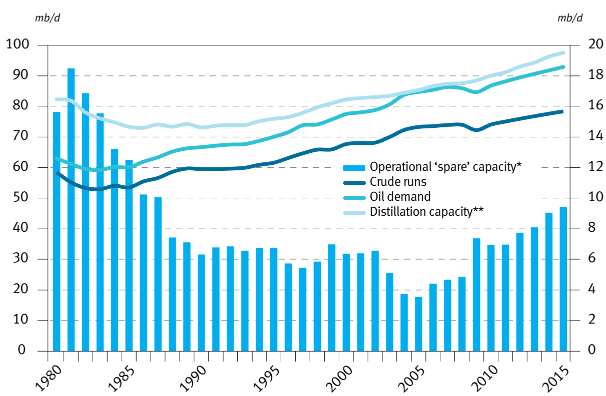
Additional cumulative refinery crude runs required and potential*



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

Effective refining 'spare capacity' approaching the level of 10 mb/d by 2015

Global oil demand, refining capacity and crude runs 1980–2015



* Effective 'spare' capacity estimated based on 90% utilization rate.
** Subject to any capacity closure after 2010.

In 2009, the oil demand collapse, combined with refinery capacity additions, led to substantially lower throughputs. This shifted effective 'spare capacity' in the global refining system to a level of more than 7 mb/d. Accounting for new projects coming on stream, the overall refining surplus could approach 10 mb/d by 2015, unless some capacity is closed. Thus, today's refinery projects – and those assessed to come on stream in the next few years – potentially represent a substantial proportion of the total additions needed over the next 10-to-15 years.

Capacity rationalization in the refining sector appears inevitable

The medium-term outlook for the downstream sector indicates sustained pressure for capacity rationalization, especially in OECD regions. The US and Europe are home to the largest capacity overhangs. In Europe, only a few facilities have been formally shut, with a total capacity of around 500,000 b/d. The prevailing trend has been to sell refineries or undertake extended maintenance and temporary shutdowns. In the US, a combination of expanding local crude production, healthy margins due to wide West Texas Intermediate differentials and rising export opportunities, could act to support capacity, leading to only minor closures in the US over the next few years. The one country where closures currently look set to occur at scale is Japan, where up to 1 mb/d of distillation capacity could eventually be closed by 2015. China is another case where legislation is likely to have an impact. However, this is related to the goal of eliminating the country's small refineries with capacities below 40,000 b/d. The elimination of very small refineries could also take place in Russia.

Declining crude share leaves little room for further refining expansion in the long-term

It is significant that, beyond the 6.8 mb/d of known projects expected to be on stream by 2015, the Reference Case outlook shows that only an additional 10.5 mb/d of cumulative additions will be needed by 2035. In the subsequent five-year periods after 2015, the required level of capacity additions averages only around 0.4–0.5 mb/d p.a. The underlying reason for this trend is that non-crude supplies increase faster than demand, and thus, as a proportion of total supply. It means that less incremental refining capacity is needed per barrel of incremental liquids demand. Indeed, by 2035, it is

Global demand growth and refinery distillation capacity additions by period *mb/d*

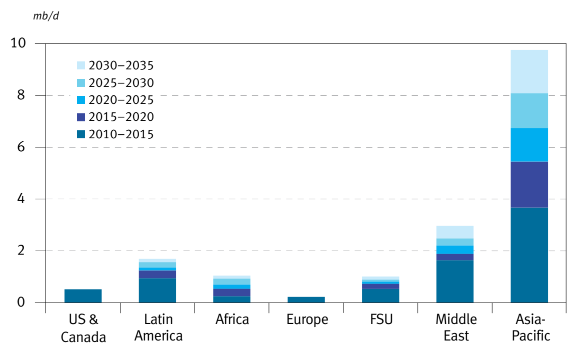
	Global demand growth	Distillation capacity additions			
		Known projects	New units	Total	Annualized
2010–2015	6.1	6.8	1.0	7.8	1.6
2015–2020	4.9	0.0	2.8	2.8	0.6
2020–2025	4.2	0.0	2.0	2.0	0.4
2025–2030	3.9	0.0	2.1	2.1	0.4
2030–2035	3.8	0.0	2.5	2.5	0.5

expected that the total supply of around 110 mb/d will be met by close to 82 mb/d of crude-based supplies and 27 mb/d of non-crudes (including processing gains).

Asia-Pacific will dominate long-term future capacity additions

The vast majority of required refining capacity expansions to 2035 are projected for the Asia-Pacific and Middle East regions, 9.8 and 3 mb/d respectively, from a global total of 17.2 mb/d. Growth in the Asia-Pacific is dominated by China and India. In Latin America, projected capacity additions of 1.7 mb/d by 2035 exceed the estimated moderate demand growth of 1.3 mb/d for the same period. Capacity requirements in Africa and the FSU region are in the range of 1 mb/d. The outlook in these regions differs markedly to that for industrialized countries, which beyond projects already under construction, see virtually no capacity expansion.

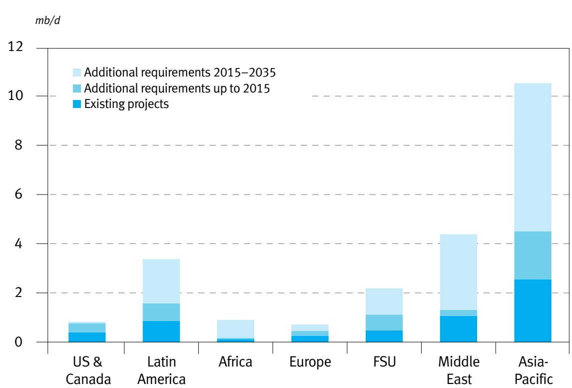
Crude distillation capacity additions in the Reference Case by period, 2010–2035



Growing importance of hydro-cracking units

Recent projections highlight a sustained need for incremental hydro-cracking, some 10 mb/d out of the 14 mb/d of global conversion capacity requirements by 2035. The need to keep investing in additional hydro-cracking capacity, with its high process energy and hydrogen costs, is expected to help support future wide distillate margins relative to crude oil and other light products. In contrast, recent substantial coking capacity additions, together with limited medium-term exports of heavy sour crudes, has led to a coking surplus, which is expected to further expand as new projects come on stream. Therefore, between 2015 and 2035, less than 1 mb/d of further coking additions are projected. The outlook for

Global capacity requirements by process type, 2010–2035



catalytic cracking is similar. It is adversely impacted by relatively slow gasoline demand growth and rising ethanol supply in the Atlantic Basin. Moreover, total conversion additions of close to 10 mb/d, above projects currently being developed, are almost 100% of distillation capacity additions. This reflects the need to increase the production of light products for every barrel of crude processed. Substantial desulphurization capacity additions will also be necessary to meet sulphur content specifications, as non-OECD regions, in particular, move progressively towards low and ultra-low sulphur standards for domestic fuels – often following the Euro III/IV/V standards. In addition, these regions can be expected to use this new capacity for exports to countries that already have advanced ultra-low sulphur standards. Over and above existing projects of 5.8 mb/d, a further 4.2 mb/d is projected to be needed by 2015, and some 13 mb/d from 2015–2035.

Oil trade continues to expand

Oil trade between the 18 model regions of the WOO's downstream outlook is set to grow over the entire forecast period. It will increase by around 4 mb/d in the period to 2015, compared to 2010 levels. Between 2015 and 2035, total oil movements are projected to increase by more than 8 mb/d, reaching a level close to 70 mb/d by 2035. Moreover, product exports will grow faster than those for crude oil. Steady increases in global crude oil exports are a result of varying trends at the regional level. The most obvious is the expanding importance of the Middle East as the key crude exporting region in the decades ahead. The largest increase in inter-regional movements relates to crude oil exports from the Middle East to the Asia-Pacific; an increase of 7 mb/d from 2010–2035. In relative terms, however, Russia and the Caspian countries will more than triple their crude exports to the Asia-Pacific, as new pipelines to China and Russia's Far East become operational. And at the same time, exports to Europe are significantly reduced. Similarly, Africa will almost double its crude exports to the Asia-Pacific by 2035.

Uncertainties surround refining investments

Substantial capital investments are required to expand and provide maintenance to the global refining system. In the period to 2035, investments are estimated at around \$1.2 trillion in the Reference Case, of which \$210 billion is for existing projects, \$300 billion for required additions and close to \$700 billion for maintenance and replacement. This excludes related infrastructure investments beyond the refinery gate, such as port facilities, storage and pipelines. These investments are, however, subject to a number of uncertainties. A refining sector that is being squeezed by the rising supply of non-crudes, could become even more pressured by further liquids supply growth, notably from NGLs, given the emergence of shale gas. In addition, biofuels represent a further 'wildcard', especially if second and third generation biofuels evolve faster than expected. On the demand side, while non-OECD demand looks robust, transportation efficiency measures in industrialized regions could lead to steeper declines there, and policy measures could reshape the demand slate. And, if the crude price to natural gas price ratio remains wide enough, liquefied natural gas could become an attractive option for marine fuels replacement, especially longer term, and on new build ships. Moreover, there are the uncertainties surrounding possible capacity shutdowns. This suggests a cautious approach should be adopted with respect to future refining investment decisions.

Adverse impacts of climate change mitigation response measures

No agreement has yet been reached in identifying a long-term goal for greenhouse gas (GHG) emissions reduction. Nevertheless, much work has been undertaken to explore implications of limiting the global average temperature to a rise of less than 2°C above pre-industrial levels, and corresponding atmospheric GHG concentrations. Although there is uncertainty over the fundamental relationship between GHG concentrations and temperature rises, it is clear that mitigation response measures could lead to large oil demand reductions, relative to the Reference Case. An important issue is the type of policies and measures that are undertaken to satisfy a given GHG emission limitation/reduction path. The other important question is how the loss in oil demand would be shared between OPEC and non-OPEC in terms of lower supply and the effect on the oil price. Under all circumstances, the implications for net OPEC crude oil export revenues would be substantial. Revenue per head in OPEC Member Countries would continuously fall. They would also be lower than historical levels. Other adverse impact channels include lower domestic demand and GDP, more expensive imports, increased financing costs, job losses and lower competitiveness. The importance of such adverse effects, actual and potential, on all developing countries, particularly those identified in Article 4, paragraph 8, of the Convention, suggests an urgent need to establish a permanent forum on response measures under the Conference of the Parties to the UNFCCC.

The importance of alleviating energy poverty

Figures from the United Nations show that 1.4 billion people have no access to electricity and some 2.7 billion rely on biomass for their basic needs. Moreover, according to the World Health Organization, relying on biomass means 1.45 million premature deaths per year, most of them children, a death toll greater than that caused by malaria or tuberculosis. It is essential that the world effectively tackles the issue of energy poverty, as a means of achieving the Millennium Development Goal (MDG) of halving the proportion of people in poverty by 2015. Sustainable development is a high priority agenda item for OPEC Member Countries. It is also the main objective of the assistance they provide to other developing countries, directly through their own aid institutions, as well as through the OPEC Fund for International Development. In total, they have provided close to $350 billion (in 2007 prices) in development assistance to other developing countries in the period 1973–2010. This amounts to nearly $10 billion a year. A significant portion of this amount, $69 billion, has been devoted to energy related projects, covering a diverse portfolio of energy sources that includes financial support to renewable energy sources. Rio+20 next year is a great opportunity to take stock, particularly in terms of the MDGs, and to define improved processes, structures and means for achieving sustainable development.

The crucial importance of human resources

The future availability of qualified technical talent remains a major challenge facing the oil industry. The Great Recession has had a significant impact in terms of job losses and a lack of job creation. However, the origins of this talent shortfall lie back in the 1980s and 1990s. It was then that the oil and gas industry saw a wave of cost cutting and redundancies, as a result of which many technical people who were then entering their mid-career left the industry for good. The industry will need more qualified people in the years ahead. It begs the question: how can the industry find, hire, train and keep talented people? The industry needs to be made more attractive; to make it accepted as an inclusive and forward looking workplace. A related issue is that of local content. This is of particular relevance to many oil and gas producing developing countries. Local content is crucial role as it can, and should, provide a strong platform for a country's economic and social development.

Energy and water: a much neglected issue

An oft neglected aspect of the energy industry is the impact that production activity can have upon water resources. Competition for this precious resource, not just in the energy sector, but also among other industries, such as agriculture, as well as from communities, is becoming increasingly visible. Processes can have effects upon the availability of water, as well as the potential contamination of supplies. It is important, therefore, to be aware of the crucial water-related challenges that lie ahead in the energy sector. For transportation fuels, it is worth noting that all alternatives to oil, when produced from conventional sources, use substantially more water in their production processes, with the exception of natural gas. It is also well known that production from oil sands involves substantial amounts of water, and more recently, emerging trends in the production of both shale gas and shale oil has drawn attention to their possible impact on water supplies. A major question for these industries will be to what extent, and how rapidly, the use of water, in terms of volumes consumed, and in potentially compromising water quality through pollution side-effects, will eventually have to be factored into cost estimates.

Dialogue and cooperation continue to support market stability

In a world of growing interdependence, the importance of dialogue is widely acknowledged. This is underscored in OPEC's Long-Term Strategy and the 'Riyadh Declaration', which concluded the Third OPEC Summit in November 2007. OPEC has also been broadening and strengthening its dialogue with consuming and producing countries, as well as other international institutions. The issues at stake are complex, broad and inter-related. They require concerted efforts and, where appropriate, joint collaboration, to find adequate, cooperative and sustainable solutions. Close engagement with major stakeholders at various levels is essential to advance mutual understanding on common challenges, such as security of supply and demand, investments, cleaner fossil fuel technologies, environmental protection, the role of petroleum in promoting sustainable development and energy poverty. Expanded, in-depth dialogue, builds confidence, aids long-term market stability, and can attend to the concerns of both producers and consumers, particularly at times of high volatility in markets.

Section One

Oil supply and demand outlook to 2035

Chapter 1

World oil trends: overview of the Reference Case

Main assumptions

Oil price

In last year's World Oil Outlook (WOO), the nominal OPEC Reference Basket (ORB) price assumption to 2020 in the Reference Case was $75–85/b. This was slightly higher than the range of prices that had been observed over the period that led up to the publication of the WOO 2010 (see Figure 1.1). Nominal prices in last year's report rose to $106/b by 2030.

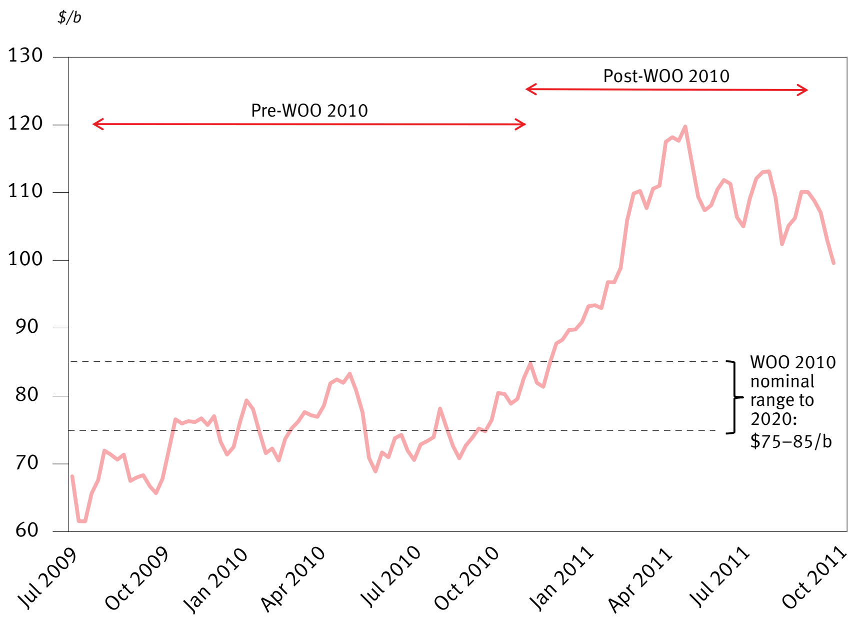
This year, however, a revision to these assumptions is warranted. This is explained by a number of factors:

- The behaviour of prices since the publication of the WOO 2010;
- Signals from the futures price;
- A reassessment of how upstream costs might evolve;
- Continued attention being paid to how environmental concerns may eventually impose additional costs on oil;
- Emerging views of a weakening linkage between oil prices and the economy/oil demand;
- Impacts of dollar exchange rate movements; and
- Revised budget requirements in OPEC Member Countries.

The average daily ORB price has moved in the range of around $80 to over $120/b since publication of the WOO 2010. This on its own points to the probable need for higher assumptions to 2020 than last year's $75–85/b. The ORB's continuous upward movement was driven in part by positive macroeconomic data and some supply concerns. In addition, speculation was also a driving force in the price rise, with increasing investor interest in the crude oil paper market, particularly in Intercontinental Exchange (ICE) Brent contracts, also playing a part.

Speculator activity on the Nymex surged to record highs in the first quarter of 2011. For example, by mid-March, open interest for the Nymex West Texas Intermediate (WTI) exceeded the unprecedented level of 1.5 million futures contracts, which is 18 times higher than the amount of daily traded physical crude. A risk premium has

Figure 1.1
OPEC Reference Basket prices since WOO 2009



been embedded in the prices seen throughout much of 2011, partly reflecting such concerns. As such, the most recent behaviour of prices should not directly feed into assumptions for prices over the medium- and long-term. It is worth noting that regulatory reforms are moving ahead to address issues related to the impact of speculative activity (Box 1.1). Moreover, since ORB prices peaked above $120/b in April, prices have gradually fallen to lower levels, below $100/b in October.

It would be inappropriate to place too much emphasis on recent price patterns as a signal for where long-term sustainable prices might settle. As noted, speculation has exaggerated price movements, and this was particularly evident in 2008, when the ORB peaked at $141/b in July, before falling to $33/b by the end of that year. The wild swings of this period were clearly mostly driven by non-fundamentals, although the downward pressures on prices at that time were also affected by fundamentals, as seen in the fact that OPEC had to cut its supply.

A more technical approach than using current price behaviour as an indicator of possible future trends, at least for the short-term, is the behaviour of the futures price. The March 2011 OPEC Monthly Oil Market Report (MOMR), for example,

Box 1.1
Regulatory reform in the energy derivative markets

The push to reform energy market regulation continues, as part of a larger international effort to overhaul the financial regulatory framework. Following the upheaval caused by the financial crisis of 2008, as well as the spike in commodity prices that preceded it, the need to update the regulatory framework has been recognized by policymakers at the highest levels. Indeed, markets have evolved significantly over the last few decades and the recent financial crisis has underscored the fact that financial regulation and financial innovation need to move in tandem. This represents a strong shift in the general 'deregulatory' approach that has dominated market oversight since the 1980s.

In principle, current initiatives seek to give regulators the necessary mandate and tools to adequately monitor and regulate the market to ensure that the principal market functions of price discovery and risk transfer are not distorted by manipulation or excessive speculation. At the same time, policymakers have recognized the importance of proceeding carefully and avoiding any adverse, unintended consequences, such as reduced market liquidity for *bona fide* hedging. Broadly speaking, these efforts can be seen to target three general areas in the commodity futures markets: data transparency; speculative position limits; and over-the-counter (OTC) derivatives.

Data transparency

Efforts in this area focus on providing expanded, more timely and more granular data. This is evident in the improved data transparency for the Nymex WTI contract, published on a weekly basis by the Commodity Futures Trading Commission (CFTC), the US regulator, which allows for a more detailed picture of the impact of speculative activity on crude oil prices.

Prior to 2009, data on trader activity on the Nymex was divided into commercial and non-commercial categories. In an effort to improve transparency, the CFTC began publishing disaggregated data divided into four more focused categories: producers and end-users; swap dealers, primarily banks and financial firms; managed money, primarily hedge funds; and other reportables, which was everyone else, including proprietary traders, such as traditional speculators and high frequency traders. Of these, the category of managed money is generally used as a proxy to gauge the extent of speculative activity in the market.

More recently, the ICE has begun to publish data on speculative activity for the ICE Brent contract. As data only goes back to 7 June 2011, however, arriving at a better understanding of the impact of speculative activity on the Brent market will take some time. Nonetheless, making the data available to the market represents an important step forward. While the new reporting of Brent data is modelled on the CFTC categories, it is being published by the ICE, rather than the Financial Services Authority, the UK's financial regulator.

These transparency improvements are important for the price discovery process, as they more clearly show periods when the inflow or outflow of speculative funds is impacting prices. Efforts to collect and publish data on OTC derivatives trading activity should also help to develop a better understanding of their impact on commodity price behaviour, including that of crude oil.

Speculative position limits

The initiative to establish position limits on the major exchanges has proved to be more challenging. The US has already released its proposal that would establish speculative limits on commodity futures contracts and eventually on similar swap derivative contracts. In addition to crude, other commodity future contracts included would be gasoline, heating oil and natural gas, as well as some precious metals and agricultural commodities. However, implementation has been postponed until the end of this year.

In addition to the US, the EU is considering some form of position limits, but such a move is far from certain. So far, the ICE has stated that it would voluntarily set position limits on the ICE gasoil contract, although no implementation date has been set thus far.

The argument in favour of speculative position limits is clear. Speculation can play a positive market role, providing liquidity when producer and consumer hedging demands are not equal or when the timing of producer and consumer hedging demands do not match. Nevertheless, recent events have shown that excessive speculation can cause prices to detach from fundamentals, distorting the essential price discovery function of the market and potentially leading to the wide price swings as witnessed in 2008.

Over-the-counter derivatives

Efforts to regulate the OTC market represents a huge and challenging undertaking. According to the CFTC, the notional value of swap derivatives in the US alone is $300 trillion, which represents $20 for every dollar in the US economy. Globally, the OTC market has a notional value of some $600 trillion dollars. In addition to commodities, the OTC market also includes derivatives for foreign exchange and interest rates, which many companies use in the course of their regular international business, and credit default swaps. At $2.8 trillion, commodity derivatives represent only a relatively small part of this total figure, although it is still a considerable amount relative to the amount invested in exchange traded commodities and indices, which is estimated to have totalled $310 billion in 2010.

Essentially, regulators are focusing on the establishment of standardized contracts, clearing houses, trade repositories, and exchange and electronic platforms for derivative trading, as well as the associated regulations and reporting requirements. The overall political direction for reforming the OTC markets is being set at the G-20 level, with leaders committing to establish greater standardization and the central clearing of OTC contracts by the end of 2012.[1]

noted that there was "bullish sentiment for future prices, because of political tensions and their eventual impact on supply in the future". However, while this may inform assumptions that need to be made for the immediate future, it becomes a less reliable guide for making longer term ones.

Instead, the longer term oil price assumption should be couched in terms of an assessment of marginal costs. This is the approach that has been adopted in earlier WOOs. However, establishing what the cost of the marginal barrel might be, and therefore what might be a sustainable long-term price, is hampered by many uncertainties, including a lack of data.

Various cost-related issues lead to signals about what might be considered a sustainable long-term oil price assumption (Box 1.2). It also helps to shape debate over why assumptions for oil prices might differ between institutions. Typically, there are differences of view over the responsiveness of both demand and supply to oil prices. While there is general agreement on the low price responsiveness in moderate price ranges, high oil prices could make large amounts of non-OPEC supply economic, both conventional and non-conventional.

There are also significant doubts over the sustainability of very high prices from the demand perspective, particularly because of impacts on the economy and through efficiency and substitution effects. Looking at the possible impacts upon the economy, it is clear that the Reference Case oil price assumption must be consistent with economic growth assumptions. For internal consistency, it is important to avoid prices that might hamper such growth assumptions. However, it is recognized that oil prices

Box 1.2
Costs and long-term price assumptions

One commonly used indicator of future costs separates the estimated range of costs by resource type. This considers the costs of conventional oil supply in various world regions, as well as the estimated costs of non-conventional oil, such as oil shales, gas-to-liquids (GTLs) and coal-to-liquids (CTLs). The range of costs portrayed suggests that long-term real price assumptions from the WOO 2010 could be considered low.[2] However, such cost curves also show that, at high prices, vast amounts of non-conventional oil would become economic. Thus, the use of such a curve to inform the debate on relevant marginal costs also questions the use of 'too high' price assumptions.

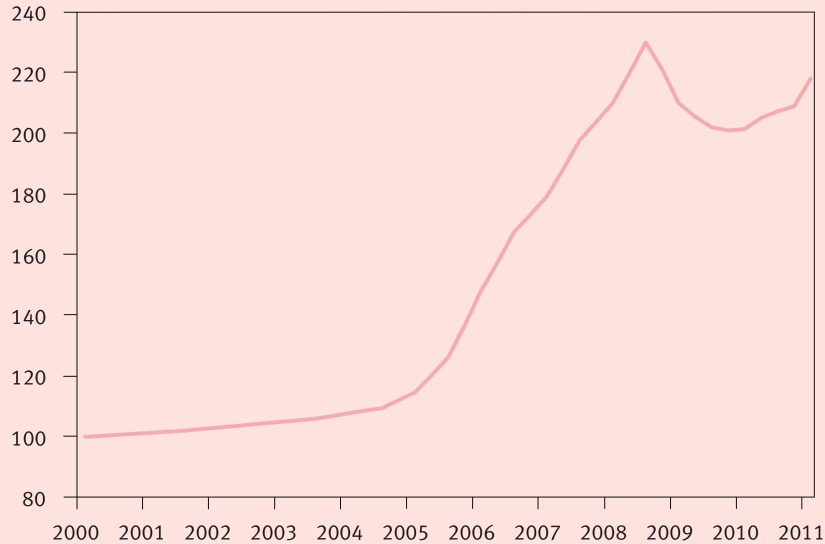
It should also be noted that the usefulness of the estimated supply cost curve is limited, as it does not provide an insight into how future costs might evolve: the outcome of the opposing forces of resource depletion and technol ogical development is a constant source of debate, due to the fact that it is unobservable. However, for non-conventional supplies – with resource depletion less of a constraint – it would be expected that costs would gradually fall. And the cost curve demonstrates that, at real prices around $110/b, practically the entire non-conventional resource base is already economic in terms of long-term supply.

What is observable is the past behaviour of costs and it is important to try to understand from these trends where costs might be heading. Figures in this Box show the development of the IHS CERA Upstream Capital Cost Index. From 2000 to 2008, third quarter costs increased by 130%. After that quarter, as the Great Recession took hold and both oil prices and oil demand were negatively affected, costs began to fall. However, costs bottomed out towards the end of 2009.

This cost behaviour reflects both structural and cyclical drivers. The structural upward pressures are known to stem largely from the move towards supplying oil from increasingly hostile environments, the expanding distances between sources of supply and markets, and geological challenges. On the other hand, cost increases were also affected by cyclical pressures, such as capacity and labour shortages and steel price behaviour, in particular in the context of surging global economic growth. The retreat of costs reflects the easing of these cyclical effects.[3]

IHS CERA's most recent data shows that costs have begun to rise once more, as oil supply activity picks up during the economic recovery. It has been suggested that regulations put in force following the Deepwater Horizon drilling rig explosion in

IHS CERA upstream capital cost index (UCCI), 2000=100



Source: IHS CERA.

the Gulf of Mexico have contributed to this rise,[4] but it is questionable whether this will have a lasting impact upon industry costs.[5]

There are other thorny issues to address when using costs as the basis for oil price assumptions. For example, how fiscal policy develops in host countries can significantly affect the cost of the marginal barrel. Moreover, the potential longer term introduction of environmental costs is a further complication. The Reference Case does not include global costs associated with attaching a price to greenhouse gas (GHG) emissions in upstream operations. Nonetheless, if these possibilities are factored into projections, then costs would clearly rise, which ultimately means that the economics of the marginal barrel could lead to an expectation for long-term rising prices. It should be noted, however, that if a strict GHG mitigation regime were to emerge – one which attached additional costs to upstream and downstream operations – then this would typically have a negative impact upon future demand and supply growth, and, in all probability, upon oil prices and costs. Thus, the net impact on the environment of the cost of the marginal barrel could be viewed as ambiguous.

Other uncertainties over the future behaviour of costs include: the future availability of a skilled labour force, and consequently, labour costs; the behaviour of non-energy commodity prices, especially cement and steel, which account on average for close to half of upstream costs;[6] the nature of the relationship between prices and costs, for example, higher prices encourage activity in higher cost areas, but this is not necessarily indicative of a change in cost structure;[7] and the rate and nature of technological progress.

All this shows that marginal cost estimates might provide an imperfect signal for long-term price paths. This route nevertheless remains a key element in making sensible assumptions for sustainable long-term prices. There could be many plausible outcomes of the conflicting pressures between technology and depletion; however, the available evidence of both current cost structures and the ability of technology to bring costs down, especially for non-conventional resources, as well as to expand the resource base, continues to be a key driver in the assessment of Reference Case oil price assumptions.

now have a far lower impact upon the global economy than in the past, given that today less oil is now used to generate each dollar of gross domestic product (GDP). For example, over the three decades between 1980 and 2010, OECD oil intensity fell by 49%, while in developing countries it fell by 30%. Research into the past impacts of oil prices on economic growth also suggests that monetary policy responses at the time of earlier price spikes were responsible for much of the growth slowdown.[8] Moreover, there is growing recognition that high oil prices have had little impact upon the economy and the recent recession.

It has also become accepted that oil price movements have relatively low direct impacts – though not zero – upon oil demand: high tax levels; exhausted options for substitution away from oil; and, low price elasticities in the transportation sector are key factors in this regard. However, there is also the often neglected impact of large price changes upon demand. This driver can be described as the asymmetric price elasticity of oil demand, since price increases affect demand differently to price falls, but it is also the result of non-linear elasticity. Thus, this poses an additional technical limit to how high oil prices can be assumed to go in the Reference Case.

Attention has also been paid to the impact of the dollar on prices. It is true that there has been a substantial weakening of the dollar in recent years. In January 2003, the €/$ rate averaged 0.94, but this had fallen to 0.68 by January 2008, a depreciation of close to one-third. This is one factor behind the gradual upward revision to oil prices that has been underway in recent years. Nevertheless, there is no reason to attribute the change in price behaviour since the release of the last WOO to changes in the strength of the dollar: in November 2010, when the WOO 2010 was released, the €/$ rate averaged 0.73, similar to the rate of 0.70 in July 2011.

Finally, changing fiscal needs in OPEC Member Countries could be seen as an influence in the development of Reference Case oil price assumptions. Recent analysis has suggested that the price assumption in the WOO 2010 is now below the fiscal breakeven price in many OPEC countries.[9]

In conclusion, the 2011 Reference Case oil price assumption is raised from its previous levels, but only moderately. It is assumed that the ORB price, in nominal terms, eventually settles in the range of $85–95/b for this decade, but rises over the long-term to reach $133/b by 2035.

Medium-term economic growth

Following the sub-prime crisis in the US and the collapse of Lehman Brothers in 2008, the global financial system appeared on the brink of meltdown. While the world was able to draw back from the precipice, high levels of sovereign debt have since triggered significant austerity measures in developed countries and brought about the threat of default. The current situation, particularly in the euro-zone and the US, may trigger further austerity measures that could curb growth in the medium-term in much of the developed world.

While developing countries have seen growth return to healthy rates, they too are facing some uncertainties. The biggest short-term uncertainty appears to be the result of their high dependency on exports to developed economies. Moreover, there have recently been significant increases in inflation with measures already being introduced in several emerging economies to combat this. This may lead to a slowdown in their economic expansion.

Thus, globally, the economic recovery remains very fragile (Box 1.3). In fact, risks have even increased recently. In the Reference Case, however, it is assumed that decisive action is taken in a timely manner to make sure the global economy remains on the path of recovery.

Notwithstanding the recognition of the fragility of the economy, in the short-term, a major change compared to the WOO 2010 is a more rapid recovery from the Great Recession, with global growth in 2010 now estimated to have been 4.7%, compared to the 3.9% assumed previously. There is even a slightly more optimistic view for global growth in 2011, now assumed to be 3.9%, compared to 3.7% in last year's WOO.[10] As noted, however, there are significant downside risks.

Box 1.3
Economic recovery: sustainable at current rates?

The global economic recovery is increasingly showing signs of weakness and it is essential to better understand where the economy might be heading. Two possible developments seem likely from here. The first is that the global economy will be marked by a low and below average trend growth, in combination with high unemployment rates in developed economies and continuing global growth imbalances. And the second is the potential failure of the current support schemes and mechanisms, which would shock the global economy, possibly pushing it back into recession. At the time of publication, this seems the less likely scenario, but it cannot be ruled out.

In general, there appear to be three main areas of concern and these will be major determinants impacting the medium-term path of the global economy.

The first, and perhaps most pressing issue, is the euro-zone crisis. While Greece's complete default has so far been avoided, sovereign debt issues remain at the heart of the euro-zone's worries. A number of other countries, many bigger, have become potential candidates for support, and many peripheral countries still face serious challenges. It appears that the euro-zone has been pushed to the edge in its ability to finance further sovereign debt fall-outs.

It seems likely that, if any one of the bigger economies within the euro-zone saw their situation worsen then the repercussions could be severe as the sovereign debt holdings of the European banking sector are considerable. A write-down could push the banking sector into serious difficulties, triggering the need for further emergency measures, which, given the state of EU economies, would be extremely difficult to finance. Research has also shown that a banking crisis scenario often leads to a debt crisis, followed by sovereign defaults.[11] To date, the latter has been avoided through various extraordinary means, but given that the measures pursued have not resolved the sovereign debt issues, the possibility of such a default remains.

The second major issue is that of the US economy. While the country's sovereign debt situation is proving to be a challenge for policymakers, the US' financial ability and the greater flexibility of the Federal Reserve Board, compared to its European counterpart, appears to offer ways to manage this more easily than in Europe. However, more important to the global economy is the relatively muted recovery in private household demand. Given that US households are responsible for more than one eighth of global GDP, it is easy to appreciate its importance. In addition to this, there is the dominance of the US-dollar as the global reserve currency and the still preeminent role of the US financial system. A failure of the US economy would have a major global impact.

After the economic crisis of 2008 and 2009, the recovery in US consumer consumption was greatly supported by government-led stimulus. However, the recovery has recently decelerated considerably after the fiscal stimulus ended and after the major 'extraordinary' monetary supply measures came to an end. Moreover, the troubling US labour market situation shows few signs of improving. It is obvious that government-financed consumption cannot continue indefinitely and that the underlying economy needs to improve in order to stand on its own feet, but there is no clear answer as to whether the US economy is actually in a position to do so. However, it currently seems unlikely that this important motor of global growth will accelerate away at any time soon.

The third major issue is the recent slow-down in developing countries, particularly the deceleration in China and India. While the global stimulus and the measures undertaken by these countries themselves have had a highly positive effect on their growth rates, these economies remain largely dependent on either capital inflows from, or exports to, developed countries. It is evident too that they have been relatively successful in building-up domestic markets and stimulating greater local demand, but they are still too weak to absorb all the capacity established in recent years. Developing countries have also recently observed significant increases in inflation that have forced them to initiate provisions to avoid their economies overheating. This has had a dampening effect on their growth rates, and it is expected that it will continue to do so. However, these countries can be expected to be a major factor supporting future global economic growth.

In summary, it is evident that sovereign intervention, in terms of stimulus packages and monetary policy, has been the main driving force behind the recovery since the financial crisis began. And this remains true today. Thus, the recovery cannot be deemed to be self-sustaining at this point in time. It is perhaps important to ask a follow up to this: is it at least sustaining? In the main, this is expected to depend on the ability of governments to continue their various support measures for as long as it takes to solve the economic issues. This can be expected to take a number of years and therefore the current best assumed outcome is a below average global growth scenario, similar to the situation at the end of 2011, as reflected in the Reference Case medium-term assumptions in Table 1.1. If the economic situation worsens post-2011, however, then this may need to be further reassessed. Although this appears unlikely at present, it cannot be ruled out entirely.

The medium-term economic growth rates for the Reference Case appear in Table 1.1. These are largely unchanged from WOO 2010 assumptions. The growth rates for Western Europe over the medium-term have been adjusted downwards slightly to reflect the financial difficulties being felt by some countries in the region. Average global growth over the period 2010–2015 is 3.9% per annum (p.a.). Average OECD growth is assumed to settle at just over 2% p.a., with the strongest expansion in North America. Growth in developing countries remains considerably stronger, especially in Asia.

Chinese growth, although gradually easing, remains above 8% p.a. One of the considerations in developing the Reference Case has been the extent to which China's 12th Five Year Plan (FYP) should be factored into assumptions. The Plan includes a reduced target for GDP growth, down to 7% p.a., compared to the 7.5% target in the previous Plan. There are also moves to balance the economy, with *inter alia*, the service sector targeted to increase its GDP share, consumer demand to be expanded, and income distribution to become more even. It is thought that the lower growth target is designed to be consistent with the structural targets, with an emphasis upon the 'quality' of growth rather than the 'quantity'.

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

	2012	2013	2014	2015
North America	2.9	2.5	2.5	2.5
Western Europe	1.9	1.8	1.8	1.8
OECD Pacific	2.9	1.9	1.9	1.8
OECD	**2.5**	**2.1**	**2.1**	**2.1**
Latin America	4.1	3.7	3.5	3.5
Middle East & Africa	3.7	3.6	3.6	3.4
South Asia	7.0	6.5	6.3	6.1
Southeast Asia	5.0	4.2	3.9	3.9
China	8.5	8.5	8.4	8.2
OPEC	4.7	3.7	3.7	3.7
Developing countries	**6.2**	**5.9**	**5.8**	**5.7**
Russia	4.5	3.8	3.4	3.2
Other transition economies	3.8	3.4	3.1	3.1
Transition economies	**4.2**	**3.6**	**3.3**	**3.2**
World	**4.1**	**3.8**	**3.8**	**3.7**

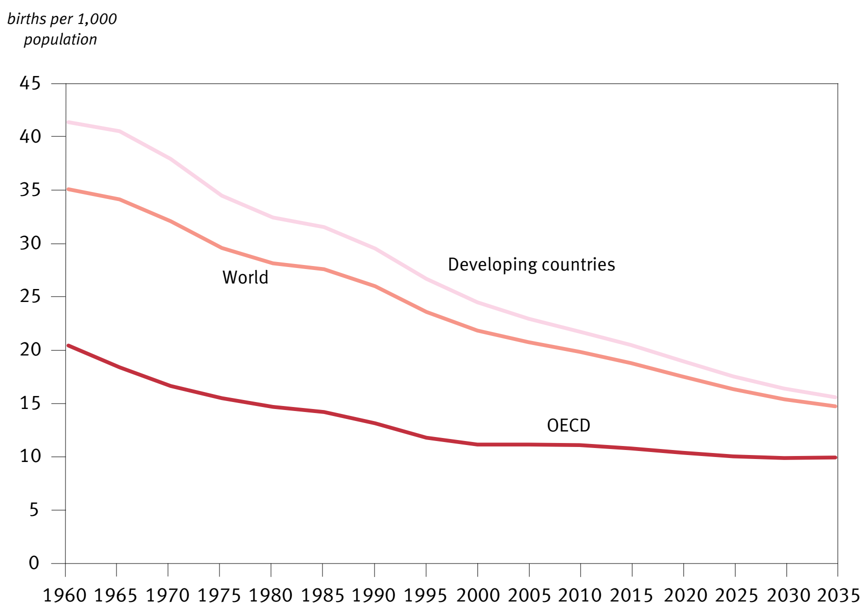
Although these reduced growth targets are ambitious in the degree to which they imply a 'cooling' of the economy, they effectively reflect the more conservative view of China's GDP growth that had already been incorporated into the WOO 2010 Reference Case. This had seen the medium-term rate of expansion fall from what was deemed unsustainably high rates. Moreover, the 7.5% GDP growth targeted for the 11th FYP was not met between 2006 and 2011 as the Chinese economy actually expanded by an average of 10.5% p.a. Consequently, no further adjustment has been made to Chinese medium-term growth, compared to the assumptions in the WOO 2010.

Long-term economic growth

Demographics

This year's extension of the timeframe to 2035 means that the impacts of population dynamics are even more pronounced, especially in terms of their implications for economic growth and energy demand trends. This applies to the slowing of

Figure 1.2
Crude birth rates



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

population growth, or even a contraction in some regions, as well as rising urbanization and an ageing population.

Population growth rates have been declining historically and this is set to continue. OECD population increased by an average of 1% p.a. in the 1970s, but this had fallen to 0.5% p.a. by 2010. In developing countries, average growth has been higher, at 2.5% p.a. in the early 1970s, but this has also declined, reaching 1.4% p.a. in 2010. These trends have been strongly driven by changes in the birth rate (although changes in mortality rates and international migration are also key drivers). In OECD countries the number of births per year fell from over 20 per 1,000 of population in the early 1960s to just 11 per 1,000 by 2010, while in developing countries the rate fell from over 40 per 1,000 to 22 per 1,000 (Figure 1.2). The downward trend in birth rates is expected to continue.

Table 1.2
Population levels and growth

	Levels *millions*		Growth *millions*	Growth *% p.a.*		
	2010	**2035**	**2010–2035**	**2010–2035**	**2010–2020**	**2020–2035**
North America	466	555	89	0.7	0.8	0.6
Western Europe	547	576	29	0.2	0.3	0.1
OECD Pacific	201	194	–8	–0.2	0.0	–0.3
OECD	**1,215**	**1,325**	**110**	**0.3**	**0.5**	**0.3**
Latin America	431	516	85	0.7	0.9	0.6
Middle East & Africa	882	1,422	541	1.9	2.2	1.8
South Asia	1,644	2,144	500	1.1	1.3	0.9
Southeast Asia	657	809	152	0.8	1.0	0.7
China	1,354	1,462	108	0.3	0.5	0.2
OPEC	405	586	181	1.5	1.8	1.3
Developing countries	**5,372**	**6,939**	**1,567**	**1.0**	**1.2**	**0.9**
Russia	141	126	–15	–0.4	-0.4	–0.5
Other transition economies	199	201	2	0.0	0.1	0.0
Transition economies	**340**	**327**	**–13**	**–0.2**	**-0.1**	**–0.2**
World	**6,927**	**8,590**	**1,663**	**0.9**	**1.0**	**0.7**

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

Global and regional population levels for 2010 and 2035 are shown in Table 1.2. The total number of people in the world rises from just over 6.9 billion in 2010 to almost 8.6 billion in 2035.[12] This 1.7 billion increase represents an average growth of 1% p.a. over the current decade, dropping to 0.7% p.a. over the period 2020–2035. Only 110 million of the increase for the period 2010–2035 is in OECD countries, while close to 1.6 billion more people will be living in developing countries (Figures 1.3 and 1.4). The greatest increase, in both numbers and in percentage terms, will be the Middle East & Africa, particularly sub-Saharan Africa, while the population will also grow rapidly in South Asia. For example, India, Pakistan and Bangladesh is seen by the United Nations (UN) to experience population increases between 2010–2035 of 313 million, 100 million and 46 million respectively. OPEC population growth rates are also expected to be among the highest, with the largest increase in Nigeria (Figure 1.5).

The implications of population dynamics on energy consumption patterns are also influenced by the changing age structure. This affects, for instance, the size of the labour force[13] for a given total population size, but also has direct consequences for energy demand patterns, for example, due to the number of people within the population that can hold drivers licences. With the ageing trend in most countries leading to a growing proportion of retirees, the share of working age people within a population is steadily shrinking. OECD countries have an

Figure 1.3
Average annual population growth rates

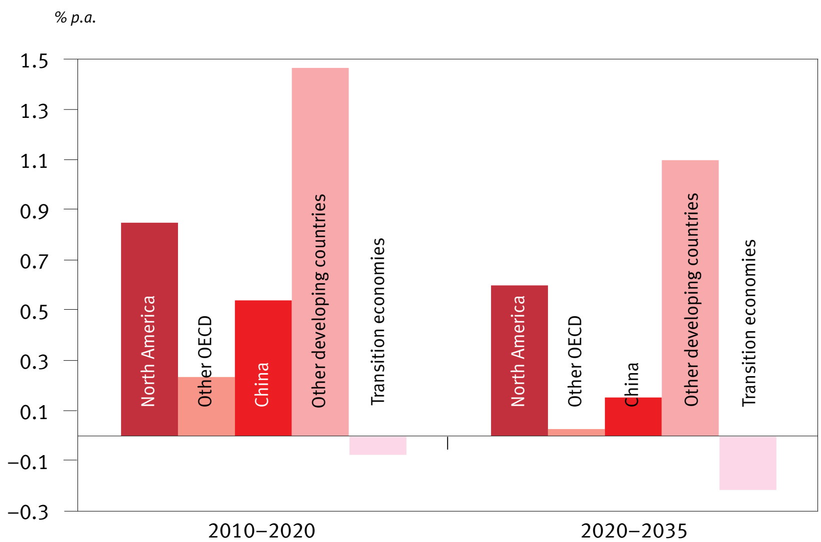


Figure 1.4
Average annual population growth

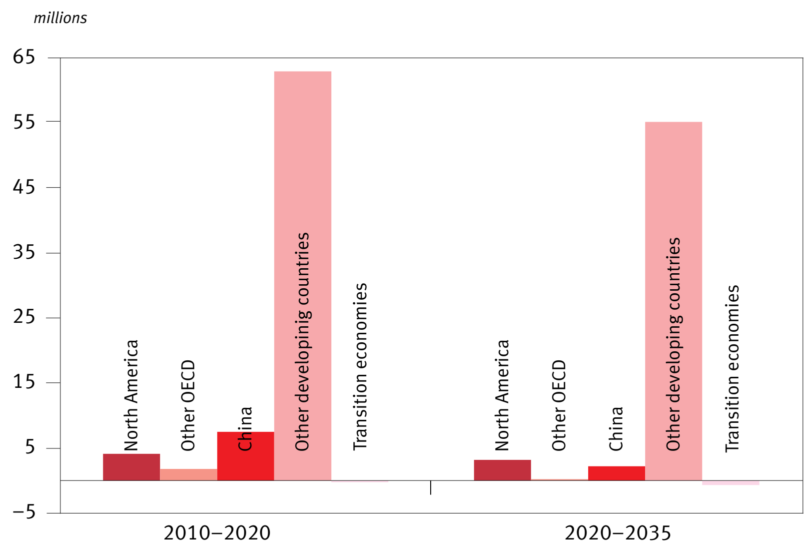
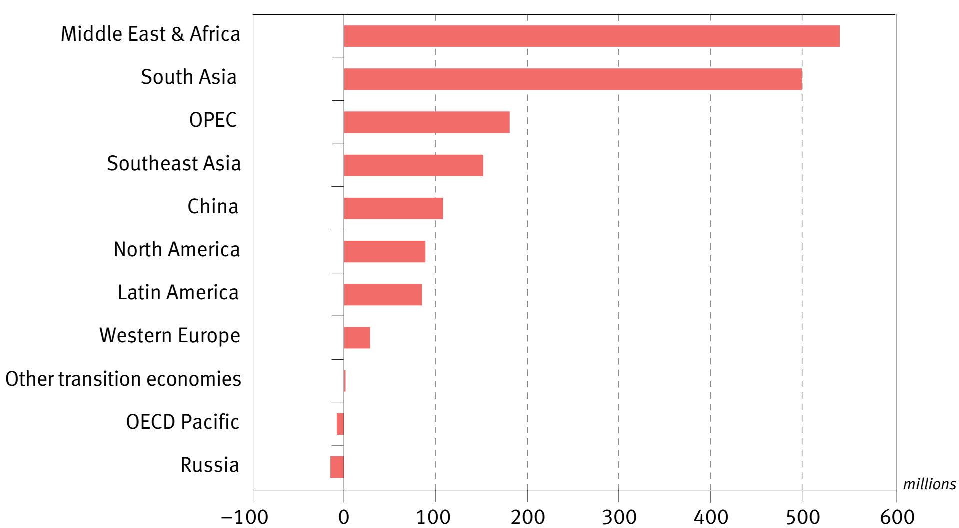


Figure 1.5
Increase in population, 2010–2035



average of 67% of the population in the age range 15–64, and this percentage is set to decline to 61% by 2035 (on the assumption that the retirement age is not increased). The OECD Pacific labour force, if defined as this age range, peaked at 117 million in 2000, and has been declining steadily since: by 2035 it will be just a little over 100 million. Similarly, the available labour force in Western Europe will fall, particularly in the post-2020 period: by 2035 it will be almost 8 million below current levels. For North America, on the other hand, this age group represents a growing share of the total population, peaking in 2025 at 68%. This means that the North American workforce will continue to increase by at least 1 million p.a. over most of the projection period.

For developing countries as a whole, the share of the 15–64 age range in the total population will continue to grow, with the labour force on average rising by more than 15 million p.a. over the years to 2035. It should be noted, however, that this increase will not occur in China, where the labour force is expected to peak within just four years. By 2035, China will have a working age population that will be 23 million below current levels, unless the one-child policy is abandoned before 2020 and the birth rate rises subsequently. In transition economies, the fall in total population levels is compounded by an ageing population, which means that the

Figure 1.6
Average annual growth rates of working age populations

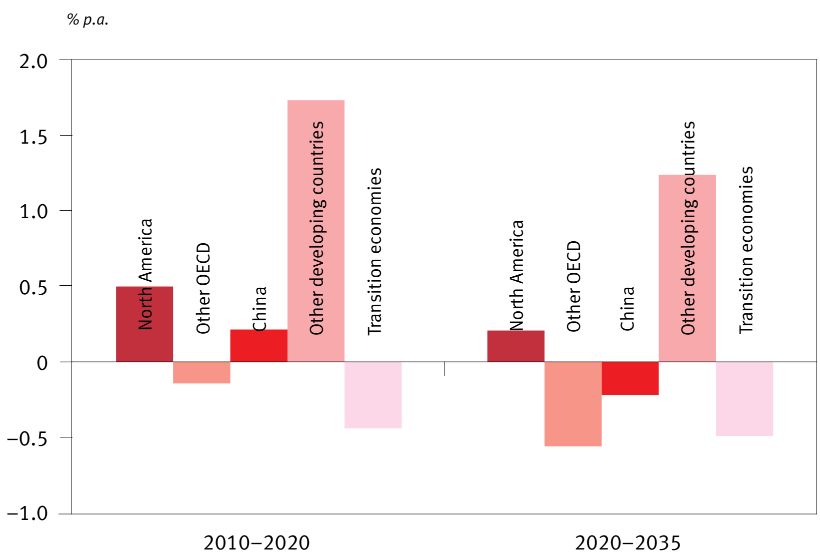
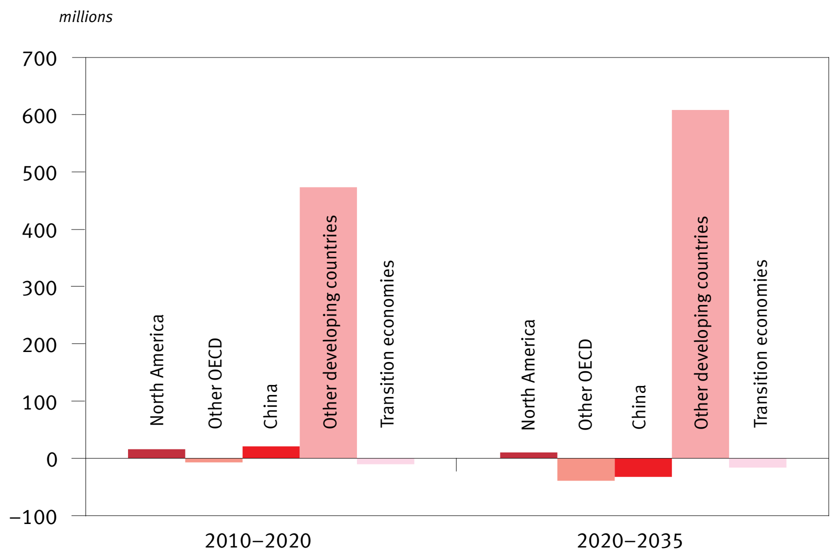


Figure 1.7
Growth of labour force, 2010–2035



workforce age range will see a fall in its share over the whole period (Figures 1.6 and 1.7).

Table 1.3 shows the regional developments of population levels for urban[14] and rural areas. As can be seen, the trend towards urbanization is expected to continue. In OECD countries, an average of 76% of the population currently lives in urban areas, and this is set to increase to 83% by 2035. The highest population concentration in cities among the OECD regions is in North America, where 82% currently live in cities, with this proportion rising to 88% by 2035. In developing countries there is generally a considerably lower share of the population living in urban areas: currently, on average, 45% reside in cities, but the share will rise strongly, reaching 58% by 2035. This trend is expected in all developing regions, but is particularly pronounced in China. Here the share rises from 47% in 2010 to 65% by 2035, as the ongoing trend to relocate from rural areas continues apace. These trends will have implications for energy demand patterns, as urbanization is associated with greater access to electricity in developing countries. There will also be implications for the transportation sector in terms of the increasing need for mobility, although congestion and local pollution concerns, as well as public transport policies, will also play a role in determining the net implications of urbanization for oil demand.

Table 1.3
Population by urban/rural classification

millions

	2010		2035		Change 2010–2035	
	Urban	Rural	Urban	Rural	Urban	Rural
North America	384	83	488	67	104	–15
Western Europe	398	149	461	115	62	–34
OECD Pacific	145	56	154	40	8	–16
OECD	**928**	**287**	**1,102**	**222**	**175**	**–65**
Latin America	362	69	462	55	99	–14
Middle East & Africa	353	529	751	671	398	142
South Asia	500	1,144	944	1,200	444	56
Southeast Asia	284	373	455	354	170	–18
China	636	717	949	513	312	–204
OPEC	259	146	442	144	182	–1
Developing countries	**2,394**	**2,978**	**4,001**	**2,938**	**1,607**	**–40**
Russia	103	38	99	27	-4	–11
Other transition economies	116	83	134	67	17	–15
Transition economies	219	121	232	95	13	–26
World	**3,541**	**3,385**	**5,336**	**3,255**	**1,794**	**–131**

Source: *Population Division of the Department of Economic and Social Affairs of the United Nations Secretariat, http://esa.un.org/unpp.*

Economic growth

In developing the economic growth assumptions, population movement estimates for future factor productivity growth are also made. In the Reference Case, past trends have been used to inform the assumptions. Productivity growth in OECD regions is assumed to initially average 2% p.a., falling to 1.5% p.a. by 2035, while higher rates are assumed for developing countries, supported by rising trade volumes, as a result of the assumed continuation of globalization.

Long-term economic growth rates appear in Table 1.4. At the global level, these average 3.4% p.a. over the period 2011–2035. This is slightly lower than in the WOO 2010, due to the inclusion of the extra five years to 2035, when economic growth is expected to be lower than in the years prior. The dynamics of population growth

Table 1.4
Long-term economic growth rates in the Reference Case *% p.a.*

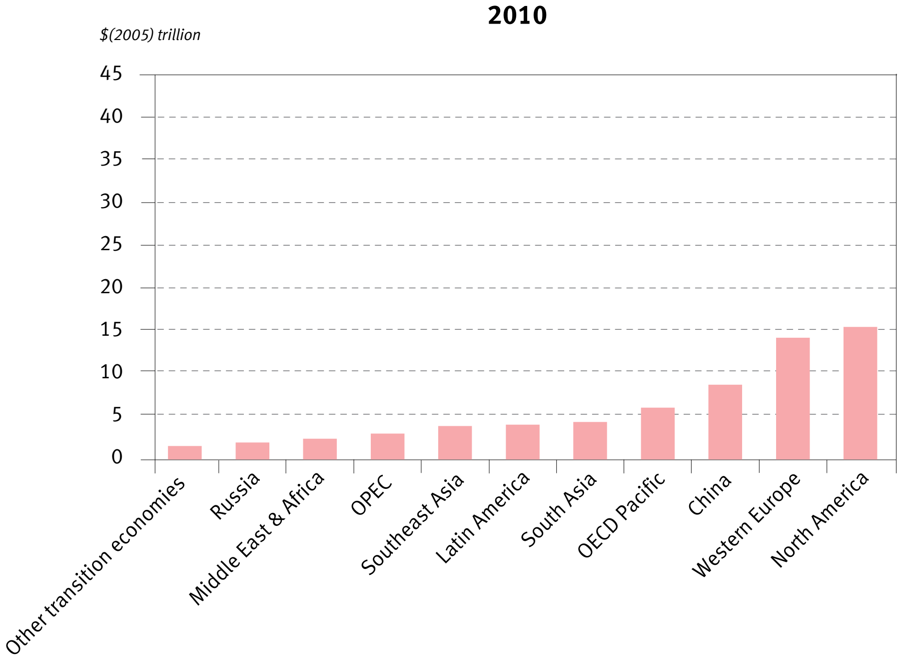
	2011–2020	2021–2035	2011–2035
North America	2.5	2.3	2.4
Western Europe	1.8	1.6	1.7
OECD Pacific	1.8	1.4	1.5
OECD	**2.1**	**1.9**	**2.0**
Latin America	3.5	2.8	3.1
Middle East & Africa	3.5	3.1	3.2
South Asia	6.1	4.3	5.0
Southeast Asia	4.0	3.1	3.5
China	7.9	5.4	6.4
OPEC	3.7	3.2	3.4
Developing countries	**5.6**	**4.3**	**4.8**
Russia	3.3	2.4	2.8
Other transition economies	3.1	2.3	2.6
Transition economies	**3.2**	**2.4**	**2.7**
World	**3.7**	**3.2**	**3.4**

have been incorporated for these additional five years. Global economic growth is assumed to average 3.7% p.a. for the current decade, falling to 3.2% p.a. for the period 2021–2035.

By 2035, the Chinese economy accounts for 27% of global GDP, approximately double the size of Western Europe (Figure 1.8). The share of developing countries in the world's economic activity is set to rise from 40% in 2010 to 57% by 2035, with Asian developing countries alone accounting for 43% of global GDP.

However, significant global disparities will remain in terms of income per capita, as shown in Figure 1.9. By 2035, OECD regions will reach almost $51,000 (2005 prices) per head in the case of North America, while developing countries will still average only $12,000 per person. China's booming economy, alongside a population that is averaging growth of just 0.3% p.a. over the period to 2035, means that GDP per capita growth is expected to rise strongly, reaching more than $28,000 per capita. This is more than the current average level in Western Europe. In Middle East & Africa and South Asia, these levels reach just $3,800 and $7,000 per capita respectively.

Figure 1.8
Real GDP by region in 2010 and 2035



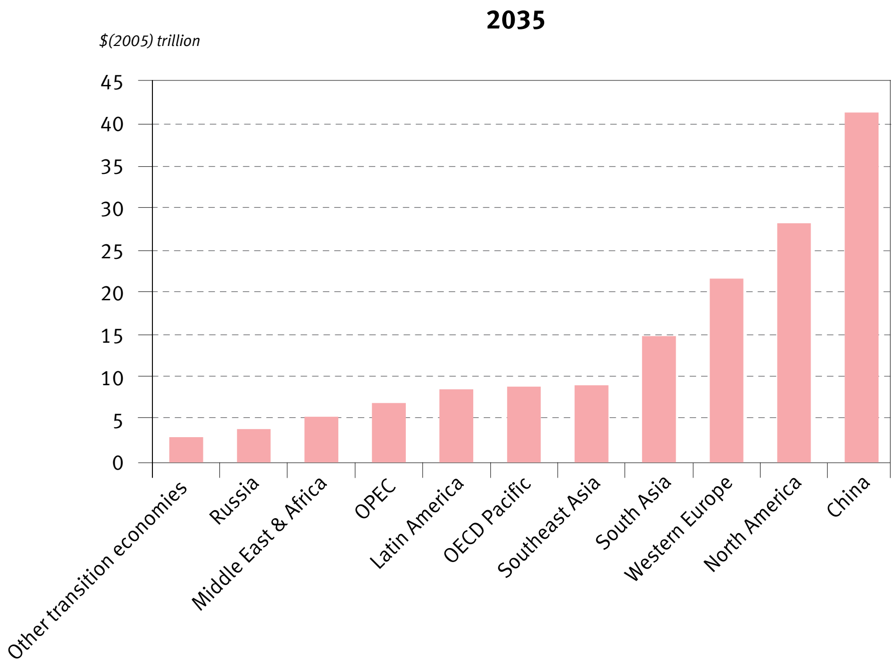
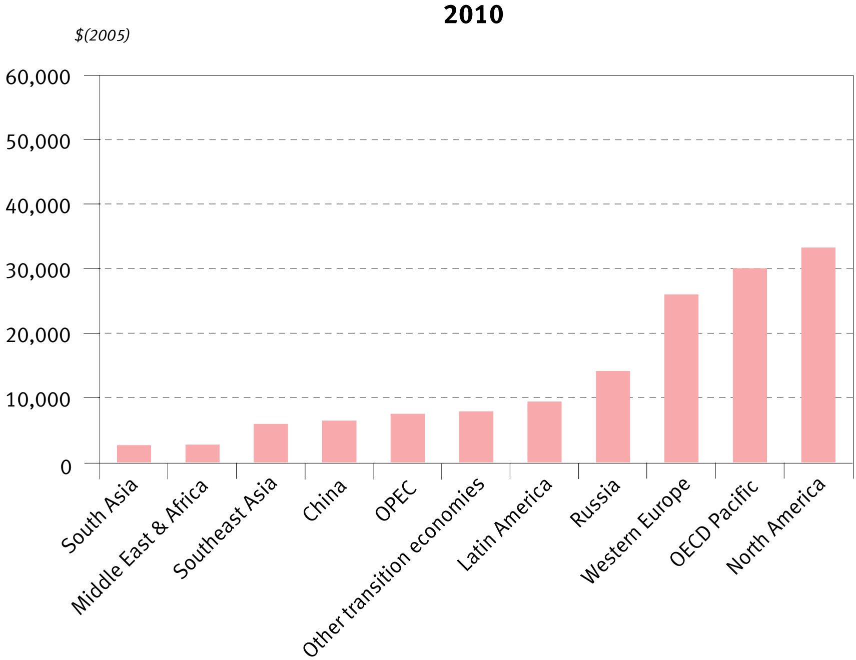
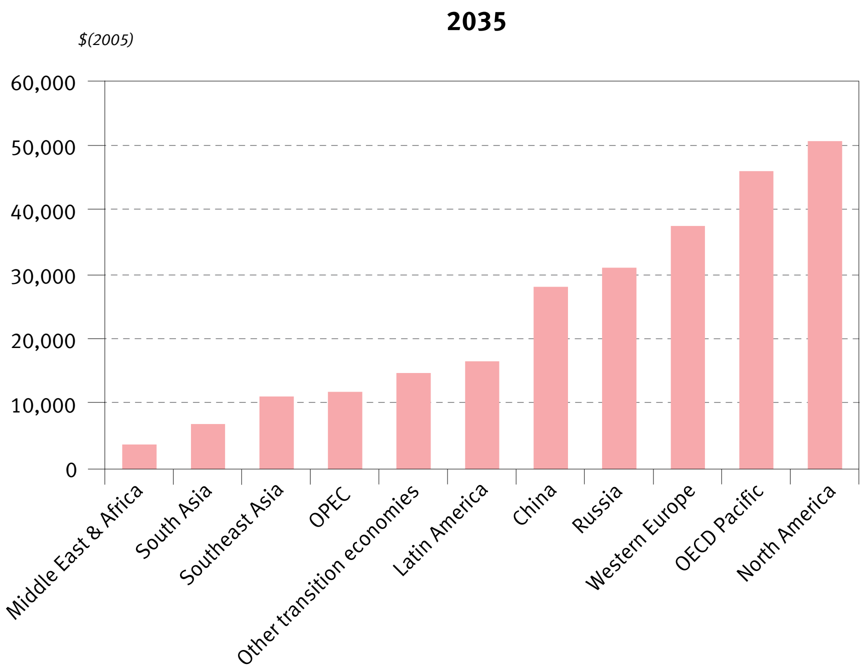


Figure 1.9
Real GDP per capita in 2010 and 2035





Policies

The Reference Case retains the principal that only policies that are already in place influence supply and demand patterns. The two key policies that are already factored in are the EU package of measures for climate change and renewable objectives and the US Energy Independence and Security Act (EISA). No change is anticipated for these two sets of policies in terms of how they might impact the Reference Case, as compared to the previous WOO.

However, China's recently announced 12th FYP (2011–2015) is one area of policy development that could be considered as having an impact on the Reference Case (Box 1.4). Factors include the already mentioned slowing of economic growth, as well as a focus upon increasing energy efficiency, reducing carbon intensities, decreasing the share of fossil fuels in the energy mix, and a push for battery cell technology development with the annual production of 1 million electric vehicles by 2015, or approximately 2% of the current stock of vehicles in China. However, previous five-year targets have not always been achieved. Efficiency and energy mix developments

Box 1.4
Energy and China's 12th Five Year Plan

China's 12th FYP for National Economic and Social Development (2011–2015), released during the National People's Congress Session in March this year underlines the importance of transforming the country's energy production and consumption and takes positions on climate change and the environment. Given China's expanding role in the global energy sector it is important to understand what the Plan might mean for the country's future energy position.

The section on energy contains three parts. The first is dedicated to energy supply and the diversification of energy sources. The other two parts refer to China's geographical energy imbalance, in terms of having the majority of its resources located in the west of the country, while its main population hubs are found in the central and eastern regions. In addition, there is also mention of China's commitment to international cooperation and the UN-led climate change negotiation process.

The Chinese government has set its energy consumption target for 2011–2015. Its goal is that the country should consume no more than 2,800 million tonnes of oil equivalent (mtoe) a year by the end of the five-year period. This is a challenging target considering that in 2010, Chinese consumption was 2,580 mtoe, or just

7.8% less than the target for 2015. In the previous five-year period, China's energy consumption actually increased by around 39%.

Given this, it can be assumed that China's energy consumption goal might be difficult to attain, particularly when reviewing its plans in other areas, such as its modernization of rural society in order to create many more small- and medium-sized cities (population under five million). These cities can be expected to generate significant economic growth, and in turn, increase China's energy consumption.

In terms of the energy mix, fossil fuels are expected to see a fall in their share from around 92% to 89% in 2015. However, it is only coal that is slated to see an actual (significant) reduction in its share by the end of the period, although this should perhaps be viewed as ambitious. Any reductions will depend strongly on price reforms and cuts in power demand growth. The target for natural gas actually projects an increase in its share, to just over 8%, with oil remaining relative stable, at around 18%. Natural gas consumption is supported by positive commercial and policy drivers, and oil consumption will be driven by increases in gasoline and diesel demand as a result of more vehicle purchases.

With regards to non-fossil fuel energies, the Plan foresees that 11% of primary energy consumption will come from these sources by 2015, as part of the move to diversify energy supplies. It is expected that there will be significant increases in both nuclear and renewables.

China plans significant investment in nuclear energy to push its capacity beyond 40 gigawatts (GW) by 2015. The country had around 10GW capacity at the end of 2010. If China meets its five-year nuclear target, it will have gone a significant way to meeting its long-term target of having an installed nuclear capacity of 70GW by 2020. While China remains steadfast in its nuclear power ambitions, the disaster at Japan's Fukushima nuclear plant earlier this year has caused some debate in Beijing. Nevertheless, China can be expected to continue to significantly increase its nuclear capacity.

During the previous FYP, China became a major player in the wind and solar energy industries. This trend is expected to strengthen in the new FYP, although the anticipated jump from a 0.6% share for renewable (excluding hydropower) to 2.6% in 2015 may prove slightly beyond the country's reach. The target share for hydropower remains fairly stable at 6.7% by the end of the period.

In other areas, plans are already being turned into actions. For example, the Ministry of Science and Technology has started the first phase of the Plan for electric vehicles, which focuses on their development over the next five years. This has a number of specific targets including: reducing the production costs of batteries by 50%; having one million electric vehicles on the country's roads by 2015; expanding the country's capacity of power batteries to 10GW; and installing over 2,000 charging stations and 400,000 charging bays in 'model cities'.

On the issue of the environment, the plan focuses on increasing energy efficiency, reducing pollution, ensuring a stable, reliable and clean energy supply and further underscoring China's commitment to environmental cooperation at the global level. A new Carbon Intensity Reduction concept is also included; in terms of CO_2 emissions per unit of GDP, the Plan sets a voluntary target to reduce this by 17% by 2015, compared to 2010 levels. The Plan also expects energy consumption per unit of GDP (energy intensity) to decrease by 16%, compared to 2010 levels. The previous FYP set a 20% energy intensity reduction target, which was almost reached (19.1%), although only with significant efforts from the country's largest consumers.

Both these figures are in line with China's voluntary objective to reduce its energy intensity by 40–45% by 2020, which was contained in its submission to the UN Copenhagen Climate Change Conference in 2009. It also laid out a commitment to generate 15% of its energy from non-fossil fuel sources by 2020.

It will be interesting to see how the next five years unfold, particularly in terms of coal use, new nuclear build and energy efficiency. In general, however, this FYP appears to be a continuation of past developments in China's energy sector. There are some ambitious targets for energy efficiency and changes in its energy mix, but the general trends remain the same.

are nevertheless reassessed in the light of the tone and content of the new Plan, and the impact of rising retail petroleum product prices in China is also considered. The change, however, is not substantial, as China's oil intensity rates decline in the previous WOO was already showing relatively strong efficiency improvements.

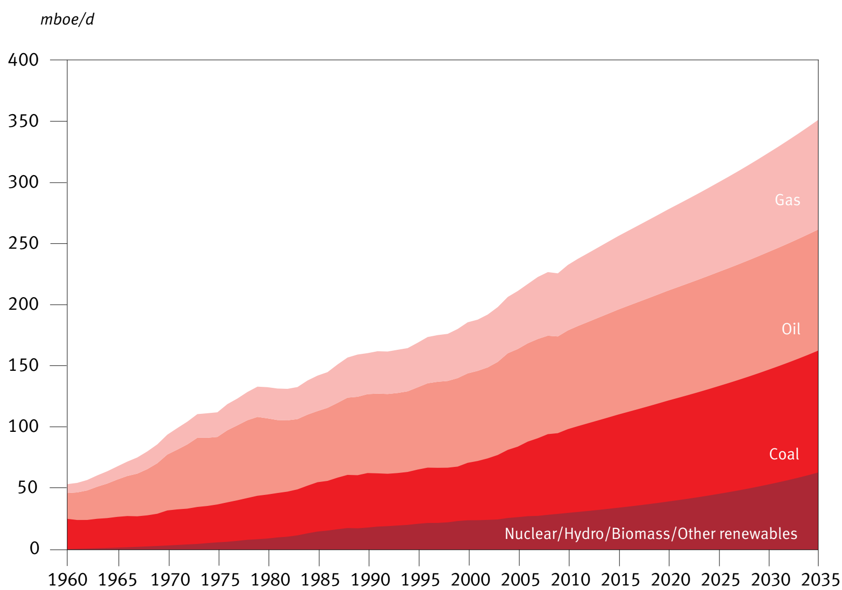
Energy demand

Over the period 2010–2035, primary energy demand[15] in the Reference Case increases by 51% (Table 1.5). Fossil fuels, currently accounting for 87% of the energy supply, will still make up 82% of the global total by 2035. For most of the projection period, oil will remain the energy type with the largest share. However,

Table 1.5
World supply of primary energy in the Reference Case

	Levels *mboe/d*				Growth *% p.a.*	Fuel shares *%*			
	2008	**2010**	**2020**	**2035**	**2008–35**	**2008**	**2010**	**2020**	**2035**
Oil	80.6	81.2	90.8	101.0	0.8	35.2	34.5	32.3	28.4
Coal	66.6	69.2	83.6	101.5	1.6	29.1	29.4	29.7	28.5
Gas	52.0	53.6	66.6	90.0	2.0	22.7	22.8	23.7	25.3
Nuclear	14.3	14.6	16.6	22.5	1.7	6.2	6.2	5.9	6.3
Hydro	5.5	5.8	7.5	10.3	2.3	2.4	2.5	2.7	2.9
Biomass	8.5	9.2	12.8	20.3	3.3	3.7	3.9	4.6	5.7
Other renewables	1.5	1.7	3.5	10.4	7.5	0.6	0.7	1.2	2.9
Total	**229.0**	**235.4**	**281.3**	**355.9**	**1.6**	**100.0**	**100.0**	**100.0**	**100.0**

Figure 1.10
World supply of primary energy by fuel type



Box 1.5
Shale gas: recent developments

In last year's WOO, it was asked whether shale gas is a game changer. The conclusion was that it remained unclear, but it was recognized that shale gas potential was undisputed and its impact on the natural gas markets was already being felt worldwide. What is the view twelve months on?

From a resources perspective, recent assessments have shown that shale gas may have even greater potential. In the US, the Colorado School of Mines Potential Gas Committee released its latest biennial resource assessment[16] in April 2011, which indicated a total natural gas resource base (excluding proved reserves) of 1,898 trillion cubic feet (Tcf). This is the highest in 46 years and exceeds the previous assessment by 61 Tcf. Much of the increase is attributed to shale gas plays in the Gulf Coast, Mid-Continent and Rocky Mountains areas. Overall, shale gas accounts for 687 Tcf and represents approximately 36% of US natural gas resources.

This figure is similar to an assessment undertaken for the Energy Information Administration (EIA) by Intek Inc., which estimates that the discovered and technically recoverable US shale gas unproved resources is 750 Tcf.[17] Upward revisions were even more dramatic in terms of proved reserves. According to the EIA, shale wet natural gas proved reserves reached a level of 60.6 Tcf at the end of 2009, an increase of 76% from 2008. They accounted for 21% of US natural gas reserves. Such a boost happened despite lower gas prices, indicating significant improvements in drilling and production technologies, as well as substantial cost reductions.

It is important, however, to stress the large geological and technical uncertainties associated with shale gas reserves and resources assessments. In general, exploration risk is lower for continuous accumulations in which the same rock acts as source, reservoir and seal. Nevertheless, heterogeneities in shale deposits, as well as the need for a tailored combination of drilling and hydraulic fracturing, make it difficult to assess the volumes of gas in place and the recovery rates.

This is all the more so outside of the US, where exploration and development of shale gas is still in its infancy and much less data is available. A recent initial estimation of 32 countries conducted by Advance Resources International Inc. assessed the shale gas resource as equal to about 22,000 Tcf of gas in-place, of which 5,760 Tcf could be technically recovered.[18] Although only indicative, those figures do demonstrate, however, that supplies from shale gas could potentially become significant worldwide.

In the US, shale gas production has grown at an impressive average rate of 48% p.a. since 2006. It reached 30% of the total marketed natural gas production[19] in May 2011, with the bulk coming from three formations: Barnett, Haynesville and Fayetteville. New formations, such as Marcellus and Woodford are also gaining in prominence, as today's hefty liquids price premium is attracting drilling into areas where shale is in the gas-condensate or oil window.

Shale gas growth has had a dramatic impact on US gas prices: the Henry Hub natural gas spot price declined from more than $13/million British thermal units (mBtu) in 2006 to around $4/mBtu at the end of 2010. Moreover, it has changed US gas prospects in less than a decade, from potentially being a Liquefied Natural Gas (LNG) importer into a largely self-sufficient and low gas price country. This has triggered pronounced effects on international gas markets. The newly built LNG capacity that was intended to initially supply the US market has had to be diverted to feed other regions, such as the EU and the Far East. The redirection of LNG cargos led to downward pressures on prices and a weakening of traditional marketing frameworks based on long-term contracts.

Outside the US, with shale gas development still in its early days, production is very limited and only a few test drillings have taken place. However, activity for acreage acquisition, merger and acquisitions and exploration have intensified in a number of countries, such as Poland, Germany, France, UK, Australia and China.

In addition to geological and technical uncertainties, many other challenges may hinder shale gas development. The first relates to economics. Achieving high well productivity necessitates the use of expensive well services, including multi-stage fracturing of horizontal wells, and complex completions, as well as a continuous adaptation process as there is no one-size-fits-all completion or stimulation design for shale wells.[20] Cost inflation has been moderated by efficiency gains, including through longer well lateral length and a higher number of fracturing stages. Shale gas wells typically exhibit high initial production rates, rapidly offset, however, by steep declines, which could be as high as 80% in the first year. This behaviour makes supply very responsive to the drilling effort and more price elastic. For example, for a shale play with a production performance similar to Fayetteville, a drilling development plan designed to achieve annual production of 1 Tcf after five years followed by a plateau over 10 years necessitates close to 11,700 wells over the 15 years, with an average of more than 700 wells per year.[21]

Well life duration is also a major uncertainty, given the limited historical data in shale gas well performance. Assumptions vary from three-to-five years, to as high as

40 years. While the early high performance production mechanism is dominated by the free gas flow from fractures and macroporosity, the lowered pressure production phase is dominated by gas desorption from the organic matter into the fracture system. The latter is not yet well understood and more research and development (R&D) is required to improve knowledge in this area.[22]

Shale gas development relies upon large scale drilling efforts, which require the availability of extensive drilling, fracturing, and well completion services, as well as adequate human skills and expertise. Given these factors, it may be difficult for the US shale gas model to be repeated in other regions of the world. Moreover, the land footprint of operations may act as a further barrier in regions where population density is high, such as in Western Europe.

Another significant issue, and probably the major one today, is the concern about the environmental impacts of shale gas development. The hydraulic fracturing process uses large amount of water to which is added potentially toxic chemical components. This raises concerns about excessive water withdrawals, and the risk of contamination of potable water aquifers. The disposal of large amounts of potentially toxic water flowing back from the wells may also cause surface pollution, if not properly controlled and managed. Some have also pointed to the risk of methane migration into domestic drinking water wells.[23] Moreover, given the dense drilling pattern necessitated by shale gas dvelopment, even if drilling pads are used, concerns have been raised about excessive land use encroachment, noise pollution and the risk of accidental blow-ups.

The regulatory response to these public concerns has been varied among countries. In the US, the Environmental Protection Agency (EPA) has launched a study on the potential impacts of hydraulic fracturing on drinking water resources. Its initial findings are expected to be made public by the end of 2012.[24] Some US states have also decided to place a moratorium on hydraulic fracturing (New York; Maryland). And in France, legislation has been enacted to ban the use of hydraulic fracturing. How policymakers and regulators respond to public concerns regarding the potential environmental risks associated with shale gas development will have a major impact on the contribution of shale gas to future world energy supplies.

There is no doubting the huge resource potential of shale gas, but given the state of play and the uncertainties just highlighted it is still too early to assess shale gas' role in the future global energy supply. However, it will clearly have some impact, and not only in the natural gas market. It has the potential to impact oil markets too.

In last year's WOO, the potential effect of shale gas on oil markets was assessed as being rather limited. There is no doubt that a lower natural gas price per unit of energy could be seen as an incentive to use more gas. However, in electricity generation, oil's share is low and has been falling in all regions, and this trend is expected to continue. In the transportation sector, natural gas could be used either directly in internal combustion engines as Compressed Natural Gas (CNG) – or even as LNG for heavy trucks – and indirectly in electricity-powered cars. According to the International Association for Natural Gas Vehicles, the global number of natural gas vehicles reached 12.7 million units in 2010, mostly in Asia and Latin America. However, this represents less than 1% of total commercial road vehicles. In the US, there are only 112,000 natural gas vehicles. Higher vehicle costs, lower energy density and a lack of refuelling stations prevent a more widespread use of natural gas in transportation. Large upfront subsidies are needed to overcome such hurdles, even if the CNG gas price premium remains high over a long period of time. Similarly, the development of electric vehicles faces many obstacles, which are explained in Box 2.1.

In terms of the main impact on oil markets, it is likely that this will be through the use of horizontal drilling and hydraulic fracturing in shales that are in the gas-condensate or oil maturity window. This would bring additional liquids supply that has the potential to be substantial. It is already happening today in the US. This is covered in Chapter 3.

by 2035 it will have been overtaken, in the Reference Case, by coal use, which will represent 29% of total energy, similar to today, while oil's share falls from 34% to 28%. Gas use will rise at faster rates than either coal or oil, both in percentage terms and volumes, with its share rising from 23% to 25%.

The prospects for nuclear energy have clearly been affected by events at Japan's Fukushima nuclear power plant in March this year (Box 1.6). The Reference Case reflects the immediate aftermath of the accident when nuclear power had to be replaced by other fuels. Moreover, moving forward, it is assumed that future prospects for nuclear power in Japan have been negatively affected. It has also led a number of other countries to effectively rule out future nuclear build, such as Germany, Switzerland and Italy (Box 1.6). It may also have implications elsewhere. In the Reference Case, nuclear energy still expands at an average rate of 1.7% p.a., although its contribution has been revised down from earlier estimates. Biomass use expands rapidly, and its contribution to total supply is approaching that of nuclear by 2035, at around 6%. Renewable energy, other than hydro, rises the

Box 1.6
After Fukushima: unclear for nuclear

The Fukushima Daichi nuclear disaster, triggered by the massive earthquake and subsequent tsunami that hit Japan earlier this year, has led to much discussion about the pros and cons of depending on this source of energy. It is a debate which, for the past few years, had been swinging behind the idea of a 'nuclear renaissance' based on a new generation of nuclear power plants in many countries. Fukushima, however, has meant the world for many suddenly seems a very different place. Has Fukushima changed the future for nuclear?

In Europe particularly, governments were quick to react. On 15 March, just a few days after the first news from Fukushima, the German government announced it would temporarily shut down seven – all reactors that went online before 1981 – of its 17 reactors. It has now proposed to close all reactors by 2022.[25] And in Italy and Switzerland there were freezes put in place for the construction and authorization of new nuclear build. Subsequently, the Swiss government decided to phase out nuclear and Italian voters gave a clear statement of intent that they wanted no new nuclear build in a nationwide referendum. There have also been public protests in a number of European countries against the use of nuclear power.

Globally, there has been much talk of the need to examine how such an event could have occurred, learn lessons from it and implement new measures and regulations as countries assess their future nuclear energy development.

The specific focus has been on safety. While it is clear that many nuclear power plants do not reside in earthquake zones and face the threat of tsunamis, it will be essential to fully examine the facts surrounding the incident. The Fukushima plant, first commissioned in 1971 and consisting of six boiling water reactors, is believed to have weathered the initial earthquake relatively well. However, the subsequent tsunami knocked out the power supply and the diesel back-ups. To put it simply, this set in motion a series of events that led to a number of explosions and radiation leaks.

Proponents of nuclear have been quick to cite that Fukushima may not be relevant to the debate about new nuclear build, given that it is an early 1960s boiling water reactor design.[26] There has obviously been much new technology developed since then. However, there is certainly the need to review safety at older plants, and questions may also be asked as to whether the builders of modern plants need to reassess the safety aspects of their designs. In the US, the Institute of Nuclear Power

Operations, the Electric Power Research Institute and the Nuclear Energy Institute have organized a formal structure to respond to the Fukushima Daiichi emergency,[27] after an inspection of US nuclear plants following the disaster found that a series of improvements in safety regulations were needed.

In addition, many questions remain unanswered with regards to nuclear waste and decommissioning. At the moment, there is no lasting solution to the disposal of nuclear waste, and decommissioning remains a delicate subject for the industry, particularly given timeframes and costs.

In fact, it may be overall project economics that prove to be the key to the building of many new nuclear plants. The fundamental question is: who can afford to build them? In Europe, there have been delays and cost overruns in the construction of Finland's Olkiluoto-3 reactor. This will certainly be looked at by investors examining new nuclear build. For private investors, the crux is the basics of business: profit and loss. They will not invest in nuclear if its overall project economics are not price competitive with other forms of fuel.

The length of time to receive planning permits is also cited by many as a major concern. Thanks to planning delays, Sizewell B, the UK's most recently built nuclear plant, took 12 years to build at a huge upfront capital cost. It is seen as one of the main reasons why no companies built nuclear plants in the UK since.

Despite these concerns and questions, it is apparent that nuclear will be around for some time to come. According to the World Nuclear Association (WNA),[28] there are currently over 440 commercial nuclear power reactors operating in 30 countries, with 377,000 MW of total capacity, providing about 14% of the world's electricity. And in some countries such as France, Lithuania, Belgium and Slovakia, over 50% of their power generation comes from nuclear.

Moreover, around 60 further nuclear power reactors are under construction, equivalent to 17% of existing capacity, while over 150 are planned, which is equivalent to 46% of present capacity. Most reactors on order or planned are in Asia, with China leading the way with some 27 reactors under construction, followed by South Korea, which plans to bring seven new reactors into operation by 2016, and India, which has four currently under construction.[29] There are also significant plans for new units in Europe, the US, Russia and the Middle East.

How these numbers are impacted by the Fukushima accident remains to be seen. Perhaps the greatest impact may be seen in some major developed countries. There is Japan itself, which has been asking a lot of questions about its nuclear future. In mid-May, Japanese government officials acknowledged that proceeding with the building of at least 14 new reactors by 2030, as originally planned, would be tough in the wake of the disaster. Prime Minister Naoto Kan has announced that the country's nuclear policy must be reviewed in its entirety.

Then there is Europe, where there has not only been concern about new nuclear build, but also concerns regarding extending the life of current plants. This can be viewed in the recent decisions taken by the German and Swiss governments, and in the Italian electorate coming down heavily against new nuclear. And in the US, where the nuclear industry had been poised to grow for the first time in over 30 years, a poll in March this year highlighted that nearly six out of 10 (58%) Americans were "less supportive of expanding nuclear power in the US" than they were a month ago (before the Fukushima disaster).[30] Although the government remains supportive,[31] further delays to possible construction start-ups can be expected.

What is obvious is that it is developing countries that will see the greatest need for more energy in the coming decades as they travel down the road of industrialization, which means that these countries may prove to be the major players in the global nuclear future. Already today, it is developing countries – particularly those that have a government-owned energy sector – that are progressing fastest with new nuclear build.

While advocates of nuclear stress that it is important to put Fukushima in context, underlining that the plant was old and that nuclear technology and reactor design continues to improve, the event has cast a shadow over the nuclear industry. There is much for governments, the industry and the general public to take on board. How all this plays out remains to be seen, which means the future for nuclear is best described as unclear.

fastest of all energy forms, but since this starts from a low base, its share is still only 3% by 2035.

The increase in energy demand is shown separately for OECD and non-OECD countries, as well as by fuel type in Figure 1.11. Clearly the dominant growth is for fossil fuel use in non-OECD countries, with the OECD only registering stronger growth than non-OECD in terms of nuclear and biomass. The single biggest increase in demand is for coal use in non-OECD countries.

Figure 1.11
Increase in energy demand 2010–2035, by fuel type, OECD vs. non-OECD

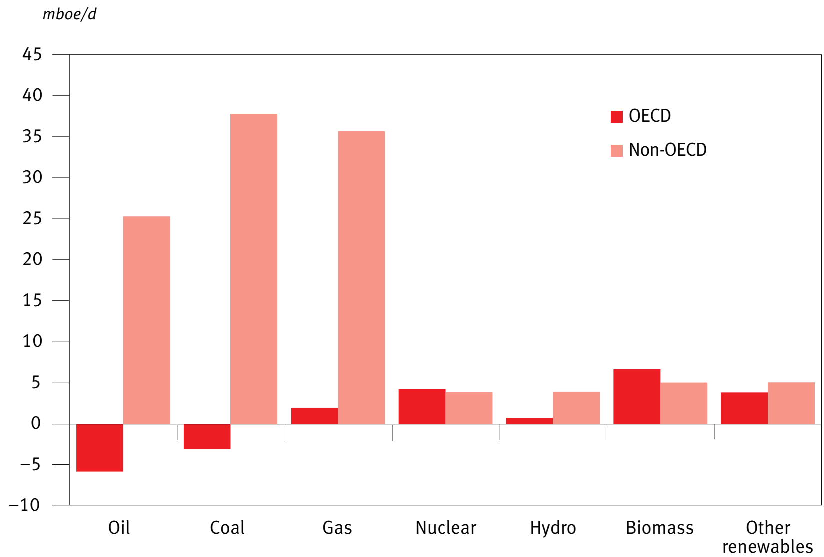


Figure 1.12
Energy use per capita

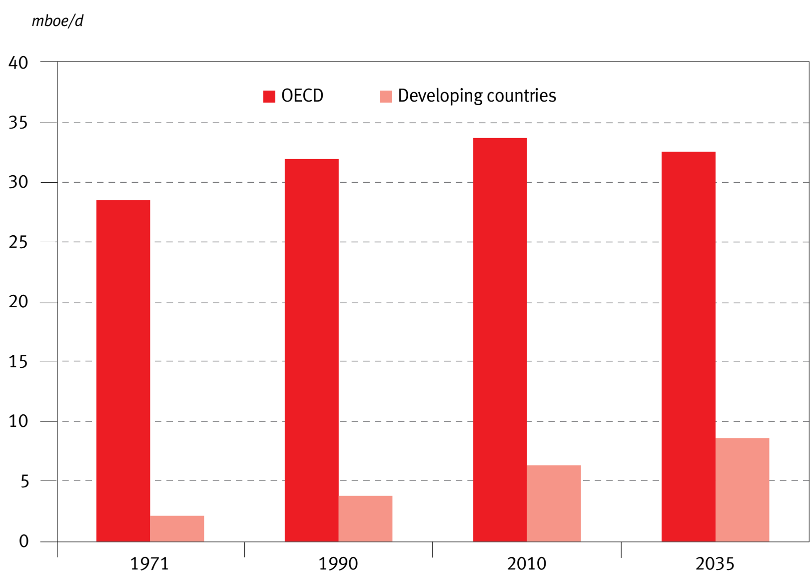


Figure 1.13
Fossil fuel use per capita

The higher growth in developing countries is evidence of the greater economic growth in these economies, but also due to the persistent existence of energy poverty and the consequent huge requirement to satisfy future development needs with higher energy use. Figure 1.12 shows that, by 2035, the OECD will still be consuming three and a half times more energy per capita than developing countries. If the comparison is limited to fossil fuels alone, the ratio rises to almost six times as much (Figure 1.13). Although the gap in energy use per head is closing, it is doing so slowly.

Oil demand

Oil demand in the medium-term

The global financial crisis of 2008 and the ensuing Great Recession had enormous implications for demand projections in both the short- and medium-term. For example, the WOO 2009 documented how dramatically GDP forecasts for 2009 were revised: while in July 2008 expected economic growth in OECD regions for this year was in the range of 1.3–1.6%, OECD economies actually shrunk by an average of 3.4%. This, in turn, had consequences for oil demand, which in OECD countries contracted by 1.4 million barrels per day (mb/d) in 2009. Moreover, the WOO 2009 foresaw recovery from the recession as being only gradual, and this affected medium-term oil demand prospects, which reached just 90.2 mb/d in 2015 compared to the 96.1 mb/d expected in the WOO 2008.

As discussed earlier in this Chapter, the recovery has in fact been swifter than expected. This had already been factored into the WOO 2010, with increased medium-term demand expectations. This process of re-evaluation has continued (Figure 1.14), with global economic growth for 2010 at an average of 4.7%.

As a result, the medium-term outlook for oil demand reflects an upward revision from last year's assessment. Table 1.6 highlights that the Reference Case now foresees demand reaching 88.2 mb/d in 2011, an increase of 1.6 mb/d compared to the WOO 2010 figure. By 2015, demand reaches 92.9 mb/d, an upward revision of 1.9 mb/d compared to last year's publication. However, it is worth stressing that risks appear skewed towards the downside, especially since the sovereign debt crisis in some EU countries seems to be spreading and the world economy slowing down further, with potential consequences for the global financial system.

Figure 1.14
WOO projections for 2015

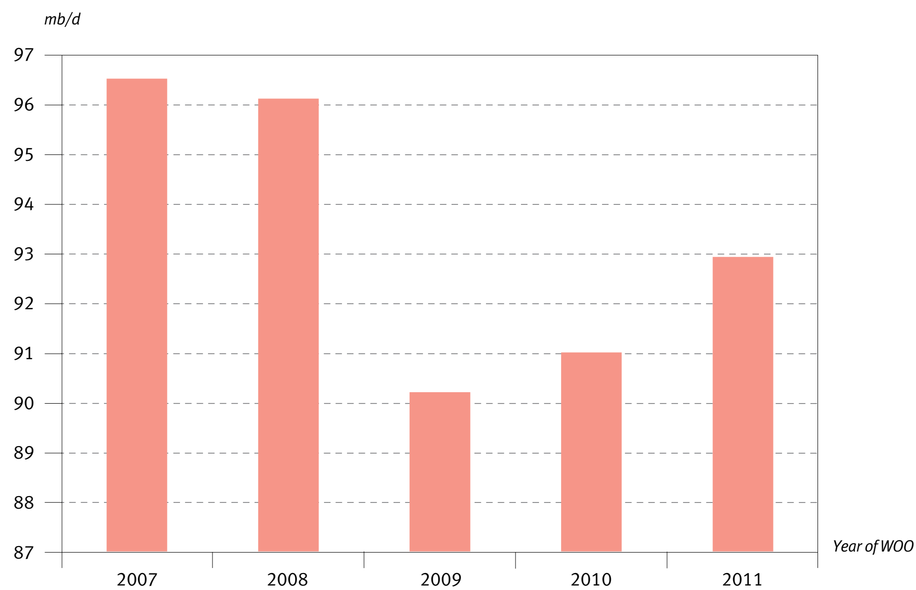


Table 1.6
Medium-term Reference Case oil demand outlook *mb/d*

	2010	2011	2012	2013	2014	2015
North America	23.9	24.1	24.2	24.2	24.2	24.1
Western Europe	14.5	14.4	14.3	14.3	14.3	14.2
OECD Pacific	7.8	7.8	7.7	7.7	7.7	7.7
OECD	**46.1**	**46.2**	**46.2**	**46.3**	**46.2**	**46.0**
Latin America	5.2	5.3	5.4	5.5	5.6	5.7
Middle East & Africa	3.4	3.4	3.5	3.6	3.6	3.7
South Asia	4.0	4.1	4.2	4.4	4.6	4.8
Southeast Asia	6.2	6.3	6.4	6.5	6.7	6.8
China	8.9	9.6	10.1	10.6	11.1	11.6
OPEC	8.1	8.3	8.6	8.8	9.0	9.2
Developing countries	**35.9**	**37.1**	**38.3**	**39.4**	**40.6**	**41.8**
Russia	3.1	3.2	3.2	3.2	3.2	3.3
Other transition economies	1.7	1.7	1.8	1.8	1.8	1.9
Transition economies	**4.8**	**4.9**	**5.0**	**5.0**	**5.0**	**5.1**
World	**86.8**	**88.2**	**89.5**	**90.7**	**91.8**	**92.9**

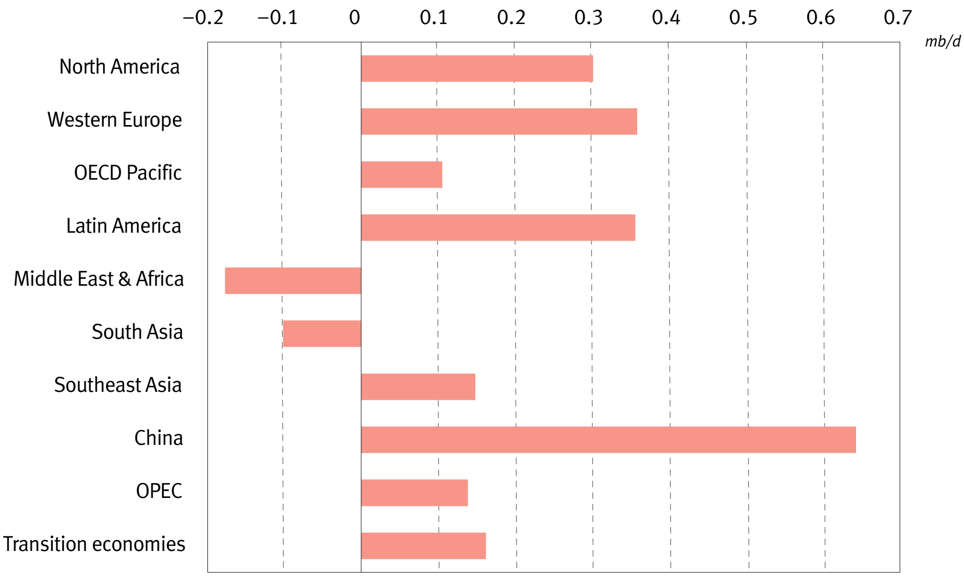
Over the period 2010–2015, OECD oil demand is essentially flat, having peaked in 2005. With transition economies registering only a minor increase, the medium-term rise of 6.1 mb/d over the years 2010–2015 comes mainly from developing countries, with 4 mb/d of this occurring in developing Asia. By 2015, non-OECD oil demand will be greater than OECD oil demand for the first time.

Figure 1.15 summarizes the revisions to demand levels in 2015, compared to the WOO 2010. Higher expectations are registered for all OECD regions.[32] In developing countries the main revisions have been for China and Latin America, mainly because of stronger than expected growth in 2010.

Oil demand in the long-term

While the central driver for medium-term oil demand is the economy, which is therefore the biggest source of uncertainty in this timeframe, in the long-term,

Figure 1.15
Revisions for 2015 oil demand: WOO 2011, compared to WOO 2010



other key drivers come in to play. As well as long-term economic growth, the future impact of policies, technologies, and, to a lesser extent, oil price developments, will increasingly influence future demand patterns beyond the medium-term.[33] To assess the impact of the related uncertainties, scenarios are developed in Chapter 4.

Given the assumptions outlined earlier in this Chapter, the outlook for long-term oil demand in the Reference Case is presented in Table 1.7. Demand increases by close to 23 mb/d over the period 2010–2035, reaching just under 110 mb/d by 2035. As previously highlighted, OECD demand has already peaked in 2005, and the longer term sees a steady demand decline in all OECD regions. Fully 80% of the increase in global demand is in developing Asia, where demand reaches almost 90% of that of the OECD by 2035 (Figure 1.16). Global demand in 2030, at close to 106 mb/d, is slightly higher than in the WOO 2010, mainly due to the swifter recovery from the recession assumed in the Reference Case.

Despite developing countries being the drivers of future oil demand increases, it does not change the fact that per capita oil use in these countries will remain relatively

Table 1.7
World oil demand outlook in the Reference Case

mb/d

	2010	2015	2020	2025	2030	2035
North America	23.9	24.1	23.8	23.4	22.9	22.3
Western Europe	14.5	14.2	14.0	13.7	13.3	12.9
OECD Pacific	7.8	7.7	7.4	7.2	6.9	6.7
OECD	**46.1**	**46.0**	**45.2**	**44.2**	**43.1**	**41.9**
Latin America	5.2	5.7	6.0	6.3	6.6	6.8
Middle East & Africa	3.4	3.7	4.0	4.4	4.7	5.1
South Asia	4.0	4.8	5.8	6.8	8.0	9.2
Southeast Asia	6.2	6.8	7.6	8.4	9.1	9.9
China	8.9	11.6	13.8	15.6	17.1	18.4
OPEC	8.1	9.2	9.9	10.7	11.6	12.5
Developing countries	**35.9**	**41.8**	**47.2**	**52.2**	**57.0**	**61.9**
Russia	3.1	3.3	3.3	3.4	3.4	3.4
Other transition economies	1.7	1.9	2.0	2.2	2.3	2.5
Transition economies	**4.8**	**5.1**	**5.3**	**5.5**	**5.7**	**5.9**
World	**86.8**	**92.9**	**97.8**	**102.0**	**105.8**	**109.7**

Chapter 1

Figure 1.16
Growth in oil demand, 2010–2035

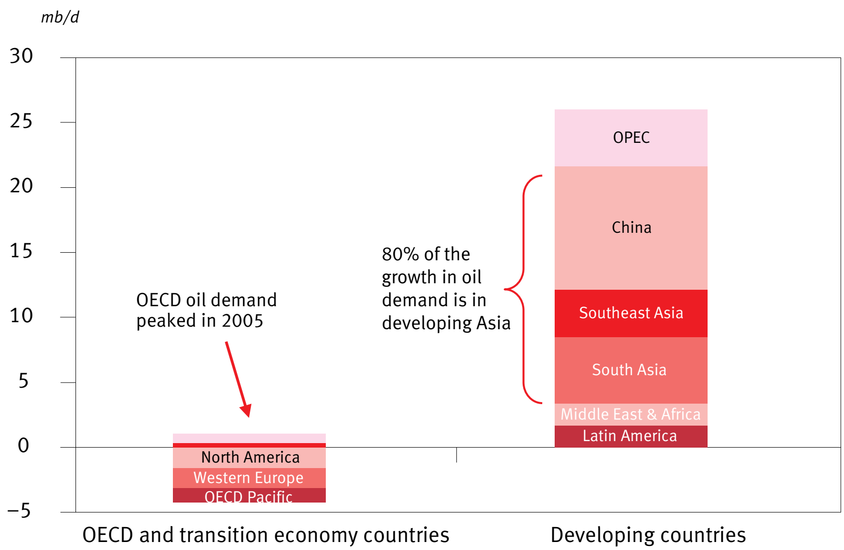


Figure 1.17
Oil use per capita in 2035

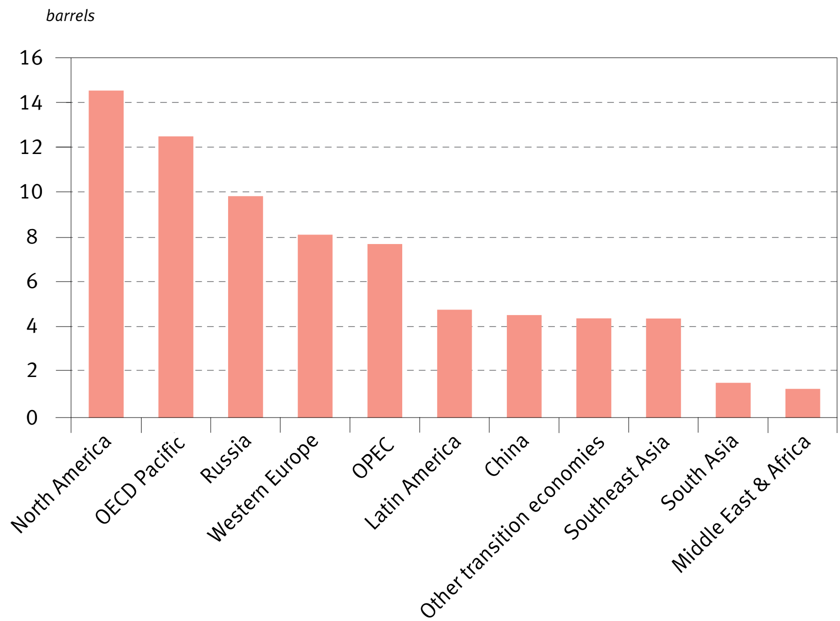
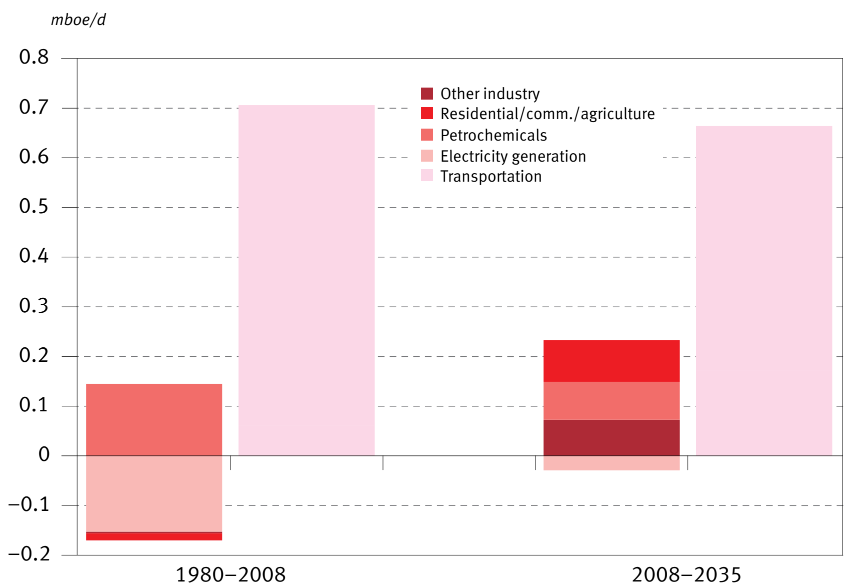


Figure 1.18
Annual global growth in oil demand by sector



low, and well below levels seen in OECD countries (Figure 1.17). By 2035, oil use per head in developing countries will average just 3 barrels, compared to close to 12 barrels on average in the OECD. This comparison disguises even greater disparities: for example, by 2035, while close to 15 barrels per head will be consumed in North America, in regions such as Middle East & Africa and South Asia, only slightly higher than 1 barrel per head will be used.

The key to future demand growth is the transportation sector of non-OECD countries (Figure 1.18), which accounts for 88% of the oil demand increase over the period to 2035.[34] Developing countries are also expected to see some rise in oil use in other sectors, particularly in industry – petrochemicals and other industrial uses – as well as in the residential/commercial/agriculture sector. Globally, the small amount of oil still used for electricity generation is expected to decline. In OECD countries, the declining use of oil is dominated by the fall in demand in road transportation due to efficiency improvements, as well as saturation effects that slow down the rate of increases in vehicle ownership. These trends are explored in more detail in Chapter 2.

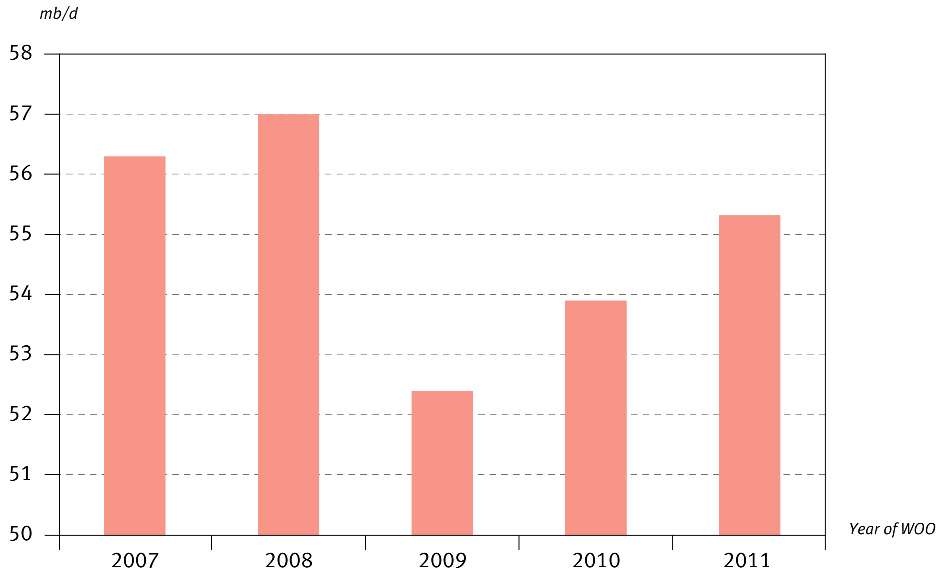
Oil supply

Oil supply in the medium-term

The medium-term Reference Case assessment of non-OPEC supply utilizes a large database covering more than 250 new upstream development projects. The expected pattern of crude and NGLs supply emerges from a risked analysis of new oil supply from fields that are to be developed, together with assumptions for the net growth/decline in existing fields. A similar approach at the project level is undertaken to derive the Reference Case medium-term paths for biofuels and non-conventional oil, the latter of which consists primarily of Canadian oil sands. Fuller details of these assessments are contained in Chapter 3.

As with demand, there are major uncertainties surrounding the expected future levels of supply from each world region. This has been reflected in the revisions to medium-term expectations made in earlier WOOs. Figure 1.19 shows, for example, that in the WOO 2009, there was a substantial downward revision to non-OPEC supply projections for 2015, from 57 mb/d in the WOO 2008 to 52.4 mb/d in the WOO 2009.[35] The context of preparing these reports is, of course, central to understanding the changing expectations. The WOO 2008, released in June of that year, was prepared at a time of high and rising oil prices and before the global financial crisis that hit later that year. At the time of writing the WOO 2008, mention was made of the short-term concerns of a significant US economic slowdown, but it was

Figure 1.19
WOO projections for non-OPEC supply in 2015



assumed that "downward pressures to economic growth are not prolonged". On the other hand, the WOO 2009 was written while the global financial crisis was in full swing, with the recognition that the subsequent recession could turn out to be "the longest and most widespread since the Second World War" and with oil prices having plummeted at the end of 2008. It is thus no surprise that the WOO 2009 assessment of medium-term supply prospects emphasizes that "lower prices are leading to cancellations and delays". Downward revisions to non-OPEC supply were therefore made across every world region.

What these past revisions clearly reflect is that supply projections, as with demand, must reflect the emerging circumstances and the corresponding possible changes in expectations for how future supply will evolve, at least in the Reference Case. Last year's WOO had already become more bullish on the prospects for non-OPEC supply, recognizing that "the potential short- and medium-term adverse impact on oil supplies of the economic crisis, the debt financing difficulties and the low oil price environment has now eased". This year's revised Reference Case set of projections continues that process, reflecting the more rapid recovery from recession and the higher price expectations that have been outlined earlier in this Chapter. It has also taken into account the potential for supply growth coming from shale oil in the US.

The medium-term Reference Case outlook for non-OPEC supply, as well as for OPEC crude, GTLs and natural gas liquids (NGLs), appears in Table 1.8, while non-OPEC supply growth over the period 2010–2015 is shown in Figure 1.20 (a more detailed analysis of these developments appears in Chapter 3). Total non-OPEC supply increases steadily over the medium-term, rising by 3 mb/d over the five years from 2010–2015. The key supply sources behind this are the rising levels of crude oil from the Caspian and Brazil, increases in the production of oil from Canadian oil sands,

Table 1.8
Medium-term oil supply outlook in the Reference Case *mb/d*

	2010	2011	2012	2013	2014	2015
US & Canada	12.0	12.3	12.5	12.7	12.9	13.0
Mexico	3.0	2.9	2.9	2.8	2.7	2.6
Western Europe	4.4	4.2	4.0	4.0	4.0	3.9
OECD Pacific	0.6	0.6	0.6	0.7	0.7	0.7
OECD	**19.9**	**20.0**	**20.0**	**20.1**	**20.2**	**20.3**
Latin America	4.7	4.9	5.2	5.3	5.5	5.7
Middle East & Africa	4.4	4.4	4.5	4.5	4.5	4.5
Asia	3.7	3.7	3.7	3.8	3.9	4.0
China	4.1	4.2	4.3	4.3	4.3	4.3
DCs, excl. OPEC	**16.9**	**17.3**	**17.7**	**17.9**	**18.2**	**18.4**
Russia	10.1	10.2	10.2	10.2	10.3	10.3
Other transition economies	3.2	3.3	3.4	3.6	3.8	4.0
Transition economies	**13.4**	**13.5**	**13.6**	**13.8**	**14.0**	**14.3**
Processing gains	2.1	2.1	2.2	2.3	2.3	2.4
Non-OPEC	**52.3**	**52.9**	**53.6**	**54.1**	**54.7**	**55.3**
of which: non-conventional	3.9	4.4	4.8	5.3	5.8	6.1
NGLs	5.7	6.0	6.1	6.2	6.4	6.4
OPEC NGLs	**4.8**	**5.1**	**5.4**	**5.7**	**5.9**	**6.2**
OPEC GTLs*	**0.1**	**0.2**	**0.3**	**0.2**	**0.3**	**0.3**
OPEC crude	**29.3**	**30.2**	**30.4**	**30.9**	**31.1**	**31.3**
World supply	**86.4**	**88.4**	**89.7**	**90.9**	**92.0**	**93.1**

* *Future growth of non-conventional oil in OPEC is expected to be dominated by GTLs. This item includes other non-crude streams, such as methyl tetra-butyl ether (MTBE).*

Figure 1.20
Growth in non-OPEC supply, 2010–2015

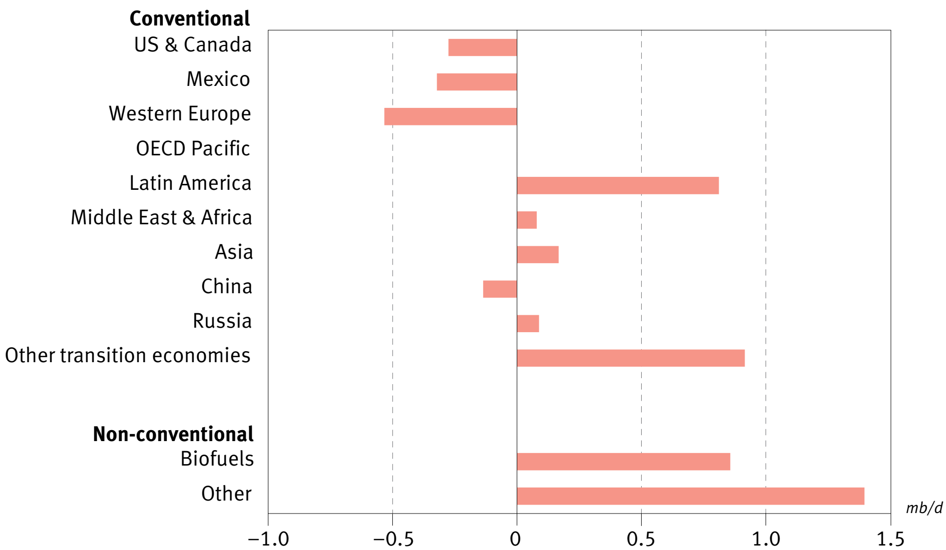
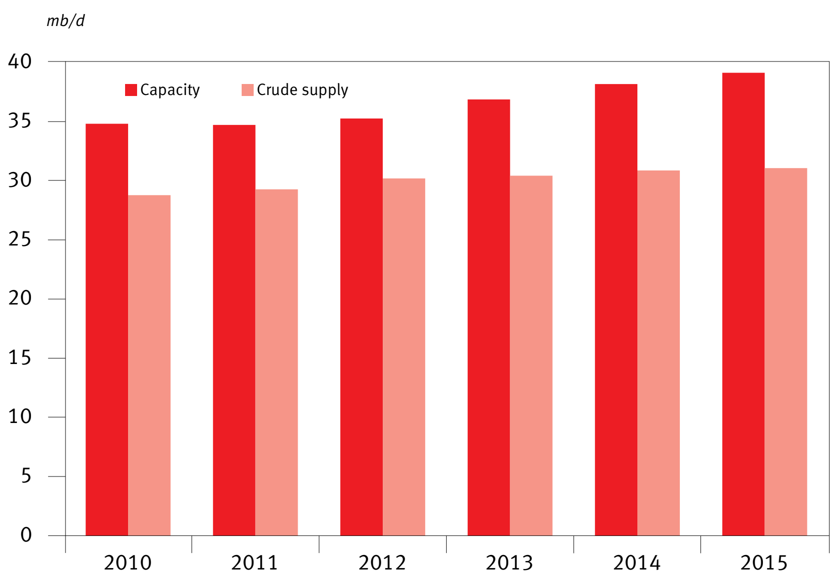


Figure 1.21
OPEC crude oil capacity and supply



stronger than previously expected supply increases from US shale oil, as well as biofuels growth, mainly in Europe and the US. These developments more than compensate for expected declines in conventional oil in North America and the North Sea.

Table 1.8 also shows that an increase in OPEC NGLs is expected in the medium-term, rising from 4.8 mb/d in 2010 to more than 6 mb/d by 2015. Combining the Reference Case demand outlook with these expectations for non-OPEC supply and OPEC NGLs suggests that the amount of OPEC crude that will be required will rise slowly, from 29.3 mb/d in 2010 to 31.3 mb/d by 2015. This is 0.5 mb/d higher than in the WOO 2010. Combined with OPEC production capacity estimates, Figure 1.21 shows that spare OPEC crude oil capacity is set to stabilize at around 8 mb/d over the medium-term, rising from an average level of around 4 mb/d in 2011.

Oil supply in the long-term

Long-term supply paths for conventional oil are developed using assessments of the resource base, based largely upon estimates from the US Geological Survey (USGS) of ultimately recoverable reserves (URR) of crude oil plus NGLs, although some adjustments are introduced where recent production figures call for changing the original USGS estimate for resources. The assessment has also taken into account the implications of the slightly higher oil price assumption that has been made in the Reference Case.

The Reference Case world oil supply outlook appears in Table 1.9.[36] Some of the patterns that have been identified for the medium-term continue to manifest themselves over the long-term. For example, increases in conventional supply from the Caspian and Brazil, as well as steady increases in biofuels, oil sands and shale oil will more than compensate for expected decreases in mature regions.

This is particularly the case for Asia and non-OPEC Middle East & Africa, which over the long-term will join OECD regions in seeing a fall in conventional oil production. Despite this, however, non-conventional oil supply growth will still mean rising net levels of non-OPEC supply. Total non-OPEC non-conventional oil supply rises by more than 11 mb/d over the years 2010–2035, as supply from the Canadian oil sands, biofuels in the US, Europe and Brazil; and shale oil, particularly in the US, continue to expand. On top of this, total NGLs supply, from OPEC and non-OPEC, increases by 6 mb/d over the period 2010–2035, from 10.5 mb/d in 2010 to almost 17 mb/d by 2035. In other words, the total increase in non-crude liquids supply will satisfy more than three quarters of the demand rise to 2035 (Figures 1.22, 1.23 and 1.24).

Table 1.9
World oil supply outlook in the Reference Case

mb/d

	2010	2015	2020	2025	2030	2035
US & Canada	12.0	13.0	13.5	14.3	15.2	16.0
Mexico	3.0	2.6	2.4	2.2	2.0	1.6
Western Europe	4.4	3.9	3.8	3.6	3.6	3.8
OECD Pacific	0.6	0.7	0.7	0.7	0.7	0.8
OECD	**19.9**	**20.3**	**20.4**	**20.9**	**21.6**	**22.2**
Latin America	4.7	5.7	6.6	7.0	7.1	7.1
Middle East & Africa	4.4	4.5	4.4	4.2	3.9	3.7
Asia	3.7	4.0	4.2	4.0	3.7	3.5
China	4.1	4.3	4.2	4.2	4.4	4.9
DCs, excl. OPEC	**16.9**	**18.4**	**19.4**	**19.5**	**19.2**	**19.3**
Russia	10.1	10.3	10.5	10.5	10.5	10.5
Other transition economies	3.2	4.0	4.4	4.7	5.1	5.6
Transition economies	**13.4**	**14.3**	**14.9**	**15.2**	**15.6**	**16.1**
Processing gains	2.1	2.4	2.6	2.7	2.9	3.0
Non–OPEC	**52.3**	**55.3**	**57.3**	**58.3**	**59.2**	**60.5**
of which: non-conventional	3.9	6.1	7.9	10.2	12.6	15.5
NGLs	5.7	6.4	6.7	6.9	7.1	7.3
OPEC NGLs	**4.8**	**6.2**	**7.2**	**8.0**	**8.9**	**9.4**
OPEC GTLs*	**0.1**	**0.3**	**0.4**	**0.5**	**0.6**	**0.6**
OPEC crude	**29.3**	**31.3**	**33.2**	**35.4**	**37.4**	**39.3**
World supply	**86.4**	**93.1**	**98.0**	**102.2**	**106.0**	**109.9**

* *Includes MTBE.*

It is important to emphasize that the dominance of non-crude liquid supply forms in future growth is often overlooked.

Finally, OPEC crude supply in the Reference Case rises throughout the period to 2035, reaching just over 39 mb/d by 2035, which allows for a small amount of additional supply necessary for stocks. The share of OPEC crude in total supply by 2035 is 36% (Figure 1.25). By 2030 OPEC crude reaches 37.4 mb, or 1.3 mb/d lower than in last year's publication.

Figure 1.22
Incremental OPEC and non-OPEC supply in the Reference Case

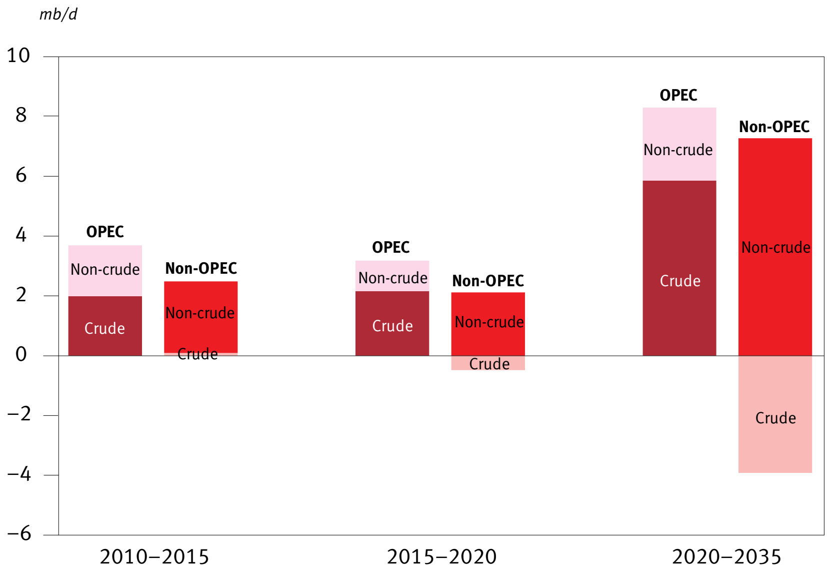


Figure 1.23
Incremental crude and non-crude oil supply in the Reference Case

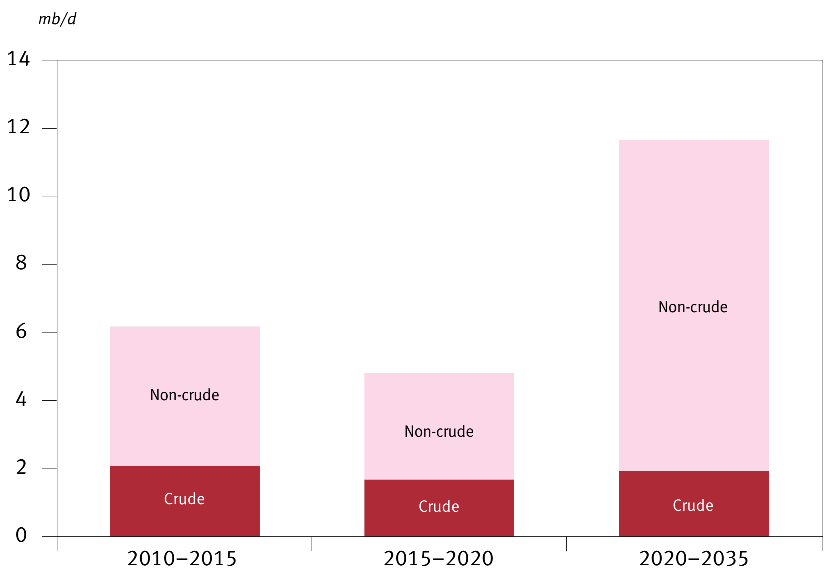


Figure 1.24
World oil supply 1970–2035: crude and other sources

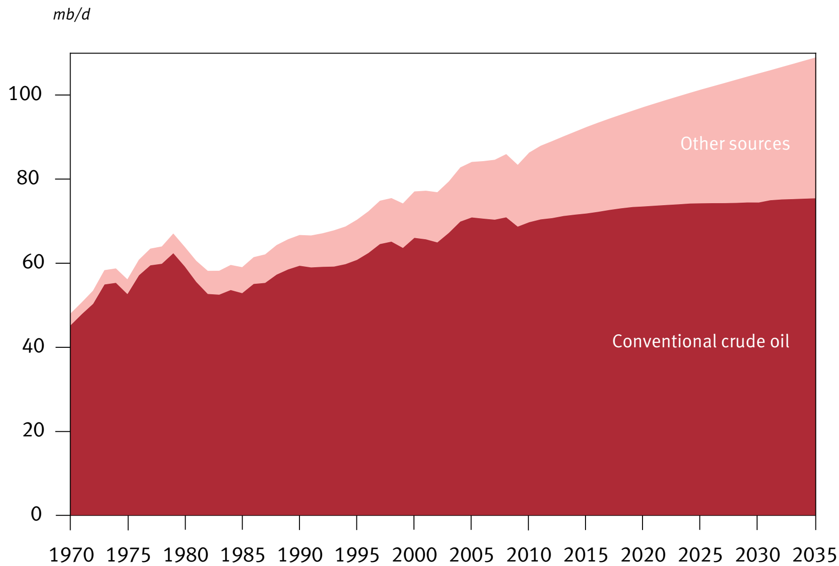
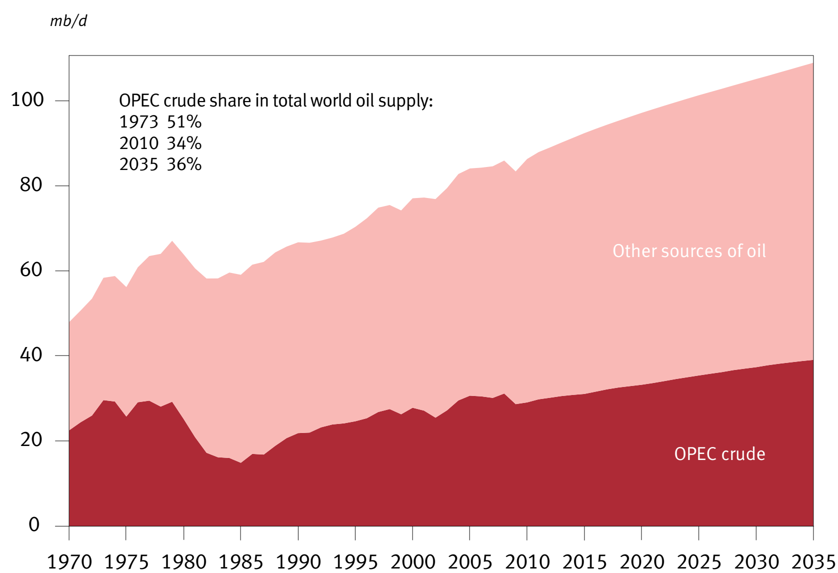


Figure 1.25
OPEC crude and other sources of liquids supply in the Reference Case

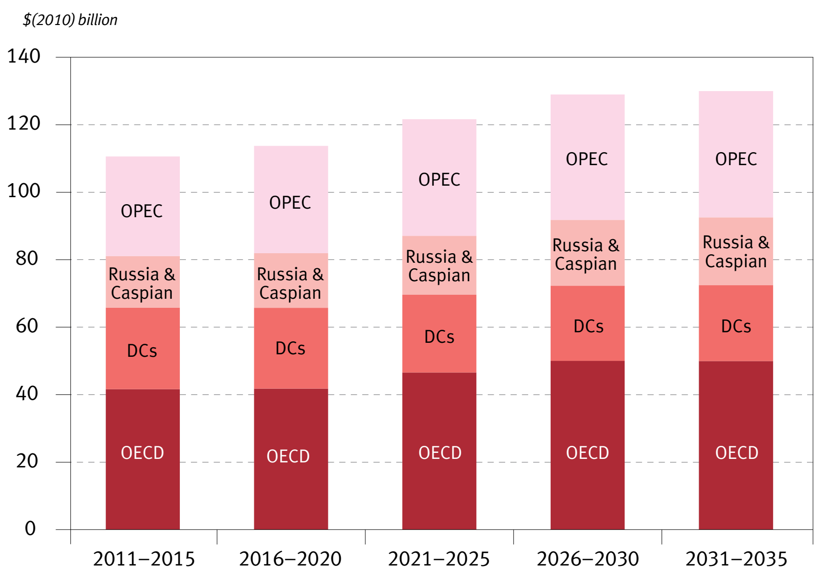


Upstream investment

In the assumptions section of this Chapter, and in particular in Box 1.2, the behaviour of upstream costs was addressed. It was shown that these costs increased by 130% from the first quarter of 2004 to the third quarter of 2008. Costs then fell as the economy faltered, but this drop bottomed out at the end of 2009. Since then they have begun to rise once more.

This behaviour was interpreted in terms of both cyclical and structural effects. There are evidently uncertainties surrounding how costs will pan out, but the evidence appears to suggest that a continuous future upward trend, at least in real terms, is not to be expected. This, however, is only a broad conclusion, and the impact of the technology versus depletion battle will almost certainly vary across regions. For example, we have seen that North Sea production prospects are very much limited by the resource base, and, for this region, it is expected that costs per b/d of additional capacity will gradually rise. In regions where the resource base is more plentiful, and where it is not expected that oil will be supplied from increasingly hostile environments, for instance, the Caspian and Russia, costs are expected to rise very little, if at all, in real terms.

Figure 1.26
Annual upstream investment requirements for capacity additions in the Reference Case, 2011–2035

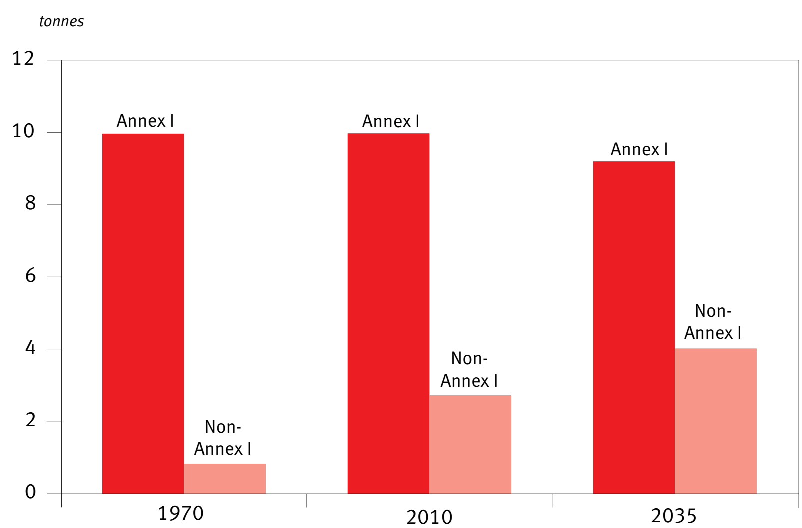


Over the period 2010–2035, upstream investment requirements for additional capacity amount to over \$3 trillion, in 2010 dollars, which it should be noted excludes investment in additional infrastructure, such as pipelines. Most of this investment will be made in non-OPEC countries: on an annualized basis, over the medium-term non-OPEC will need to invest an average of \$77 billion p.a., rising to well over \$90 billion p.a. in the longer term. OPEC, on the other hand, would be expected to invest an average of \$30 billion annually over the medium-term, rising towards \$40 billion p.a. in the long-term (Figure 1.26). The OECD's share in global investment will be close to 40% in the longer term, given the high costs and decline rates.

CO_2 emissions

The pattern of Reference Case energy demand use has shown that fossil fuels will continue to satisfy a large share of world energy needs, with coal becoming the number one fuel type by the end of the projection period. Of course, this means, in the likely absence of an early and widespread deployment of carbon capture and storage (CCS), there will be an increase in global annual CO_2 emissions, which rise in the Reference Case by 43% from 2010–2035. By 2012, Annex I and non-Annex I emissions are approximately equal. By 2035, non-Annex I emissions account for 65% of the global total and by this time, Annex I emissions are 2% below their 1990 levels. It should be stressed, however, that the per capita situation for CO_2 emissions paints a much

Figure 1.27
Per capita CO_2 emissions in the Reference Case

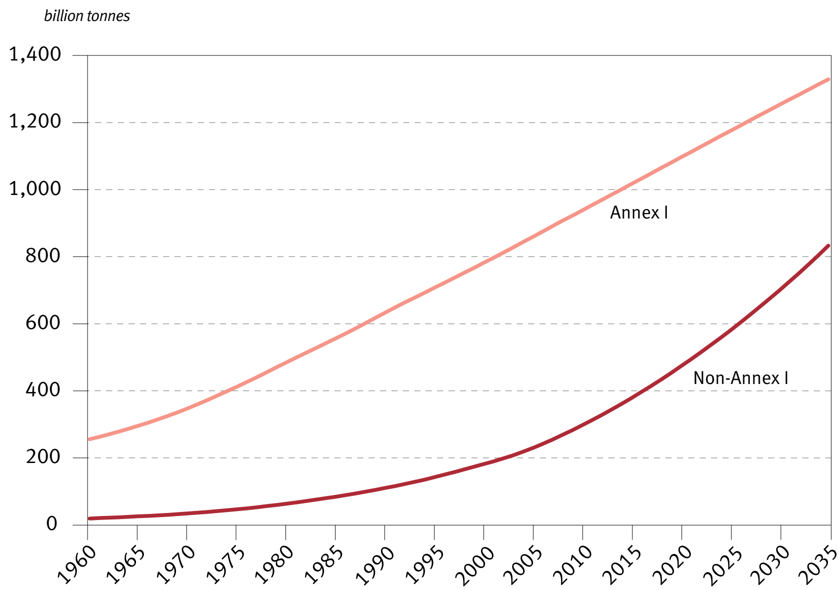


different picture. By 2035, Annex I countries emit, on average, 2.3 times more CO_2 than non-Annex I countries (Figure 1.27).

Moreover, cumulative emissions from Annex I will continue to be far higher than from non-Annex I countries: by 2035, they will still represent 61% of cumulative CO_2 emissions since 1900 (Figure 1.28).

Chapter 1

Figure 1.28
Cumulative CO_2 emissions from 1900, 1960–2035

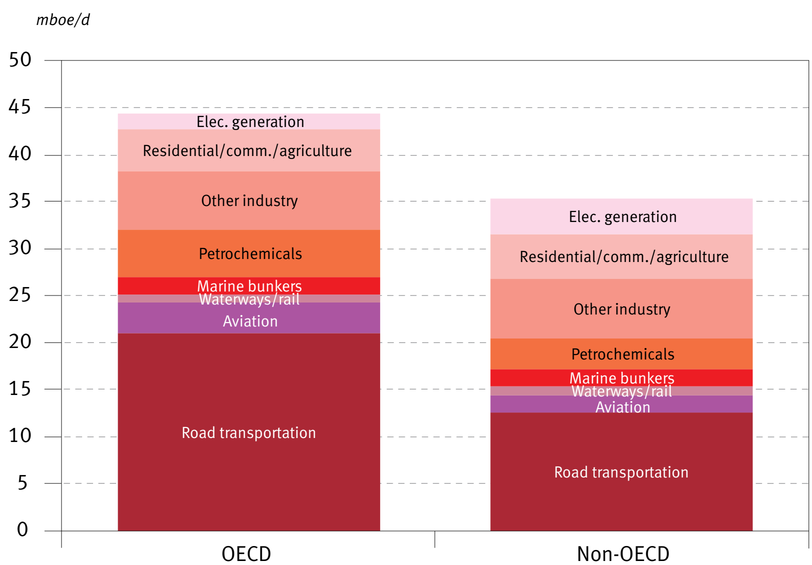


Oil demand by sector

This Chapter looks in more detail at oil demand developments at the sectoral level. Figure 2.1 shows the level of oil consumption in 2008 by sector for the OECD and non-OECD countries, while demand shares are shown in Figure 2.2.

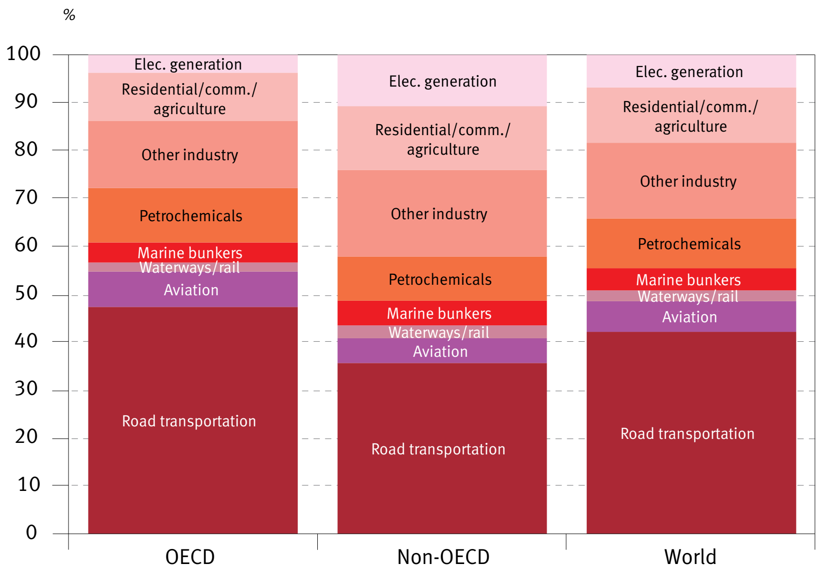
Transportation, consisting of road, aviation, internal waterways, rail and international marine bunkers, accounted for 55% of total oil consumption in 2008. Road is clearly the single most important transportation sector for oil use, in both OECD and non-OECD regions. The drivers behind future oil demand prospects in this sector are complex and varied: in OECD countries, car ownership will increasingly exhibit saturation effects, while the significant potential for future car ownership expansion in developing countries, will face some constraints, as congestion and local pollution may lead to future policies aimed at slowing expansion and pushing towards favouring public transport. Similarly, future developments in technology, and the rate of diffusion, coupled with consumer preferences, will have significant implications for future oil demand in this sector (Box 2.1).

Figure 2.1
Oil demand by sector in 2008



Source: OECD/IEA Energy Balances of OECD/non-OECD countries, 2010.[37]

Figure 2.2
The distribution of oil demand across sectors in 2008



Elsewhere, some sectors will continue to rely on oil use. In non-OECD countries, total industrial oil consumption, including petrochemicals and other uses, accounted for 31% of all oil demand in 2008, and is growing in importance. Other sectors are expected to see oil use dwindle, for instance, the electricity generation sector in OECD countries, which has been on a downward trend since the 1970s.

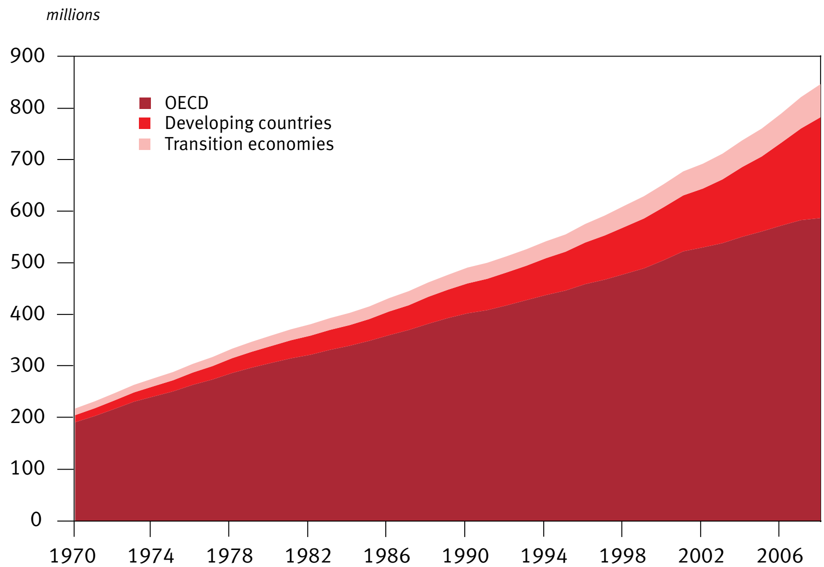
This underscores the importance of analyzing the various factors in play across these sectors when making an assessment of oil demand prospects.

Road transportation

Passenger car ownership

In 2008, there were almost 850 million passenger cars[38] in the world, with almost 70% of these cars in OECD countries. However, the share of cars in developing countries has been rising rapidly: from just 6% of the global stock in 1970 to more than 23% in 2008 (Figure 2.3).

Figure 2.3
Passenger cars in use, 1970–2008



This rapid acceleration of the car stock in countries that have relatively low per capita ownership levels has come with rising income levels. And today, there remains huge potential for growth in the stock of cars in many developing countries. For example, car ownership in OECD countries in 2008 averaged 489 per 1,000 people, while in developing countries it averaged just 38 per 1,000. Table 2.1 and Figure 2.4 document the huge differences in car ownership per capita for individual countries, as well as world regions. For instance, while 722 cars per 1,000 people were on the road in the US in 2008, the level was as low as just one car per 1,000 in parts of Africa and Asia.

The rapid growth in the number of cars in developing countries is emphasized in Figure 2.5. China saw by far the fastest growth of car ownership over the years 2000–2008, increasing by 27 million over that period.

While rising disposable income levels continued to push car ownership to higher levels in the OECD over the period 2000–2008, an increase of 82 million in the stock of cars, saturation effects will increasingly come into play. Indeed, these effects are already visible in some countries, notably the US and Canada (Figure 2.6). On top of this, the amount of kilometres driven per car also tends to reach saturation levels, or

Table 2.1
Vehicle and passenger car ownership in 2008

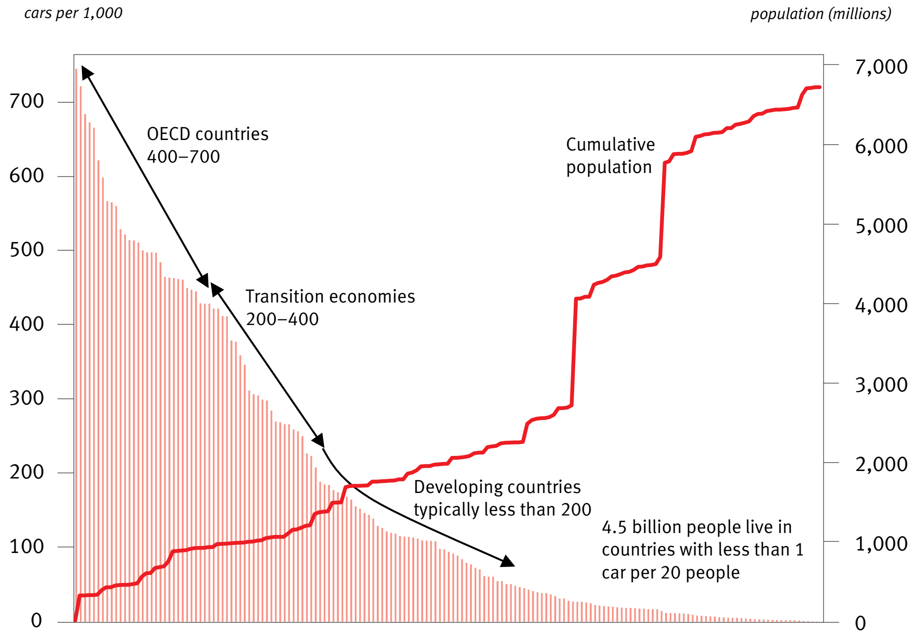
	Population *millions*	**Vehicles** *millions*	**Cars** *millions*	**Cars** *per 1,000*
North America	457.7	299.9	265.5	580.1
Canada	33.3	19.5	18.9	566.8
Mexico	108.6	28.0	19.2	177.3
US	311.7	245.9	225.0	721.8
Western Europe	542.2	274.2	236.0	435.3
Austria	8.3	4.7	4.3	514.0
Belgium	10.6	5.8	5.1	484.5
France	62.0	37.2	30.9	497.3
Germany	82.3	45.5	41.2	500.6
Greece	11.1	6.2	5.0	445.1
Hungary	10.0	3.6	3.1	305.2
Italy	59.6	40.2	35.7	598.5
Luxembourg	0.5	0.4	0.3	684.1
Netherlands	16.5	8.5	7.4	447.2
Poland	38.1	18.9	16.1	422.0
Portugal	10.7	5.6	5.5	511.0
Spain	44.5	27.6	22.1	497.8
Turkey	73.9	10.2	6.8	92.0
UK	61.2	32.3	28.4	463.7
OECD Pacific	200.8	111.2	85.9	427.8
Australia	21.1	14.7	11.8	560.1
Japan	127.3	76.0	59.0	463.3
New Zealand	4.2	3.1	2.6	622.0
South Korea	48.2	16.8	12.5	259.3
OECD	**1,200.6**	**685.3**	**587.4**	**489.2**
Latin America	421.7	76.2	59.7	141.5
Argentina	39.9	13.4	10.6	266.3
Brazil	192.0	40.1	32.3	168.3
Chile	16.8	2.9	1.8	108.6
Colombia	45.0	2.6	1.8	41.1
Peru	28.8	1.6	1.0	34.6
Uruguay	3.3	0.7	0.6	184.2
Middle East & Africa	824.1	35.0	22.4	27.2
Egypt	81.5	3.5	2.5	31.2
Ethiopia	80.7	0.3	0.1	0.9
Ghana	23.9	0.8	0.5	21.7
Jordan	6.1	0.9	0.6	98.0
Kenya	38.8	0.9	0.7	17.7
Morocco	31.6	2.3	1.7	54.8
South Africa	49.7	8.1	5.4	109.7
Sudan	41.3	1.2	0.8	20.3
Syria	21.2	1.3	0.6	26.0

Table 2.1 (continued)
Vehicle and passenger car ownership in 2008

	Population *millions*	**Vehicles** *millions*	**Cars** *millions*	**Cars** *per 1,000*
South Asia	1,595.4	24.9	16.6	10.4
Bangladesh	160.0	0.4	0.2	1.1
India	1,181.4	20.4	14.0	11.8
Pakistan	177.0	1.8	1.4	8.1
Sri Lanka	20.1	1.2	0.4	19.0
Southeast Asia	641.5	53.1	33.7	52.5
Indonesia	228.2	17.6	9.9	43.2
Malaysia	27.0	9.0	8.1	298.3
Philippines	90.3	3.0	1.0	11.5
Singapore	4.6	0.7	0.6	119.8
Taiwan	22.7	6.7	5.7	250.0
China	1,337.4	49.5	36.0	26.9
OPEC	384.8	39.8	28.7	68.5
Algeria	33.9	3.8	2.5	72.7
Angola	17.5	0.7	0.7	39.9
Ecuador	13.8	0.8	0.5	36.8
Iran	71.3	9.2	8.2	114.5
Iraq	29.5	2.7	0.8	27.1
Kuwait	2.9	1.3	0.8	256.6
Libya	6.3	1.8	1.4	223.4
Nigeria	151.5	6.7	3.4	22.5
Qatar	0.9	0.6	0.4	428.7
Saudi Arabia	24.8	6.4	5.6	226.7
United Arab Emirates	4.5	1.5	1.4	306.7
Venezuela	27.9	4.1	3.1	112.2
Developing countries	**5,205.0**	**278.4**	**197.0**	**37.9**
Russia	142.0	34.8	29.5	207.8
Other transition economies	198.8	38.2	34.7	174.6
Belarus	9.7	3.2	2.8	284.5
Bulgaria	7.6	2.7	2.4	311.6
Kazakhstan	15.7	3.1	2.6	164.6
Romania	21.4	4.7	4.0	188.5
Ukraine	46.0	6.9	6.4	139.0
Transition economies	**340.7**	**73.0**	**64.2**	**188.4**
World	**6,746.3**	**1,036.7**	**848.6**	**125.8**

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

Figure 2.4
Passenger car ownership per 1,000, 2008



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

Figure 2.5
Increase in passenger cars, 2000–2008

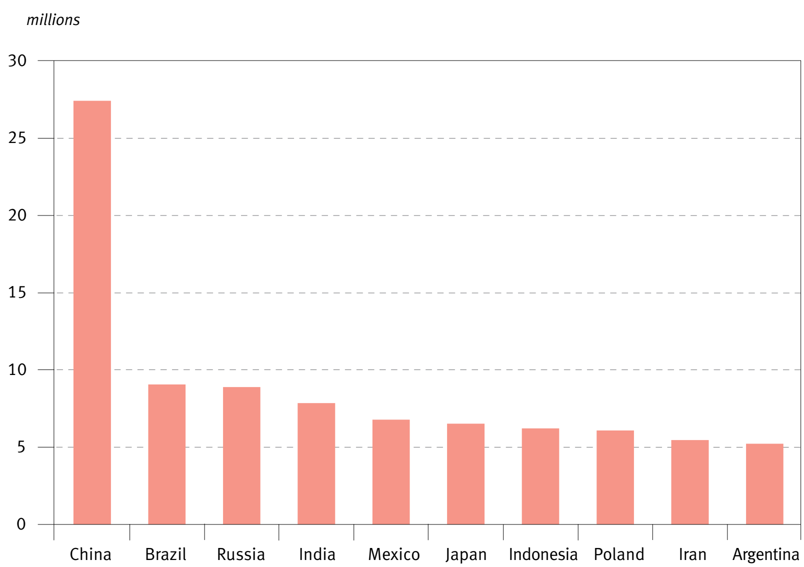
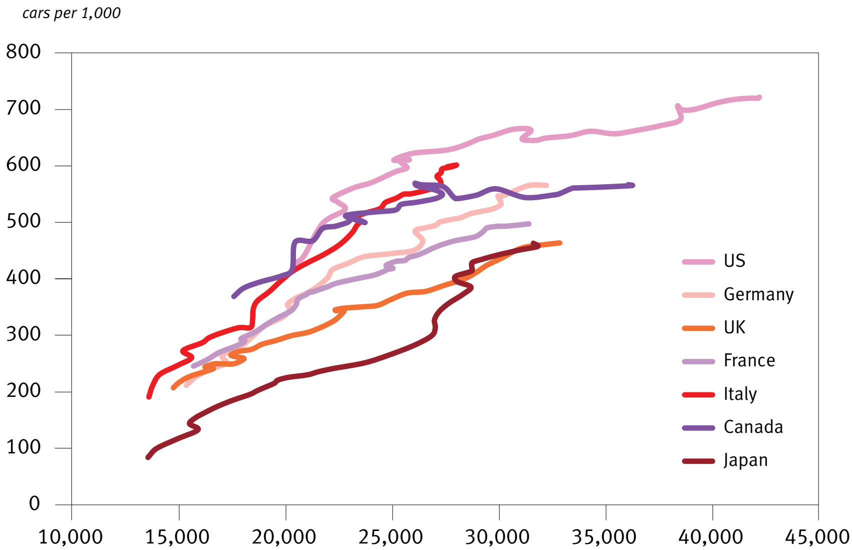


Figure 2.6
Car ownership levels compared to real GDP per capita



even fall, as incomes increase and car ownership ratios rise. These impacts are key to the oil demand growth slowdown observed in OECD countries.

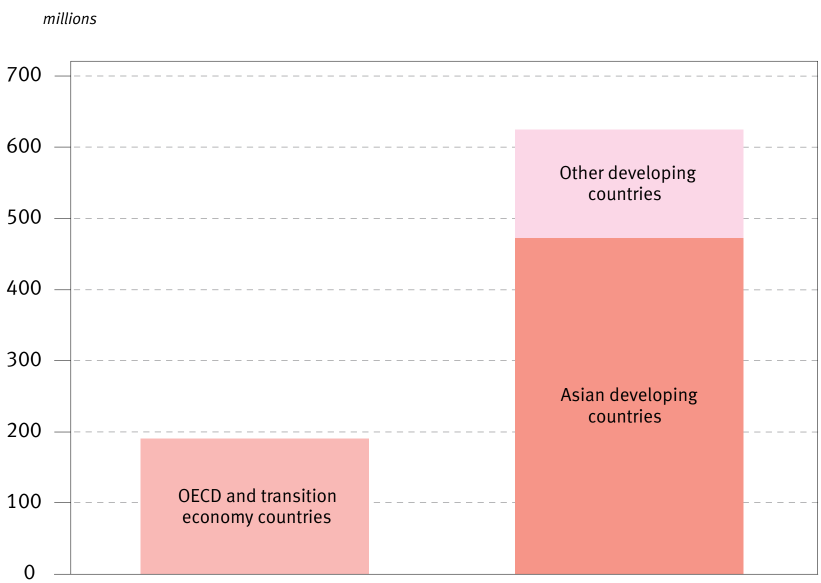
Table 2.2 presents the Reference Case projections for the number of passenger cars. By 2035, there will more than 1.6 billion cars in the world. Over the period 2008–2035, OECD countries see an additional 131 million cars on the road. For developing countries, however, the increase is far more dramatic, with the number of cars rising by 628 million (Figure 2.7). This means that within two decades there will be more cars in developing countries than in the OECD. More than 58% of the increase in cars over this timeframe will be in developing Asia.

In the period to 2035, the per capita car ownership picture changes markedly. In developing countries it increases from an average of 37 per 1,000 in 2008 to 118 per 1,000 by 2035, while OECD rates of ownership increase from 489 to 539 per 1,000. In line with recent developments, and its huge growth potential, China sees the most dramatic rise, from just 27 cars per 1,000 in 2008 to 194 per 1,000 by 2035, similar to the rate seen in Western Europe in 1974, and the OECD Pacific in 1982. Transition economies see a rapid rise in car ownership too, from 125 per 1,000 in 2008 to 379 per 1,000 in 2035. Latin America and Southeast Asia also rise to considerably higher ownership rates,

Table 2.2
Projections of passenger car ownership to 2035

	Cars *per 1,000*			Cars *million*			Car growth *% p.a.*
	2008	**2020**	**2035**	**2008**	**2020**	**2035**	**2008–2035**
North America	580	583	610	263	296	339	0.9
Western Europe	435	453	482	235	256	278	0.6
OECD Pacific	428	472	508	86	95	98	0.5
OECD	**489**	**508**	**540**	**584**	**647**	**715**	**0.8**
Latin America	142	174	215	59	82	111	2.4
Middle East & Africa	27	38	52	22	41	74	4.5
South Asia	10	27	71	16	50	153	8.6
Southeast Asia	53	90	155	33	66	125	5.0
China	27	85	194	36	121	284	8.0
OPEC	68	84	128	26	41	75	4.0
Developing countries	**37**	**66**	**118**	**193**	**401**	**821**	**5.5**
Russia	208	257	312	30	35	39	1.1
Other transition economies	175	276	423	35	56	85	3.4
Transition economies	**188**	**268**	**380**	**64**	**91**	**124**	**2.5**
World	**125**	**148**	**195**	**841**	**1,138**	**1,660**	**2.6**

Figure 2.7
Increase in number of passenger cars, 2008–2035



but ownership in South Asia and Africa will still only be around one car per 20 people in 2035. The OPEC car ownership rate almost doubles, from 68 to 128 per 1,000.

Commercial vehicles

The Reference Case projection for commercial vehicles[39] is shown in Table 2.3. Total volumes in 2035 reach just over 440 million, increasing on average by 3.5% p.a., similar to the expected average rate of global economic activity. Once more, developing Asia is the key source of growth, accounting for 55% of the global rise (Figure 2.8).

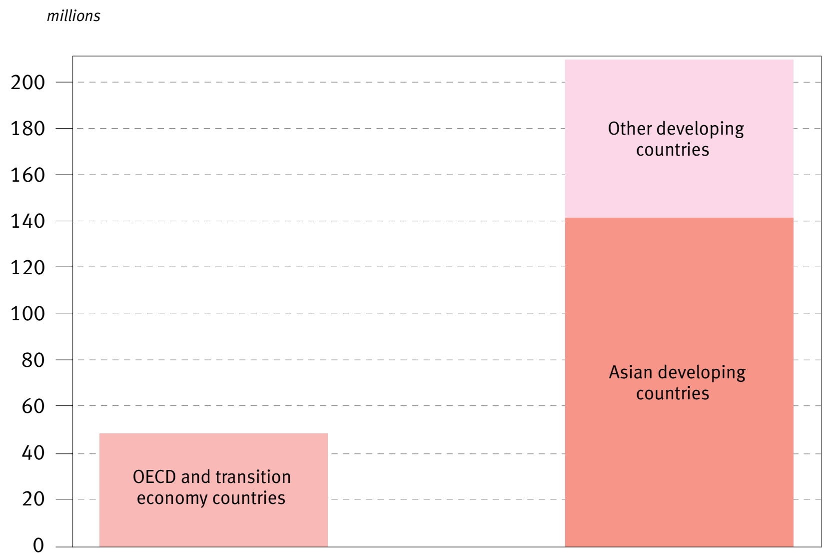
Oil use per vehicle

Many factors will affect average oil use per vehicle. Wealth levels can have opposing effects, positively, as increases in wealth affect car purchase decisions, but also negatively

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

	2008	2020	2035	Growth *% p.a.* 2008–2035
North America	30	37	43	1.3
Western Europe	38	49	69	2.3
OECD Pacific	25	25	26	0.2
OECD	**93**	**112**	**138**	**1.5**
Latin America	15	25	38	3.6
Middle East & Africa	10	19	37	5.1
South Asia	8	25	64	8.1
Southeast Asia	18	37	72	5.3
China	14	27	50	4.9
OPEC	10	17	28	3.7
Developing countries	**74**	**150**	**289**	**5.2**
Russia	6	6	7	0.7
Other transition economies	3	5	7	2.6
Transition economies	**9**	**11**	**13**	**1.6**
World	**176**	**273**	**441**	**3.5**

Figure 2.8
Increase in volume of commercial vehicles, 2008–2035



as saturation effects tend to reduce the kilometres driven per car. Critical to the long-term evolution of oil use per vehicle, however, is government policy and technological development (Box 2.1). As discussed in Chapter 1, the US EISA and the EU package of energy and climate change measures have been incorporated into the Reference Case, which has direct implications for this variable. The measure of average oil use per vehicle is therefore a very important scenario variable, reflecting major uncertainties over future oil demand patterns.

Table 2.4 documents the Reference Case assumptions, which globally shows average efficiency improvements of 1.7% p.a. OECD countries are assumed to see an average decline of 1.5% p.a. in terms of oil use per vehicle, a more rapid fall than that witnessed over the past two decades. This is a reflection of the new policies that have been introduced. Developing countries see an average decline of 2.4% p.a., the same as observed over the period 1990–2008. This could be viewed as a conservative assumption of how future patterns might emerge, especially if policies develop that target efficiencies in these countries, on top of the considerable potential for spillover effects from developed to developing countries through technology diffusion. This possibility, however, is left as a scenario option in Chapter 4 that explores the nature of uncertainties regarding future demand patterns.

Table 2.4
Average growth in oil use per vehicle

% p.a.

	1971–1980	1980–1990	1990–2008	2008–2035
North America	–1.6	–0.8	0.0	–1.5
Western Europe	–0.7	–0.4	–0.8	–1.6
OECD Pacific	–1.6	0.4	–1.0	–1.5
OECD	**–1.3**	**–0.5**	**–0.5**	**–1.5**
Latin America	–4.7	–2.9	–1.4	–1.6
Middle East & Africa	–0.6	–1.0	–1.1	–2.6
South Asia	5.0	–2.1	–5.5	–2.7
Southeast Asia	1.2	–0.6	–3.4	–2.4
China	–5.1	–5.1	–2.9	–3.4
OPEC	2.5	–0.5	–2.5	–1.9
Developing countries	**–1.6**	**–1.9**	**–2.4**	**–2.4**
Russia	n/a	n/a	–5.4	–1.2
Other transition economies	n/a	n/a	–4.7	–1.1
Transition economies	**2.0**	**–2.1**	**–5.3**	**–1.2**
World	**–1.1**	**–0.8**	**–0.9**	**–1.7**

Box 2.1
Road transportation technology: where are the wheels turning?

Given the central role of the road transportation sector in future oil demand growth prospects, it is essential to better understand where technology in the sector is heading. Of the many drivers at play, it is policies that could constitute the major factor in influencing the research, development, diffusion and deployment of more advanced vehicle-related technologies, as well as consumer choices.

Until now, policy has typically focused upon improving air quality by mandating reduced pollutant emissions (nitrogen oxide (NOx), sulphur oxide (SO_2), aromatics, etc.) and imposing more stringent product specifications. This will continue in the future. Increasingly, however, other objectives are also being pursued by policymakers. Two appear to be gaining in prominence: to limit GHGs, particularly CO_2, and to improve fuel economies. While the former is at present mainly being pursued in Europe, the latter concerns all regions of the world. This is impacting all road transportation technologies.

Conventional powertrain technology is expected to remain a source of efficiency gains. Manufacturers will focus on a range of evolutionary steps to realize improvements for CO_2 emissions and fuel consumption. These will centre on base engine updates, thermal management, energy management and the downsizing of engines. Non-powertrain improvements, such as reduced roll resistance tyres, vehicle weight reduction and aerodynamic improvements will also play a significant role.

Today, clean diesel engines offer at least 20% better fuel consumption than conventional gasoline engines. The limited popularity of diesel (except in Europe), however, means that wide scale technology improvements will be dependent on gasoline engine updates. These offer significant potential, in the areas highlighted earlier, and it is expected that the performance gap to diesel engines will be progressively reduced.

Hybrid and plug-in vehicles will also begin to have an impact on the vehicle sales mix, with the share of internal combustion engine hybrids and plug-ins in new passenger car sales expected to reach 15% and 20%, respectively, by 2035. Their expansion will be spurred on by legislative targets imposed by regulators in a growing number of the world's major consuming markets. Several types of hybrid, such as stop-start macro hybrids, mild hybrids and full hybrids, as well as plug-ins, are expected to be introduced, targeted at specific applications and vehicle segments.

Hybrid vehicles are currently disadvantaged by such factors as high system costs, particularly in terms of engine production, higher prices, limited battery life, replacement costs and the idea that their 'real world fuel economy' may not match a manufacturers' stated levels. The relative take-up of different types of hybrids is likely to be significantly influenced not only by price premiums, but also by regional differences and car manufacturer policy. The markets with established niche positions, such as the US and Japan, as well as hybrid-focused manufacturers, like Toyota and Honda, have a strong preference for gasoline hybrids. Diesel hybrids face higher powertrain costs and are likely to be more successful in the premium vehicle segment and in regions where there is a greater acceptance of diesel.

Plug-in hybrid electric vehicles and electric vehicles are set to grow, but technology and infrastructure are still in their infancy and customer habits will need time to change. Moreover, the market share of electric vehicles is likely to remain small, particularly for as long as battery performance does not dramatically improve in terms of costs, charging time, power density and the car's lifespan. Thus, without substantial subsidies, they only really constitute a niche market.

Hydrogen fuel cells will require dramatic technological advances and cost reductions to become a viable road transportation technology; it is an evolution that seems unlikely for the foreseeable future. Indeed, many challenges lie ahead, including solutions for storing hydrogen in the vehicle, a renewables-based source of hydrogen, and infrastructure for the storage and distribution of the fuel. If these challenges are not met, it is unlikely that significant numbers of hydrogen fuel cell cars will enter the marketplace before 2030.

With regard to trucks, the focus is now also turning to CO_2/fuel consumption targets. In this regard, Japan is leading the way, but other markets are making some headway. In the US, policymakers have for the first time taken firm steps towards implementing fuel efficiency standards for heavy duty vehicles. This could include the development of the first-ever GHG and fuel efficiency regulations for medium- to heavy-duty vehicles. The proposed regulations cover model years between 2014 and 2018, with increasing stringency for each model year.

However, the implementation of CO_2/fuel consumption targets for trucks will be slower overall than for passenger cars, and will be mainly dependent on improvements in conventional powertrains and transmissions.

The fuel consumption of the base diesel engine for trucks is unlikely to significantly change in the near future, but the addition of waste heat recovery systems, a reduction of rolling resistance, improved vehicle aerodynamics, and lighter materials, could improve fuel efficiency.

In terms of alternative powertrains, the penetration of hybrids will be limited and affect only light- and medium-duty trucks and short range/endurance products. Truck hybrids will benefit from technologies developed for the passenger car market.

The main challenge for hybrid technology in this segment is to improve its financial attractiveness – in terms of payback – and to overcome the technical challenges, particularly in terms of battery energy storage and power density. Some plug-in applications are possible, but they are not yet a focus of truck manufacturers. Nevertheless, plug-in hybrids are more likely to be developed for the light- and medium-duty markets, with initial applications probably in urban environments for fleets that return to the same base on a daily basis.

The development of CNG commercial vehicles has seen them establish positions in specific applications areas, but in general it will be a niche market. This is due to lack of a refuelling infrastructure, the significant increase in vehicle acquisition costs, and the lower energy density of CNG, which means frequent refuelling.

Conventional technology improvements and the take-up of new powertrain technologies are anticipated to affect average fuel consumption for new passenger vehicles by more than 50% over the next 25 years, although fuel consumption improvements will be much more modest for trucks. Lower levels of hybridization and limited opportunities for plug-ins, combined with limited improvements to mainstream diesel engine technology, mean that overall fuel consumption reductions will be closer to 20%. These improvements and penetration prospects for new technologies are factored into the Reference Case, but it is also clear that an alternative, more rapid take-off and diffusion is possible, especially with more aggressive policies. This is explored in Chapter 4.

One of the key unknowns for this variable is how future legislative and technological developments in the commercial vehicle sector will evolve. For example, CO_2 emission standards have had, and will continue to have, a sizeable impact upon fuel efficiencies in the OECD road transportation sector. To date, however, the impact has been limited to passenger cars. Nevertheless, it is important to ask the question whether, and when, such standards might be applied to trucks and buses. Adapting to future possible standards is already influencing the industry, and truck manufacturers are positioning themselves for such moves.

Some policies affecting oil consumption in this sector are already in place. For example, in the EU, minimum tax levels were introduced in 1992. A speed limit of 90 kilometres per hour (kph) for heavy vehicles and the labelling of the rolling resistance of tyres have also had an impact. On top of this, road charges could have significant effects upon truck usage: such charges have already been introduced in Austria, Germany, the Czech Republic, Slovakia and Portugal, and in 2012 they are due to appear in France, Poland and Hungary. The distances travelled by trucks in Germany have been markedly affected since the introduction of road charges in 2005. Such road charges are becoming an EU-wide trend, and could prove to be influential in determining future oil use by trucks.

Road transportation demand projections

Road transportation oil demand levels and growth rates appear in Tables 2.5 and 2.6. Demand increases by close to 10 million barrels of oil equivalent per day (mboe/d) over the period 2008–2035. OECD road transportation demand falls throughout

Table 2.5
Oil demand in road transportation in the Reference Case

mboe/d

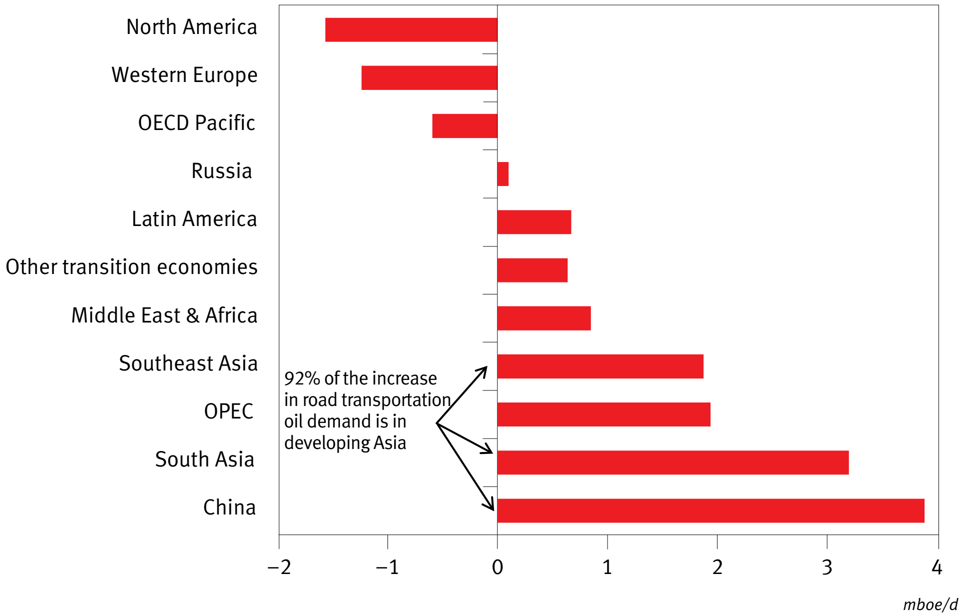
	Levels				Growth
	2008	2010	2020	2035	2008–2035
North America	12.3	12.2	12.0	10.7	–1.6
Western Europe	6.3	5.8	5.6	5.0	–1.2
OECD Pacific	2.5	2.5	2.3	1.9	–0.6
OECD	**21.0**	**20.6**	**19.9**	**17.6**	**–3.4**
Latin America	2.0	2.1	2.5	2.6	0.7
Middle East & Africa	1.2	1.3	1.7	2.1	0.8
South Asia	1.0	1.2	2.2	4.2	3.2
Southeast Asia	1.8	2.1	2.7	3.6	1.9
China	2.3	2.6	5.2	6.2	3.9
OPEC	2.6	2.7	3.6	4.6	1.9
Developing countries	**10.9**	**12.0**	**17.8**	**23.3**	**12.4**
Russia	0.8	0.9	1.0	0.9	0.1
Other transition economies	0.8	0.7	1.0	1.4	0.6
Transition economies	**1.6**	**1.6**	**2.0**	**2.4**	**0.7**
World	**33.7**	**34.2**	**39.7**	**43.3**	**9.7**

Table 2.6
Growth in oil demand in road transportation in the Reference Case

% p.a.

	1990–2008	2008–2020	2020–2035
North America	1.7	–0.2	–0.7
Western Europe	1.5	–1.0	–0.6
OECD Pacific	1.4	–0.4	–1.5
OECD	**1.6**	**–0.5**	**–0.8**
Latin America	3.2	1.9	0.5
Middle East & Africa	3.5	2.5	1.5
South Asia	3.5	6.6	4.4
Southeast Asia	4.4	3.7	1.9
China	9.8	7.1	1.2
OPEC	4.2	2.6	1.6
Developing countries	**4.6**	**4.2**	**1.8**
Russia	–0.7	0.6	–0.3
Other transition economies	–0.7	2.0	2.4
Transition economies	**–0.7**	**1.3**	**1.2**
World	**2.2**	**1.4**	**0.6**

Figure 2.9
Increase in oil consumption in road transportation, 2008–2035



the entire period, as efficiency gains more than compensate for the expansion in the number of vehicles. Figure 2.9 emphasizes that 95% of the oil demand increase in road transportation will occur in developing Asia. Within a decade, non-OECD oil use in this sector will be greater than in OECD countries.

Aviation

In 2008, the aviation sector accounted for around 6% of world oil demand, with the OECD making up around two-thirds of this. Over the period 1980–2008, oil demand in this sector more than doubled. Freight tonnage and the number of passengers carried by air increased at close to twice this rate, but efficiency gains from improved aircraft design, materials and engines kept demand in check. At the same time, load factors[40] have improved steadily over the past three decades, at close to an average of 1% p.a. Load factors are also known to respond to higher jet fuel prices. Economies of scale have contributed to productivity increases, as the average aircraft size has grown. It is a trend that is expected to continue in the future. EU-based airplane manufacturer, Airbus, estimates a rate of 1.2% p.a. over the next 20 years, which will help alleviate congestion at major airports.[41] Other efficiency gains have come from operational measures, such as taxiing using one engine, reducing the weight of onboard equipment, and better navigation and traffic control. Although some of these gains will be difficult to improve on in the future, the International Air Transport Association (IATA)[42] has adopted a voluntary target to reduce fuel consumption and CO_2 emissions by at least 25% by 2020 – per revenue tonne kilometre – compared to 2005 levels.[43]

In developed countries, the market is approaching saturation, particularly in the US. Indeed, the lowest percentage increase in aviation passenger traffic over the past three decades has been in North America. Looking forward, it is clear that there is huge potential for air traffic growth in developing countries. This is borne out by the dramatic differences in aviation traffic growth observed across regions. While the world average for aviation travel was about one flight per person in 2007, it ranged from 0.006 flights per head in Bangladesh, to over 13 flights per head in Ireland.[44]

Table 2.7 shows that while passenger kilometres flown in the OECD grew by an average of just over 3% p.a. in the period 2000–2007, developing countries' flights

Table 2.7
Passenger kilometres flown

billions

	1980	2000	2007	1980–2000	2000–2007
North America	452.5	1,225.5	1,436.6	5.1	2.3
Western Europe	206.1	852.0	1187.6	7.4	4.9
OECD Pacific	47.8	296.4	339.9	9.6	2.0
OECD	**706.4**	**2,373.9**	**2,964.1**	**6.2**	**3.2**
Latin America	33.1	103.0	116.9	5.8	1.8
Middle East & Africa	30.2	55.7	96.2	3.1	8.1
South Asia	18.5	49.4	100.8	5.0	10.7
Southeast Asia	43.8	228.9	340.6	8.6	5.8
China	n/a	82.7	273.4	n/a	18.6
OPEC	23.3	39.3	176.6	2.6	23.9
Developing countries	**148.9**	**559.0**	**1,104.5**	**6.8**	**10.2**
Russia	n/a	25.9	80.1	n/a	17.5
Other trans. economies	3.2	20.2	31.5	9.7	6.6
Transition economies	**n/a**	**46.1**	**111.6**	**n/a**	**13.5**
World	**n/a**	**2,979.0**	**4,180.2**	**n/a**	**5.0**

Source: ICAO online database, www.icaodata.com.

rose by an average of more than 10% p.a. China grew by a massive 18.6% p.a., while OPEC countries' flights increased even faster, as the Middle East emerged as an important hub for international air traffic.[45]

The table also demonstrates the wide variation in traffic volumes: in 2007, OECD countries accounted for 71% of global passenger traffic. The International Civil Aviation Organization (ICAO) expects strong growth in air traffic to continue, with an average annual increase in passenger kilometres for the next two decades approaching 5%.[46] Close to half of the increase in traffic is expected to be from, or to, destinations in Asia and the Middle East. However, OECD traffic is also expected to continue to rise strongly, at well over 2% p.a.

Tables 2.8 and 2.9 document the Reference Case levels and growth rates for oil demand in this sector. Over the period 2008–2035, average global growth of 1% p.a. sees demand growth approaching 2 mboe/d. Despite saturation effects, there is still growth in OECD countries. However, developing countries will expand faster in both

Table 2.8
Aviation oil demand in the Reference Case

mboe/d

	Levels				Growth
	2008	2010	2020	2035	2008–2035
North America	1.7	1.7	1.9	2.0	0.2
Western Europe	1.2	1.1	1.2	1.3	0.1
OECD Pacific	0.4	0.4	0.5	0.6	0.2
OECD	**3.3**	**3.3**	**3.5**	**3.8**	**0.5**
Latin America	0.2	0.2	0.2	0.3	0.1
Middle East & Africa	0.2	0.2	0.2	0.3	0.1
South Asia	0.1	0.1	0.2	0.3	0.1
Southeast Asia	0.5	0.5	0.6	0.8	0.3
China	0.2	0.3	0.4	0.7	0.4
OPEC	0.3	0.3	0.3	0.4	0.1
Developing countries	**1.5**	**1.6**	**2.0**	**2.7**	**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	**5.1**	**5.2**	**6.0**	**7.0**	**1.9**

Table 2.9
Growth in aviation oil demand in the Reference Case

% p.a.

	1990–2008	2008–2020	2020–2035
North America	0.2	0.7	0.3
Western Europe	3.6	0.3	0.4
OECD Pacific	2.7	1.0	1.3
OECD	**1.5**	**0.6**	**0.5**
Latin America	3.2	1.5	0.9
Middle East & Africa	3.4	1.2	1.3
South Asia	5.3	2.5	2.8
Southeast Asia	5.9	1.9	1.5
China	15.9	5.1	3.0
OPEC	1.6	2.5	0.8
Developing countries	**4.8**	**2.5**	**1.7**
Russia	–2.4	2.6	1.9
Other transition economies	–2.7	1.8	1.1
Transition economies	**–2.5**	**2.4**	**1.7**
World	**1.9**	**1.3**	**1.0**

percentage and volume terms, with developing Asia accounting for 45% of the global demand increase. Nevertheless, growth rates are expected to be considerably lower than witnessed in the past, as airport and airspace congestion, and even the availability of aircraft, increasingly act as constraints to growth.

Rail and domestic waterways

Other oil demand elements in transportation-related activities are for trains, domestic waterways, which includes coastal shipping, although not oil used for fishing, which is defined as agricultural energy use, and oil used for the pipeline transportation of materials. It also covers what is termed 'non-specified transport'. This element of demand accounted for just under 2 mboe/d in 2008. While demand in OECD countries has been constant or falling, total use in developing countries has been increasing steadily, primarily because of China's growing consumption in both rail and domestic waterways. Oil use for passenger trains will be affected positively by the rising number of domestic train journeys in China, but the expansion of electrification will limit the diesel demand rise in this sector. Increasing domestic freight transport should support growth in the use of oil in domestic waterways in China.

Table 2.10
Oil demand in rail and domestic waterways in the Reference Case

mboe/d

	Levels				Growth
	2008	2010	2020	2035	2008–2035
North America	0.4	0.4	0.4	0.4	–0.1
Western Europe	0.3	0.3	0.2	0.2	0.0
OECD Pacific	0.2	0.2	0.1	0.1	0.0
OECD	**0.8**	**0.9**	**0.8**	**0.7**	**–0.1**
Latin America	0.1	0.1	0.2	0.3	0.1
Middle East & Africa	0.0	0.0	0.0	0.0	0.0
South Asia	0.1	0.1	0.1	0.2	0.1
Southeast Asia	0.1	0.1	0.1	0.1	0.1
China	0.5	0.6	1.0	1.5	0.9
OPEC	0.0	0.0	0.0	0.0	0.0
Developing countries	**0.8**	**1.0**	**1.4**	**2.1**	**1.2**
Russia	0.1	0.1	0.1	0.1	0.0
Other transition economies	0.1	0.0	0.0	0.0	0.0
Transition economies	**0.1**	**0.1**	**0.1**	**0.2**	**0.0**
World	**1.8**	**1.9**	**2.3**	**2.9**	**1.1**

Table 2.11
Growth in oil demand in rail and domestic waterways in the Reference Case

% p.a.

	1990–2008	2008–2020	2020–2035
North America	–1.6	–0.9	–0.6
Western Europe	0.0	–0.6	–0.6
OECD Pacific	–0.4	–1.0	–0.2
OECD	**–0.9**	**–0.8**	**–0.5**
Latin America	3.5	2.4	2.8
Middle East & Africa	7.2	0.0	0.0
South Asia	2.9	2.3	2.9
Southeast Asia	2.3	2.0	2.3
China	9.7	3.7	2.7
OPEC	3.8	1.5	1.5
Developing countries	**6.4**	**3.2**	**2.6**
Russia	–6.6	1.3	1.5
Other transition economies	–3.1	–0.4	–1.0
Transition economies	**–5.5**	**0.7**	**0.7**
World	**0.6**	**1.5**	**1.6**

The Reference Case outlook for oil demand levels and growth rates in this sector are shown in Tables 2.10 and 2.11. As in the past, China is key to future growth, with demand increasing by close to 1 mboe/d over the period 2008–2035, which represents 82% of the global increase.

Marine bunkers[47]

Expansion in world trade inevitably means increasing shipping activity, but at the same time, oil use efficiency improvements in the marine bunkers sector will limit the scope for oil demand growth. This will be compounded by a gradual increase in the size of ships and, of course, the turnover of the capital stock as scrapped ships are replaced by newer more efficient ones (regulatory issues in this sector are looked at in detail in Section Two). Tables 2.12 and 2.13 show that the oil demand increase in marine bunkers is more than 4 mboe/d over the period 2008–2035. The biggest increase is in China and Southeast Asia, accounting for 78% of demand growth.

Table 2.12
Oil demand in marine bunkers in the Reference Case *mboe/d*

	Levels				Growth
	2008	2010	2020	2035	2008–2035
North America	0.5	0.5	0.5	0.4	–0.1
Western Europe	1.1	1.0	1.1	1.1	0.0
OECD Pacific	0.3	0.2	0.1	0.1	–0.2
OECD	**1.9**	**1.7**	**1.7**	**1.6**	**–0.3**
Latin America	0.2	0.2	0.2	0.3	0.1
Middle East & Africa	0.1	0.1	0.1	0.1	0.0
South Asia	0.0	0.0	0.0	0.0	0.0
Southeast Asia	0.8	0.7	1.0	1.5	0.7
China	0.2	0.2	0.6	2.1	1.9
OPEC	0.5	0.4	0.5	0.7	0.3
Developing countries	**1.7**	**1.7**	**2.4**	**4.7**	**2.9**
Russia	0.0	0.0	0.1	0.1	0.1
Other transition economies	0.1	0.1	0.1	0.1	0.0
Transition economies	**0.1**	**0.1**	**0.1**	**0.2**	**0.1**
World	**3.7**	**3.5**	**4.3**	**6.5**	**2.8**

Table 2.13
Oil demand growth in marine bunkers in the Reference Case *% p.a.*

	1990–2008	2008–2020	2020–2035
North America	–1.1	0.0	–0.9
Western Europe	2.3	0.6	0.7
OECD Pacific	3.7	–7.6	–0.2
OECD	**1.4**	**–0.6**	**0.2**
Latin America	4.9	2.5	3.0
Middle East & Africa	–0.3	1.0	0.7
South Asia	-0.4	–4.0	–0.2
Southeast Asia	5.7	2.7	3.6
China	10.1	15.1	8.6
OPEC	4.6	2.0	4.2
Developing countries	**5.0**	**4.4**	**5.2**
Russia	0.0	6.8	5.6
Other transition economies	4.9	2.1	2.3
Transition economies	**2.5**	**4.1**	**4.1**
World	**2.8**	**2.1**	**3.6**

Other sectors

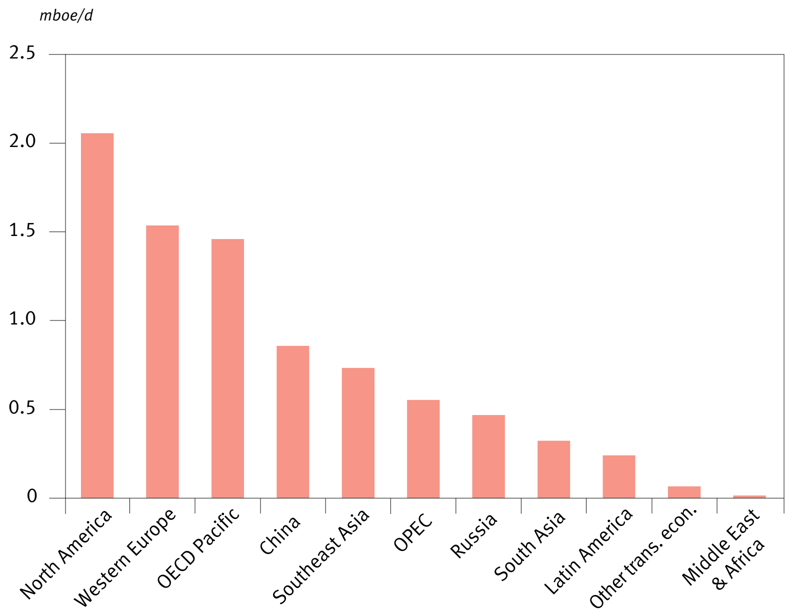
Petrochemicals

Oil use in the petrochemical sector accounts for over 10% of total oil use, both as feedstock and as energy to transform these feedstocks into products. Thus, the prospects for growth in this sector are an important element in assessing future demand patterns. Growing demand for plastics, synthetic fibres, synthetic rubber, detergents, paints, adhesives, aerosols, insecticides and pharmaceuticals, both for domestic consumption and for trade, underpins the sector's demand rise.

The greatest level of consumption at present is in OECD countries, with 61% of total global use, with most of the rest, around 30%, in OPEC and developing Asia countries (Figure 2.10). Since the early 1980s, new capacity has been progressively added in all world regions, but particularly in the Middle East and Asia.

Regional developments, as well as other production technology- and environment-related trends, contribute to this industry's restructuring in terms of regional capacity distribution, major players, feedstocks, global trades and economics.

Figure 2.10
Oil use in the petrochemical sector in 2008



Petrochemicals are being increasingly used by a plethora of economic sectors to help develop new products or to replace more costly or less effective conventional materials. Consequently, petrochemical demand is mostly driven by economic growth in sectors where these products play a major role, such as transportation, manufacturing and construction.

World ethylene demand has typically expanded at a multiple of around 1.5 times global GDP. However, the relationship between ethylene growth and regional economic growth has been shifting, in part due to the evolution of the structure of GDP, with the service sector increasing in importance in relation to manufacturing.

Capacity developments in Latin America are also expected to accelerate, taking advantage of the relatively high derivative demand growth. Central and Eastern Europe are anticipated to develop some new capacities encouraged by the desire to develop national industries and access neighbouring Western European markets.

The Reference Case outlook for oil use in the petrochemical sector is shown in Tables 2.14 and 2.15. Demand in developing countries rises to 5.3 mboe/d by 2035, higher than

Table 2.14
Oil demand in the petrochemical sector in the Reference Case *mboe/d*

				Levels	Growth
	2008	2010	2020	2035	2008–2035
North America	2.1	1.9	1.9	1.9	–0.1
Western Europe	1.5	1.4	1.3	1.2	–0.3
OECD Pacific	1.5	1.4	1.5	1.5	0.0
OECD	**5.1**	**4.6**	**4.7**	**4.6**	**–0.5**
Latin America	0.2	0.2	0.3	0.3	0.1
Middle East & Africa	0.0	0.0	0.0	0.0	0.0
South Asia	0.3	0.3	0.4	0.5	0.2
Southeast Asia	0.7	0.8	0.9	1.1	0.4
China	0.9	1.0	1.2	1.3	0.5
OPEC	0.6	0.6	1.0	1.9	1.4
Developing countries	**2.7**	**2.9**	**3.8**	**5.3**	**2.5**
Russia	0.5	0.5	0.5	0.5	0.1
Other transition economies	0.1	0.1	0.1	0.1	0.0
Transition economies	**0.5**	**0.5**	**0.6**	**0.6**	**0.1**
World	**8.3**	**8.1**	**9.1**	**10.5**	**2.2**

OECD oil use in this sector at that time. In fact, Reference Case projections suggest that non-OECD demand for oil in the petrochemicals sector will already exceed that of OECD countries by 2024. As expected, the only significant demand growth is in OPEC and developing Asia. Oil use in petrochemicals stays approximately flat in the OECD throughout the period 2010–2035, with its overall share in this sector falling to 44% by 2035.

Other industry sector

The sector termed 'other industry' covers a wide range of activities, including iron and steel, glass and cement production, construction and mining. The evolution of oil use in these areas has been markedly different across the developed and developing world. While the OECD has seen a decline in oil use in other industry sectors, developing countries have witnessed a strong increase (Figure 2.11). In fact, by 2007, oil use in this sector was greater in developing countries than in the OECD.

In OECD regions, there was a significant shift away from oil use in this sector when oil prices trended upwards in the 1970s and early 1980s. To a large extent, this

Table 2.15
Growth in oil demand in the petrochemical sector in the Reference Case *% p.a.*

	1990–2008	2008–2020	2020–2035
North America	2.1	–0.6	0.0
Western Europe	1.0	–1.2	–0.7
OECD Pacific	2.8	0.0	0.0
OECD	**1.9**	**–0.6**	**–0.2**
Latin America	1.5	1.6	1.2
Middle East & Africa	–6.2	0.6	0.5
South Asia	5.4	2.0	1.9
Southeast Asia	7.1	1.7	1.5
China	5.2	3.0	0.5
OPEC	5.3	4.7	4.7
Developing countries	**5.0**	**2.8**	**2.2**
Russia	1.0	1.0	0.2
Other transition economies	0.1	0.8	0.8
Transition economies	**0.9**	**0.9**	**0.3**
World	**2.7**	**0.8**	**0.9**

shift was a move from oil to natural gas (Figures 2.12, 2.13 and 2.14). Although this strong decline in oil's share limits the scope for further switching, it is likely that relative prices will continue to have impacts moving forward. This could be particularly influenced by the availability of large quantities of unconventional gas at discount prices compared to liquid fuels. However, there are some uses of oil in this sector that are essentially 'captive' in nature. A key example is the use of bitumen for roads and roofing. In contrast, there are ongoing downward pressures upon demand as the share of manufacturing in OECD GDP continues to decline. In sum, oil use in the OECD in this sector is expected to keep falling, but not quite as fast as observed in the past.

Of the oil demand increase for developing countries in this sector over the period 1990–2008, China led the way with 39% of the increase, followed by South Asia and OPEC, both accounting for 19%. Combined, Asia and OPEC accounted for 85% of the rise in developing country oil use in the sector. For developing Asia, part of this rapid increase is linked to the growing share of industry in total GDP (Figure 2.15). Other important demand growth elements have been the use of bitumen for the construction of roads and increasing glass and cement production as infrastructure has developed. Due

Figure 2.11
Oil use in other industry

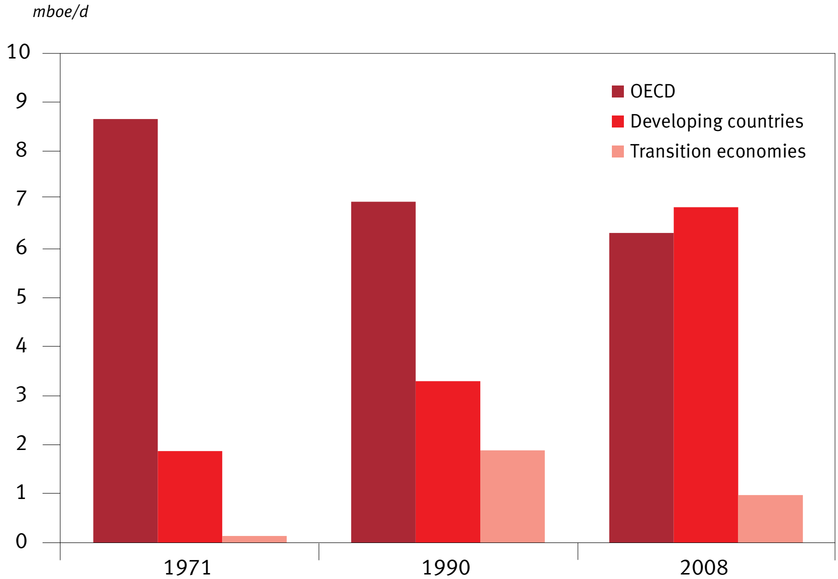


Figure 2.12
Oil and gas shares in energy use in other industry, North America

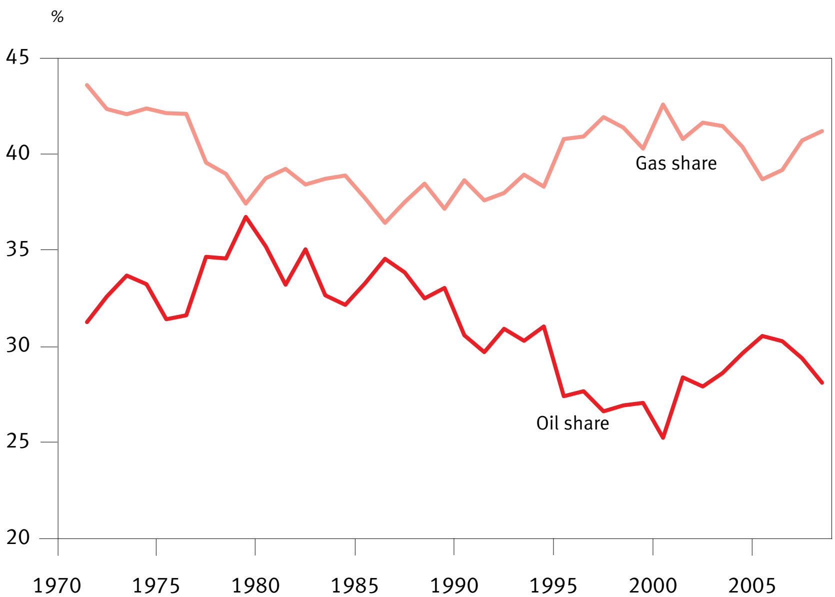


Figure 2.13
Oil and gas shares in energy use in other industry, Western Europe

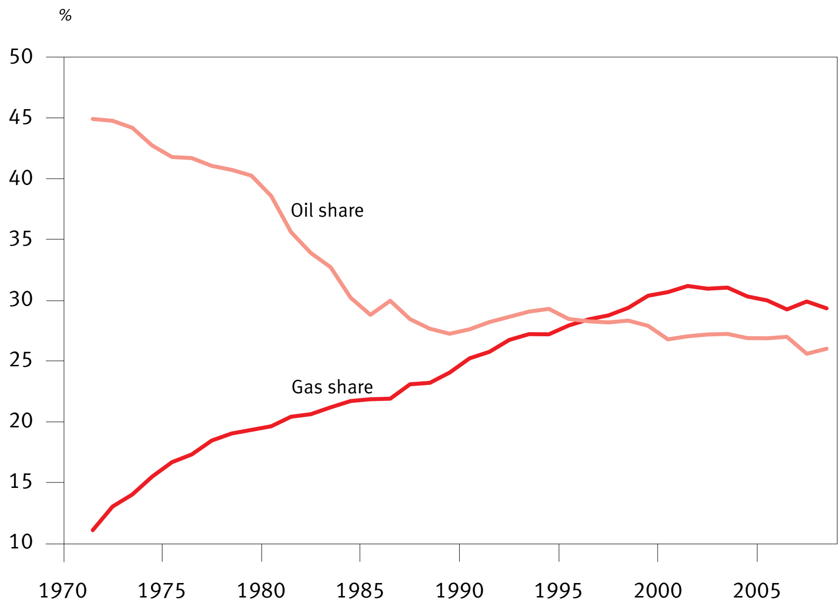


Figure 2.14
Oil and gas shares in energy use in other industry, OECD Pacific

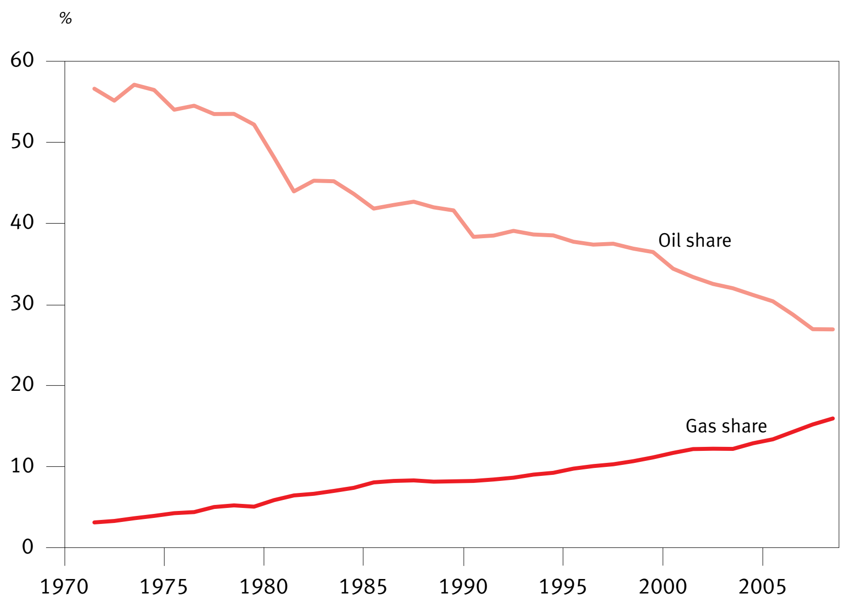
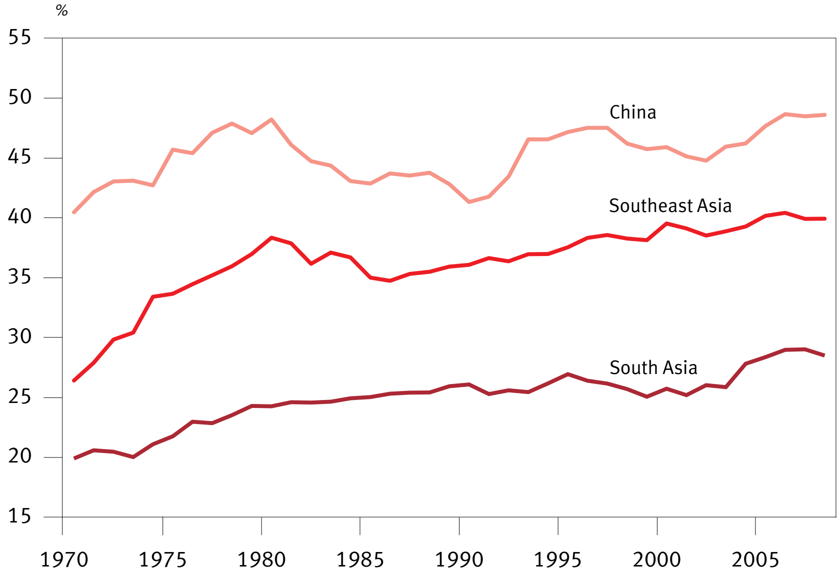


Figure 2.15
Share of industry in total GDP in developing Asia



Source: Sources: World Bank, World Development Indicators; IMF, International Financial Statistics; OPEC Secretariat estimates.[48]

Table 2.16
Oil demand in other industry in the Reference Case *mboe/d*

	Levels				Growth
	2008	**2010**	**2020**	**2035**	**2008–2035**
North America	3.2	3.3	3.3	3.3	0.1
Western Europe	2.1	2.0	1.9	1.8	–0.3
OECD Pacific	1.0	1.0	0.9	0.9	–0.2
OECD	**6.3**	**6.2**	**6.2**	**6.0**	**–0.3**
Latin America	0.9	0.9	1.0	1.0	0.1
Middle East & Africa	0.6	0.6	0.7	0.8	0.2
South Asia	1.0	1.0	1.2	1.6	0.6
Southeast Asia	0.9	0.9	1.0	1.1	0.2
China	2.0	2.1	2.4	2.6	0.6
OPEC	1.5	1.6	1.8	1.9	0.5
Developing countries	**6.9**	**7.2**	**8.1**	**9.0**	**2.2**
Russia	0.6	0.6	0.6	0.7	0.1
Other transition economies	0.4	0.4	0.4	0.5	0.0
Transition economies	**1.0**	**1.0**	**1.1**	**1.1**	**0.1**
World	**14.2**	**14.5**	**15.4**	**16.1**	**2.0**

to these factors, as well as the assumed robust economic growth, developing country oil use in this sector is anticipated to continue to rise steadily.

Tables 2.16 and 2.17 show the Reference Case projections for oil use in other industry. This underscores the fact that only developing countries are expected to see a demand rise, increasing by more than 2 mboe/d by 2035, compared to 2008. As with recently observed trends, the strongest growth is in developing Asia and OPEC. Oil use in this sector in the OECD and transition economies is expected to remain approximately flat, or possibly decline slightly.

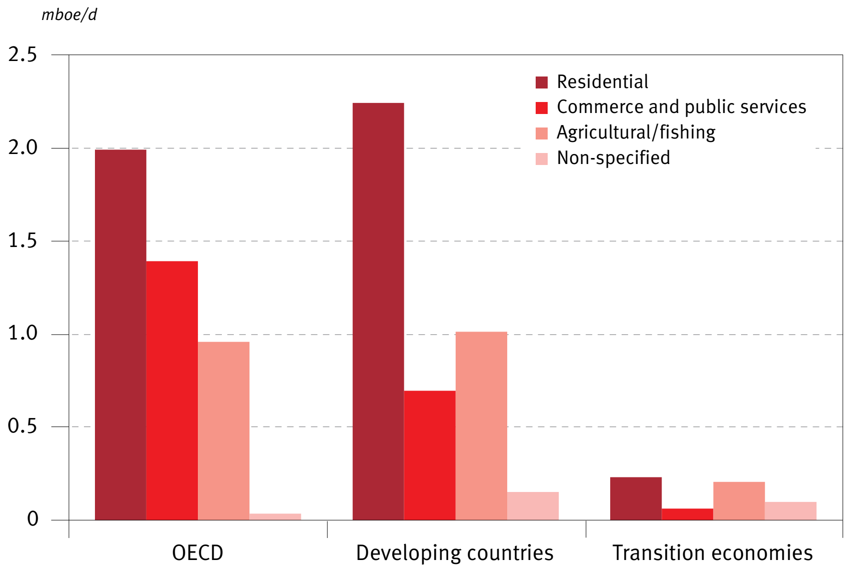
Table 2.17
Oil demand growth in other industry in the Reference Case *% p.a.*

	1990–2008	2008–2020	2020–2035
North America	–0.4	0.2	0.1
Western Europe	–0.4	–0.6	–0.6
OECD Pacific	–1.2	–0.8	–0.4
OECD	**–0.5**	**–0.2**	**–0.2**
Latin America	3.0	0.7	0.2
Middle East & Africa	1.7	0.9	1.0
South Asia	6.9	1.8	1.7
Southeast Asia	2.1	1.1	0.4
China	6.7	1.6	0.6
OPEC	3.5	1.8	0.4
Developing countries	**4.1**	**1.4**	**0.7**
Russia	–1.7	1.2	0.2
Other transition economies	–5.3	0.2	0.3
Transition economies	**–3.6**	**0.8**	**0.3**
World	**0.9**	**0.7**	**0.3**

Residential/commercial/agriculture

This sector covers residential oil use, other than fuel used for transportation, as well as oil use in commercial and public services, agriculture, forestry and fishing. Figure 2.16 shows that the residential segment is dominant, accounting for close to half of the oil consumption in this sector.

Figure 2.16
Oil use in residential/commercial/agriculture/other, 2008



More oil is used by the residential sector in developing countries than in the OECD. This has been the case since 2007. The strong upward trend in residential oil use in developing countries (Figure 2.17) is partly driven by rising income levels, which allows the switch to commercial energy use instead of traditional fuels, such as wood, dung or crop residues. This has important health implications in developing countries: indoor pollution involving the breathing in of fumes from these traditional fuels when cooking, leads to almost two million people dying around the world annually. Another potential driver behind this growth in the residential sector in developing countries is the move towards urbanization. In 1970, only 25% of people in these countries, on average, lived in urban areas, while by 2010 this had risen to 45%. This trend is expected to continue.

In the OECD commercial sector, the downward trend is again apparent, given fuel switching away from oil, and efficiency improvements to oil-powered water and space oil-heaters. The trend in developing countries is opposite, as the number of offices, shops and hotels grow rapidly. However, this sector is not seen as a very strong driver for oil demand, and oil use in the developing countries' commercial sector is still well below that of the OECD.

Figure 2.17
The evolution of oil demand in the residential sector

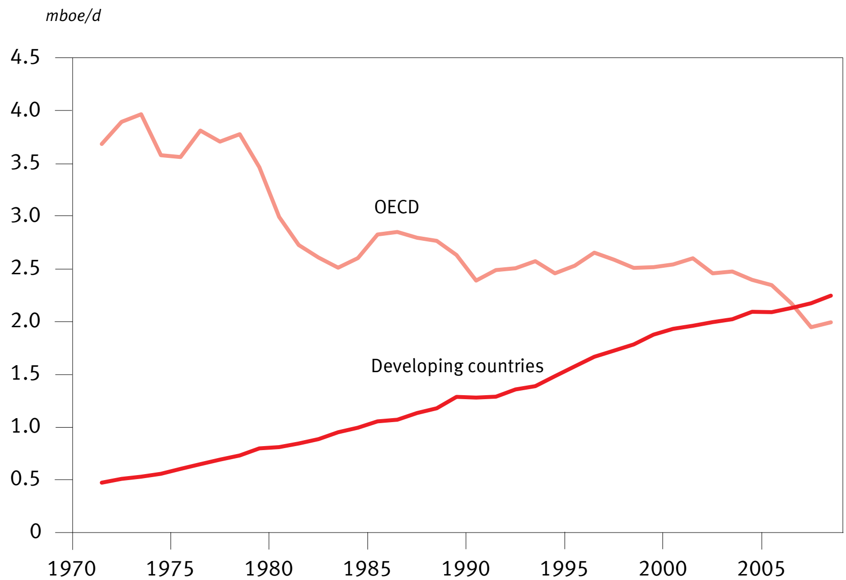


Table 2.18
Oil demand in residential/commercial/agriculture in the Reference Case *mboe/d*

	Levels				Growth
	2008	**2010**	**2020**	**2035**	**2008–2035**
North America	1.6	1.6	1.5	1.3	–0.3
Western Europe	1.9	1.8	1.7	1.4	–0.5
OECD Pacific	1.0	0.9	0.9	0.8	–0.2
OECD	**4.5**	**4.3**	**4.1**	**3.6**	**–0.9**
Latin America	0.6	0.6	0.8	1.1	0.6
Middle East & Africa	0.5	0.5	0.6	0.8	0.3
South Asia	0.7	0.7	0.9	1.3	0.6
Southeast Asia	0.6	0.6	0.6	0.7	0.1
China	1.2	1.2	1.8	2.4	1.3
OPEC	0.6	0.7	0.9	1.0	0.3
Developing countries	**4.1**	**4.3**	**5.6**	**7.3**	**3.2**
Russia	0.3	0.3	0.3	0.2	–0.1
Other transition economies	0.3	0.3	0.3	0.2	–0.1
Transition economies	**0.6**	**0.6**	**0.5**	**0.5**	**–0.1**
World	**9.2**	**9.3**	**10.2**	**11.3**	**2.2**

Table 2.19
Oil demand growth in residential/commercial/agriculture in the Reference Case *% p.a.*

	1990–2008	2008–2020	2020–2035
North America	–0.2	–0.5	–0.8
Western Europe	–1.1	–1.1	–1.0
OECD Pacific	–1.0	–0.6	–0.7
OECD	**–0.8**	**–0.8**	**–0.9**
Latin America	1.0	3.2	2.3
Middle East & Africa	3.4	1.3	1.8
South Asia	4.5	2.5	2.4
Southeast Asia	2.5	0.9	0.6
China	6.8	3.7	2.0
OPEC	1.3	2.5	0.9
Developing countries	**3.3**	**2.6**	**1.8**
Russia	–3.5	–1.1	–1.5
Other transition economies	–5.3	–0.9	–0.7
Transition economies	**–4.5**	**–1.0**	**–1.1**
World	**0.2**	**0.9**	**0.7**

Oil demand in the agricultural sector has also been rising rapidly in developing countries, with demand exceeding that of the OECD in 2003. This growth comes mainly from rising food production and the use of tractors. OECD oil use in this sector peaked in the mid-1990s and has been on a slow decline since. These two trends are set to continue.

Given these various influences, the expected evolution in the Reference Case for aggregate oil demand growth in the residential/commercial/agriculture sector is shown in Tables 2.18 and 2.19. Demand in developing countries increases by more than 3 mboe/d between 2008 and 2035. The downward trend in OECD oil use is expected to persist, with demand falling by close to 1 mboe/d over this timeframe. As a result, global oil use in the sector rises by just over 2 mboe/d by 2035.

Electricity generation

The importance of oil as an input to electricity generation has dramatically declined over the past three decades mainly in response to the high oil prices of the 1970s and early 1980s. The most striking decline has been Asia: between 1980 and 2008 it fell

Figure 2.18
Oil share in electricity generation in 1980 and 2008

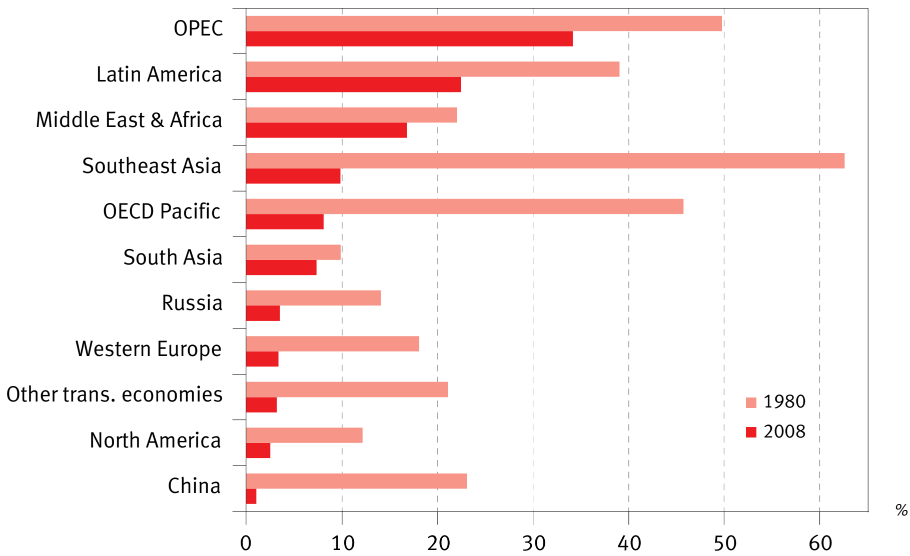
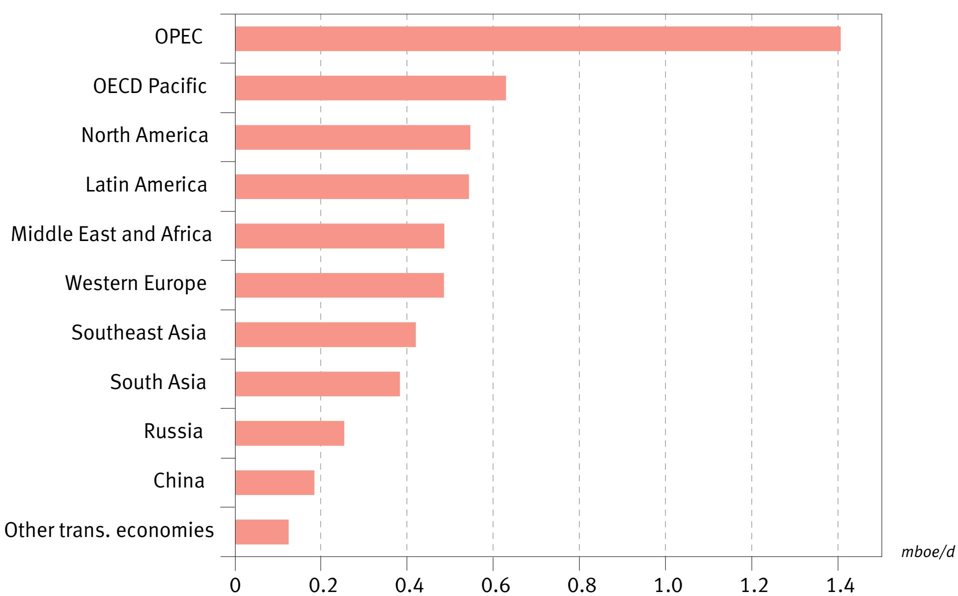


Figure 2.19
Oil use in electricity generation in 2008



from 63% to 10% in Southeast Asia, from 46% to 8% in OECD Pacific, and from 23% to just 1% in China.[49] However, the share has fallen everywhere: it now accounts for just 3% of inputs in North America, Western Europe and transition economies. Although it has also dropped in importance relative to other fuels, notably natural gas, oil still retains a significant share in OPEC and Latin American electricity generation, at 34% and 23%, respectively (Figure 2.18).

In absolute terms, OPEC remains the most important user of the regional groupings for electricity generation, accounting for more than one quarter of all oil used in this sector globally (Figure 2.19). It should be noted, however, that despite the low share in OECD countries, this group of countries still contributes over 30% to oil demand in electricity generation. However, there is growing impetus for a shift towards the use of natural gas in this sector.

It is expected that there will continue to be limited scope for oil use in this sector, with further switching towards other fuels likely. Some short-term responses to the Fukushima nuclear disaster in Japan demonstrated the flexibility that comes from

Table 2.20
Oil demand in electricity generation in the Reference Case *mboe/d*

	Levels				Growth
	2008	**2010**	**2020**	**2035**	**2008–2035**
North America	0.5	0.6	0.6	0.5	0.0
Western Europe	0.5	0.4	0.4	0.3	–0.2
OECD Pacific	0.6	0.6	0.5	0.3	–0.3
OECD	**1.7**	**1.6**	**1.4**	**1.1**	**–0.5**
Latin America	0.5	0.5	0.5	0.5	–0.1
Middle East & Africa	0.5	0.5	0.6	0.8	0.3
South Asia	0.4	0.4	0.5	0.7	0.3
Southeast Asia	0.4	0.4	0.4	0.4	0.0
China	0.2	0.2	0.2	0.1	–0.1
OPEC	1.4	1.5	1.4	1.2	–0.2
Developing countries	**3.4**	**3.5**	**3.6**	**3.7**	**0.3**
Russia	0.3	0.2	0.2	0.1	–0.1
Other transition economies	0.1	0.1	0.1	0.1	–0.1
Transition economies	**0.4**	**0.4**	**0.3**	**0.2**	**–0.2**
World	**5.5**	**5.4**	**5.3**	**5.0**	**–0.4**

retaining some oil-based power generation capacity, but it is not expected that this will have a lasting impact upon oil use. It should be stressed, however, that some rural areas in developing countries will continue to benefit from diesel-powered generators where there is not the necessary infrastructure available for alternative means of electricity provision. Tables 2.20 and 2.21 document the Reference Case projections for this sector. The only net growth to 2035 comes from Africa and South Asia.

Table 2.21
Oil demand growth in electricity generation in the Reference Case *% p.a.*

	1990–2008	2008–2020	2020–2035
North America	–2.9	0.3	–0.2
Western Europe	–3.7	–2.1	–2.5
OECD Pacific	–3.2	–1.9	–2.9
OECD	**–3.2**	**–1.2**	**–1.6**
Latin America	4.6	0.0	–0.8
Middle East & Africa	3.1	1.5	2.0
South Asia	6.7	2.1	2.5
Southeast Asia	–0.5	–0.2	–0.4
China	–3.0	–1.2	–1.5
OPEC	5.3	0.2	–1.0
Developing countries	**3.1**	**0.5**	**0.2**
Russia	–8.5	–3.0	–3.0
Other transition economies	–12.3	–3.2	–3.0
Transition economies	**–10.1**	**–3.1**	**–3.0**
World	**–1.8**	**–0.2**	**–0.4**

Chapter 3

Oil supply

In the overview of the Reference Case in Chapter 1, it was shown that non-OPEC liquids supply is expected to continue to rise over the projection period, due mainly to the rise in supply from non-crudes. This Chapter looks in more detail at these expectations. The first two sections examine the prospects for non-OPEC crude and NGLs, over both the medium- and long-terms. The third and fourth sections then present projections for non-conventional oil and biofuels.

Medium-term non-OPEC crude and NGLs

The oil industry's reaction to the precipitous fall in oil prices in the second half of 2008 was rapid. Both upstream and downstream spending fell swiftly in 2009. However, the recovery in prices since then has restored investor confidence, and upstream capital expenditures in 2010 returned close to 2008 levels.

The medium-term Reference Case oil supply projections are developed using a large database of upstream projects. The expected supply projections combine incremental volumes from new fields with observed declines in existing fields.

Total non-OPEC crude oil and NGLs supply rises slowly over the medium-term, from 46.3 mb/d in 2010, to 46.8 mb/d in 2015 (Table 3.1). The 1.3 mb/d fall in OECD supply over this period, mainly from the US and the North Sea, is more than compensated by increases in Latin America, mainly Brazil, and the Caspian region, primarily Kazakhstan. By 2012, developing countries already supply as much crude and NGLs as the OECD. Russian production, currently accounting for 22% of the non-OPEC total for crude and NGLs, is expected to remain constant at just over 10 mb/d throughout the medium-term, assuming that fiscal constraints such as export taxes are not eased.

US crude oil and NGLs production in the medium-term is projected to stay steady at close to 7.5 mb/d. This is almost 0.5 mb/d higher than WOO 2010 projections, which were impacted by the high uncertainties associated with the aftermath of the Deepwater Horizon accident in the Gulf of Mexico. This level is expected to be maintained for a number of years as new projects come on stream, including both existing and new ultra deepwater fields, such as Cascade & Chinook, Galapagos, Thunder Bird, Jack & St. Malo, Knotty Head, Puma, Big Foot and Mars B.

In Canada, although the Outlook envisages an expansion in total liquids supply, due mainly to oil sands and shale oil developments, the country's conventional crude oil plus NGLs production is projected to start declining in 2012 at an annual rate of around 0.1 mb/d, reaching 1.7 mb/d by 2015. In the Reference Case, the US & Canada's total crude oil plus NGLs production is set to decline from 9.4 mb/d in 2010, to 9.1 mb/d in 2015.

Last year, Mexico managed to slow its production decline. During 2010, production fell by only 20,000 b/d, compared to a 190,000 b/d drop in 2009. However, it is anticipated that Mexican production will continue to decline over the medium-term. The main reasons for this include the more rapid decline in the giant Cantarell field compared to that expected only a few years ago, a peaking in production from Ku-Maloob-Zaap complex, and doubts that additional production from Chicontepec will offset declines in other fields. In the Reference Case, Mexico crude oil and NGLs production is set to fall from 3 mb/d in 2010 to 2.6 mb/d in 2015.

Crude and NGLs production in Western Europe fell by 350,000 b/d in 2010. As in previous years, this was mainly due to declines in North Sea output. This North Sea production trend is anticipated to persist in the coming years. Western Europe's crude oil and NGLs production is projected to fall to 3.5 mb/d in 2015, down from just over 4 mb/d in 2010.

Breaking down the North Sea figures further, both Norway and the UK see falls of 0.2 mb/d for the period 2010-2015. In Norway, declines in mature fields, limited additional volumes and some government policies continue to increase the medium-term risks for lower output. Projects such as Vigdis NE, Trestakk, Visund South, Hyme, Katla, Goliat, Jardbaer, Bream, Froy, Ekofisk South and Eldfisk II are expected to translate into additional supply over the medium-term, but this is not sufficient to offset declines in mature fields. Norwegian crude and NGLs production fell 220,000 b/d in 2010, to 2.14 mb/d. Over the medium-term, it is expected to decline at a slower annual rate of around 0.05 mb/d, reaching 1.9 mb/d by 2015.

In the UK, following a reduction in exploration and appraisal spending and heavy declines in existing fields, crude oil and NGLs production fell by around 120,000 b/d during 2010. This trend, which began around ten years ago, is expected to continue in 2011 and beyond. The recent 10% increase in tax on supplementary corporate profits for the oil and gas industry, from 20% to 30%, is anticipated to reduce investment levels even further. It should be noted, however, that this might be partially offset by a potential increase in tax support for offshore oil and gas companies. Nevertheless, UK crude oil and NGLs production is expected to fall from around 1.4 mb/d in 2010, to 1.2 mb/d in 2015.

Table 3.1

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

	2010	2011	2012	2013	2014	2015
United States	7.5	7.5	7.5	7.5	7.4	7.4
Canada	1.9	1.9	1.9	1.8	1.8	1.7
US & Canada	**9.4**	**9.4**	**9.4**	**9.3**	**9.2**	**9.1**
Mexico	**3.0**	**2.9**	**2.9**	**2.8**	**2.7**	**2.6**
Norway	2.1	2.1	2.0	2.0	1.9	1.9
United Kingdom	1.4	1.3	1.3	1.2	1.2	1.2
Denmark	0.2	0.2	0.2	0.2	0.2	0.2
Western Europe	**4.1**	**3.8**	**3.6**	**3.5**	**3.5**	**3.4**
Australia	0.5	0.5	0.5	0.5	0.5	0.5
OECD Pacific	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**
OECD	**17.0**	**16.7**	**16.5**	**16.2**	**15.9**	**15.7**
Argentina	0.7	0.7	0.7	0.7	0.7	0.7
Brazil	2.1	2.2	2.3	2.4	2.6	2.7
Colombia	0.8	0.9	0.9	0.9	0.9	0.8
Latin America	**4.1**	**4.2**	**4.4**	**4.6**	**4.7**	**4.9**
Bahrain	0.2	0.2	0.2	0.2	0.2	0.2
Oman	0.9	0.9	0.9	0.9	0.9	0.9
Syrian Arab Republic	0.4	0.4	0.4	0.3	0.3	0.3
Yemen	0.3	0.3	0.3	0.3	0.3	0.2
Middle East	**1.8**	**1.8**	**1.8**	**1.7**	**1.7**	**1.7**
Congo	0.3	0.3	0.3	0.3	0.3	0.3
Egypt	0.7	0.7	0.7	0.7	0.7	0.6
Equatorial Guinea	0.3	0.3	0.3	0.3	0.3	0.3
Gabon	0.2	0.2	0.2	0.2	0.2	0.2
Sudan	0.5	0.5	0.5	0.5	0.5	0.5
Africa	**2.4**	**2.4**	**2.5**	**2.5**	**2.5**	**2.5**
Middle East and Africa	**4.2**	**4.2**	**4.3**	**4.3**	**4.3**	**4.3**
Brunei	0.2	0.2	0.2	0.2	0.2	0.2
India	0.9	0.9	0.9	0.9	1.0	1.0
Indonesia	1.0	1.0	1.1	1.1	1.0	1.0
Malaysia	0.7	0.7	0.7	0.7	0.7	0.7
Thailand	0.3	0.3	0.3	0.3	0.3	0.3
Vietnam	0.4	0.4	0.4	0.4	0.4	0.4
Asia	**3.6**	**3.6**	**3.7**	**3.7**	**3.8**	**3.8**
China	**4.1**	**4.1**	**4.1**	**4.1**	**4.0**	**4.0**
DCs, excl. OPEC	**16.0**	**16.2**	**16.5**	**16.7**	**16.8**	**16.9**
Russia	**10.1**	**10.2**	**10.2**	**10.2**	**10.2**	**10.2**
Kazakhstan	1.6	1.7	1.8	1.8	2.0	2.1
Azerbaijan	1.1	1.1	1.2	1.2	1.2	1.2
Other transition economies	**3.2**	**3.3**	**3.4**	**3.5**	**3.8**	**4.0**
Transition economies	**13.1**	**13.3**	**13.5**	**13.7**	**13.8**	**14.1**
Total non-OPEC crude & NGLs	**46.3**	**46.4**	**46.6**	**46.6**	**46.7**	**46.8**

Non-OPEC Latin America's production of crude and NGLs is expected to continue growing over the medium-term, from 4.1 mb/d in 2010, to 4.9 mb/d in 2015. This represents the second highest regional growth among all non-OPEC regions, following the transition economies region. It is mainly supported by production increases in Brazil. The Peregrino (Chinook), Waimea and Marlim Sul Module 3 P-56 are set to add at least 300,000 b/d of capacity by the end of 2011. A further 15 major projects – Aruana, Baleia Azul (Whale Park), Tiro/Sidon, Guara, Papa-Terra, Whale Park expansion P-58, Roncador Module 3 and Module 4, Guara Norte, Cernambi (Lula) Oliva & Atlanta, Guaiama, and Carioca – with a total production capacity in excess of 2 mb/d are anticipated to further contribute to medium-term growth. In the Reference Case, Brazil's production is set to grow steadily from 2.1 mb/d in 2010, to 2.7 mb/d in 2015.

Elsewhere in non-OPEC Latin America, Colombia crude oil and NGLs production is expected to increase by more than 110,000 mb/d, from 790,000 b/d in 2010, to 900,000 b/d in 2015. This expansion will come from the planned redevelopments of the Rubiales heavy oil field, Castilla, Quifa-14 and the La Cira Infantas. Argentina's crude oil and NGLs production is anticipated to remain flat, at about 700,000 b/d.

In the medium-term, non-OPEC Middle East & Africa crude oil and NGLs production is also expected to stay flat, at just over 4.3 mb/d. In the non-OPEC Middle East region, Oman will continue to depend on heavy oil developments and enhanced oil recovery (EOR) projects such as Mukhaizna, Qarn Alam and Harwel to offset declines and sustain a production level of around 0.9 mb/d. Oman is also planning to add about 45,000 b/d from Amal and Amin steam EOR projects in 2012. On the other hand, medium-term production from Yemen and Syria is expected to decline slowly. For both countries, the current high political risk adds another layer of uncertainty for medium-term projections. Crude oil and NGLs production in the non-OPEC Middle East is expected to fall slightly from 1.8 mb/d in 2010, to 1.7 mb/d in 2015.

In non-OPEC Africa, some modest growth in 2012 is expected in Ghana, Uganda, Niger and Equatorial Guinea, but this will be offset by possible declines in Sudan, Egypt and other countries. In the medium-term Reference Case, crude oil and NGLs production in non-OPEC Africa is thus expected to remain at approximately 2.5 mb/d.

Medium-term crude oil and NGLs production in non-OPEC Asian countries, excluding China, is expected to see steady growth, reaching around 3.8 mb/d by 2015. India is anticipated to be the main growth area, with projects including the Bhagyam, Saraswati/Raageshwari and the Krishna-Godavari Cluster fields coming online. These are slated to add production capacity in excess of 220,000 b/d, As a result, Indian crude oil and NGLs production is expected to increase from 850,000 b/d in 2010, to 1 mb/d in 2015.

Elsewhere, Malaysia's medium-term production is anticipated to stay flat at about 700,000 b/d. Vietnam's production decline in 2010 will be offset by projects that will come on stream by 2013, including the Te Giac Trang, Hai Su Den, Hai Su Trang and Su Tu Trang fields. As a result, the country's production is expected to remain at close to 400,000 b/d in the period 2010–2015. Supply is not projected to grow in Indonesia, Brunei, Papua New Guinea, Pakistan and Thailand.

China's crude oil and NGLs production experienced healthy expansion in 2010, growing from 3.8 mb/d in 2009, to 4.1 mb/d in 2010. This trend is expected to continue in 2011. Over the medium-term, production declines from the Daqing, Shengli and Liaohe giant fields are expected to be offset by additional volumes coming from new projects, such as Yuedong, Weizhou & Weizhou South, Chunxiao and other phases for Nanpu. These new fields are slated to add more than 300,000 b/d between 2011 and 2015. In the Reference Case, China's medium-term crude oil and NGLs production is projected to stay almost flat, at 4.1 mb/d.

Despite investment cutbacks in late 2008 and early 2009, particularly in the three largest producing transition economy countries (Russia, Azerbaijan and Kazakhstan), the region will continue to lead total non-OPEC medium-term volume growth. Crude oil and NGLs production in this group of producers is anticipated to grow from around 13.3 mb/d in 2010 to 14.2 mb/d by 2015.

Russian supply grew from 9.9 mb/d in 2009 to over 10.1 mb/d in 2010. This trend is expected to continue in 2011. An anticipated decline in output from the Volga-Urals region is likely to be offset by additional volumes from a number of new projects. Over the next few years, projects including Prirazlomnoye (Pechora Sea), Yaraktinskoye Stage 1, Pyakyakhinskoye, Kuyumbinskoye, Yurubcheno-Tokhomskoye (Phase I), Russkoye (Yamal-Nenets) and Vladimir Filanovsky are slated to add a combined production capacity of 750,000 b/d. It should be stressed, however, that taxation, investment, technology and field declines will continue to be significant determinants when it comes to Russia's supply projections. In the Reference Case, crude oil and NGLs production in Russia is projected to stay flat at 10.2 mb/d until 2015.

Azerbaijan and Kazakhstan will continue to lead production growth in the other transition economy countries. Crude oil and NGLs production is slated to increase from 3.2 mb/d in 2010, to 4 mb/d by 2015. In Azerbaijan, expansion will be driven by the continuing ramp-up of the Azeri Chirag Guneshli fields and the additional supply of 180,000 b/d from the Ciraq Oil Project in 2013. Azerbaijan's crude oil and NGLs production is expected to increase from 1.1 mb/d in 2010, to 1.2 mb/d in 2015. In Kazakhstan, production growth will be supported by expansions at the Tengiz and Kashagan fields. Production from Kashagan Phase 1 will start in 2012. It is anticipated to result in additional capacity of 450,000 b/d over the medium-term. First production from the Tengiz expansion will start in 2013 and is projected to add another 370,000 b/d. It is important to stress, however, that it is assumed that oil export transport infrastructure challenges do not put a cap on production levels. Crude oil and NGLs production in Kazakhstan is projected to increase from 1.6 mb/d in 2010, to 2.1 mb/d in 2015.

Long-term non-OPEC crude and NGLs

The long-term outlook for non-OPEC crude and NGLs supply is influenced by a range of determinants, such as the oil price, technology, costs, fiscal conditions and investments. It is also, and more importantly, linked to the remaining URR by country and region. This calculation consists of cumulative production, proven reserves, field reserves growth due to improvements in recovery rates and a re-evaluation of the amount of oil in place, as well as estimates of discoveries yet to be made.

The URR assessments are taken largely from the USGS. Estimates of URR have increased over time, and this process is expected to continue, due to technological developments, such as horizontal, multilateral and extended reach drilling, hydraulic fracturing, EOR, intelligent completions, data integration, as well as 3-D and 4-D seismic. The URR estimates used are presented in Table 3.2. Here, USGS URR figures published in 2000 have been used, supported by more recent updates where available. Adjustments have also been made to account for countries that are now producing oil, but were not included in the initial USGS assessment. This includes such countries as Vietnam, Papua New Guinea, Philippines, Thailand, Chad, South Africa, Mauretania and Uganda. On top of this, the large amounts of extra-heavy oil in Venezuela have been included.

Table 3.2 shows that OPEC Member Countries account for the majority of world's proven reserves – 80% in 2009 – and have considerably higher reserve growth expectations compared with non-OPEC. Cumulative production of crude oil plus NGLs is just over 30% of the original endowment. And more than 30% of the resource base is yet to be turned into proven reserves.

It is important to look at how these resource estimates are used to put together feasible production paths for crude oil and NGLs to 2035. The starting point is to understand the relevance of standard reserves-to-production (R/P) ratios as a

Table 3.2
Estimates of world crude oil and NGLs resources

billion barrels

	OPEC	Non-OPEC	Total world
Cumulative production to 2009 (a)	437	627	1,063
Proved reserves (b)	1,064	273	1,337
Reserves to be added ultimately (c)	**553**	**513**	**1,066**
Of which:			
Reserves growth	342	163	505
Discoveries yet to be made	211	350	561
Original Endowment (a) + (b) + (c)	2,054	1,413	3,465

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

possible guide to the future. The R/P ratio, using the current levels of global production and the current estimates of global proven reserves for 2009, amounts to just 43 years. For non-OPEC, it is in fact, less than 15 years. Interpreting this ratio (incorrectly) as a guide to future supply potential, suggests that for the non-OPEC ratio to remain at this level, non-OPEC production must immediately fall. Even at the global level, supply would need to plateau within this decade. Of course, however, this calculation ignores future reserves to be added. Taking figures from Table 3.2, it is evident that using the remaining reserves, including not only proven reserves, but also those reserves expected to be added in the future, then the global R/P ratio is 84 years. This ratio can then be used in the estimation of feasible long-term production profiles.

The R/P ratio is calculated for all countries and regions to develop long-term production paths, in accordance with observable trends, and consistent with ratios gradually declining. These declines, however, cannot continue indefinitely. An R/P ratio of zero implies an infeasible production path; one that suddenly comes to a standstill. Instead, the rate of decline must taper off and eventually lead to stable R/P ratios over the long-term. This, in turn, gives rise to long-term production paths that are feasible, given URR estimates.

Clearly there is no unique R/P path: any number of assumptions can be made. Nevertheless, within the constraint that downward trends must eventually decelerate there emerges a clear picture of whether, and where, the resource base acts as a limiting factor for feasible supply paths. This analysis becomes increasingly important the further the projection extends into the future.

The long-term Reference Case projections for non-OPEC crude oil plus NGLs supply up to 2035 are shown in Table 3.3. Output from all OECD regions continues to fall. By 2035, OECD supply from these conventional sources has fallen by close to 6 mb/d compared to 2010. This persistent decline is implied by the assumed levels of URR. It is important to note that shale oil resources are not included in the estimates of the conventional oil resource base.

The outlook for some developing country regions is positive. For this decade, supply levels in these regions will not be severely affected by a lack of resources. However, in the post-2020 period, a steady decline in Asia, non-OPEC Middle East and Africa is to be expected, due to the resource constraint. Resources in Latin America, however, are sufficient to allow production to rise until the middle of the next decade, followed thereafter by only a gentle decline. This means that the region, mainly due to Brazil, will remain the largest supplier of conventional oil in developing country regions, outside of OPEC. In the Reference Case, these regional developments mean that developing country production of crude oil and NGLs will continue to increase

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

	2010	2015	2020	2025	2030	2035
US & Canada	9.4	9.1	8.5	7.9	7.4	6.8
Mexico	3.0	2.6	2.4	2.2	2.0	1.6
Western Europe	4.1	3.4	3.0	2.7	2.4	2.2
OECD Pacific	0.6	0.6	0.6	0.6	0.6	0.6
OECD	**17.0**	**15.7**	**14.5**	**13.3**	**12.3**	**11.2**
Latin America	4.1	4.9	5.7	5.9	5.7	5.4
Middle East & Africa	4.2	4.3	4.2	3.9	3.6	3.4
Asia	3.6	3.8	3.9	3.7	3.3	3.0
China	4.1	4.0	3.7	3.5	3.3	3.1
DCs, excl. OPEC	**16.0**	**16.9**	**17.5**	**17.0**	**15.9**	**14.9**
Russia	10.1	10.2	10.4	10.4	10.4	10.4
Other transition economies	3.2	4.0	4.4	4.7	5.1	5.5
Transition economies	**13.4**	**14.2**	**14.8**	**15.1**	**15.5**	**15.9**
Non-OPEC	**46.3**	**46.8**	**46.8**	**45.4**	**43.8**	**42.0**

this decade, before beginning a decline in the post-2020 period. By 2030, supply has fallen below 2010 levels, and by 2035 it reaches 14.7 mb/d, just over 1 mb/d less than in 2010. The R/P analysis points to an accelerated decline in the post-2035 period for both OECD and developing countries, in terms of crude oil plus NGLs supply.

Russia, the largest producer of conventional oil among non-OPEC countries, reaches a plateau of 10.4 mb/d in the Reference Case by 2020. The resource base is sufficient to maintain this plateau for several decades. This projection assumes that the fiscal regime will not be dramatically adapted to attract more upstream investments that would lead to higher annual output, which is possible given the resource base, followed by a steeper decline. Caspian supply, in particular from Azerbaijan and Kazakhstan, is expected to rise steadily over the entire projection period, with the Reference Case seeing crude and NGLs supply increase from 3.2 mb/d in 2010, to 5.5 mb/d by 2035. This assumes that bottlenecks in this region's transport system are removed, and that additional export capacity is likely, which would allow for increased exports from these countries.

The outlook for OPEC crude and NGLs was described in Chapter 1. The R/P approach has also been applied to OPEC Member Countries, both to test feasibilities and to glean broad inferences for the post-2035 period. Not only is the Reference Case outlook for OPEC supply of crude plus NGLs fully compatible with the resource base, the current assessment of the resource base is sufficient to sustain further increases in OPEC supply post-2035.[50] Nevertheless, in this longer term period, it should be noted that non-conventional fuels are likely to garner a larger share of production.

Non-conventional oil (excluding biofuels)

As already emphasized, non-conventional oil is expected to make an increasingly important contribution to liquids supply. Significant non-conventional resources exist throughout the world. Major examples include US shale oil and the oil sands of Alberta, Canada. However, the potential for future oil supplies from non-conventional sources will partly be determined by how production costs develop.

The medium-term Reference Case outlook appears in Table 3.4. Canadian oil sands production dominates current non-conventional oil production, and the Reference Case sees supply continue to increase over the medium-term. On top of this, shale oil production in the US is currently experiencing a surge in activity, supported by robust oil prices. The combined growth of these fuels, together with some increase in CTLs, sees North America non-conventional supply rise from 1.7 mb/d in 2010, to 2.8 mb/d by 2015. Elsewhere, some increases in CTLs is expected, mainly from South Africa, China and Australia, with overall volumes almost doubling over the medium-term.

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

mb/d

	2010	2011	2012	2013	2014	2015
US & Canada	1.7	1.9	2.0	2.3	2.6	2.8
Western Europe	0.1	0.1	0.1	0.1	0.1	0.1
OECD Pacific	0.0	0.0	0.1	0.1	0.1	0.1
OECD	**1.8**	**2.0**	**2.2**	**2.6**	**2.8**	**3.0**
Middle East & Africa	0.2	0.2	0.2	0.2	0.2	0.2
Asia	0.0	0.0	0.0	0.0	0.0	0.1
China	0.0	0.1	0.1	0.1	0.1	0.2
Developing countries, excl. OPEC	**0.2**	**0.2**	**0.3**	**0.3**	**0.4**	**0.4**
Non-OPEC	**2.0**	**2.3**	**2.5**	**2.8**	**3.2**	**3.4**

Turning to the long-term, non-OPEC non-conventional oil (excluding biofuels) rises in the Reference Case by more than 6 mb/d over the period 2010–2035, to reach 8.4 mb/d by 2035 (Table 3.5). This increase is mainly from shale oil and Canadian oil sands. The rate of increase is slightly higher than in last year's WOO; partly a reflection of the higher oil prices assumed.

Despite the large oil sands resource base, production is characterized by a relatively low level of peak production, which is balanced by a slow rate of decline. Therefore, oil sands have a much lower and much longer production plateau than conventional oil fields. This will limit the rate of production increases over the long-term. Moreover, oil sands require additional external energy, such as natural gas, for production. This has implications for CO_2 emissions associated with the production of this oil. Thus, any move to introduce carbon pricing in the future would have direct implications for supply economics. There are also other constraints, such as transportation infrastructure and water availability.

Shale oil has also been associated with a number of negative impacts upon the environment. Carbon emissions, groundwater pollution and high levels of water usage are commonly cited problems. Nevertheless, estimates of shale oil resources remain uncertain, but seem to indicate large technically recoverable volumes. Moreover, shale oil is not only found in the US, but also in Australia, parts of Europe, China and Russia. The expanding interest in this fuel points to a potentially significant contribution to future oil supplies (Box 3.1).

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

mb/d

	2010	2015	2020	2025	2030	2035
US & Canada	1.7	2.8	3.7	4.7	5.8	6.6
Western Europe	0.1	0.1	0.1	0.1	0.1	0.1
OECD Pacific	0.0	0.1	0.1	0.1	0.1	0.1
OECD	**1.8**	**3.0**	**3.9**	**5.0**	**6.1**	**6.9**
Latin America	0.0	0.0	0.0	0.1	0.1	0.1
Middle East & Africa	0.2	0.2	0.2	0.2	0.2	0.2
Asia	0.0	0.1	0.1	0.1	0.1	0.1
China	0.0	0.2	0.2	0.4	0.7	1.1
DCs, excl. OPEC	**0.2**	**0.4**	**0.5**	**0.8**	**1.0**	**1.5**
Russia	0.0	0.0	0.0	0.1	0.1	0.1
Non-OPEC	**2.0**	**3.4**	**4.4**	**5.8**	**7.1**	**8.4**

Box 3.1
Shale oil: more than just marginal additions?

Following on from what have some have termed the 'US shale gas revolution', which is also now having some impact globally, questions are being asked as to whether shale oil will have a similar effect, particularly in the US. Shale deposits rich in organic matter and movable oil are very common and exist in almost all known oil fields, but to date there has been very little exploitation of this resource. Is this about to change?

It is important to stress that there has been much interchangeable use of the terms 'shale oil', 'oil shale' and kerogen. The focus of this box is on the production of crude oil from shale deposits, not the conversion of kerogen from shale into crude oil. Here, the term 'shale oil' (sometimes described as 'tight oil') will be used to refer to crude oil produced by the hydraulic fracturing of shale.

Despite widespread shale deposits, it is not yet clear whether the availability of economically viable shale oil is as great as that for shale gas. It is already evident that some deposits will not be sufficiently mature to contain liquids, and some will be over-mature. The geographical, geological and operational challenges and associated costs across countries and regions will be diverse. Nevertheless, given the size of known shale oil deposits, even if only a fraction of them contain viable liquids, it translates into a significant resource.

Known shale oil resources cover several basins in the US (Bakken, Eagle Ford, Niobrara, Utica, Leonard Avalon, Woodford and Monterey), but also in other parts of the world (Beetaloo in Australia, Exshaw and Macasty in Canada, Paris in France and Vaca Muerta in Argentina). Due to the lack of data, estimates of oil in place and recoverable volumes from these formations are still the subject of huge uncertainties.

To date, only the Bakken oil shale formation in North Dakota and Eagle Ford in Texas have been exploited for a sufficient period of time to have a clear understanding of actual resources and reserves. A number of other deposits are being targeted, but given that many are in their infancy, data on the resources in place and the estimated recoverable reserves is generally limited, and beset with uncertainties. As a result, a wide variety of claims – both conservative and optimistic – have been made, but so far it remains difficult to ascertain the long-term prospects for shale oil.

At the global level, a very conservative estimate of global shale oil 'proved' reserves, based on a 3% recovery factor, is less than 100 billion barrels. In this case, shale oil will only add incremental amounts to the medium-term global oil supply.

A more optimistic estimate of global shale oil 'proved' reserves, again with a 3% recovery factor, is projected to be more than 300 billion barrels. In this case, shale oil might prove to be a significant long-term contributor to global oil supply.

In terms of development and production, what makes shale oil unusual is that it does not involve a new technology or a newly-discovered resource. The hydraulic fracturing technology has been used for many years – especially in the US – and the resource, although not exploited, exists in most known fields. As in the case of shale gas, this can be expected to speed-up the rate at which exploitation occurs and implies that the time it will take to spread will be faster than if these were completely new fields. On the other hand, supply is very dependent on the drilling effort and, thus, is more price elastic.

Significant constraints over the next ten years include: the need for geological analysis of other shales; trained people to perform hydraulic fracturing; and acquiring the horizontal drilling and fracturing equipment. In the US already, costs have accelerated sharply as the demand for fracing equipment cannot be met. Thus, delays in initiating fracturing jobs are common. In some areas, such as northern Europe, environmentally-driven political opposition can also be expected to slow or possibly prevent development.

Outside of the US and Canada, there are at present only three basins that have been analyzed sufficiently to be viewed as having potential for near-term production. These are the Vaca Muerta in Argentina, the Beetaloo in Australia, and the Paris basin in France. The last, however, faces strong political opposition and development will likely be delayed for years.

Elsewhere, China is moving aggressively to study and exploit its shale oil resources and production there is likely to start growing following a few years of evaluation and human resource training. And if other countries such as Brazil, as well as those with shale oil deposits in North Africa, encourage operations, then after around five years, perhaps small increments may also be observed from these areas. Regions such as central Africa and Siberia will not be developed soon, because of their lack of infrastructure, and regions such as the Middle East have no need at present to develop a higher-cost, unconventional resource.

Development costs for shale oil appear to be roughly in the \$30–\$80/b range, excluding taxes and royalties. However, as the industry develops and moves further along the learning curve, costs can be expected to come down, perhaps sharply over the medium-term, before flattening out. Depletion will not be a significant factor, due to the size of the resource, but in the short-term, pressure on the limited amount of crews and equipment could drive costs up.

Looking ahead, it is evident that output from new shale oil deposits will not grow at a similar rate of 60,000 b/d per year as the Bakken basin is presently, but capacity will expand for years to come as more and more rigs and fracing equipment are brought in. Within a decade, it is quite possible that shale oil production could rise at relatively significant levels year-on-year, assuming prices remain well above \$60/b, and regions such as Argentina, Australia and Canada do not significantly restrict operations. At present, however, shale oil should not be viewed as anything more than a source of marginal additions.

Biofuels

The pattern of biofuels supply in the Reference Case follows three distinct phases. Over the medium-term, there is an initial supply surge, with first generation technologies used to supply the vast bulk of this. In the medium-term, biofuels rise from

1.8 mb/d in 2010, to 2.7 mb/d in 2015 (Table 3.6). This increase is focused mainly on the US, Europe and Brazil.

Increasingly, however, in the second of these phases, sustainability issues place a limitation on how much first generation biofuels can be produced. Indeed, recently, some countries have revised their policy push in favour of biofuels by relaxing their blending mandates, for example, in Germany, or by developing sustainability criteria, as seen in the EU as a whole. Higher sugar prices have also led to a downward revision of ethanol mandated blending in Brazil. Moreover, the economic crisis and the resulting pursuit of fiscal consolidation in many countries will likely make it more difficult to justify and sustain expensive support programmes that favour biofuels. This means that, after the medium-term period, the Reference Case sees a slowdown in the rate of increase. This will be particularly apparent in the US and Europe, which in turn may mean that some ambitious targets may not be met.

In the longer term, the third phase, it is assumed that second generation technologies – and third generation biofuels technology, such as algae-based fuels – become increasingly economic, leading to a resurgence in biofuels supply growth. The Reference Case sees biofuels supply rising by more than 5 mb/d from 2010, to reach 7.1 mb/d by 2035 (Table 3.7). The growing importance of second and third generation biofuels over the longer term introduces considerable uncertainty to the outlook. Increases could feasibly be considerably higher, once these technologies become a commercial reality and should costs decline substantially. The development of these technologies is also likely to be sensitive to how oil prices evolve.

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

	2010	2011	2012	2013	2014	2015
US & Canada	0.9	1.0	1.0	1.1	1.1	1.2
Western Europe	0.2	0.3	0.3	0.3	0.4	0.4
OECD	**1.1**	**1.3**	**1.4**	**1.4**	**1.5**	**1.6**
Latin America	0.6	0.7	0.7	0.8	0.8	0.8
Asia	0.0	0.1	0.1	0.1	0.1	0.1
China	0.0	0.1	0.1	0.1	0.2	0.2
Developing countries, excl. OPEC	**0.7**	**0.8**	**0.9**	**1.0**	**1.0**	**1.1**
Non-OPEC	**1.8**	**2.1**	**2.3**	**2.4**	**2.5**	**2.7**

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

	2010	2015	2020	2025	2030	2035
US & Canada	0.9	1.2	1.4	1.7	2.1	2.6
Western Europe	0.2	0.4	0.6	0.8	1.1	1.5
OECD Pacific	0.0	0.0	0.0	0.0	0.0	0.1
OECD	**1.1**	**1.6**	**2.0**	**2.6**	**3.2**	**4.1**
Latin America	0.6	0.8	0.9	1.1	1.3	1.6
Middle East & Africa	0.0	0.0	0.0	0.1	0.1	0.2
Asia	0.0	0.1	0.2	0.2	0.3	0.4
China	0.0	0.2	0.2	0.4	0.5	0.7
DCs, excl. OPEC	**0.7**	**1.1**	**1.3**	**1.7**	**2.2**	**2.9**
Other Europe	0.0	0.0	0.0	0.0	0.0	0.1
Non-OPEC	**1.8**	**2.7**	**3.4**	**4.4**	**5.5**	**7.1**

The considerable uncertainty in the biofuel outlook will be addressed through continuous monitoring of its main drivers; mainly government mandates and policies that provide the required incentives to increase biofuel production. These mandates, although varying considerably from country-to-country, will continue to be the most important factor in the biofuel equation. So far, and regardless of all the fiscal challenges (increased feedstock costs, the food versus fuel debate and the argument that biofuels are not as environmentally-friendly as was previously believed), new mandates continue to be introduced in support of biofuel programmes. For example, in the US, the reinstatement of the biodiesel blender tax credit at the end of 2010 is the main reason behind its production increase in 2011.

OPEC upstream investment activity

In 2010, OPEC's spare capacity stood at more than 5 mb/d. While this capacity fell to about 4 mb/d during the second and third quarter of 2011 as a result of the disruption in Libya's production, it is expected to stabilize at about 8 mb/d over the medium-term, as noted in Chapter 1.

Given the industry's long-lead times and high upfront costs, it is indeed an extremely challenging task to strike the right balance for investment in new capacity. The ever-evolving dynamics of supply and demand, as well as other market uncertainties, adds further to the budgeting and planning complexity.

Of utmost importance, in respect to investments, is a stable and realistic oil price; one that is high enough for producers to continue to invest and develop resources and low enough to not hinder global economic growth. It is important not to forget the renewed sense of caution that the financial crisis of 2008 planted in investors' minds. The oil and gas industry, which has typically been slow to increase investment when the oil price goes higher, will likely continue to respond faster to low oil prices. Nonetheless, this does not mean that costs will respond in the same way, as even during the financial crisis the high cost environment persisted. Costs did fall a little towards the end of 2009, but they are now back to the same high levels of 2008.

Regardless of all the challenges and uncertainties, OPEC Member Countries continue to invest in additional capacities. On top of the huge capacity maintenance costs that Member Countries are faced with, they continue to invest in new projects and reinforce their commitment to the oil and gas market and as well as to the security of supply for all consumers. Needless to say, this is only a reflection of OPEC's well-known policy that is clearly stated in its Long-Term Strategy and its Statute.

Based on the latest upstream project list provided by Member Countries, the OPEC Secretariat's database comprises 132 projects for the five-year period 2011–2015. This could translate into an investment figure of close to $300 billion should all projects be realized. This shows how large OPEC's project portfolio is. Investment decisions are influenced by many factors, such as the price of oil and the perceived need for OPEC oil. Under the Reference Case conditions, and taking into account all OPEC liquids, including crude, NGLs and GTLs, as well as the natural decline in producing fields and current circumstances, the net increase in OPEC's liquids capacity by 2015 is estimated to be close to 7 mb/d above 2011 levels, with more thereafter, leading to comfortable levels of spare capacity.

Chapter 4

Upstream challenges

The annually published WOO documents the OPEC Secretariat's view of a central set of energy supply and demand expectations, as mapped out in the Reference Case in Chapters 1, 2 and 3. These projections are internally consistent, as well as credible in the absence of major changes to the input assumptions, such as major departures from observable trends. It is evident, however, from both the discussion of these assumptions, as well as the analysis of specific issues in the boxes in this publication, that there are major uncertainties and specific challenges ahead, that may need to be addressed in the years ahead. In particular, the first three Chapters have emphasized the potential for alternative developments in policies, technological advancement, as well as economic growth. These could all substantially alter the medium- and long-term oil and energy outlook.

The challenge of recognizing and adapting to possible alternative energy futures is explored in detail in this Chapter. The initial challenge revolves around a world where there is an accentuation of the extent to which technology and policies – limited in this analysis to the transportation sector – affect demand for oil. This scenario also considers the accelerated penetration of non-conventional fuels, including biofuels. Ultimately, the scenario demonstrates the genuine uncertainties regarding the amount of oil that OPEC will be expected to supply, over the medium- and long-term.

The second scenario then explores further uncertainties for oil demand stemming from realistic alternative assumptions for future economic growth, both from a downside and upside perspective.

These scenarios are then followed by a broad discussion of a variety of other challenges that the oil and energy industry is either facing, or is likely to face in the future.

Accelerated Transportation Technology and Policy scenario (ATTP)

This Outlook has so far documented the assumptions and implications of the Reference Case. However, it is important to explore developments to the drivers of supply and demand that could feasibly emerge under realistic alternative assumptions. Indeed, the question might be asked as to whether the Reference Case is regarded as a 'most-likely' scenario. It is, in fact, not to be interpreted as such: it is essentially a 'dynamics-as-usual' world, but these dynamics are clearly subject to a wide range of influences and, therefore, bring with them a wide range of potential qualitative and quantitative impacts on supply and demand.

The role that OPEC plays in supporting market stability by adjusting its crude production levels is widely acknowledged as an important factor in underpinning the general health of the oil industry, as well as for broader economic stability. What this means, however, is that OPEC is particularly exposed to uncertainties relating to both demand and supply.

The ATTP scenario explores the potential impacts upon the call on OPEC crude of an alternative set of assumptions impacting the projected volumes required. Specifically, alternative rates of development and implementation of technologies in the transportation sector are assumed. This scenario's focus is solely on the transportation sector in order to put the spotlight on technologies and policies that are clearly linked to reducing oil use in what is evidently the most important sector for future oil demand levels and growth. It should be noted, however, that the uncertainties documented here could easily be amplified if technologies and policies in other sectors were to be incorporated into such a scenario.

There are many driving forces behind these alternative assumptions. One important starting point is to recognize that objectives to reduce oil demand vary across regions. For example, some countries might regard addressing local environmental concerns as the overriding priority. Thus, rising local pollution – often linked to urbanization and motorization trends – is and could continue to be a key factor in developing new policies. In terms of air quality, the transportation sector would likely continue to be a prime target, despite the huge progress made so far in lowering tailpipe emissions.

Climate change concerns stemming from rising cumulative levels of GHGs could potentially lead to major policy shifts, including in the energy sector. Ongoing negotiations under the Kyoto Protocol have not yet reached agreement on the second and subsequent commitment periods, which would begin after the expiry of the first period at the end of 2012. Following the Great Recession, the likelihood of any agreement has receded further. It appears that the global economic crisis has reordered global priorities. Preventing a financial meltdown, combating high unemployment, and debate over the severity of sovereign debts have all taken precedence. This does not mean that efforts to move to a low-emission economy have disappeared altogether, but in the coming years placing a cost on GHG emissions may not be such a key driver of change that some had envisioned prior to 2008.

Nevertheless, efforts to set targets and mandates, such as renewable energy standards in the power generation sector and increasingly stringent targets for fuel efficiency in the transportation sector, will likely play an expanding role. In the past year or so, it has also become evident that the unconventional gas revolution in the US – and potentially elsewhere – has increased the attractiveness of natural gas as an avenue to reduce carbon intensity in power generation, and, possibly, the transportation sector. This could affect the attractiveness of electric vehicles in the future. For example, well-documented concerns over the need to consider 'well-to-wheels' emissions for electric vehicles, particularly when coal is used to generate electricity for the electric car, could be fundamentally affected by these developments. More shale gas use could lessen the need for coal. Another specific area requiring close attention is the future regulation of emissions from commercial vehicles, particularly in developing countries.

It should also be emphasized that capabilities for various technologies differ from region-to-region. For instance, wind energy is more likely to take off where the wind blows most reliably, such as in Northern Europe; prospects for solar can be expected to be brighter in sunnier climes, such as the Mediterranean region; and hydropower is anticipated to make greater waves in developing countries, given the fact that many developed countries have little hydropower potential left to exploit.

Overall, climate change concerns are a key potential driver of policies and technologies that may lead to significantly different energy paths from those described in the Reference Case. And even if a global climate policy agreement is unlikely in the current environment, national and regional initiatives are continuing to emerge.

Yet another future driver of change relates to concerns over energy security. The notion of energy independence has long been dismissed in sober assessments as unrealistic and, ultimately, unhelpful. However, the fact that some regions of the world will continue to import a major proportion of their oil requirements, could see the concept continue to dominate thinking at both the policy and electoral levels. In turn, this may lead to future developments that target oil imports. In this context, it is worth noting that energy supply security is essentially an electricity issue: key outages experienced across the globe over the past 15 years have practically all been related to electrical power cuts. Nevertheless, oil supply security concerns are likely to constitute another magnet for policies that focus upon reduced oil demand, and encourage the development and supply of alternative fuels.

There are several other areas that could drive policy and technology into directions that are markedly different from the Reference Case, and, in turn, reduce oil use and encourage supply from alternative fuels. For example, support for agriculture could help address surplus crops to further develop biofuels, or to better use low yield land. Such policies could also be linked to economic transformation efforts that aim to develop new industries and new export opportunities. An example of this was the early support given to Brazil's biofuels industry. In the current economic climate, this could potentially go two ways. It could mean that unemployment policy becomes increasingly linked to energy policy to generate jobs growth. Indeed, this has already been very visibly in the case of Germany, where domestic coal has been historically subsidised in order to protect jobs. However, there is the possibility that government support for such industries might be withdrawn.

Given all these factors, alternative paths to the Reference Case are increasingly likely. The ATTP scenario therefore makes a number of assumptions to explore the possible impacts of feasible and realistic alternatives to these. Specifically, it is assumed that:

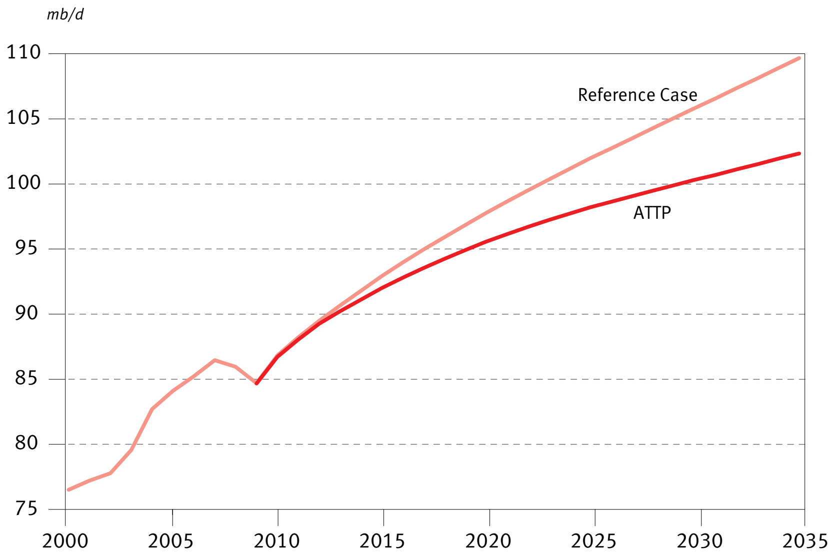
- Efficiency improvements to internal combustion engines, accelerated shifts to hybrids, and in some parts of the world electric vehicles, a more rapid penetration of natural gas in the transportation sector, again in some parts of the world, and an accelerated move to regulate efficiencies in commercial vehicles, lead to an additional 0.5% p.a. improvement in the average oil use per vehicle;
- Concerns over import dependency leads to more aggressive support for alternative fuels, in particular biofuels, CTLs, biomass-to-liquids (BTLs) and CNG;
- Regulation of international marine bunkers leads to more efficient fuel use in this sector, also at an additional rate of 0.5% p.a. This will stem increasingly from stringent regulation, as well as alternative assumptions for how the international marine industry responds to higher oil prices than in the past, for example, through greater emphasis on 'slow-steaming'; and
- Increased efficiencies will lead to reduced costs of travel, and, therefore, the potential for some 'rebound effect' in the form of higher transportation activity.

Table 4.1
Oil demand in the ATTP scenario

mb/d

	2015	2020	2025	2030	2035
OECD	45.7	44.3	42.7	41.0	39.3
Developing countries	41.3	46.1	50.2	53.9	57.6
Transition economies	5.0	5.2	5.3	5.4	5.5
World	**92.0**	**95.6**	**98.2**	**100.3**	**102.3**
Difference from Reference Case					
OECD	–0.4	–0.9	–1.5	–2.1	–2.6
Developing countries	–0.4	–1.1	–2.0	–3.1	–4.3
Transition economies	–0.1	–0.2	–0.2	–0.3	–0.4
World	**-0.9**	**–2.2**	**–3.8**	**–5.5**	**–7.3**

Figure 4.1
World oil demand in the ATTP scenario



Chapter 4

This effect is deemed small, however, especially relative to the overall downward stresses on demand.

Table 4.1 documents the impacts of the ATTP scenario upon oil demand. The scenario results in a reduction in oil use compared to the Reference Case of 7.3 mb/d by 2035, when volumes reach just over 102 mb/d. The impact is summarized in Figure 4.1.

Table 4.2 shows how the supply side is affected in this scenario. Non-OPEC supply is close to 3 mb/d higher by 2035, compared to the Reference Case. Consequently,

Table 4.2
OPEC crude and non-OPEC supply in the ATTP scenario *mb/d*

	2015	2020	2025	2030	2035
Non-OPEC	55.4	57.8	59.4	61.3	63.4
OPEC crude	30.3	30.5	30.6	29.8	29.1
Difference from Reference Case					
Non-OPEC	0.0	0.5	1.0	2.1	2.9
OPEC crude	−1.0	−2.7	−4.8	−7.6	−10.2

the call on OPEC crude by 2035 shows a reduction of more than 10 mb/d compared to the Reference Case. The ATTP scenario effectively implies that there is hardly any room for additional OPEC crude supply in the future: indeed, by 2035, the amount of OPEC crude that will be required will be less than current levels. This underscores that OPEC upstream investment requirements are subject to huge uncertainties, and demonstrates clearly the genuine concerns over security of demand.

Uncertainties over economic growth

The global economic situation remains a concern for policymakers, businesses and individuals the world over and how the economic recovery plays out in the coming years will have a major impact on the oil industry. It is thus important to document how uncertainties over economic growth, in the short-, medium- and long-term, have very important implications for the evolution of oil demand and how this further complicates the challenge of making appropriate investment decisions along the oil supply chain.

Uncertainties over economic growth have been brought to the fore by the recent global financial crisis and subsequent Great Recession. The prevention of a total global financial system collapse and the buoying of economies came at the cost of large expansions in the balance sheets of central banks, as well as huge fiscal deficits, which in some countries are believed to be reaching unsustainable levels. In the medium-term, there is now much concern about the need for fiscal consolidation and mitigating the systemic risks stemming from banks' weakening balance sheets.

Whatever happens, however, it is clear that countries burdened by heavy government debt will be hampered in their growth prospects if fiscal consolidation is not properly pursued. In the medium-term, new financial regulations that are currently being debated may act to dampen growth as they limit leverage and excessive risk-taking and increase the cost of capital, even as they attempt to prevent a repetition of future financial crises. Moreover, increasingly there are longer term questions being raised over the rate of economic growth in the face of a possible retreat of globalization.

For the short-term, economic growth will remain uncomfortably reliant on further government support. An uncoordinated and premature exit of government support is a major risk in the short-term.

There is rising concern about the rapidly deteriorating budgetary positions and fiscal sustainability of debt. One risk of ballooning government debt is that public debt issuance will crowd out private sector credit growth, with interest rates gradually being raised for private borrowers. In turn, this puts a drag on the economic recovery. At the same time, nervousness in financial markets may reduce confidence in indebted countries, raising the cost of borrowing in these nations, which then curbs economic recovery.

There are also a number of potential medium-term consequences from the global financial crisis. Bank lending is not expected to recover soon. Furthermore, higher government debt and the need to cut expenditure could slow down productivity growth. In general, increased risk aversion, the necessity of banks to deleverage and capitalize, as well as disenchantment with financial innovation that contributed to boosting liquidity, points to the possibility of higher borrowing costs for both developed and developing countries. This could lead to a decline in the potential growth rate, since financial services are critical to the smooth functioning of an economy.

In many respects, pessimism over longer term global economic growth potential can be traced to concerns that a backlash against globalization may come as a result of the disillusionment with the vulnerability of open markets, in particular capital market liberalization. Increased protectionism and more regionalism could endanger the present expectations of a benign recovery in global trade and economic welfare.

For all of these reasons it is important to consider alternative, lower economic growth paths from the Reference Case assumptions.

The assumption made in the lower economic growth scenario is for each region to witness 0.5% lower growth than in the Reference Case throughout the projection period. This does not, of course, preclude the possibility of more severe short-, medium- or long-term downward pressures upon growth.

On the other hand, uncertainties over economic growth can also point to upside potential. A central focus of such a higher growth scenario would be how this might translate into oil demand, as well as the call on OPEC crude.

The drivers behind such higher economic growth could be several. Firstly, in the coming years, emerging markets that are not as financially constrained as major OECD regions increasingly become the motors of world growth. The shift in economic weight to emerging markets, especially those in Asia, will have far-reaching economic and geopolitical consequences, some of which are slowly beginning to unfold. The emergence of the G-20 as the premier economic forum and the recognition by the G-20 in its Pittsburgh Summit Leaders Statement in September 2009 that "critical players need to be at the table and fully vested in our institutions to allow us to cooperate to lay the foundation for strong, sustainable and balanced growth" is an acknowledgement of the increased economic weight of emerging economies.

At the global level, in the coming years strong economic growth may require a rebalancing of growth in deficit countries, such as the US, the UK and Spain, from domestic consumption to exports, while a reverse process would be needed in surplus countries such as China, Japan and Germany. US saving rates have risen recently and this single factor could impact growth substantially given the fact that private consumption accounts for 70% of GDP. It is likely that the savings rate will remain higher than in the years preceding the crisis, due to the necessity for private households to deleverage. Meanwhile the Chinese government remains committed to fiscal expansion and to the aim of rebalancing growth towards domestic consumption, and in the higher economic growth scenario, this would provide an important growth impetus.

As with the lower economic growth scenario, the stronger growth that emerges in the higher economic growth scenario is a credible alternative to the Reference Case. Therefore, the assumption is made that average global growth over the period is 0.5% p.a. higher than in the Reference Case throughout the projection period. In turn, there is an assumed correction of oil prices in accordance with demand developments.[51] This gives rise to some feedback impacts upon both demand and supply, but the dominant effect remains through the alternative economic growth assumptions.

The results for these two scenarios are shown in Tables 4.3–4.6, and summarized in Figures 4.2 and 4.3. In the lower growth scenario, demand by 2035 reaches 100.6 mb/d, or about 9 mb/d lower than in the Reference Case.[52] Because of the slightly softer oil prices, non-OPEC oil supply is lower than in the Reference Case by about 2 mb/d by 2035. This means that the call on OPEC crude oil by 2035 is 7 mb/d lower than in the Reference Case. In this scenario, the need for OPEC crude oil rises slowly to around 32 mb/d, where it stays approximately flat.

In the higher economic growth scenario, global oil demand rises more swiftly, to reach over 112 mb/d by 2030 and 118 mb/d by 2035. Part of the pressure upon the demand rise is ameliorated by the higher oil price. Of course, this scenario would need to be placed into the context that such a strong demand increase would likely cause concerns over rising imports, which, in turn, would likely lead to new policies being introduced to limit growth. Nevertheless, it demonstrates the innate uncertainty over future oil demand due to economic growth, from both the upside and downside. In this scenario, OPEC crude supply would need to rise to 45 mb/d by 2035.

Table 4.3
World oil demand in the lower economic growth scenario *mb/d*

	2015	2020	2025	2030	2035
OECD	45.4	43.8	42.2	40.4	38.5
Developing countries	41.1	45.6	49.4	53.0	56.5
Transition economies	5.0	5.2	5.3	5.4	5.6
World	**91.5**	**94.6**	**96.9**	**98.8**	**100.6**
Difference from Reference Case					
OECD	–0.7	–1.4	–2.1	–2.8	–3.4
Developing countries	–0.7	–1.7	–2.8	–4.0	–5.4
Transition economies	–0.1	–0.1	–0.2	–0.3	–0.3
World	**–1.5**	**–3.2**	**–5.1**	**–7.0**	**–9.1**

Table 4.4
Oil supply in the lower economic growth scenario *mb/d*

	2015	2020	2025	2030	2035
Non-OPEC	55.1	56.4	56.9	57.4	58.6
OPEC crude	30.0	30.8	31.8	32.1	32.2
Difference from Reference Case					
Non-OPEC	–0.2	–0.8	–1.4	–1.8	–1.9
OPEC crude	–1.3	–2.3	–3.6	–5.2	–7.1

Table 4.5
World oil demand in the higher economic growth scenario *mb/d*

	2015	2020	2025	2030	2035
OECD	46.6	46.4	46.2	45.8	45.4
Developing countries	42.2	48.6	54.7	60.8	67.1
Transition economies	5.2	5.5	5.7	6.0	6.2
World	**94.0**	**100.5**	**106.6**	**112.6**	**118.7**
Difference from Reference Case					
OECD	0.5	1.2	2.0	2.7	3.4
Developing countries	0.5	1.4	2.5	3.8	5.3
Transition economies	0.1	0.1	0.2	0.3	0.4
World	**1.1**	**2.7**	**4.6**	**6.8**	**9.1**

Table 4.6
Oil supply in the higher economic growth scenario *mb/d*

	2015	2020	2025	2030	2035
Non-OPEC	55.6	58.6	60.7	62.3	63.8
OPEC crude	32.1	34.6	37.6	41.1	45.2
Difference from Reference Case					
Non-OPEC	0.2	1.3	2.4	3.1	3.2
OPEC crude	0.8	1.4	2.2	3.7	5.8

Comparing these results to the ATTP scenario, in terms of oil demand growth, oil supply and investments, offers up some interesting contrasts. Over the medium-term, the downside risk to demand is slightly more pronounced in the lower economic growth scenario. However, over the long-term, when policies begin to have impacts upon efficiencies and the development and introduction of alternative fuels, the ATTP scenario has much greater downside and the impacts upon OPEC become more significant.

Figure 4.2
World oil demand in the higher and lower economic growth scenarios

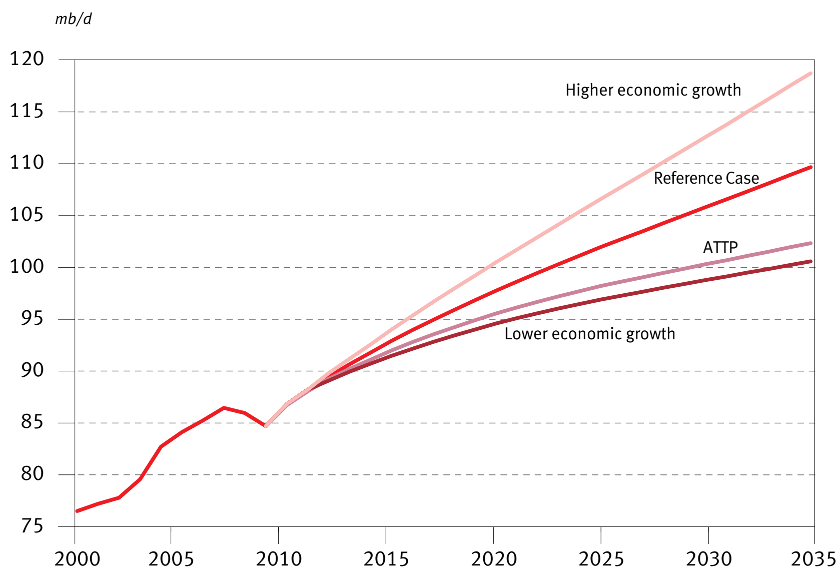
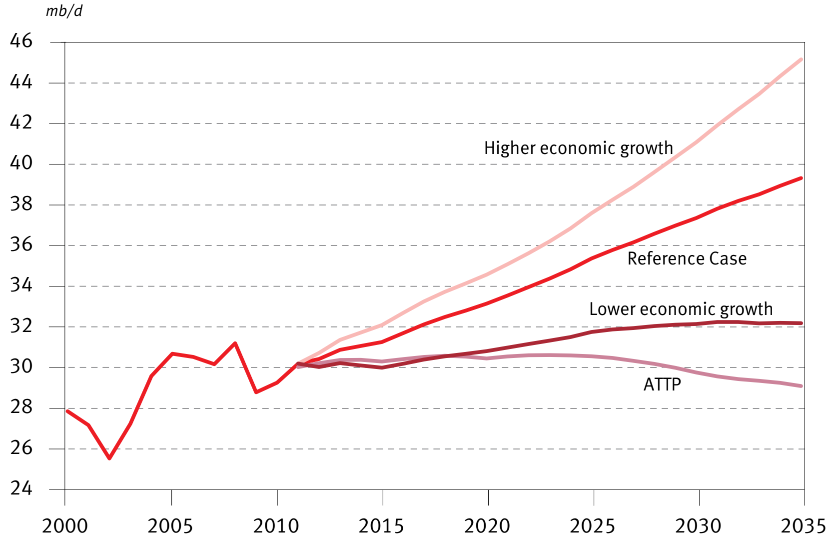


Figure 4.3
OPEC crude oil supply in the lower and higher economic growth scenarios



The key conclusions from these scenarios are:

- In regards to security of demand, at least over the short- to medium-term, uncertainty over economic growth is probably as big a concern as the development of policies and technologies;
- Downside demand risks can be even greater than portrayed in the scenarios if elements from the each of the scenarios are fused;
- Impacts of policies and technology changes could be substantial, with effects less visible in the short- to medium-terms; and
- On the back of strong economic growth, upward pressure upon prices could lead to significant reactions in non-OPEC supply.

Adverse impacts of climate change mitigation response measures

The negotiation process relating to the UNFCCC and its Kyoto Protocol is now being held under a two-track approach with the Ad Hoc Working Group on Long-Term Cooperative Action under the Convention (AWG-LCA) and the Ad Hoc Working Group on Further Commitments for Annex I Parties under the Kyoto Protocol (AWG-KP).

COP-16, held in Cancun at the end of 2010, resulted in the 'Cancun Agreements'. Parties recognized that deep cuts in global greenhouse gas emissions are required, so as to limit the global average temperature rise to less than 2°C above pre-industrial levels. However, no agreement has yet been reached for any future GHG atmospheric concentration long-term goal.

An important initial focus for any analysis of the impact of mitigation policies and measures on the amount of oil that OPEC will be required to supply in the future is the relationship between expected surface temperature change and global atmospheric GHG concentrations, expressed as CO_2-equivalent parts per million (ppm). The 2007 IPCC assessment[53] developed mappings between the two variables. However, uncertainties in the fundamental relationship between GHG concentrations and temperature rise have not been eliminated even by decades of research.[54]

The IPCC Working Group III, in its contribution to the IPCC's Fourth Assessment Report (AR4), developed six categories of concentration stabilization scenarios and from the available literature mapped corresponding CO_2 emission paths. The ranges of concentrations, for both CO_2 and CO_2-equivalent, are shown in Table 4.7.

The key mitigation options through which abatement occurs are, of course, higher energy efficiencies, fuel switching away from higher carbon content fossil fuels, in particular coal, and an increased use of non-fossil fuels. These developments would come from a mixture of price signals that specifically penalize carbon emissions, as well as regulation. In scenarios that assess these measures, contributions also should be

Table 4.7
Characteristics of 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	855–1,130	5

Sources: 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.

considered through sinks, such as carbon capture and storage (CCS) and forestry as well as the role of market mechanisms. It is also important to note that anthropogenic GHGs are attributable to a wide range of activities, with CO_2 emitted from fossil fuels accounting for only 57% of the total.

Inevitably, severe abatement targets would significantly impact oil demand.[55] Indeed, global oil use would eventually decline substantially. A very important element of any assessment of such developments, however, and one which is often overlooked, is the extent to which oil demand reduction, relative to the Reference Case, would be absorbed by OPEC. If the only supply implications were for OPEC, Reference Case prices could be assumed to prevail throughout the projection but there would be dramatic implications for OPEC's crude supply path. However, it is highly unlikely that OPEC alone could entirely absorb this fall in demand.

Instead, if the loss in oil demand, relative to the Reference Case, is shared between OPEC and non-OPEC in terms of lower supply, the oil price would need to fall sufficiently to bring about the corresponding non-OPEC supply reaction. But how far would the price need to fall for this to occur?

The key to this question lies in the price elasticity of non-OPEC supply. If non-OPEC is highly price responsive to a price fall, then only relatively small price adjustments would be needed to elicit a non-OPEC reaction to the demand loss. If, on the other hand, elasticity is low, the price fall would need to be greater for any given decline in non-OPEC supply. With an elasticity of 0.2, the long-term price would probably need to be around half of the Reference Case levels.

As a result, a more realistic pattern emerges when taking into account a sharing of the demand loss. Instead of OPEC absorbing the reduction alone and its crude declining dramatically over the projection period, the outlook for OPEC crude would be more plausible. For this to be the case, however, non-OPEC supply would also have to fall.

In any case, the implications for net OPEC crude oil export revenues would be substantial.

With growing populations, oil export revenues per capita hardly grow even in the Reference Case. With mitigation response measures, revenues per head would almost certainly decline below historical levels. Other adverse impact channels include lower domestic demand and GDP, more expensive imports, increased financing costs, job losses and lower competitiveness. The importance of such adverse effects, actual and potential, on all developing countries, particularly those identified in Article 4, paragraph 8, of the Convention, suggests an urgent need to establish a permanent forum on response measures under the Conference of the Parties to the UNFCCC.

Energy poverty

The latest figures on global energy poverty are staggering: according to the UN, 1.4 billion people have no access to electricity and some 2.7 billion rely on biomass for their basic needs. The World Health Organization also states that, relying on biomass means 1.45 million premature deaths per year, most of them children, a death toll greater than that caused by malaria or tuberculosis. Moreover, relying on biomass means less time at school for children and certainly more deforestation.

It is also important to underline the link between energy poverty and other types of poverty. Energy poverty exacerbates other types of poverty such as food poverty, health poverty, education poverty, and income poverty. It is important that sustainable and durable solutions to energy poverty are promoted: solutions that seek to move the energy poor up the energy ladder, enabling them to earn a sustainable income and benefit in terms of health and education, which will in turn, help them move out of the poverty trap.

The World Summit on Sustainable Development (Johannesburg, 2002) acknowledged that eradicating poverty is the greatest global challenge facing the world today and an indispensable requirement for sustainable development, particularly for developing countries. It also called for "joint actions and improve efforts to work together at all levels to improve access to reliable and affordable energy services for sustainable development sufficient to facilitate the achievement of the Millennium Development Goals (MDGs), including the goal of halving the proportion of people in poverty by 2015, and as a means to generate other important services that mitigate poverty, bearing in mind that access to energy facilitates the eradication of poverty". Rio+20 next year is a great opportunity to take stock, particularly in terms of the MDGs, and to define improved processes, structures and means for achieving sustainable development, including the issues of funding and capacity building.

OPEC Heads of State in Riyadh in 2007 recognized that energy is essential for poverty eradication, sustainable development and the achievement of the MDGs. They associate their countries "with all global efforts aimed at bridging the development gap, making energy accessible to the world's poor, while protecting the environment".

Sustainable development, with its three intertwined and mutually supportive pillars of economic development, social progress and environment protection, is a high priority agenda for OPEC Member Countries. It is also the main objective of the assistance they provide to other developing countries, directly through their own aid institutions, as well as through the OPEC Fund for International Development (OFID). In total, they have provided close to $350 billion (in 2007 prices) in development assistance to other developing countries in the period 1973–2010. This amounts to nearly $10 billion a year.[56] A significant portion of this amount, $69 billion, has been devoted to energy related projects, covering a diverse portfolio of energy sources that includes financial support to renewable energy sources. OFID particularly targets least developing countries and assists in the pursuit of sustainable social and economic advancement. Today, 129 countries from the developing world have benefited from OFID assistance.

Human resources

The human resource plays a strategically important role in the oil and gas business. The ability to innovate, explore, plan, and execute large-scale, complex development projects in a cost effective and environmentally-friendly manner requires a highly qualified and experienced work force. However, the future availability of qualified technical talent remains a major challenge facing the oil industry.

The Great Recession has had a significant impact in terms of job losses and a lack of job creation in the industry. However, the origins of this talent shortfall lie back in the 1980s and 1990s. It was then that the oil and gas industry saw a wave of cost cutting and redundancies. The result of this was that many technical people who were then entering their mid-career left the industry for good. Moreover, it was as this time that many universities cut back drastically on the number of student places for energy disciplines because the industry was not deemed to need graduates in such numbers. In recent years, there has also been fierce competition for talent, particularly from the service and emerging knowledge economies. And in addition, there is a sizeable section of the industry's workforce, particularly the large numbers that entered the industry in the 1970s, that are now approaching retirement.

It is clear, however, that the industry will need more qualified people in the years ahead. It begs the question: how can the industry find, hire, train and keep talented people?

It is evident from the history of the oil industry that there have been periods that could be characterized 'boom' and others that could be viewed as 'bust'. In periods of growth, companies have traditionally boosted their capital expenditure and recruited more staff. And when the industry has struggled somewhat, the situation has normally been reversed. It is important, however, that the industry finds new approaches and identifies sustainable long-term solutions to manage workforce demographics, even during challenging times.

The industry needs to be made more attractive; to make it accepted as an inclusive and forward looking workplace. It needs to be sure it is well presented as a prime long-term employment choice. This needs to begin before actual employment – with education. It is important for the industry to be significantly involved in developing and nurturing new graduates and its potential workforce at an early stage. The focus is on cultivating better relationships between prospective employees, universities and the industry.

A related issue is that of local content. This is of particular relevance to many oil and gas producing developing countries. Local content has a crucial role to play; a role that can, and should, provide a strong platform for a country's economic and social development.

In this regard, it is useful to have a well-defined, coherent, effectively managed and well-administered local content framework that positively engages and mobilizes all the relevant stakeholders – local communities, local industries, service companies, national oil companies (NOCs), governments and international oil companies (IOCs) – and in a manner that enables economic growth and social progress.

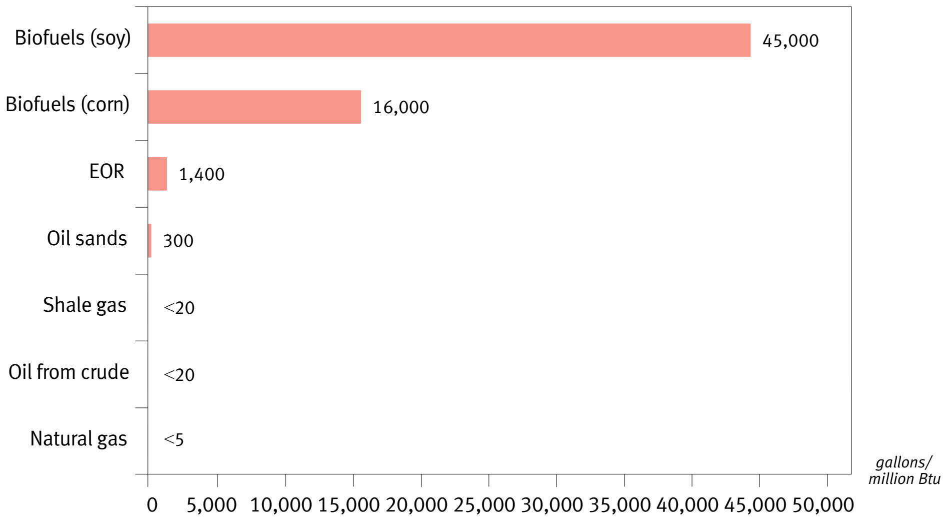
In the context of the EU-OPEC energy dialogue, a study and roundtable is planned to assess the underlying causes of the human resource problem, the resultant implications for the energy industry, and potential ways to move forward to correct the growing discrepancy between the need for, and the availability of skilled labour.

Energy and water

An oft neglected aspect of the energy industry is the impact that production activity can have upon water resources. Competition for this precious resource, not just in the energy sector, but also among other industries, such as agriculture, as well as from communities, is becoming increasingly visible. Processes can have effects upon the availability of water, as well as the potential contamination of supplies. It is important, therefore, to be aware of the crucial water-related challenges that lie ahead in the energy sector, in general, including the oil sector.

For transportation fuels, it is worth noting that all alternatives to oil produced from conventional sources use substantially more water in their production processes, with the exception of natural gas. Figure 4.4 shows, for example, that biofuels

Figure 4.4
Average water consumption by transportation fuel



Source: *'The water-energy nexus: adding water to the energy agenda', World Policy Institute, March 2011.*[57]

produced from irrigated soy, uses on average over 3,000 times as much water for the same energy content compared to oil from crude.

It is also well known that production from oil sands involves substantial amounts of water, and more recently, emerging trends in the production of both shale gas and shale oil has drawn attention to their possible impact on water supplies. In particular, as noted in Box 1.5, the process of hydraulic fracturing has significant implications for water pollution. These concerns were reflected strongly in an April 2011 report from the Proceedings of the National Academy of Sciences, which established "systematic evidence for methane contamination of drinking water associated with shale-gas extraction".[58]

A major question for these industries will be to what extent, and how rapidly, the use of water, in terms of volumes consumed, and the potentially compromising of water quality through polluting side-effects, will eventually have to be factored into cost estimates. In turn, this could have implications for the cost estimates of the marginal barrel, and could therefore be a factor in making future assumptions for sustainable oil prices.

Chapter 4

Beyond the oil sector, there are major tensions between energy production and water resources, most notably in electricity generation. In fact, the reliability of electricity supply is closely related to water availability, with most of the usage related to cooling. Of course, the exception to this is renewable electricity sources, such as wind and solar. Additional water-related hazards are specific to nuclear power, as was unfortunately demonstrated by the Fukushima disaster earlier this year.

The relationships between energy production, water use and contamination are therefore of great significance, and it seems inevitable that energy producers will need to improve their data regarding the impacts upon water quality and availability. It is important to become more aware of the costs associated with these effects, and to better understand the implications for issues central to sustainable development.

Technology and R&D

Technology has played a crucial role across the entire petroleum industry; in finding oil fields, developing them and in bringing the oil to market. It has also been an essential element in helping transform crude into desirable fuels and other demanded quality products. And in the transportation sector, technology advances have been key to the improvements in energy efficiency and the minimization of pollutants emissions, as explored in Box 2.1.

For oil supply, technology is continuously being developed and utilized to discover more oil, often in remote and/or hostile places, and to deliver it to end-users. This includes geological modeling, improved subsurface imaging through the use of advanced 3-D seismic acquisition techniques, directional drilling and the use of high pressure high temperature tools, improved reservoir data acquisition and simulation, as well as more efficient compact and reliable processing equipments. Looking ahead, more technologies will need to be developed to enable the sustainable exploitation of difficult finds, and increase the maximum recovery from traditional fields. In the downstream, catalysts and processing technologies need to continuously evolve to enable the processing and purification of the most difficult crudes, and to transform them into the demanded transportation fuels and petrochemical intermediates. And further along the value chain, in all demand sectors technology solutions are needed to improve energy efficiencies, allow for the incorporation of non-conventional fuels, and to control GHGs and other emissions.

Throughout its history, the petroleum industry has been successful in advancing and deploying technologies to reduce its environment footprint, for example, in drilling, gas flaring reduction and cutting plant emissions. And the automotive industry, as well as the refining industry, has a good track record in continuously reducing the pollutant emissions of vehicles. It is essential for the industry to continually look to advance the environmental credentials of oil, both in production and use, in terms of improving operational efficiencies and recovery rates, and in pushing for the development and use of cleaner fossil fuel technologies.

One very important area where R&D and technological development will increasingly need to be applied relates to CO_2 emissions when burning fossil fuels. With the world expected to rely heavily on fossil fuels for decades to come, it is essential to ensure that the early development and deployment of cleaner mitigation technologies continues. CCS in geological formations is an identified technology with great potential in this regard. The IPCC has stressed that CCS has a large mitigation potential and could contribute up to 55% of the global cumulative mitigation effort by 2100. To help advance CCS technology and accelerate its deployment, several international initiatives have been established. These include the International Energy Agency's (IEA) GHG Programme, the Carbon Sequestration Leadership Forum (CLSF) and the Global CCS Institute (GCCSI). OPEC is actively participating in two of these initiatives, namely the IEA GHG Programme and the GCCSI.

The recognition of CCS as a potential climate change mitigation option and the support given to the advancement of this technology by governments, research institutions and companies has already resulted in several integrated demonstration CCS projects being executed. However, more efforts are needed to speed up the full commercialization of CCS. How quickly this proceeds beyond the demonstration phase will depend on successfully addressing challenges such as storage potential assessment and storage security, public awareness and knowledge sharing.

In the context of knowledge sharing, OPEC is collaborating with the IEA CCS Unit in developing a roadmap for the use of CO_2 for EOR by hosting a workshop on the subject in Kuwait in the first quarter of 2012. This workshop is expected to address the potential for utilizing captured CO_2 in enhancing oil and gas production in the Middle East region. While many countries are collaborating in the advancement and deployment of CCS, including OPEC Member Countries, it is envisaged, however, that developed countries should continue to take the lead in commercializing CCS, given their historical responsibility and their ability to develop the required technology and finance early projects.

It is evident that technology will increasingly be leveraged by the industry to overcome existing and new challenges as it looks to minimize exploitation costs and reduce its environmental footprint. To ensure that the required technology is available, and at the right cost, timely and substantial investment in R&D is key. To this end, OPEC Member Countries are collaborating among themselves, as well as with other international research and technology development institutions to identify gaps and opportunities in all technologies in the petroleum industry.

Dialogue & cooperation

In a world of growing interdependence, the importance of dialogue is widely acknowledged. This is underscored in OPEC's Long-Term Strategy and the 'Riyadh Declaration', which concluded the Third OPEC Summit in November 2007. OPEC has also been broadening and strengthening its dialogue with consuming and producing countries, as well as other international institutions. The issues at stake are complex, broad and inter-related. They require concerted efforts, and where appropriate, joint collaboration, to find adequate, cooperative and sustainable solutions.

Close engagement with major stakeholders at various levels is essential to advance mutual understanding on common challenges, such as security of supply and demand, investments, cleaner fossil fuel technologies, environmental protection, the role of petroleum in promoting sustainable development and energy poverty. Expanded, in-depth dialogue, builds confidence, aids long-term market stability and can attend to the concerns of both producers and consumers, particularly at times of high volatility in markets.

The global producer-consumer dialogue continues to evolve. OPEC, which has been actively involved in this global dialogue since its inception, collaborates closely with the IEF on a number of issues, including work related to the G-20 Energy Agenda and the Joint Oil Data Initiative (JODI). The latter has proved to be an effective vehicle for improving oil data transparency, and is recognized as an essential mechanism for the promotion of energy data transparency at the global level.

On top of this, emphasis on international energy cooperation and dialogue, such as with the EU, Russia and China, will remain a high priority for OPEC, as well as with other international organizations, such as the International Energy Agency, the World Bank, the International Monetary Fund, the World Trade Organization and various UN bodies. Over the past year, OPEC has also been heavily involved in collaborative work related to the G-20.

A significant feature of the IEA-IEF-OPEC dialogue is the start of an annual series of Symposia on Energy Outlooks, the first of which was held on 24 January 2011, in Riyadh, Saudi Arabia. It offered a platform for sharing insights and exchanging views about energy market trends and uncertainties, as well as short-, medium- and long-term energy outlooks, not only from the three organizations, but invited external experts too.

The EU-OPEC Energy dialogue, which was set up in 2005, has continued to go from strength-to-strength. It held its 8th Ministerial-level meeting in June 2011. The dialogue has resulted in a greater awareness of the need for closer consumer-producer cooperation to address common concerns and challenges. In this context, several joint studies and roundtables on various topical issues have been undertaken.

OPEC has long recognized the importance of dialogue and adopting a cooperative approach to address major topical oil industry issues, as well as in related areas. It is essential that the industry continues to expand and evolve its collaboration in the years ahead.

Section Two

Oil downstream outlook to 2035

Chapter 5

Oil demand by product

In 2010, the world emerged from the global economic crisis that choked growth in 2008 and 2009. This has continued into early 2011, although the risks have escalated and growth rates are markedly varied across countries and regions. In terms of the oil market, demand has recovered more strongly than anticipated in last year's WOO, returning back to pre-crisis levels. Understandably, this has affected downstream industry operations.

In 2009, the collapse in oil demand, combined with downstream capacity additions, led to substantially lower refinery throughputs. This shifted the global refining system into a level of effective 'spare capacity' of more than 7 mb/d. This level of 'spare capacity' was last seen in the industry at the end of the 1980s. In 2010, the situation was somewhat mitigated as a resurgence in refinery runs outpaced refining capacity additions, which reduced spare capacity levels, albeit moderately.

However, new projects coming on stream over the next five years are expected to reverse this trend; the overall refining surplus could approach 10 mb/d by 2015 unless some capacity is closed. Thus, today's refinery projects – and those assessed to come on stream in the next few years – potentially represent a substantial proportion of the total additions that will actually be needed over the next ten-to-15 years. This will certainly affect future utilization rates and likely lead to a period of depressed margins and relatively poor economics for refining sector.

It is also important to stress that the level of regional demand decline during the Great Recession saw strong regional differences with significant implications for the refining sector. This is notable when contrasting growth requirements in non-OECD regions, especially the Asia-Pacific, and the surpluses in the US, Europe and Japan. This became particularly obvious in 2010 and is expected to be amplified in both the medium- and long-term.

In the medium-term, an implication of this 'two-tier' development is that OECD surpluses are not seen to be deterring projects in non-OECD regions. Countries with major projects such as China, India, Brazil and Saudi Arabia, are pursuing expansions in part, or in whole, to retain domestic product self-sufficiency. This trend is set to continue in the long-term with the majority of future refining investment projected to take place in developing countries.

At the centre of a refiners' short-, medium- and long-term concerns is how to deal with the challenges of overcapacity, alongside the uneven demand movements in various regions. This Section of the WOO examines these developments and provides a quantitative analysis of the likely evolution of the downstream sector, encompassing supply, refining capacity and investments, pricing and differentials and trade. This is developed using the World Oil Refining Logistics and Demand (WORLD[1]) model as a working framework, as well as the projections described in detail in Section One, as a base for supply and demand levels. However, because of trade flows, the regional definition used in this Section is based on a geographic, rather than an institutional basis. The model breaks the world into 18 regions, which for reporting purposes are aggregated into the seven major regions defined in Annex C.

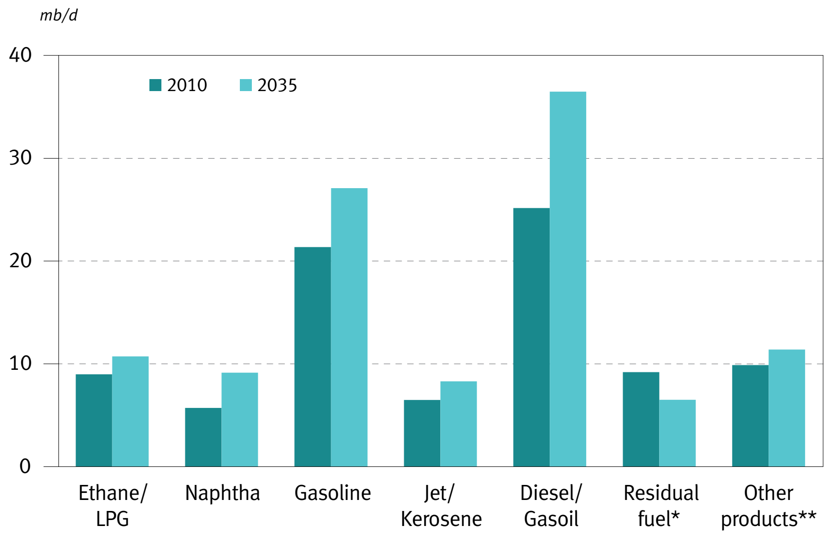
A major driver of future refining capacity requirements and economics is the level and quality of product demand. Oil demand developments in specific sectors, set out in Section One, determine to a great extent the current and future demand structure in respect to the product slate. Observed key trends in sectoral demand are

Table 5.1
Global product demand, shares and growth, 2010–2035

	Global demand mb/d						Growth rates % p.a.		Shares %	
	2010	**2015**	**2020**	**2025**	**2030**	**2035**	**2010–2015**	**2015–2035**	**2010**	**2035**
Light products										
Ethane/LPG	9.0	9.5	9.9	10.2	10.4	10.7	1.1	0.6	10.4	9.8
Naphtha	5.7	6.4	7.1	7.8	8.4	9.1	2.2	1.8	6.6	8.3
Gasoline	21.4	22.5	23.7	24.9	26.1	27.1	1.1	0.9	24.6	24.7
Middle distillates										
Jet/Kerosene	6.5	7.0	7.3	7.6	8.0	8.3	1.5	0.9	7.5	7.6
Diesel/Gasoil	25.2	28.7	32.0	33.8	35.3	36.5	2.7	1.2	29.0	33.3
Heavy products										
Residual fuel*	9.2	8.6	7.4	7.2	6.9	6.5	-1.3	-1.4	10.6	5.9
Other**	9.9	10.2	10.3	10.5	10.8	11.4	0.6	0.6	11.4	10.4
Total	**86.8**	**92.9**	**97.8**	**102.0**	**105.8**	**109.7**	**1.4**	**0.8**	**100.0**	**100.0**

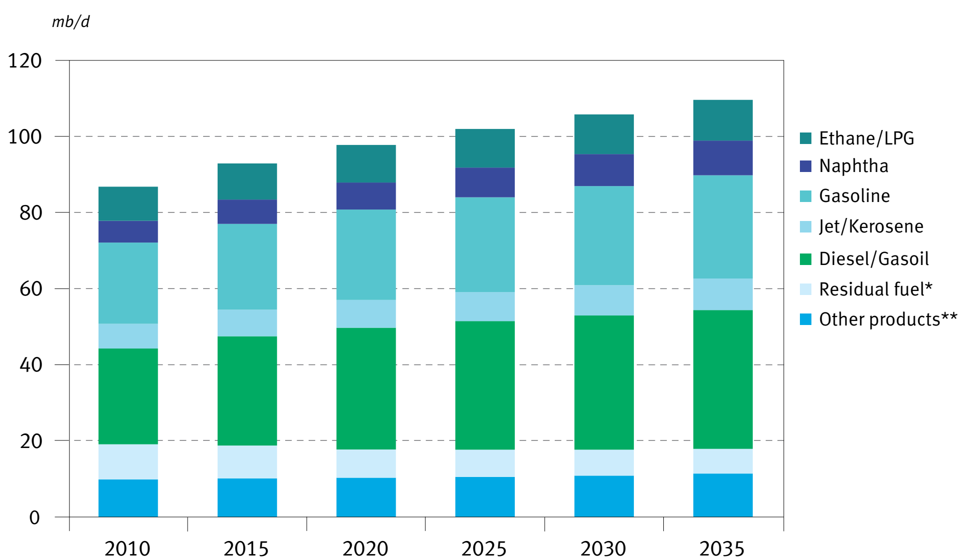
* *Includes refinery fuel oil.*
** *Includes bitumen, lubricants, waxes, still gas, coke, sulphur, direct use of crude oil, etc.*

Figure 5.1
Global product demand, 2010 and 2035



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

Figure 5.2
Global outlook for oil demand by product, 2010–2035



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

clearly reflected in global product demand projections, as presented in Table 5.1 and Figures 5.1 and 5.2.

These projections reflect the continuing importance of the transportation sector for overall product demand, and following the trend of the past few years, the prevailing feature is the continuing shift to middle distillates and light products. This is clearly evident in this year's WOO. Out of 23 mb/d of additional demand by 2035, compared to the 2010 level, around 57% is for middle distillates – gasoil/diesel and jet/kerosene – and another 40% is for gasoline and naphtha. The key reason for this is the growth in the road transportation sector, which is steering demand for gasoline and diesel. Demand for diesel oil also receives support from marine bunkers, and jet/kerosene from the expanding aviation sector. The growing petrochemical industry provides momentum for naphtha demand, while residual fuel oil is set to decline in all key sectors of its consumption.

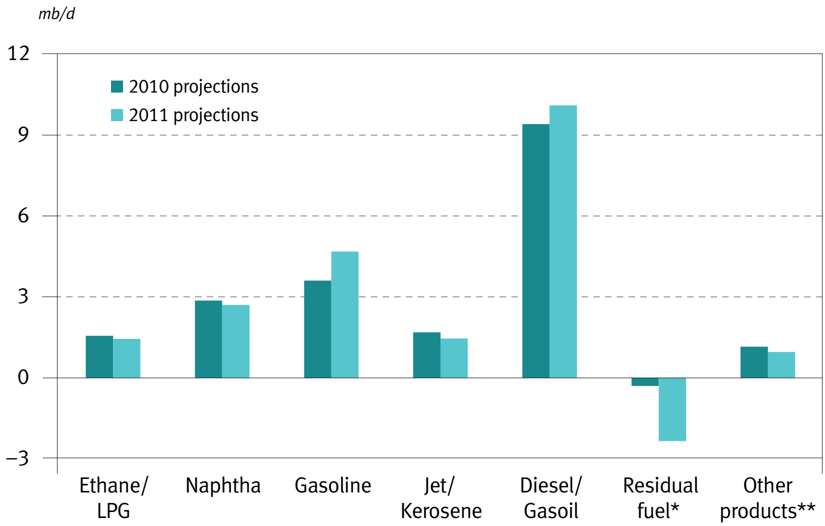
An obvious consequence of these demand trends is a progressive change in the make-up of the future product demand slate. Middle distillates will not only record the biggest volume rise, they will also increase their share in the overall slate from 36% currently, to 41% by 2035. The share of light products – ethane, LPG, naphtha and gasoline – will also expand, but this is at more moderate levels. Their total share rises only 1% from 42% in 2010 to 43% in 2035. In contrast, the share of the heavy end of the refined barrel will decrease by around 6%, from 22% in 2010 to 16% by 2035.

Needless to say, these structural changes cannot be achieved by simply increasing refinery crude runs. They require investments to change the configuration of the global refining system (See Chapter 7).

In addition to the trends already highlighted, there are two new policy issues documented in this Outlook that will alter both the level and relative growth of specific products. Figure 5.3 provides an indication of these product demand changes compared to last year's WOO. Modifications to projected 2030 demand levels – the time horizon for the WOO 2010 – for ethane/LPG, naphtha and jet/kerosene primarily reflect updates to the historical base data and the overall oil demand trends outlined in Section One. By 2030, demand for these products is marginally lower in the current update compared to last year. The main reason is this year's lower overall oil demand in 2030. In principle, the same is true for the group 'other products'. No structural and policy change was assumed in making these projections.

However, there are more fundamental reasons behind the modified projections for gasoline, gasoil/diesel and fuel oil. In respect to gasoline, the EU proposal

Figure 5.3
Global product demand change between 2010 and 2035



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

('*Council Directive amending Directive 2003/96/EC restructuring the Community framework for the taxation of energy products and electricity*'), outlined in Box 5.1 is expected to provide impetus for higher future European gasoline demand. Although the proposal's medium-term implications are likely to be limited, in the long-term it is seen as a policy shift away from one that gave preference – and tax advantages – to diesel. This had led to the so-called 'dieselization process' in Europe's transportation sector. Several institutions and publications had questioned the sustainability of this dieselization trend, not only in Europe, but also globally. If the dieselization shift has continued at historical rates, it would have eventually led to an extreme demand imbalance between gasoline and diesel, far worse than that which exists today. The recent EU proposal is understood to signal a more pragmatic approach that takes into account the realities and limitations of refining technology and the expected composition of future oil supply. Moreover, current projections for gasoline demand assume some 'spill over' effect of this policy to other countries and regions. Thus, gasoline demand by 2030 is around 1 mb/d higher than last year's projection.

Despite the fact that both this and last year's projections for gasoil/diesel demand growth are similar through to 2030 – the difference by 2030 is 0.7 mb/d – there are

Box 5.1
Europe: taxing times for diesel?

After almost two years of difficult internal and external discussions, the European Commission (EC) finally released its '*Proposal for Council Directive amending Directive 2003/96/EC restructuring the Community framework for the taxation of energy products and electricity*'. This proposal is now with the European Parliament, the Council and the European Economic and Social Committee, commencing the project's legislative procedure.

Under the existing energy taxation directive the minimum tax rates for energy products are based on volumes. This creates, according to the EC, unfair competition among fuel sources and unjustifiable tax benefits for certain types of fuel compared with others. Indeed, the effect of this tax system is that products with lower energy content, such as gasoline, carry a greater taxation burden per energy unit than products with a higher calorific value, such as diesel. However, although the current taxation system does not explicitly take into account a fuel's CO_2 output, the favourable treatment of diesel fuel was often linked to the better fuel efficiency of diesel engines, which results in lower tailpipe CO_2 emission per kilometre.

Translated into numbers, diesel fuel enjoys a relative tax advantage of around 24% compared to gasoline – measured on energy bases – while it generates about 32% more CO_2 emissions. This has led to a situation in which the open market diesel price is higher than that for gasoline due to greater diesel demand, but retail prices for final consumers are reversed at the pump because of lower taxation rates. This creates even more demand for diesel, despite EU shortages. The EC wants to put an end to this distortive treatment, with diesel currently taxed at a lower rate than gasoline in all but one EU member state (the UK).

Two other issues the EC's new proposal seeks to resolve relate to the taxation of renewable fuels and policy consistency in the tax system in relation to the objectives of the EU Emissions Trading Scheme (ETS). Currently, the minimum tax on renewable fuels is equal to the tax rate of the conventional fuels they replace. For example, ethanol is taxed as gasoline, even though emissions from these fuels are different. Moreover, the current tax directive does not take into account ETS rules, or the potential interaction with this system. Thus there are overlaps in a number of areas. As a result, it eliminates some potential effects of the ETS by distorting price signals.

Two elements of the energy tax

With the new tax proposal, the EC introduces a distinction between fuels specifically linked to carbon intensity (CO_2-related taxation) and energy taxation with the purpose of generating budget revenue (a general energy consumption taxation). The first component, the CO_2-related taxation, will be based on the reference CO_2 emission factors set out in Commission Decision 2007/589/EC. The second component, the general energy consumption tax, will be calculated based on the net caloric value specified in Annex II to Directive 2006/32/EC. In the case of biomass and products based on biomass, the reference values shall be those set out in Annex III of the EU's Renewable Energy Directive (RED). For biofuels, these reference values may be applicable only if biofuels meet the sustainability criteria specified in the RED, otherwise the energy content should be the value used for the equivalent heating fuel or motor fuel. The proposed minimum levels for motor fuels are summarized in the table below.

Proposed minimum levels of taxation for motor fuels from 1 January 2013

	CO_2-related tax €/tCO_2	General energy consumption tax €/GJ					
	1 January 2013	1 January 2013		1 January 2015		1 January 2018	
	On-road and Off-road	On-road	Off-road	On-road	Off-road	On-road	Off-road
Gasoline	20	9.6	0.15	9.6	0.15	9.6	0.15
Gasoil	20	8.2	0.15	8.8	0.15	9.6	0.15
Kerosene	20	8.6	0.15	9.2	0.15	9.6	0.15
LPG	20	1.5	0.15	5.5	0.15	9.6	0.15
CNG	20	1.5	0.15	5.5	0.15	9.6	0.15

Based on HART Energy Special Report, European Union: Proposal for New Scheme on Energy Taxation.

Despite a number of exceptions to these general guidelines, the proposal assumes a gradual increase to the minimum tax level for on-road motor fuels – apart from gasoline – so by 2018 the minimum tax rate for all fuels is equal. For key motor fuels, gasoline and diesel, the implication is that minimum tax rates on diesel are set to increase by around 25% from €0.33/litre to €0.41/litre, while the minimum duty on gasoline stays roughly the same, at €0.36/litre. Moreover, restrictions on fuel tax neutrality after 2020 could see minimum diesel taxes eventually rise 15% above gasoline.

It is important, however, to recall that only these figures represent minimum tax rates and EU member states are free to set rates much higher. Currently, gasoline is taxed at €0.72/litre in the Netherlands, twice the minimum required rate, while, in the UK, diesel is taxed at €0.66/litre, or double the minimum rate.

Under the new tax directive, diesel taxes would have to rise in more than half the EU's 27 member states. However, they are already higher in Europe's largest car markets – Germany, the UK and France – where no changes would be necessary.

On the other hand, this proposal could also be viewed as a signal to EU member states to reverse unwarranted tax advantages to diesel and to steer towards a more balanced future demand pattern which is sustainable for the refining industry. An early assessment of the potential implications of this proposal on gasoline and diesel demand in Europe suggests that the progressive shift in diesel taxes will not be sufficient to reverse diesel demand growth within this decade. However, it could slow down the rate of new diesel car registrations in the coming years, with a subsequent gradual shift to a higher share for gasoline engines.

It is too early at this point, however, to determine the full extent of this proposal. Depending on the response of EU member states to this new directive, the effect is likely to be limited in the medium-term, but should become more visible after 2020.

two important factors, with counterbalancing effects, that underlie the 2011 projections for this product group. The first is the EU tax directive highlighted in Box 5.1. The second relates to the regulation of quality specifications for marine bunker fuels by the International Marine Organization (IMO). Recent regulations have significant implications for refining and petroleum demand. An institutional background of these regulations is outlined in Box 5.2.

It must be recognized, however, that uncertainties exist over the implications of IMO regulations on marine fuels and energy efficiency improvements in the sector. Today, driven by higher fuel costs, shippers already use 'slow steaming' to reduce fuel demand. Slowing a ship's speed is a highly effective means of cutting fuel consumption since, in general, a 10% reduction in vessel speed leads to around a 25% reduction in fuel consumed. Additional speed reductions can yield further significant fuel reductions. Most sectors of the shipping industry are presently in a position to slow steam because the aftermath of the recession has left them with spare capacity. If continued over time, slow steaming would mean building more ships, in effect trading higher capital and fixed operating costs for reduced variable operating costs. However, this raises uncertainties regarding the extent to which slow steaming could be maintained as a future efficiency measure, and thus impact marine fuels demand over the longer term.

Box 5.2
IMO bunker fuel regulation: overview of regulatory changes

Standards for international marine bunker fuels are administered by the IMO, an organ of the UN, under the International Convention for the Prevention of Pollution from Ships (MARPOL), which was first signed in 1973. Under the MARPOL convention, the IMO establishes specifications for marine fuels, namely the distillate grades – marine gasoil (MGO) and marine diesel (MDO) – and several grades of residual type Intermediate Fuel Oil (IFO).[2]

Concerns regarding the implications of marine-based emissions led the IMO to embark on a programme to not only tighten fuels specifications under ISO-8217, as applied globally to marine fuels, but also to enable countries and regions to establish Emission Control Areas (ECAs).[3] ECAs were a departure in that they fundamentally laid down standards covering emissions of SOx, NOx and/or particulate matters (PM) and then set out options for compliance. The ECA standards allow for a vessel to achieve compliance by either using fuel that meets the specified ECA standard or to use other means, notably on-board exhaust gas scrubbing to achieve the equivalent emissions reductions. These new standards were ratified as MARPOL Annex VI at the October 2008 meeting of the IMO Marine Environmental Protection Committee (MEPC). They have since come into full force as member countries representing more than 84% of tonnage have adopted the convention.

The global fuel standard for MARPOL Annex VI was lowered from 4.5% to 3.5% sulphur in January 2011. This, however, had little practical impact as the overwhelming majority of IFO fuels have sulphur levels below 3.5%. Far more significant for this Annex is the eventual tightening of the global standard to 0.5% sulphur. This is slated to come into effect in January 2020, but is subject to a review no later than 2018 to confirm sufficient fuel availability. Should the study indicate substantial supply issues, then Annex VI allows for the possibility of delaying the standard, but to a date no later than January 2025.

Annex VI and an accompanying NOx Technical Code set out standards for ECAs. The petroleum industry is primarily impacted by the standard's sulphur limits. The 1.5% limit that has applied since 2008 was lowered to 1% in July 2010 and will be cut to 0.1% as of January 2015. The ISO-8217 set of specifications has been updated to correspond to these Annex VI standards. In addition, the latest ISO-8217 bans the use of lubricating oils and sets standards for catalyst fines metals.

The IMO has also taken action to address marine vessel energy efficiency and GHG emissions. The July 2011 meeting of the IMO MEPC resulted in significant new regulations, namely the first-ever GHG regulations for new ships. In this regard, it is worth recalling that Annex I Parties to the Kyoto Protocol have committed to pursue the limitation or reduction of GHG emissions from marine bunker fuels through the IMO.

MARPOL Annex VI allows for two means of compliance: either change the fuel, or leave the fuel as it is and use on-board scrubbing. Scrubbing on land is an established technology, but on-board scrubbing for vessels is very much an evolving one. Several marine engine manufacturers and shipping companies have expressed interest in scrubbers and are currently testing various designs. On-board scrubbers are claimed to remove almost all SOx, most of the PM and some NOx, depending on the design.

To date, comparative studies of the economics of switching from IFO to lower sulphur marine diesel, versus staying with IFO and installing and using on-board scrubbers, generally show the latter to be more economical. However, issues remain regarding scrubber performance, their reliability, the acceptability of the wash-water effluent generated, their usability in port, and shore disposal of the resultant waste slurry. The general view is that more will be known in the next year or two as the results of current testing programmes become clearer. However, even if successful, it will be several years before scrubbers start to play any significant role.

In terms of ECAs, to date two ECAs are in operation, both of which are in Europe. These are the Baltic ECA and the North Sea ECA. In addition, the US and Canada have submitted applications for ECAs on both Atlantic and Pacific coasts that will come into effect in August 2012. For 2015, the fuel standard in the ECAs will be a maximum 0.1% sulphur, as opposed to 1% today. So far, compliance in the two existing European ECAs has been achieved using mainly low sulphur residual fuel. Meeting the 0.1% standard, however, will require the use of marine diesel as a displacement of IFO with distillate, given the expected limited role of scrubbers in this timeframe. Therefore, the enactment of an ECA is likely to have an appreciable impact on refining and oil markets.

There is some uncertainty over the exact volumes of fuel that will be impacted under any ECA. It will depend on trade patterns and the extent to which vessels entering and leaving the ECA opt to use only the minimum ECA-compliant fuel, or more than this, in order to minimize fuel switching. Vessels trading entirely within the ECA would have to use 100% ECA compliant fuel.

Another potential factor that could impact demand for liquid marine fuels over the longer term is LNG use. On the basis that the crude to natural gas price ratio remains much wider than 6:1 (on calorific value and taking into account the difference in gas and diesel engine efficiencies); that LNG trade will continue to grow; and that marine fuels regulations will increase fuel costs, LNG could become an attractive option, especially longer term and on new build ships. In effect, any displacement of IFO and marine distillates by LNG would represent an extension of the trend on land for natural gas replacing residual fuel and heating oil. On the other hand, however, safety concerns and infrastructure constraints will likely limit the expansion of LNG use as a bunker fuel.

It is assumed that ECA standards will have to be met entirely via fuel compliance in the shorter term to 2015. From 2020 onwards, however, a limited and slowly increasing penetration of scrubbing in ECAs is anticipated. Moreover, it is assumed that additional countries and regions would progressively adopt ECAs. This includes the Caribbean, the Mediterranean, Japan and Singapore. For non-ECA areas and fuels, scrubbers would be progressively adopted, especially after 2015. The global fuel standard for MARPOL Annex VI is assumed to be met by 2020, with an 80:20 rule applied. In other words, a view quite widely held in the industry is that scrubbers will eventually be fitted to about 20% of the marine fleet, but that these will be the largest ships. Thus, around 80% of compliance will be via scrubbing and 20% via fuels.

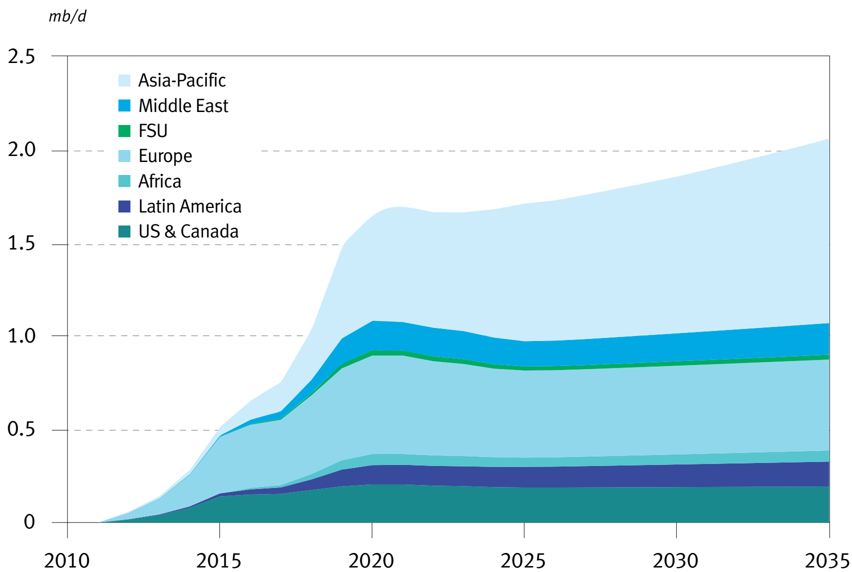
There are at least two reasons for this viewpoint. Firstly, it is the larger vessels that run primarily on IFO and for which fuel consumption is a relatively high proportion of total cost, and as such, they have the biggest economic incentive to stay with the cheaper fuel by using scrubbing. Secondly, on-board scrubbers take up considerable space and height. Smaller ships are therefore less likely to be able to accommodate them, both in terms of the available space or given the possible adverse effects caused by raising the ship's centre of gravity. This is likely to be the case if the ship is a new fit or retrofit. Conversely, larger vessels, either new or retrofit, are more likely to be able to accommodate a scrubber. Again, it must be reiterated that a significant range of uncertainty applies to this assumption.

The net results of these presumptions – expressed in terms of projected IFO that would be switched to marine distillate – are set out in Figure 5.4.

The two key compliance dates are 2015 and 2020. Recognizing this, fuel switching was smoothed to recognize that some suppliers would invest and start supplying the compliant fuels early, and that full compliance would not be achieved until somewhat after the official compliance date. Consequently, the projection is for:

- A first 'ramp up' to meet the 2015 standard, which essentially constitutes Northern Europe plus the US and Canada moving to the 0.1% ECA standard;

Figure 5.4
Projected IFO switched to diesel oil, 2010–2035



- With some easing in the years 2016/2017, there is a second major ramp up in IFO switching to diesel in the following period 2020/2021 to meet the 0.5% global standard – with 80% scrubbing, 20% fuel – and the implementation of additional ECAs;
- A flattening and even lessening in the required switching from IFO in the period from 2021 to around 2023, due to the assumption that the use of scrubbers will increase gradually;
- A resumption of gradual switching to distillate from around 2024-to-2035. In line with the premise that smaller ships would not use scrubbing, the 80:20 ratio would hold, and therefore, some further switching would be required given the continuing marine fuel demand growth. It is possible of course that longer term technology advances could reduce the need for further IFO switching to distillate, in which case the curve out to 2035 would be flatter, or even decline; and
- A significant role for fuel switching to distillate in Europe in the earlier years. This is in line with the region's considerable marine fuel consumption, combined with its active ECAs. There would then be a progressive shift to switching in developing country regions, led by the Middle East and the Asia-Pacific, with switching from IFO in the period from around 2018 onwards. This

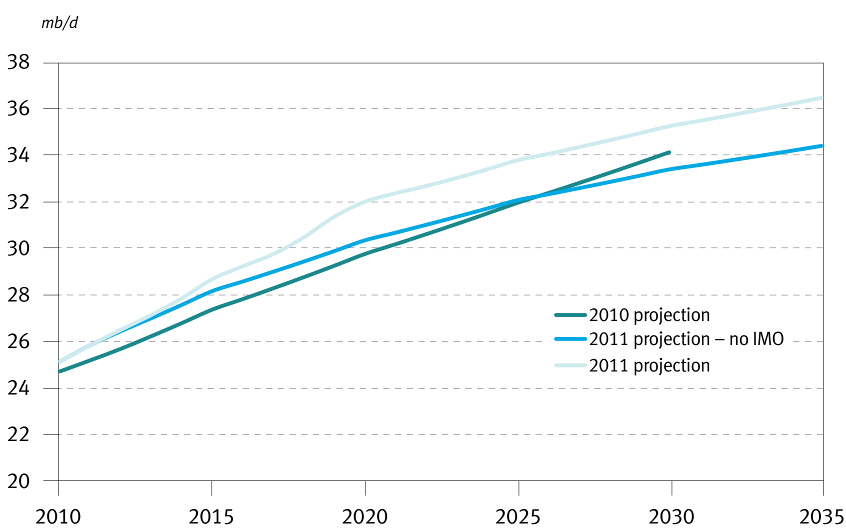
is to comply with the global standard, and the ECAs assumed for selected countries.

The net effect is a projection for 0.5 mb/d of IFO to be switched to distillate by 2015, 1.7 mb/d by 2020 and 2.1 mb/d by 2035. Turning back to the outlook for diesel/gasoil demand, an expected long-term implication of the recent EU tax proposal is some shift in demand growth from diesel oil to gasoline (Figure 5.5 – 2011 projection – no IMO). Primarily due to the higher base demand in 2010, gasoil/diesel demand exceeds last year's projection in the medium-term. It then slows down in the period after 2020 due to the estimated impact of EU policy changes.

While the effect of the proposed EU directive is a long-term reduction in gasoil/diesel demand, the implications of the IMO regulations more than offsets this reduction and leads to a 'two step' demand increase, the first before and after 2015, and the second post-2010. Overall, there is a net increase of around 1.1 mb/d in global gasoil/diesel demand by 2030, compared to last year's projection.

Although recent policy changes suggest some moderation in long-term diesel use in the road transportation sector, the progressive diesel/gasoil demand growth still creates a shift from gasoline to diesel. In 2010, the demand difference was below 4 mb/d. By 2015, projected diesel/gasoil demand is almost 6 mb/d higher than that

Figure 5.5
Comparison of global diesel/gasoil demand, 2010–2035



for gasoline, and by 2035 the difference exceeds 9 mb/d. A critical question in this respect is how the future structure of the car fleet in developing countries will evolve. Will it follow the European path – rising penetration of diesel-based engines – or will it be dominated by gasoline? The outlined projections assume an increasing share of diesel cars in developing countries, however, not to the levels experienced in Europe. Moreover, a decline in new diesel car registrations and a revival of gasoline engines is foreseen in Europe.

Within the forecast period, diesel/gasoil is expected to witness the highest volume gain, although naphtha will be the fastest growing product on a percentage basis, especially in developing Asian countries. Demand growth for naphtha resumed in 2010, following a temporary decline in 2009, and is expected to continue over both the medium- and long-term. In terms of average growth rates for naphtha, in the medium-term it is 2.2% p.a. and in the long-term it is 1.8% p.a. The main driver for this is high petrochemicals demand growth and volume increases in the Asia-Pacific, as well as expanding demand in many other developing countries, albeit from a lower volume base. These increases more than compensate for stagnant or declining naphtha demand in OECD regions. Moreover, growth in naphtha demand helps partially offset the moderate projected global growth rate of 0.9% p.a. for gasoline as it represents a significant portion of the light gasoline range when crude oil is distilled.

The significance of North America and Europe in total gasoline demand is the main reason behind gasoline's low growth rate. The two regions comprised 54% of global gasoline demand in 2010. Therefore, the projected demand decline in North America and relatively stable demand in Europe will have a significant impact on the global picture, offsetting increases in other regions. Gasoline demand grows fastest in the Asia-Pacific region in the medium-term – 2.7% p.a. between 2010 and 2015 – driven by developments in China and India where annual growth reaches almost 5%. Significant gasoline demand growth is also projected for the Middle East, Africa and Latin America.

Moderately above-average growth rates are foreseen for the product group of jet kerosene and domestic kerosene. Currently this fuel group consists of around 80% aviation jet fuel and 20% kerosene, the latter used for lighting, heating and cooking. There is, however, a continuing shift away from kerosene to jet fuel for aviation. While jet fuel demand is projected to grow steadily, especially in non-OECD regions, kerosene will continue to be displaced by alternative fuels in most regions, leading to a steady decline in demand. This means that this product group's overall growth is lower than it would have been if jet kerosene was considered alone. Consequently, jet/kerosene demand is projected to grow by 0.9% p.a. on average for the entire forecast period.

In terms of fuel oil, its use in industry – mainly electricity generation and refineries – faces competition from natural gas in most regions. This points to a drop off in demand, with the trend foreseen to continue in the future. Moreover, this demand decline will be accelerated by the shift of fuel oil to diesel in marine bunkers. In total, fuel oil demand is set to decline by close to 3 mb/d between 2010 and 2035. The biggest demand drop is expected in the period between 2017 and 2020. This is a timeframe that sees the run-up to the implementation date for the IMO's regulation for a 0.5% sulphur standard for all non-ECA fuel and the expected full global compliance with the new regulation.

The last product group of 'other products' consists mainly of heavy products, including bitumen, lubricants, waxes, solvents, still gas, coke, sulphur, as well as the direct use of crude oil, for example, in Saudi Arabia and Japan. At the global level, demand for these products is projected to increase by 1.7 mb/d by the end of the forecast period, compared to 2010. This represents an average growth rate of 0.6% p.a.

However, there are significant regional variations in projected demand changes, as well as differences in demand trends for specific products within this group. These range between declining demand in Europe and North America – around 1% p.a. – to strong increases in Africa, Middle East and Asia, with average regional growth rates of between 2% and 4% p.a. At the product level, demand for such products as bitumen, lubricants, waxes and solvents is strongly linked to economic growth and that for the production of still gas, coke and sulphur is very much a function of a growth or decline in refining activity.

Table 5.2 provides a breakdown of product demand to the major regions.

Table 5.2
Product demand by region

mb/d

	World	US & Canada	Latin America	Africa	Europe	FSU	Middle East	Asia-Pacific
	2010							
Ethane/LPG	9.0	2.5	1.1	0.4	1.2	0.4	1.0	2.5
Naphtha	5.7	0.4	0.3	0.0	1.2	0.3	0.2	3.4
Gasoline	21.4	9.3	1.9	0.9	2.3	1.1	1.2	4.7
Jet/Kerosene	6.5	2.0	0.3	0.3	1.2	0.3	0.4	2.0
Diesel/Gasoil	25.2	4.4	2.4	1.4	6.2	1.0	1.8	8.0
Residual fuel*	9.2	0.7	1.0	0.7	1.5	0.4	1.5	3.3
Other products**	9.9	2.6	1.3	0.1	1.8	0.4	0.7	3.0
Total	86.8	21.8	8.3	3.8	15.4	3.9	6.7	27.0
	2015							
	World	**US & Canada**	**Latin America**	**Africa**	**Europe**	**FSU**	**Middle East**	**Asia-Pacific**
Ethane/LPG	9.5	2.5	1.1	0.4	1.2	0.5	1.1	2.7
Naphtha	6.4	0.3	0.4	0.0	1.2	0.3	0.2	4.0
Gasoline	22.5	9.2	2.2	1.0	2.2	1.1	1.4	5.4
Jet/Kerosene	7.0	2.0	0.3	0.3	1.2	0.3	0.5	2.3
Diesel/Gasoil	28.7	4.8	2.7	1.6	6.8	1.1	2.0	9.7
Residual fuel*	8.6	0.6	0.9	0.7	1.1	0.3	1.6	3.4
Other products**	10.2	2.5	1.3	0.2	1.5	0.5	0.8	3.3
Total	92.9	21.9	9.0	4.3	15.2	4.1	7.5	30.9
	2035							
	World	**US & Canada**	**Latin America**	**Africa**	**Europe**	**FSU**	**Middle East**	**Asia-Pacific**
Ethane/LPG	10.7	2.2	1.3	0.5	0.9	0.5	1.5	3.7
Naphtha	9.1	0.3	0.4	0.1	1.0	0.4	0.4	6.5
Gasoline	27.1	8.6	2.9	1.4	2.4	1.5	2.1	8.2
Jet/Kerosene	8.3	1.8	0.5	0.5	1.2	0.4	0.7	3.2
Diesel/Gasoil	36.5	4.6	3.4	2.1	6.5	1.3	3.0	15.5
Residual fuel*	6.5	0.3	0.7	0.8	0.5	0.3	1.5	2.4
Other products**	11.4	2.1	1.3	0.3	1.3	0.5	1.3	4.6
Total	109.7	19.9	10.6	5.7	13.9	4.9	10.4	44.1

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

Chapter 6

Distillation capacity requirements

Given the figures for future supply, demand and refined product quality already set out, this Chapter discusses the likely implications for the downstream sector in terms of required distillation capacity.

In the medium-term to 2015, distillation capacity requirements are estimated using a combination of existing base capacity at the end of 2010, capacity assessed to come on-stream from existing projects and additional required capacity – above existing projects – that is needed to meet projected levels for refined products demand.

Assessment of refining capacity expansion – review of existing projects

In determining requirements, it is important to initially carry out a careful review of existing projects for refining capacity expansion. This year's analysis indicates renewed investor interest in building new capacity, despite the fact that overcapacity persists globally, which is depressing refining margins and keeping utilization rates low in most regions. On the flip side, however, is the prospect of demand increases in Asian countries and the Middle East, combined with an emerging trend among crude producers to refine especially heavier crudes domestically. This is expected to result in significant medium-term capacity additions.

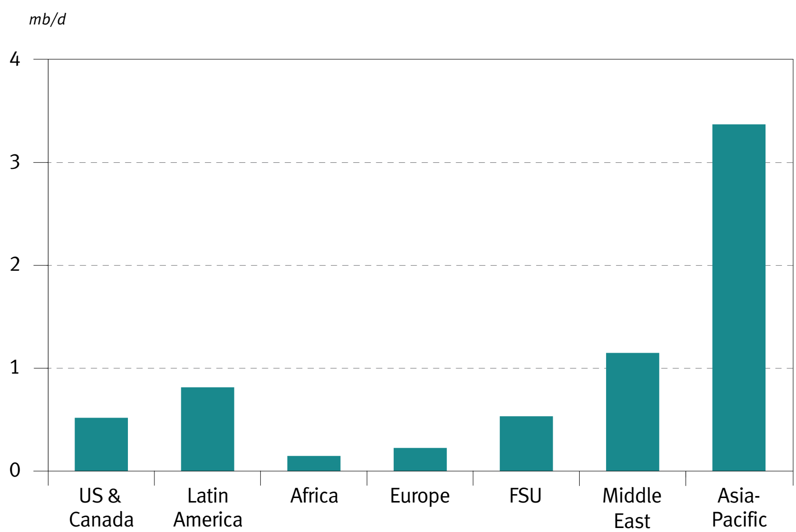
Continued interest to invest in refining is reflected in the list of announced capacity projects that served as the basis for the capacity assessment. However, given the list totals more than 40 mb/d of potential new capacity it was necessary to develop a reasonable methodology to risk assess these projects. Consequently, all identified projects were allocated into one of four major categories according to the likelihood of their implementation in the period to 2015.

The criteria focused on current status, commitments undertaken by investors, as well as regional and domestic conditions that support or discourage execution. For the category of 'certain projects', those mainly already under construction or where there is an indication of firm commitments, it is assumed that they will be implemented. For the middle two categories, a likelihood of implementation of 80% ('probable') and 60% ('possible') were applied. Projects under the final category of 'unlikely/speculative' were effectively excluded. This category typically contains projects that are either competing for the same market or where a realistic assessment indicates that they will not materialize in the target timeframe of 2015. In addition to implementation rates, the assessment includes a set of delay factors for each category, in order to give a more realistic estimation of additional capacity projections for a particular year.

The summary of assessed capacity additions from existing projects is presented in Figure 6.1. It is estimated that around 6.8 mb/d of new crude distillation capacity will be added to the global refining system in the period from 2011–2015. The highest portion of this new capacity is expected to materialize in the Asia-Pacific – mainly China and India – which accounts for 50% of additional capacity, or 3.4 mb/d. This high proportion of total capacity additions is a continuation of the trend of the last few years whereby the biggest refining projects have come on stream in these two countries. While investments in the Asia-Pacific's refining capacity are predominantly driven by domestic demand, in the other two regions with highest capacity additions to 2015, the Middle East and Latin America, the incentive is a combination of local demand and a value-added oriented policy. Similar reasons could also be given for FSU countries, although here expansion is mainly driven by the prospect of increased products exports, with local demand providing less incentive for expansion.

The scale of new distillation capacity in developing countries is in stark contrast to that assessed to come on stream in developed countries. Together, the US & Canada and Europe show an increase of 0.7 mb/d for the period to 2015, not taking

Figure 6.1
Distillation capacity additions from existing projects, 2011–2015



into account any planned or potential capacity closures. For developing regions, the corresponding figure is almost 5.5 mb/d. Moreover, this medium-term trend is set to continue over the long-term.

There are several other factors affecting future capacity expansion. In the US and Europe particularly, the situation for refiners is becoming ever more complicated and uncertain, due to the adopted or pending mandates for biofuels supply, transport fleet efficiency, emissions and carbon regimes. In contrast, capacity expansion in several emerging markets is being supported by policy incentives and favourable treatment. This is the case in India where export-oriented refineries enjoy tax holidays, including exemption from paying the minimum alternative tax, effectively 20%, and duty free crude oil imports to at least April 2012.[4] This includes the Reliance Jamnagar refineries that are located in a Special Economic Zone, where there are significant tax advantages.

Similarly, Chinese refineries have enjoyed competitive advantages in the form of a large stimulus plan to support capacity expansion and the upgrading of existing facilities to produce lighter and cleaner products. Moreover, in December 2008, the Chinese government introduced a new pricing regime that effectively guarantees a 5% profit for refiners when crude prices – in this case, a basket of Brent, Dubai and Cinta – are below $80/b. For crude prices moving between $80/b and $105/b, the margin decreases incrementally to zero at $105/b. Refiners are then compensated with subsidies when crude rises above $130/b. Up until February 2011, when prices were below $105/b, the system guaranteed reasonable margins for Chinese refineries. However, with crude prices moving in the range of $105–130 for a good part of 2011, it has meant refiners have operated at negative margins.

This situation has led to proposals for adjustments to the domestic fuel pricing mechanism. The proposed changes, suggested by the National Development and Reform Commission (NDRC), in consultation with Chinese refiners, would narrow the range in which the 22 working day moving average of crude prices can fluctuate, from the current 4% to a yet unspecified value, before changes are made to the retail prices of refined products. In addition, the monitoring period for making a change is proposed to be 10 working days, rather than the current 22. It is also thought that the authority for setting retail prices will be transferred to key companies in the refining sector, namely Sinopec, PetroChina and the Chinese National Offshore Oil Corporation (CNOOC).

Nevertheless, part of China's existing capacity could be eliminated by capacity closures resulting from the April 2011 release of the Guidance Catalogue for Adjustment of Industrial Structure. According to the catalogue, which took effect at the start of June this year, China will shut crude distillation units with an annual capacity of less than 2 million metric tonnes, or 40,000 b/d, by the end of 2013. This regulation could affect around 80% of China's independent refineries, including all 'teapot' refineries that account for around 2 mb/d of crude distillation capacity. However, the net effect of this regulation remains to be seen. Some small independent refineries may elect to expand capacity as a means to survive, and others could choose to merge or be acquired by state-owned companies, or switch to bitumen or chemical production. In addition, regional governments may not strictly execute the elimination policy because of local interests. Nonetheless, some capacity will certainly be shut down and replaced by more efficient and complex refineries in the coming years.

A further example of policy changes that may lead to favourable treatment for new refining projects is related to Russian export duties for refined products. In this regard, a new policy has recently been approved and it is very likely that the end result will be incentives for both capacity expansion and more complexity in the Russian refining system (Box 6.1).

Box 6.1
Russia's oil exports tax dilemma: crude or products?

In Russia, the previous system of export duties for crude oil and refined products was in place for several years. It was based on export duties levied on crude oil, which are set by the finance ministry (Figure 1). Export duties for refined products were then derived from this crude export duty as a given percentage, depending on the product type. In past years, export duties for light products, such as gasoline and diesel/gasoil, were around 70% of the duty rate for crude, while heavy products, mainly fuel oil, had lower rates of around 40% (Figure 2).

Figure 1
Russia's crude oil export duty

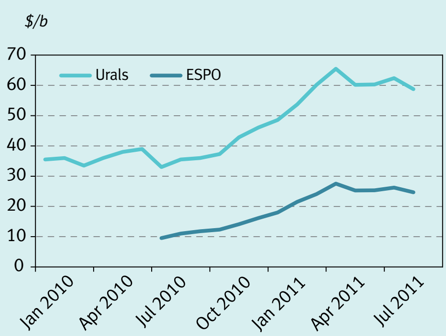
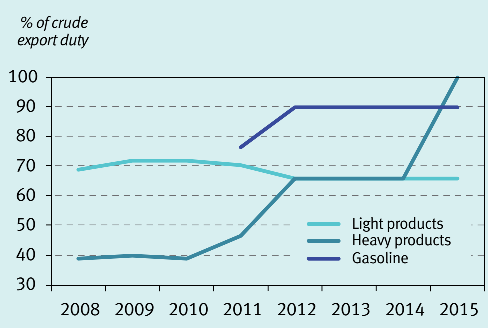


Figure 2
Refined products export duties in Russia*



** Duties for 2011–2015 estimated based on recent decision.*

The setting of these export duty rates significantly impacts both domestic production and the structure of Russia's oil exports.

Changes to the level of crude export duty affect the amount of crude oil that is profitable for production, especially in traditional oil producing regions. Moreover, they affect the cash flows and operational profitability of oil companies and, consequently, availability of capital for investments in both traditional and new fields. On the other hand, changing the proportions at which exports of refined products are charged shifts export volumes from crude to products and vice versa, as well as the composition of product exports.

The objective behind the provision of favourable rates for refined products in comparison to crude oil was to benefit from the value added to crude oil in the domestic refining process. This was supposed to provide incentives to revive investments in the refining sector; in order to modernize the industry and make it competitive internationally. In reality, however, this goal was not achieved as there was much less of an investment inflow than originally anticipated.

The key reason for this was that the ratios of export duties for light and heavy products at 70% and 40% led to increased volumes of heavy fuel[5] oil exports. This meant there was little incentive to invest in expensive conversion capacity as the difference between the average refining margins in simple hydro-skimming refineries and the more complex FCC cracking refineries in Russia was not sufficient to justify investments in conversion capacity. Moreover, under the tax system in place during 2010, even simple refineries in Russia could comfortably enjoy relatively high profits, while similar refineries in Europe were struggling to survive. The net result of this situation was that most of the investments in Russian refineries were directed to expanding desulphurization capacity, rather than to conversion.

Aware of the situation, towards the end of 2010 the Finance Ministry of Russia announced plans to alter the level of export duties for refined products with the overall goal of amalgamating the rates for light and heavy products. Unifying the export duty for refined products would certainly make simple refineries less profitable, thus potentially supporting investments to increase refinery complexity. Such a step creates an incentive for refineries to reduce their fuel oil output and to redirect these volumes, either to higher value products, or to crude oil exports.

The first part of the so-called '60-66 regime' proposal was approved by the Russian Government on 26 August 2011 and enacted as of 1 October 2011. The taxation of all products – with the exception of gasoline – will be unified at 66% of the crude oil export tax until 31 December 2014 (Figure 2). From 2015, heavy products will be taxed at 100%, while light products – still without gasoline – will remain at 66%. In terms of gasoline, the 2011 spring shortage led to a 90% taxation level that was introduced in May 2011, and according to the new legislation this will remain in effect until 2015. Some officials, however, are indicating that the high level might only be temporary and a reduction to 66% might occur sooner.

At the same time, the formula for the calculation of the export tax on crude oil will change. The tax will be set at $29.20/t (US$4/b) plus 60% of the difference between the average Urals price over the set monitoring period and $25. Prior to the change, the percentage of the difference used in the calculation was 65%.

Discussions are also under way to remove the tax reduction for ESPO crude oil in light of the recently sustained higher prices. However, there seems to be a general understanding that the tax break is needed to maintain Russia's crude production at its current levels, and as yet, no final decision has been made.

Asia-Pacific

In terms of actual projects, after the completion of two grassroots refineries in China during 2009, and a further two projects in Tianjin and Qinzhou last year, both adding 200,000 b/d, less is expected to be completed during 2011. In fact, only a China National Petroleum Corporation (CNPC) 100,000 b/d crude distillation project in Yinchuan, Ningxia province, is scheduled to become operational this year.

However, substantial refining capacity increases, on average around 500,000 b/d p.a., are expected between 2012 and 2015. The most likely projects slated for 2012 are refineries in Guangdong, Sichuan and Hubei provinces. These are in an advanced construction stage. In Guangdong province, Sinopec is expanding the crude capacity of its Maoming refinery by adding a 200,000 b/d crude unit, while closing two small older units. PetroChina is constructing a 200,000 b/d refinery in Sichuan province, which is integrated with an ethylene complex, and is doubling the capacity of its plant in Hubai province to 200,000 b/d. Looking further out toward 2015, there are potential expansion projects and grassroots refineries in several locations, including joint venture projects between Chinese companies and Kuwait Petroleum (a 300,000 b/d refinery in Zhanjiang, Guangdong province, combined with a 1 million-tonne-a-year ethylene plant), Saudi Aramco (a 200,000 b/d refinery in Yunnan province) and Venezuela's PDVSA (a 400,000 b/d refinery in Jieyang).

The biggest increase during this period is expected in 2013 when the Chinese refining sector could expand by more than 0.6 mb/d. One of the projects slated to be completed in 2013 is of significant strategic importance for China, as it links new pipelines running from Kyaukryu port in Myanmar to Kumming in China, thus bypassing the Malacca Strait. The pipeline's capacity is projected to be 0.45 mb/d, with the crude distillation unit at the refinery able to absorb 0.2 mb/d of imported crude. Altogether, this means that by 2015, total distillation capacity in China will be 2.1 mb/d higher, compared to the 2010 base.

Substantial medium-term capacity expansion is also expected in India, which dominates the region of 'Other Asia'. While India's publically-owned refining sector is experiencing some growth, it is the private sector that is changing the nature of Indian refining. From the mid-1990s, government laws have allowed private refining companies to construct new projects and many have been large in scale. For example, Reliance Industries' 550,000 b/d refinery in the Jamnagar Special Economic Zone, which has now been expanded to 660,000 b/d. A second 580,000 b/d refinery was added in 2009. In addition, Essar Oil started up a refinery at Vadinar in 2006/7, initially with a 210,000 b/d capacity, but this has also been expanded to 280,000 b/d. A further two-phase expansion is planned for this refinery, first to 360,000 b/d in 2011 and a doubling to 720,000 b/d by 2013. While the first phase is in an advanced stage of construction, there is little sign of progress with the subsequent doubling to 720,000 b/d and, therefore, this project's completion has been shifted to beyond 2015.

Today, the total combined capacity for these three refineries on India's west coast exceeds 1.5 mb/d. To put this in context, combined, this is higher than Singapore's total capacity of 1.35 mb/d. Moreover, it is large scale, complex, sophisticated and primarily export-oriented. Should Essar move ahead with both phases of its planned expansion, the combined capacity will essentially total 2 mb/d.

In the medium-term, India's refining capacity will also see some significant expansion from projects operated by local refiners, such as Indian Oil, Hindustan Petroleum, Nagarjuna Oil and Bharat Oman Refineries. Indian Oil's Paradip refinery is expected to commission its first unit in March 2012, with eventual capacity reaching 300,000 b/d. Some smaller projects are in advanced stages in Bhatinda, Punjab (180,000 b/d), and Bina, Madhya Pradesh (120,000 b/d), constructed by Hindustan Petroleum and Bharat Oman Refineries, respectively. And Nagarjuna Oil Corporation's 125,000 b/d Cuddalore project in Tamil Nadu is slated to commence operations by the end of 2011.

These Indian projects, combined with additions expected from the Korangi project in Pakistan, the Petrovietnam project in Nghi Son, Vietnam, and the expansion of the Chittagong refinery in Bangladesh, will result in 1.1 mb/d of additional crude distillation capacity in the 'Other Asia' region by 2015.

Within this region, the rapidly growing and already large-scale Reliance and Essar entities need to be closely monitored. Sited on the west coast of India, their locations are convenient for processing crude oils from the Middle East, and secondarily North and West Africa. And as their capacity rises, they should become greater crude oil consumers, including the heavy and difficult grades that may otherwise be difficult to place. However, since most of their output is intended for export markets, and since they do, or will have the capability to produce the most advanced product specifications with low operating costs, they will increasingly be viewed as global competition in the downstream. Furthermore, both companies are expanding their interests in oil and gas production and marketing, advancing their vertical integration. They are also integrating horizontally too, through involvement in sectors such as shipping, construction, petrochemicals, steel and power.

Middle East

The Middle East is projected to add 1.1 mb/d to its refining capacity between 2011 and 2015, with the majority expected to come from new grassroots projects. The most likely projects, among several announcements, are Jubail and Yanbu in Saudi Arabia, adding 400,000 b/d each, and the Ruwais refinery in the UAE. These projects are expected to start production towards the end of the 2015 forecast period. In addition to the grassroots refineries, several expansion projects are also underway in the region, but these will only add some minor capacity.

There are also a number of other possible expansion projects, but the timing of these is uncertain. Saudi Arabia is pushing for another refinery at Jizan Industrial City, but this is unlikely to be completed before the end of 2015. Similarly, the huge 625,000 b/d Al-Zour project in Kuwait is also unlikely to be finalized before 2015. In addition, Iraq is in negotiations with several investors to build four new refineries with a total capacity of 0.75 mb/d, the UAE has announced plans to build a new refinery in Fujairah and Qatar has announced projects in Ras Laffan and in Mesaieed, the latter to process expected additional barrels from the Al-Shaheen field.

Although not in the category of refining, it is worth mentioning that in June 2011 the first cargo from the Pearl GTL project marked the start-up of Qatar's Ras Laffan facility. The joint venture between Shell and Qatar Petroleum is expected to reach full output in 2012, processing 1.6 billion cubic feet per day of gas from the North Field, separating out 120,000 b/d of condensate and NGLs and producing 140,000 b/d of GTL transport fuels, lubricants, detergents and chemical feedstocks.

Latin America

In Latin America, around 0.8 mb/d of new crude distillation units are expected to come on stream by 2015. The majority will be in Brazil and is linked to the policy of the country's national oil company, Petrobras, to connect incremental crude production to local refining. Over the next two years, additional capacity will mainly come from smaller expansion projects in existing facilities, such as the refineries in Paulinia, Araucaria and Clara Camarão, and from a 230,000 b/d project in Abreu e Lima, Pernambuco. Thereafter, the majority will be from new world scale refineries at the Rio de Janeiro Petrochemical Complex (COMPERJ), which is designed to process heavy oil from the Marlim field in the Campos Basin, offshore Brazil, and from the first phase of the Premium refinery in Maranhao. Petrobras has also recently announced a number of other refinery projects, but completion of these is assessed to be beyond 2015.

In Mexico, state oil company Pemex is moving ahead with its refinery expansion at Minititlan, which is designed to add 100,000 b/d of new capacity by 2012. Similarly, progress is being reported on two projects in Colombia, in Barrancabermeja-Santander and Cartagena, which will add 220,000 b/d of combined distillation capacity to the Colombian refining system. Additional capacity will also be realized through expansion projects in existing refineries in Caripito and Santa Ines in Venezuela, Esmeraldas in Ecuador and Cienfuegos in Cuba. Besides these expansion projects, Venezuela's PDVSA and Italy's ENI have established a joint venture to build a new facility with a combined processing capacity of 350,000 b/d. This will convert 240,000 b/d of heavy crude from the Junin 5 block of the Orinoco belt into light crude and produce 110,000 b/d of refined products, primarily diesel fuel, for export to Europe. The expected start-up of this facility is, however, for 2016.

FSU

Compared to last year's WOO, there are more capacity increases in the FSU by 2015. Existing projects in the region will add around 0.5 mb/d of additional capacity, with the projects scattered through several existing refineries in Russia and Belarus. The major ones are the expansion of the Tuapse refinery by Russia's Rosneft, the expansion of the Mozyr refinery in Belarus by Russia's Slavneft and the Nizhnekamsk refinery by the CJSC Nizhnekamsk Refinery company. The latter was completed at the end of 2010, but operations did not begin until this year.

In Russia, several projects are oriented towards adding conversion and hydrotreating capacity to match the rising middle distillate demand and to meet required quality specifications, both domestically, and for export. Russia has also announced its intentions to add significant refinery capacity on its Pacific coast to be fed by the newly operational ESPO pipeline from Eastern Siberia. The options under discussion include new refineries in the ports of Nakhodka and Kozmino, and an expansion of the Khabarovsk or Komsomolsk refineries.

In addition, both Kazakhstan and Turkmenistan are considering investments in their refining industries to modernize – or possibly replace – ageing refineries. However, these projects are at too early a stage to be considered for a 2015 start-up.

North America

Medium-term refinery capacity additions from existing projects in North America are expected to reach 0.5 mb/d, dominated by developments in the US. These additions will be achieved exclusively through the expansion of existing facilities. Following Marathon's expansion at its Garyville refinery in Louisiana last year, the next major capacity addition will come from the Motiva project in Port Arthur, Texas. This will add 325,000 b/d of distillation capacity and is expected to be on stream in 2012. The rest of the capacity additions will be achieved from smaller projects, including the expansion of the Wood River refinery by ConocoPhillips and Encana; BP's project in Whiting, Indiana; and Marathon's refinery in Detroit, Michigan; in Canada there is also Co-operative Refineries Limited's expansion of the Regina refinery. It should be noted that many of the US projects, especially those in the US mid-west, are geared to configuring refineries to receive increasing amounts of Canadian oil sands crudes; a switch from light sweet, or sour crude feedstock, to heavier ones.

Europe

Europe's refining industry continues to suffer from overcapacity. Therefore, investment in crude distillation capacity expansion is limited to specific needs in some areas of Europe. The biggest ongoing expansion is Spain's Cartagena refinery, adding 110,000 b/d, followed by projects executed by Poland's Grupa Lotos, which will add 90,000 b/d of new capacity to its facility in Gdansk, and Portugal's Galp Energia at its Porto refinery. No expansion of crude distillation capacity is expected in Northern Europe. On the contrary, a number of refineries, mainly in Western Europe, are either for sale, being converted to storage terminals, or face closure (Box 6.2).

Africa

Despite the high number of announcements, there are not many projects in Africa that a have real chance of implementation before 2015. One clear case of a project that has gone ahead, and is now complete, is a small 20,000 b/d refinery in N'Djamena, Chad. The project has been financed by China's CNPC, which includes constructing a local crude oil pipeline that links N'Djamena to the Ronier oil field in central Chad.[6] The refinery will mainly produce transport fuels, including some petrochemicals. Refinery capacity in some form or other is also likely to be realized in Uganda in the medium-term, although it is not yet clear which of the three proposed projects will actually go ahead. The largest project under construction in Africa is the Lobito refinery in Angola, originally designed to add 200,000 b/d of new capacity.

The growing demand for refined products in Africa, as well as the availability of local crude, would certainly justify more investment in Africa's refining capabilities, but due to a variety of local circumstances and constraints, only around 0.15 mb/d of new distillation capacity is estimated to become available by 2015, compared to the 2010 base.

Capacity additions

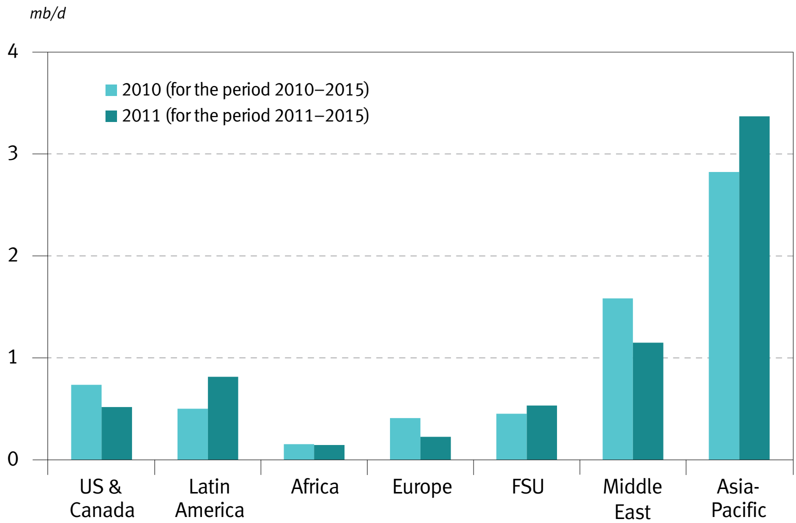
Figure 6.2 compares the latest 2011 assessment of existing refining projects to that of the WOO 2010. Although total capacity additions are not dissimilar, currently 6.8 mb/d compared to last year's 6.7 mb/d, this year's review indicates an increased interest in building new capacity, as well as regional shifts in placing this capacity. Last year's review covered the period 2010–2015, and thus, if around 0.8 mb/d of realized capacity during 2010 is accounted for, the current estimation is almost 1 mb/d higher than last year, implying a higher rate of capacity addition from 2011–2015.

Moreover, while OECD regions show a decline, because of the elimination of projects that came on stream during 2010 and a lack of future projects, new capacity is increasingly shifting to developing countries. Not surprisingly, the 'major winner' in absolute increment terms is the Asia-Pacific, although in relative terms it is Latin America. The latter signals the trend in a number of Latin American crude producing countries, such as Venezuela, Brazil, Colombia and Mexico, to expand refining capacity to process heavy domestic crudes. This trend is also evident in the Middle East and Russia.

The case of the Middle East is an interesting one, given the apparent decline from 2010–2011. The decline in new distillation capacity is primarily due to shifting some major projects beyond 2015, rather than eliminating these projects from the list altogether.

The net effect of this is that not all of the increased volumes of heavy crude are going to reach the open market in the future. On the contrary, markets will likely see increased competition on the product side, especially for light transport fuels, as these

Figure 6.2
Distillation capacity additions up to 2015 from existing projects, 2010 and 2011 assessment



new refining projects are typically fairly complex and efficient. Another implication is the potential sustained competition between complex deep conversion refineries for heavy crude supplies, which has implications for complex refining margins and for differentials between heavy and medium sour crude grades.

In addition to announced projects, some refining capacity increases are also being achieved through minor 'debottlenecking' within existing facilities, often during maintenance turnarounds. Adding in the effect of capacity creep, crude distillation will increase 7.5 mb/d by 2015 from the 2010 base level. The yearly distillation capacity increments resulting from both existing projects and capacity creep are presented in Figure 6.3.

This figure also indicates the potential for additional crude runs, based on annual capacity increases that take into account a maximum sustainable utilization rates of 90%, as well as the fact that new capacity gradually becomes available for production over the course of the period to 2015. While the figures for capacity additions represent total increases at the end of each year, the potential for additional crude runs reflects the yearly average capacity that contributes to the supply of refined products. For the entire 2011–2015 period, the potential for additional crude runs is projected to increase by 6.6 mb/d. This figure does not account for any possible capacity closures.

In respect to conversion capacity, a significant feature of existing projects is the increasing complexity. The majority of new grassroots projects fall in the category of complex refineries and many expansion projects are exclusively adding conversion capacity, particularly hydro-cracking and coking. This development is clearly visible when comparing the share of conversion capacity additions to distillation units. Typically, this proportion used to be in the range of 40–50%, however, for projects coming on stream in the period to 2015 distillation units are expected to account for around 65%. A similar trend is also evident in respect to sulphur removal processes, with tighter specifications on sulphur content in OECD countries, as well as a number of major developing countries, forcing an expansion in hydro-treating capacity. This trend remains visible in the number of projects under construction to 2015, with total hydro-treating capacity additions around 85% of distillation units.

Table 6.1 presents the results of the review of existing projects in respect to secondary process units. Additions to global conversion units are estimated at 4.4 mb/d for the period 2011–2015. Most of this capacity will come in the form of

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

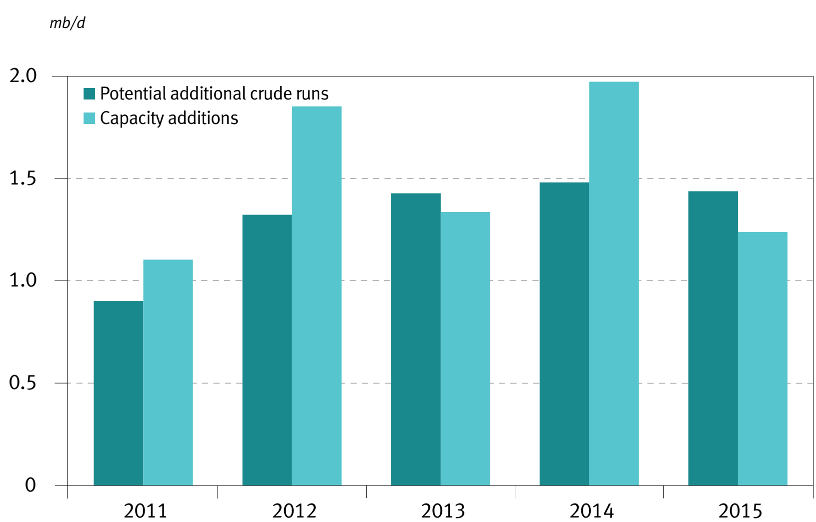


Table 6.1
Estimation of secondary process additions from existing projects, 2011–2015 *mb/d*

	By process		
	Conversion	Desulphurization	Octane units
2011	1.0	0.9	0.3
2012	1.1	1.4	0.5
2013	0.8	1.2	0.3
2014	1.0	1.4	0.2
2015	0.5	0.9	0.2
	By region		
	Conversion	Desulphurization	Octane units
US & Canada	0.6	0.4	0.2
Latin America	0.6	0.9	0.2
Africa	0.1	0.1	0.1
Europe	0.5	0.3	0.0
FSU	0.5	0.5	0.1
Middle East	0.5	1.1	0.3
Asia-Pacific	1.6	2.6	0.8
World	4.4	5.8	1.6

hydro-cracking units (1.7 mb/d), followed by coking (1.6 mb/d) and fluid catalytic cracking (FCC) units (1.1 mb/d).

New hydro-crackers will be scattered throughout almost all regions, including South and Eastern Europe and North America, primarily to increase the production of much needed middle distillates. However, most hydro-cracking units will be constructed in the Asia-Pacific, where diesel demand growth is highest, and within the FSU, driven by prospects for higher diesel and gasoil exports to Europe, which is, and will remain, short of this product.

Out of 1.6 mb/d of global additional coking capacity, around 0.5 mb/d is projected for the Asia-Pacific, more than 0.3 mb/d will be built in Latin America and a comparable capacity will come on stream in North America. FCC units, accounting for around 1 mb/d of conversion capacity, will almost exclusively be constructed in developing countries, mainly in Asia and the Middle East.

In terms of desulphurization capacity, there is expected to be an increase of 5.8 mb/d in the period to 2015. Most of the new capacity will again be in the Asia-Pacific (2.6 mb/d), with 1.1 mb/d and 0.9 mb/d in the Middle East and Latin America, respectively. This partly reflects the recent trends towards cleaner products within these regions – predominantly based on Euro III/IV/V specifications – but also efforts by export-oriented refineries to provide low or ultra-low sulphur products for potential customers in developed countries. This rationale is also driving desulphurization capacity additions in Russia. The remaining capacity additions are shared by North America (0.4 mb/d), Europe (0.3 mb/d) and Africa (0.1 mb/d).

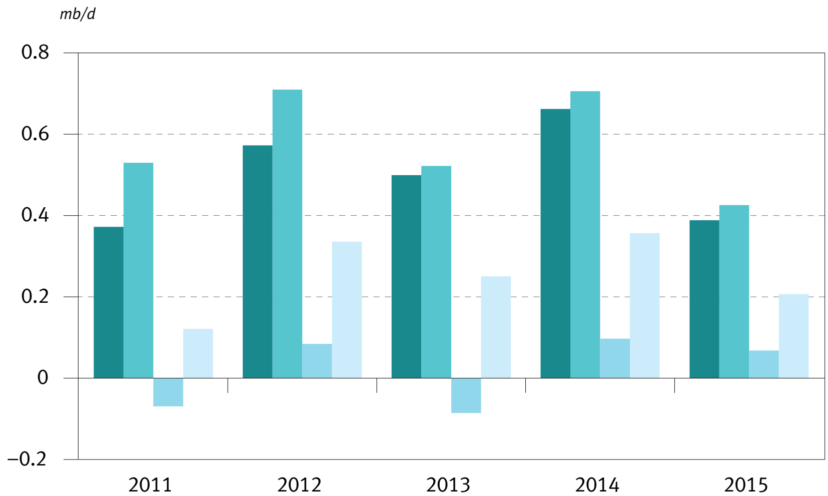
Additions in North America and in Europe are mainly related to the provision of adequate support to expansions in distillation capacity, as these regions almost entirely comply with ultra-low sulphur gasoline and diesel standards. Some additions may relate to achieving full compliance with new standards for off-road diesel. Within Europe, the majority will be added in the south and eastern parts of the continent. The northern part is already at full compliance with the standards.

The final category of capacity additions, referred to as octane units, relates to the quality of finished gasoline and comprises mainly catalytic reforming, isomerization and alkylation. It is projected that around 1.6 mb/d of these processes will be added to the global refining system from 2011–2015. Out of this, catalytic reforming will account for the majority, 1.2 mb/d globally. In terms of location, capacity will mainly be constructed in regions where gasoline demand increases are expected, for example, in the Asia-Pacific (0.7 mb/d), the Middle East and Latin America (0.2 mb/d each). as well as in North America (0.1 mb/d), which is gasoline dominated. In addition to reforming, lesser amounts of isomerization (0.2 mb/d) and alkylation (0.2 mb/d) units are planned. As these processes are also gasoline-related, the regional distribution of additions is similar to reforming capacity. To support the various cracking, desulphurization and octane units, significant additions are also evident in hydrogen, sulphur recovery, as well as other related units.

The combination of projected additional crude distillation capacity and secondary process units determines the refining system's potential to produce incremental barrels of specific refined products. To some extent, particular refiners have the flexibility to optimize their final product slate, either through altering feedstock composition and/or adjusting process unit operating modes. However, especially at the global level, and for the larger regions, this flexibility is fairly limited.

Bearing all this in mind, Figure 6.4 presents an estimation of the potential incremental output of refined products resulting from existing projects, grouped into major product categories. In total, the assessed implementation of current projects

Figure 6.4
Potential for incremental product output



would allow for around 6.8 mb/d of additional products to be available by 2015, compared to 2010 levels. The bulk of the increase is for middle distillates (2.9 mb/d) and light products, naphtha and gasoline (2.5 mb/d). The ability to produce fuel oil sees a minor increase of 0.1 mb/d and other products account for the remaining 1.3 mb/d.

The implications of these developments for the refining balance in the medium- and long-term are discussed later in this Chapter. It should also be noted that these projects are added to the capacity base for the model cases from 2015 through to 2035. Further primary and secondary capacity additions are based on projected demand levels.

Medium-term outlook

This year's projection for 2015 overall global oil demand is somewhat higher, at 92.9 mb/d, or 2 mb/d above last year's estimate of 90.9 mb/d.

Last year's supply outlook included substantial growth in NGLs and biofuels, supported by more modest growth in GTLs and CTLs. As a result, the non-crude supply as a percentage of total supply was projected to rise from 16% in 2010 to 22% in 2030. This year's outlook shows limited change in the non-crude supply outlook versus last year, except for a somewhat higher projected biofuels growth, especially during the last decade of the forecast period. Combined with stronger short-term demand, because of an anticipated faster recovery from the economic recession, and the associated higher demand for crude oil that acts as the balancing mechanism in the supply stream, the non-crudes supply share for 2015 is now projected to be marginally lower against last year's estimate.

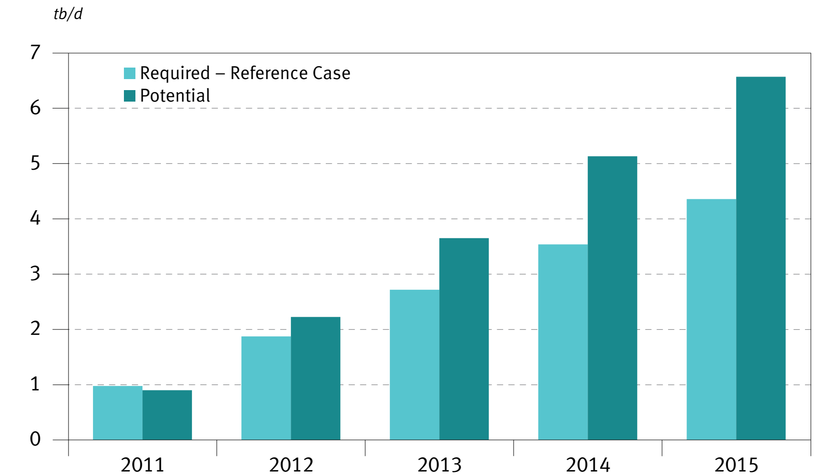
However, the long-term trend for non-crudes meeting a steadily higher proportion of total supply still holds true, and in fact, the trend is expected to strengthen. The net effect is that non-crudes are now projected to comprise 22.4% of total oil supply in 2030, against a projection of 22% last year. Again, it is crude oil, acting as the market's balance, which is impacted. In this year's projection, the required crude supply in 2015 is 1.7 mb/d higher than that projected last year, which then falls to about 1 mb/d in 2020 and to below last year's projection by 2030. Although the shifts versus last year's outlook are not large, they do translate into higher medium-term demand for refining throughputs and capacity and lower ones in the long-term.

In previous WOOs, a list of refinery projects were compared with estimates for incremental refinery throughput requirements based on demand growth. The effects of the global recession, combined with new projects coming on stream, has led to a situation of expected capacity surplus, in contrast to the expectation of a medium-term refinery capacity deficit that was the widely held view in the pre-recession years.

Figures 6.5 and 6.6 show the results of the latest comparison of estimated medium-term requirements for distillation capacity increases from refining projects. It is clear that there continues to be an expected medium-term capacity surplus. The required incremental refinery runs are based on projected incremental global demand from 2011–2015, less the incremental supply from non-crudes that bypass the refining system. The potential incremental refinery crude runs are based on the assessed nameplate capacity additions, less a factor for the expected maximum sustainable utilizations. Except for 2011, the incremental ability to refine crude oil is projected to exceed the incremental 'call on refining' in each year to 2015. In 2011, the deficit is very small, less than 0.1 mb/d, but by 2012 it has turned into an excess of about 0.4 mb/d, while every year thereafter it is close to, or over 0.6 mb/d.

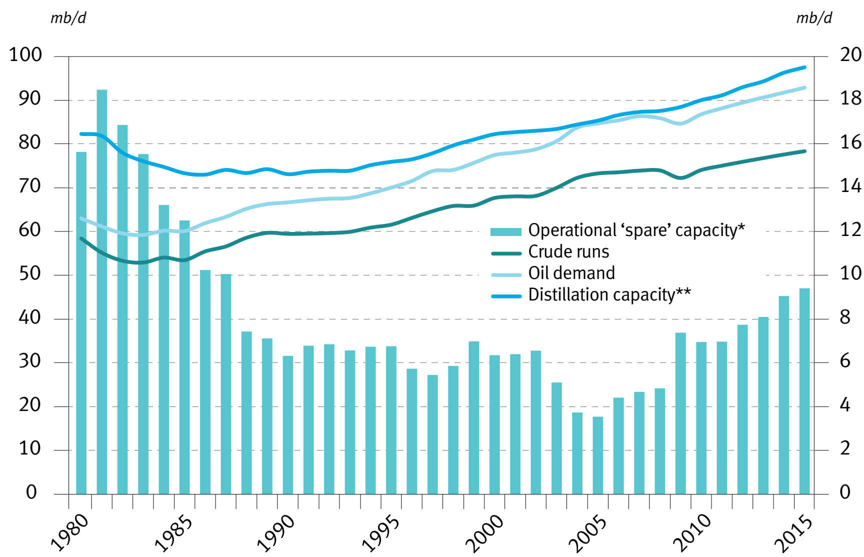
The net effect is that excess refinery capacity is expected to grow by 2.5 mb/d by 2015, compared to current levels. This assumes no refinery closures. It is important to recognize that this projected expanding medium-term surplus comes on top of the surplus that was created in 2009. In that year, refining capability from projects increased by around 1 mb/d, whilst required runs dropped by 1.6 mb/d. This led to

Figure 6.5
Additional cumulative refinery crude runs, required and potential*



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

Figure 6.6
Global oil demand, refining capacity and crude runs, 1980–2015



* *Effective 'spare' capacity estimated based on assumed 90% utilization rate.*
** *Subject to any capacity closure after 2010.*

a gap in operational refining capacity for 2009 – assuming a 90% utilization rate – of 2.4 mb/d. As emphasized in Figure 6.6, this shifted the global refining system into a new level of operational 'spare capacity', beyond the 7 mb/d level. This was last seen in the industry at the end of the 1980s. In 2010, the situation was somewhat reversed as a resurgence in refining runs outpaced refining capacity additions, thus moderately reducing the spare capacity level. However, the set of new projects coming on stream in the next five years are expected to see the 2009 trend resumed. By 2015, the total refining surplus could approach 10 mb/d, unless some capacity is closed.

This trend is not good news for refinery utilizations and economics. It reinforces the expectation of a challenging period for the industry with lower refinery utilizations and weak margins. In turn, it will exacerbate the need for capacity rationalization especially in the regions with the largest capacity overhang and lowest utilization rates.

It is clear that substantial regional differences already exist and will continue to do so. This is most notable in the continuing growth requirements of non-OECD regions, especially the Asia-Pacific, and the sustained surpluses in the US, Europe and Japan. The implications for some kind of industry restructuring are obvious. This is discussed in Box 6.2.

Another implication from this year's assessment is that the known surpluses are not deterring projects, or, to be more precise, the surpluses evident in OECD regions are not discouraging projects in non-OECD regions. Countries with major projects, such as China, India, Brazil and Saudi Arabia, are pursuing expansions in part, or entirely, to retain domestic product self-sufficiency and, in some cases, to boost refined product exports. Nevertheless, the overall implication is that a number of active refineries, as well as those currently being built or at the planning stage, need to face increased scrutiny, with a reassessment for costs, markets and a number of other factors.

Box 6.2
Outlook for refinery closures: what's next?

In the 2010 WOO, the state of play for refinery closures was described as a possible 'drama in three acts'. The premise being that the industry was at a point where there was an obvious need for substantial refinery closures, but at the time refiners were looking more to sell, than close. In many respects, it could be said that a number of refiners in the OECD were playing a waiting game to see if other refinery's closed first.

It was suggested that what might followe this act would be a sustained period of closures, followed by a final unknown act. All this would eventually lead to an industry that looked very different.

It begs the questions: what has happened since then? And does the picture look any different today? The short answer to both questions is not much.

The economic recovery has been stronger than was anticipated a year ago. And as a consequence, the WOO now sees a faster pace and more total refinery capacity additions over the next few years. The net effect of this is a projection for a medium-term refining surplus that will if anything, be greater than that estimated a year ago. The market remains, however, in the phase where refiners are trying to sell their facilities. There is talk of closures, but to date, there has been very little action.

The one country where closures look set to occur on a significant scale is Japan. In July 2009, Japan's Ministry of Economy, Trade and Industry (METI) issued an ordinance that requires refiners to meet a cracking to crude distillation ratio of 13% by March 2014. (Cracking under this ordinance is defined as resid FCC plus coking, plus resid hydro-cracking, which means it excludes vacuum gasoil FCC and hydro-cracking.) To meet this requirement, refiners must either close distillation capacity and/or increase resid upgrading. Given Japan's outlook for a continuing decline in petroleum demand – even following the Fukushima nuclear disaster the long-term trend remains down – refiners are generally electing for closures over investment. By early 2011, the JX Group, Idemitsu and Showa Shell had made, or announced, combined closures of around 600,000 b/d. Other companies, such as TonenGeneral and Cosmo Oil are expected to close a further 200,000 b/d. All told, up to 1 mb/d could eventually be closed by 2015. Elsewhere in OECD Asia, there has been discussion of one or two closures, for example, the Shell Clyde refinery in Australia, but to date, no actual closures.

While China is expected to increase its overall distillation capacity, legislation is expected to have an impact on the make-up of the industry. In its goal to eliminate the country's small refineries, China's central government has raised the minimum capacity limit to around 40,000 b/d. The targets are the small, but numerous independent, 'social' or 'teapot' refineries. While this duel over closures may prove to be long and drawn out, it could lead to some capacity being shut down over the next five-to-ten years.

Europe and the US are home to the largest capacity overhangs, but to date there has been relatively little movements in terms of closures. EU refiners face the combined prospect of declining demand, a continued gasoline and diesel imbalance, with the stresses this creates for refining margins, and a requirement to pay for a rising share of their CO_2 emissions. Despite these downside drivers, by July 2011, only five facilities had been formally shut down, with a total capacity of around 500,000 b/d. The prevailing trend has been to undertake extended maintenance or temporary shutdowns. Nevertheless, refineries totalling some 900,000 b/d are reportedly up for sale, and there has been a fairly active market both in terms of selling refineries and in turning some into terminals.

The majority of companies selling and closing refineries have been the majors, for instance, Shell, Total, Chevron and ConocoPhillips. However, buyers comprise a wide array of entities, including UK-based Ineos with Petrochina, India's Essar Oil, Klesch from Switzerland, Russia's Rosneft and Lukoil, and Valero from the US. In terms of the business objectives behind the purchases, these appear to be equally varied; from locking in downstream outlets for crude production (Rosneft, Lukoil), to gaining a foothold in Europe as part of international expansion plans (Petrochina, Essar), to running independent refining operations (Klesch), to gaining synergies with the US refining system (Valero). Valero's position is particularly intriguing as the company recently sold two US East Coast refineries and yet bought Chevron's Pembroke facility in the UK. It has been reported that Valero sees this as part of a strategy to take gasoline to the US, while back-hauling distillates from its US refineries to Europe.

One somewhat puzzling aspect in Europe is that most of the sales and closures have been in Northern Europe. There has been little activity in Southern Europe. Although the south has historically reacted more slowly than the north to changing market conditions, one would expect Mediterranean refineries to be impacted, particularly given the much-discussed financial difficulties in Greece, Spain and Italy.

In the US, the picture is also intriguing, and arguably, changing. A few US refineries have been closed, but mainly the smaller or older ones. In terms of sales, BP has put both its 451,000 b/d Texas City and its 251,000 b/d Carson City, California, refineries up for sale. BP's post-Macondo position could well be a factor in this. Texas City also has a chequered history because of a deadly process unit explosion, but it is unusual to see such a sizeable and complex Gulf Coast refinery up for sale. The Carson City refinery is also complex, but BP may see California's recent Law AB32, with its embedded low-carbon fuel standard, as a sign to exit.

Despite these developments, and recognition of the expected slow decline in both gross petroleum product demand and net ex-refinery demand courtesy of biofuels mandates and supply growth, there is little other US closure activity. One possible reason lies in the current rapid growth of 'local' crude oil supplies. This encompasses both the rising US Lower 48 production from the Bakken, Eagle Ford and other shale oil plays, as well as expanding Western Canadian production, led by oil sands. In the short-term, these trends, combined with inadequate logistics to get crudes to US Gulf Coast markets, are creating price discounts. It means that leading inland US refineries are enjoying significant refining margins. This departure from normal market conditions is working 'against' regional crude producers, but 'for' refiners whose crude contracts are priced off WTI or are related to Canadian heavy grades.

While pipeline projects should see the market return to more typical conditions over the next few years, it is evident that the US is enjoying the benefits of a resurgence in domestic and nearby crude supplies. Access to local crude production generally boosts refinery viability. This can perhaps be viewed in the fact that domestic US demand has dropped over the last few years, while exports of products from US refineries have sharply increased. In 2010, exports of finished products – including petroleum coke – surpassed 2 mb/d, up from 1 mb/d in 2005. Growth has been across all products, but led by distillates. These have soared from 138,000 b/d in 2005 to 656,000 b/d in 2010. A combination of expanding local crude production, with rising export opportunities, and the absence – at least for now – of any climate change legislation outside of California, could act to support capacity, leading to only minor closures in the US over the next few years.

In parallel with these developments though, the trend among majors toward 'dis-integration' is taking hold. Most of the majors have set firm goals to reduce their presence in the downstream, especially in the industrialized regions. Going beyond this, Marathon recently split into two companies, Marathon Oil for exploration and production and Marathon Petroleum for refining. ConocoPhillips is now talking of following suit. For national and other emerging country oil companies, this could be viewed as both an opportunity and a warning; an opportunity to build downstream presence and capacity, but a warning that several of the world's leading oil companies do not see the downstream as the best place to achieve financial returns.

In returning to the idea of a 'drama in three acts', it appears that we are now well into act one, with the market seeing some limited closures. And with the sales of a number of refineries, due in part to the threat of closures, the industry is also seeing some significant changes in downstream ownership. The extent and timing of act two – a period of sustained closures – remains somewhat unclear. In Japan it is beginning to take shape. In Europe, the threat continues to hang in the air. As for the US, it might escape largely unscathed, courtesy of rising regional crude production, growing demand in markets that will take its refined products and healthy margins, but the question remains, however, for how long?

Long-term outlook

The level of 'spare capacity' in refining is projected to expand in the medium-term, which, in turn, poses a challenge for the industry in the long-term. Unless a substantial amount of closures take place, it will limit future capacity additions. Another factor putting a 'cap' on additional capacity requirements is the expansion of non-crude supplies. These, combined with moderate long-term demand growth, result in a projection for a significant slowing in additional capacity requirements after 2015, as summarized in Table 6.2.

In this table, known projects are assessed under the Reference Case as those that will be constructed in the period to 2015. New units represent the further additions – major new units and de-bottlenecking – added in order to balance the global refining system. To do this, the period to 2015 indicates a total of 1 mb/d of required additional refining capacity, essentially de-bottlenecking. The period to 2020 adds a further 2.8 mb/d and the five year-periods to 2025, 2030 and 2035 an additional 2 mb/d, 2.1 mb/d and then 2.5 mb/d, respectively, compared to the previous time period. The review of known projects brings about a Reference Case assessment of 6.8 mb/d of new capacity additions on-stream by 2015. This is somewhat higher

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
2010–2015	6.1	6.8	1.0	7.8	1.6
2015–2020	4.9	0.0	2.8	2.8	0.6
2020–2025	4.2	0.0	2.0	2.0	0.4
2025–2030	3.9	0.0	2.1	2.1	0.4
2030–2035	3.8	0.0	2.5	2.5	0.5

	Global demand growth	Distillation capacity additions			
		Known projects	New units	Total	Annualized
2010–2015	6.1	6.8	1.0	7.8	1.6
2010–2020	11.0	6.8	3.9	10.6	1.1
2010–2025	15.2	6.8	5.8	12.6	0.8
2010–2030	19.0	6.8	7.9	14.7	0.7
2010–2035	22.8	6.8	10.5	17.2	0.7

than the 6.5 mb/d assessed last year for the period 2009–2015. This signifies a much faster pace of capacity addition, particularly given the fact that the time period is one year less.

The additional 1 mb/d of projects by 2015 are needed in the Asia-Pacific, the Middle East and Latin America. In the subsequent five-year periods, the required level of capacity additions average around 2.4 mb/d per five years, or 0.4–0.5 mb/d per year. This stands in contrast to the 1.6 mb/d per year rate for 2010–2015, which is driven predominantly by projects under way. Those projects are – in part – a reflection of the pre-recession investment decisions, but the net effect is a significant contribution to the medium-term capacity surplus.

It is also significant that, beyond the 6.8 mb/d of known projects expected to be on stream by 2015, the Reference Case outlook is that only an additional 3.9 mb/d of cumulative additions will be needed by 2020, 5.8 mb/d by 2025, 7.9 mb/d by 2030 and 10.5 mb/d by 2035. These projections are lower than last year. They reflect the combined effects of higher short-term capacity additions, a somewhat lower projected global demand in the longer term, and some upward revisions in the total projected growth for non-crudes supplies.

Thus, today's projects potentially represent a substantial proportion of the total additions that will be needed over the next 10-to-15 years. As Table 6.2 underlines, cumulative refinery capacity additions are ahead of global demand growth to 2015, but then fall progressively below in the period from around 2020 through to 2035.

The underlying reason for this trend, where refining additions fall increasingly behind demand growth over the longer-term, is that non-crude supplies – NGLs, biofuels, CTLs, GTLs and petrochemical returns – increase faster than demand, and thus, as a proportion of total supply. It means that less incremental refining is needed per barrel of incremental liquids demand.

Over the period 2010–2035, cumulative refinery capacity additions equate to only 75% of total demand growth. More critically, because of the large number of projects currently underway, that further extend the capacity surplus created by the recession, refining capacity additions after 2015 are required at a rate of only around 55% of incremental liquids demand. It points to a major reduction in the role of refining in meeting incremental demand at the global level. It must be remembered, however, that these projections represent a combination of new capacity additions in non-OECD, especially the Asia-Pacific, at rates much closer to the levels of regional demand increases, with the use of at least some of the now surplus capacity in OECD regions contributing to supply for the growing non-OECD demand.

The global and regional outlook, in terms of refinery crude throughputs and utilizations, is presented in Table 6.3. The stronger than previously expected global economic recovery has already put 2010 crude throughput levels back above 2007 and 2008 levels of around 74 mb/d. Despite this, over the medium- and long-term, lower future demand growth and rising non-crude supplies lead to a curb in the growth of refinery crude throughputs. After a period of respectable growth of around 4 mb/d, or 0.8 mb/d p.a., from 2010–2015, global refinery crude throughputs are projected to grow at an average rate of only around 0.2 mb/d p.a. from 2015–2035. Thus, as stated in last year's WOO, global refining cannot be called a growth industry and maintaining its viability will be a major challenge for those involved.

The overall outlook is for a slow decline in global refining utilizations, while throughputs gradually rise from 74.3 mb/d in 2010 to 82.7 mb/d in 2035. Impacts are not, however, regionally uniform. Table 6.3 highlights the contrast between

Table 6.3
Crude unit throughputs and utilizations

	Total crude unit throughputs *mb/d*							
	World	**US & Canada**	**Latin America**	**Africa**	**Europe**	**FSU**	**Middle East**	**Asia-Pacific**
2010	74.3	16.3	6.0	2.8	13.1	6.6	5.9	23.6
2015	78.4	16.1	6.9	2.9	12.7	6.9	6.9	26.1
2020	79.6	15.7	7.1	3.1	12.4	7.1	6.9	27.4
2025	80.7	15.3	7.3	3.3	11.7	7.3	7.0	28.8
2030	81.6	14.8	7.5	3.5	11.0	7.3	7.2	30.3
2035	82.7	14.3	7.6	3.6	10.4	7.4	7.5	31.8
	Crude unit utilizations *per cent of calendar day capacity*							
	World	**US & Canada**	**Latin America**	**Africa**	**Europe**	**FSU**	**Middle East**	**Asia-Pacific**
2010	82	83	74	78	76	81	90	88
2015	81	80	76	75	73	80	88	85
2020	80	78	76	76	71	80	85	85
2025	79	77	77	76	67	81	84	85
2030	78	74	78	77	63	81	84	86
2035	77	72	78	78	60	82	83	87

US & Canada and Europe, or – more broadly – the (northern) Atlantic Basin, and other regions. Together, the US & Canada and Europe lose 5 mb/d of throughputs between 2010 and 2035, while all other regions combined gain around 13 mb/d. Of this 13 mb/d, 8 mb/d, or over 60%, is in the Asia-Pacific. It should be noted that the 8 mb/d increase in this region is itself a combination of a decline, potentially over 0.5 mb/d in Japan and Australia, with an increase for the rest of the region of more than 8.5 mb/d.

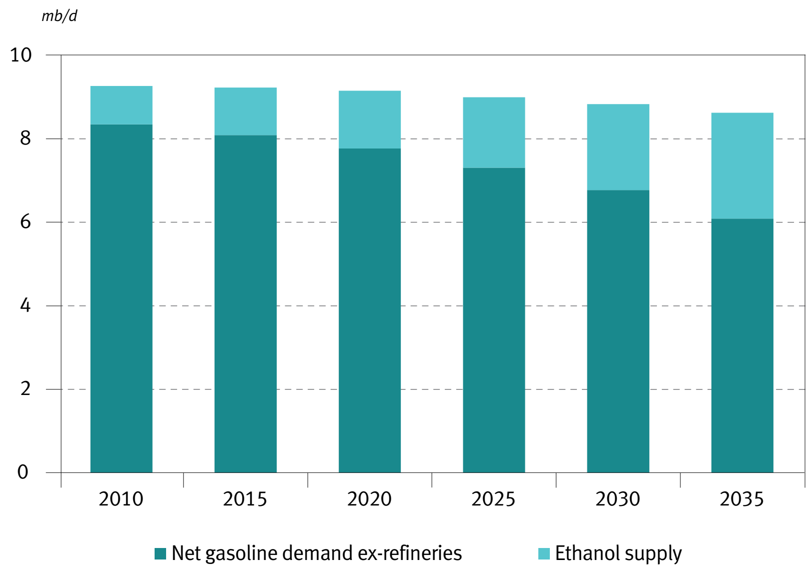
In both the US & Canada and Europe, refinery throughputs are projected to decline steadily from 2010 to 2035. The corresponding utilizations drop to 72% and 60% respectively by 2035. This assumes no further closures. The primary drivers in both regions are progressively declining transport fuel consumption, as a result of policy efficiency improvements, as well as other legislation and rising biofuel supplies. Even though the rate of dieselization in Europe is expected to moderate appreciably under the proposed new EU initiatives (Box 5.1), the Atlantic Basin is still projected to be characterized by a diesel and gasoil deficit, and a gasoline surplus.

One of the key contributing factors is US ethanol supply growth. Figure 6.7 illustrates how US & Canada gasoline demand is projected to decline gradually, from 9.3 mb/d in 2010 to 8.6 mb/d in 2035, and how ethanol supplies grow rapidly. This is a continuation of the recent trend for ethanol supply growth. In 2005, ethanol supplies were 0.3 mb/d, by 2015 they are expected to be 1.1 mb/d and by 2035, 2.5 mb/d. As a result of the ethanol supply increases, the net demand for gasoline ex-refineries[7] peaked in 2006 at around 9.4 mb/d, falling to 8.3 mb/d in 2010. Ex-refinery gasoline requirement continues to decline through to 2035 as ethanol supplies rise, while improved vehicle efficiencies cut consumption. The projected decline sees ex-refinery requirements of less than 8 mb/d by 2020 and close to 6 mb/d by 2035.

After allowing for closures in 2009, the US & Canada's current capacity, plus assessed projects to 2015, is slightly above 20 mb/d. This compares with a projected crude throughput of 16 mb/d in 2015 and 14 mb/d in 2035. It is clear that US refinery throughputs have peaked, and will need to adjust to a progressive decline in domestic demand. One impact already witnessed are the increasing product exports from US refineries. These are helping mitigate what would otherwise be an even more severe decline in throughputs.

Refinery throughputs in the US East Coast are projected to continue to decline. From 1.5–1.6 mb/d in the late 1990s through to 2007, throughputs have since progressively dropped to around 1 mb/d in 2011. Projections are for this decline to continue to around 0.8 mb/d by 2020 and 0.6 mb/d by 2035. This is

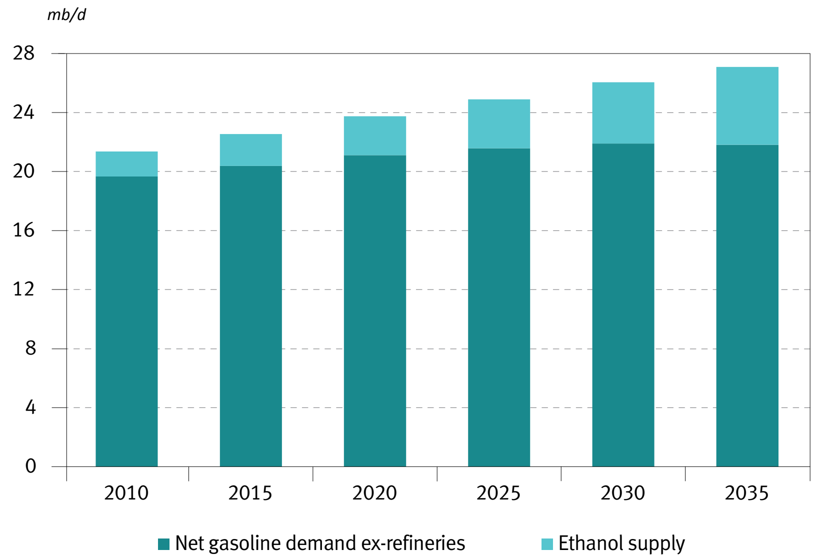
Figure 6.7
Total gasoline demand and ethanol supply in the US and Canada, 2010–2035



a reflection of competitive pressures and the age of the region's refineries. Crude throughputs in other US and Canadian regions are expected to also decline gradually, although the US Gulf Coast refineries are likely to see greater impacts than those in the interior. The latter are more protected from international competition and have the benefit of growing crude supplies from Canadian oil sands, as well as increasing shale oil production.

Expanding ethanol supplies also impact global gasoline production. Global ethanol supply is projected to rise from 1.7 mb/d in 2010 to 2.6 mb/d by 2020, and then accelerate to 5.3 mb/d by 2035 (Figure 6.8). Over the same 2010–2035 period, global gasoline consumption is projected to rise from 21.4 mb/d to 27.1 mb/d. Thus, ethanol as a share of total gasoline production grows from 8% in 2010 to almost 20% by 2035. Put another way, ethanol supply growth comprises 63% of the incremental global gasoline demand growth to 2035, leaving only 37%, or 2 mb/d, to be supplied from refineries. While the emphasis in refinery projects has shifted to distillates, every refinery expansion inevitably increases potential gasoline and naphtha production. Even with healthy naphtha and gasoline demand growth, respectively 3.4 mb/d and 5.7 mb/d from 2010–2035, the NGL/condensate and ethanol supply increases and refinery production

Figure 6.8
Global gasoline demand and ethanol supply, 2010–2035



increments act to sustain a 'soft' market for gasoline and naphtha, with consequences for refinery margins.

A similar scenario to the US is found in Europe. With a demand decline of around 1.5 mb/d by 2035, and additional biofuels supply in the range of 1.2 mb/d over the same period, no refinery capacity expansion beyond current projects is estimated to be required in the period to 2035. Rather, as in the US, regional refinery throughputs are projected to drop relative to the recent highs of around 13.5 mb/d; to 12.4 mb/d by 2020 and then 10.4 mb/d by 2035. With few actual refinery closures to-date, utilizations are projected to steadily decline to 60% by 2035, again signifying the potential for a substantial rationalization of the region's capacity.

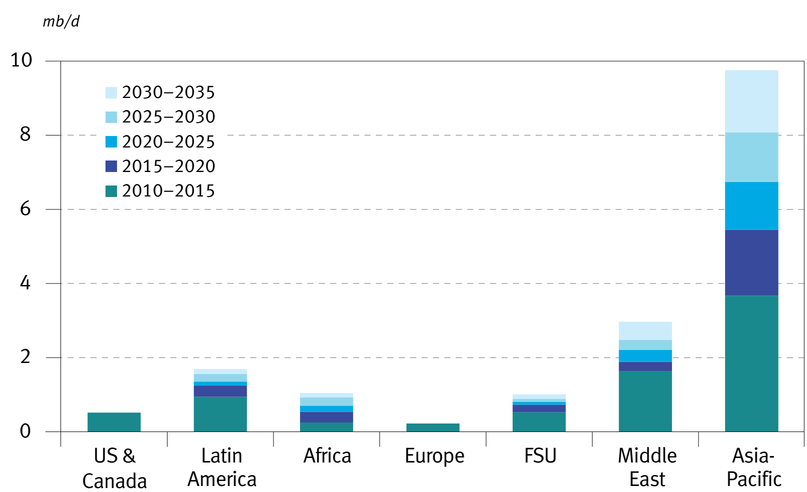
Declining demand in the Pacific Industrialized region – Japan and Australasia – creates a similar situation. No new refinery capacity is needed to 2030 and utilization rates – before closures – also drop to 60% by 2035. It should be stressed, however, that a series of refinery closures in Japan is likely, as previously highlighted in the Chapter. It appears that Japanese refiners – faced with declining domestic demand and potential climate change legislation – are taking the path of closures rather than upgrading.

The outlook in these three major industrialized regions is in stark contrast to that for developing regions, especially non-OECD Asia-Pacific. As illustrated in Figure 6.9, the vast majority of refining capacity expansions to 2035 are projected to be required in the Asia-Pacific and the Middle East, 9.8 and 3 mb/d respectively, out of a global total of 17.2 mb/d. Expansions in the Asia-Pacific are dominated by China and India.

In the FSU region, capacity is projected to rise by 1 mb/d by 2035, or annually, by only 40,000 b/d on average. This reflects the region's modest demand growth, as well as constrained demand in Europe. Projected utilizations are in the range of 80–82%. Moreover, FSU refining capacity growth may well be affected by policy changes that require Russian refineries to invest more to supply domestic markets. This is discussed in Box 6.1.

In Latin America, projected capacity additions of 1.7 mb/d by 2035, exceed the projected moderate demand growth of 1.3 mb/d for the same period. In Brazil, the combination of rising crude supplies and ethanol production, and aggressive plans for refinery expansion including for product exports, are the most important regional factor. Utilizations are expected to gradually rise from 74% in 2015, to 78% by 2035.

Figure 6.9
Crude distillation capacity additions in the Reference Case by period, 2010–2035



In the Middle East, demand for oil products is projected to grow at almost 1.8% p.a., leading to a demand increase from 2010–2035 of 3.7 mb/d. Total capacity additions through to 2035 are projected to be 3 mb/d. Of these, 1.6 mb/d are projects estimated to be on stream by 2015. Thus, the region's project additions are 'front loaded'. From 2015–2020, capacity increases are projected to see a relative lull, and then progressively increase post-2020. Crude throughputs are estimated to expand from 5.9 mb/d in 2010 to 7.5 mb/d in 2035. This is a somewhat slower rate than projected last year and reflects the lower target for global demand by 2035. One implication is that the Middle East could also play a role as the market balancing product supplier, just as it does for crude supplies. Current projections foresee around 2 mb/d of finished products being exported by 2030. In terms of volume, however, refined product exports are projected to exceed exports of NGLs and other streams.

Demand in Africa is projected to rise by 1.9 mb/d between 2010 and 2035. However, current firm construction in the region is minimal, around 0.2 mb/d, and total expansion by 2035 is projected to be 1 mb/d, well below anticipated demand increases. In addition to rising demand, there is also growing domestic and regional crude oil production, mainly of good quality. However, many of the refineries in the region face the challenges of being small in scale, old, and with relatively low complexity and low energy efficiency. On the one hand, this situation should provide incentives for the rapid expansion of the refining sector. On the other, however, the region is exposed to intense and expanding competition from product imports coming from Europe, the Mediterranean, the Middle East/Red Sea, India, and even the US. These factors, alongside a lack of resources and instability in some parts of the continent, will likely limit any substantial expansion of refining capacity for the foreseeable future.

Chapter 7

Conversion and desulphurization capacity additions

Conversion and product quality related capacity play vital roles in processing raw crude fractions into increasingly advanced finished products. In fact, they deliver most of a refinery's 'value added'. Over the past decade, the importance of these secondary processes has been growing with the general trend toward lighter products and more stringent quality specifications. This trend is expected to continue for the foreseeable future.

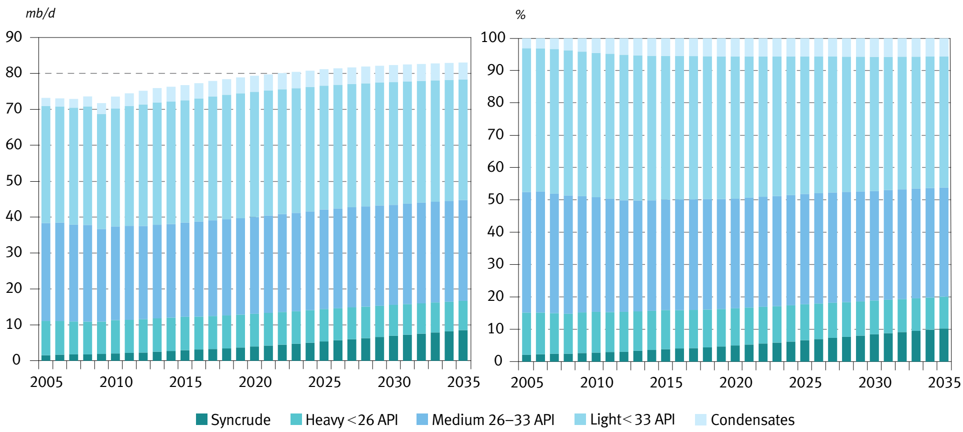
There are several factors determining the future required level of secondary processes. These include expected future demand volumes, the demand mix, the quality specifications of refined products, the future supply structure and the quality of feedstock available to refiners. Projected supply and demand levels and their structure were discussed in Section One and in Chapter 5. To complete the picture, it is essential to analyze the expected major developments in respect to the quality of the global crude slate and current and future product quality specifications.

Crude quality

Crude oil quality, typically measured in terms of API gravity and sulphur content, does, and will increasingly play an important role in determining future refining requirements. Given the rising share of lighter products in the global product slate, the lower the API of a crude oil, the less value it has to a refiner, as heavier crude oil requires more conversion capacity to produce a given yield of light products. Moreover, heavier crude streams typically contain more sulphur, which will in turn, necessitate intermediate process additions, notably hydro-treating, hydrogen and sulphur recovery. Despite the fact that there are some exceptions to this general rule, for instance, synthetic crudes and high TAN streams,[8] projections for quality characteristics in respect to API gravity and sulphur content comprise an important driver of future downstream sector investment requirements. Results presented include crude oil, condensates and synthetic crudes.

Figure 7.1 shows historical developments and projections of the global crude oil supply by major categories. Compared to the 2010 crude slate structure, in terms of share, synthetic crudes will gain more than 7% followed by condensate crudes, which increase by around 1%. This leads to the other three major crude types, light, medium

Figure 7.1
Global crude supply by category, 2010–2035



and heavy streams, witnessing a fall in their shares. The biggest drop in share is projected for light (typically sweet) crudes, at about 4%, heavy crudes decline by almost 3% and medium streams by close to 2%.

In terms of volume, however, all crude categories are projected to expand, except that for heavy crudes. Between 2010 and 2035, the largest volume increases are foreseen in the category of syncrudes, at more than 6 mb/d. Moderate increases in the category of medium (mostly sour) crudes of around 2 mb/d over the same period are primarily due to developments in the Middle East, Latin America and Russia. Projected declines in some of these streams, such as Russian Urals, are compensated by increases in others, for example, in Brazil and the Middle East. Condensates and light sweet crudes will also expand, each by roughly 1 mb/d over the entire forecast period. While the key region for condensates expansion is the Middle East, the most promising region for additional light crudes is the FSU, driven by new Caspian production and supported by developments in Sakhalin and Siberia. Other regions seeing an expansion in these streams are Africa, the Middle East and some countries of Latin America. Combined, this growth will more than compensate for the declining supply of this crude category in the North Sea.

The composition of the heavy crude category (typically sour crudes) is determined by developments in both parts of the American continent. In total, production of these crudes is expected to decline by more than 1 mb/d by 2035, compared to 2010 levels. The main increases come from Brazil, supported by some streams in the Middle East and high TAN crudes from Africa. However, dwindling production from Mexican Maya crude, as well as some other streams in North America and Latin America, will cause this crude category to decline. It should be noted, however, that the synthetic crude streams reaching the market mostly fall in the category of heavy crude, below 26° API. Therefore, if combined with conventional heavy grades, the net effect, compared to 2010, would be a substantial increase of total heavy crudes available by 2035 rather than a decrease.

The expected quality changes in oil supply streams to 2035 are presented in Figures 7.2 and 7.3. Global averages for API gravity and for sulphur content indicate a relatively stable future crude slate. This is particularly clear in respect to API gravity. The figure is projected to improve marginally to around 33.5° API by 2015, from 33.4° API in 2010, and then move back to 33° API by 2035, a level not very dissimilar to the present one. Figure 7.2 also underscores that the global average for the entire forecast period is anticipated to remain in a fairly narrow range of less than 1° API.

A similar pattern can also be observed for average sulphur content projections (Figure 7.3). Although the expected variations in average sulphur content are somewhat wider, they are still in the range of 10% over the 25-year forecast period. This is not seen as a major problem for the downstream industry, although it will necessitate some extra desulphurization capacity.

Figure 7.2
Crude quality outlook in terms of API gravity

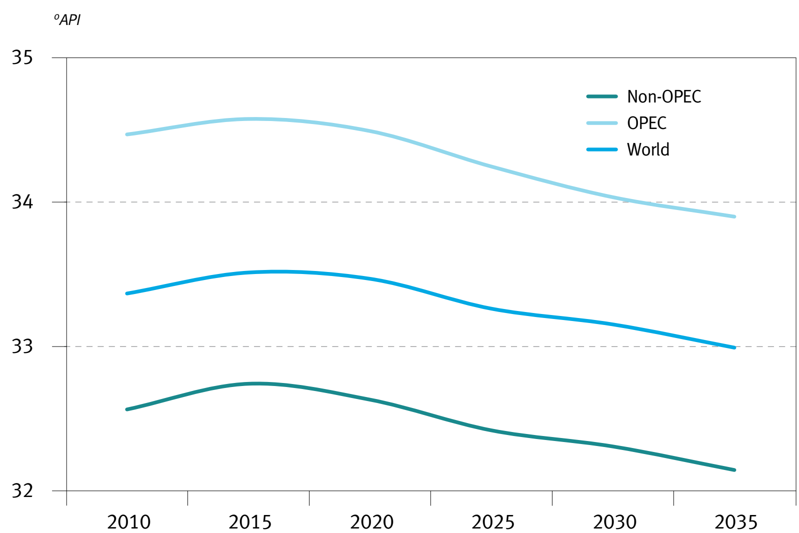
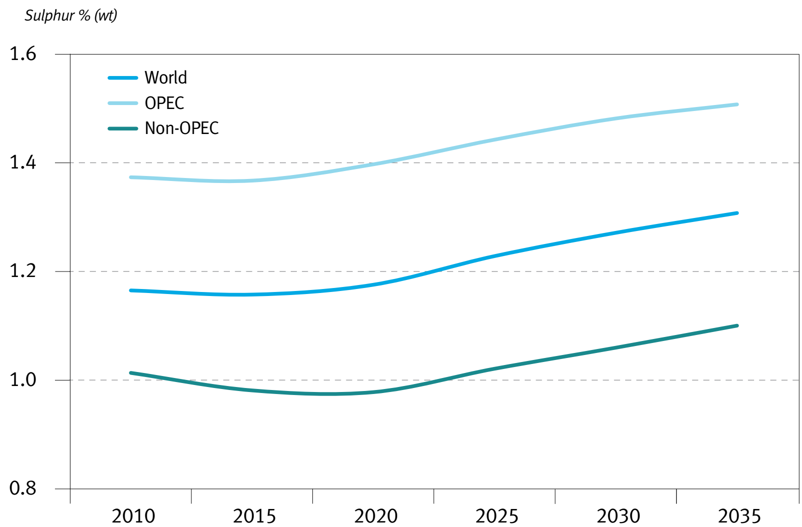


Figure 7.3
Crude quality outlook in terms of sulphur content



Driven mainly by increases in syncrudes, condensates and light crude oils, it is projected that the global crude slate will become marginally sweeter in the period to 2015, compared to 2010. The trend then reverses towards a sourer slate, with the sulphur content slightly above 1.3% (wt)[9] by 2035. A similar pattern is also observed when countries are grouped into non-OPEC and OPEC, although on average, OPEC crudes are generally sourer than those in non-OPEC countries.

Products quality specifications

In addition to the quality of crude oil used as a feedstock to the refining system, another significant factor affecting future downstream investment requirements is the quality specifications of finished products. In the past few decades, refiners worldwide have invested billions of dollars to comply with tightening refined product quality specifications. Throughout the 1980s and 1990s, regulators focused on lead content in gasoline. After a gradual shift to unleaded gasoline – the worldwide completion of this process is still ongoing – the focus turned to sulphur content in the mid-1990s, especially in Europe, Japan and the US. This shift, combined with the growing importance of diesel oil and gasoil, especially in the road transport sector, resulted in the tightening of quality requirements for these products too.

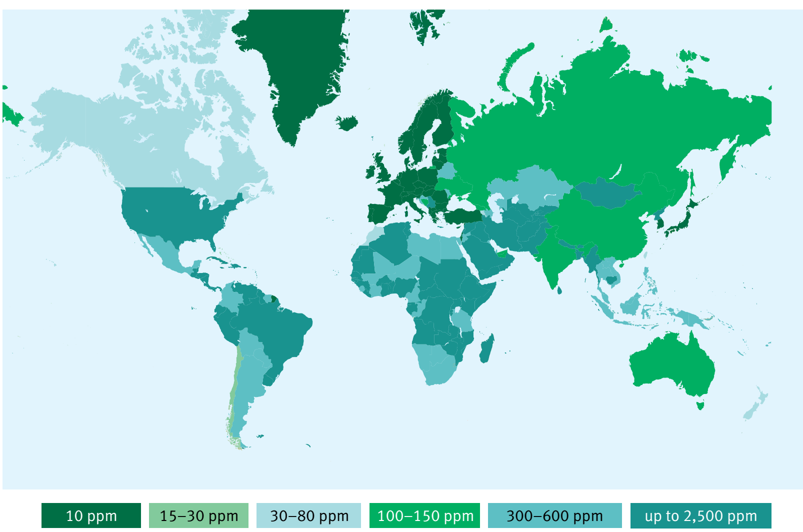
An overall aim of policymakers is to produce transportation fuels that have a sulphur content below 10 parts per million (ppm). The next step, which has already begun in a number of countries, is the extension of stricter sulphur specifications beyond on-road transportation to other products, particularly fuel oil, marine bunkers and jet fuel. And to continue tightening other specifications, such as the cetane number, aromatics and benzene content.

Figures 7.4 and 7.5 show the global maximum legislatively permitted sulphur content in gasoline and on-road diesel fuel, respectively. These figures map the status as of September 2011, but it should be noted that actual sulphur content levels for products available in specific countries can differ from the ones permitted by regulators.

Recent quality specifications for gasoline emphasize the widespread use of ultra-low sulphur gasoline, with improved ecological properties through an increase in the octane number and a reduction of benzene and aromatics. This trend is particularly evident in developed countries, but it is now increasingly being adopted in the developing world too.

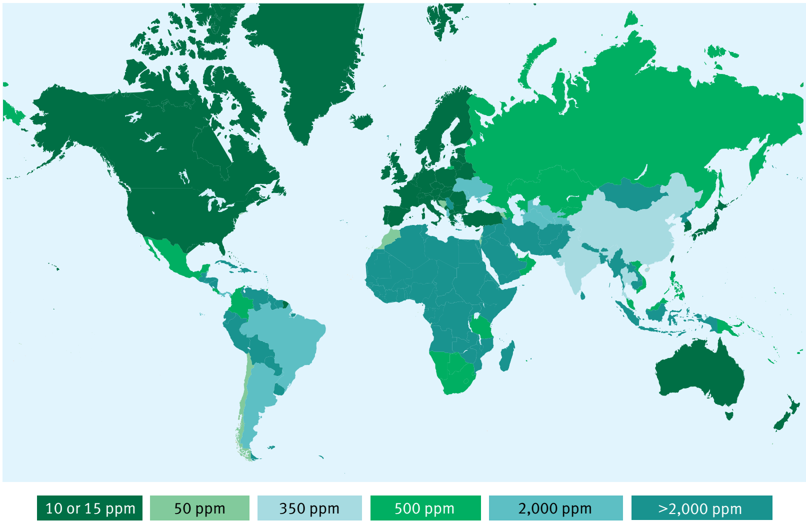
The US ultra-low sulphur gasoline programme – with an 80 ppm per gallon cap and a 30 ppm annual average – was phased in as of 2004. Since 2010, the US has

Figure 7.4
Maximum gasoline sulphur limit, September 2011



Source: Hart Energy, International Fuel Quality Centre (IFQC), September 2011.

Figure 7.5
Maximum on-road diesel sulphur limit, September 2011



Source: Hart Energy, IFQC, September 2011.

limited it to a 30 ppm maximum standard for all refiners, although California has its own stricter specifications set at a maximum 15 ppm. Since 2005, EU member states have also required certain volumes of 10 ppm fuels in their markets, alongside 50 ppm fuels. This was further tightened in January 2009, when the EU stipulated that all gasoline should contain a 10 ppm maximum sulphur content. It should be noted, however, that many member states reached full penetration of 10 ppm gasoline before 2009. Based on IFQC data, elsewhere, Canada implemented a 30 ppm sulphur limit in 2005; Japan 10 ppm in January 2008, although this level was achieved in 2005; South Korea 10 ppm in January 2009; and Hong Kong a 10 ppm maximum in July 2010.

Increasing gasoline consumption in a number of developing countries means that any quality improvement has a considerable impact on refining. However, despite some improvements in several countries, such as in China and India, in general, these countries lag somewhat behind.

China's nationwide gasoline sulphur limit was reduced to 150 ppm in December 2009. Stricter fuel quality requirements of 50 ppm have been imposed in Beijing, Shanghai, Guangzhou and Shenzen. It is expected to lower its nationwide limits to 50 ppm by December 2013, and possibly to a maximum 10 ppm in the 2016 time-frame. In Beijing, a 10 ppm sulphur gasoline requirement is planned for 2012.

India has required 150 ppm sulphur gasoline nationwide and 50 ppm sulphur gasoline for 13 selected cities since September 2010. The Ministry of Petroleum and Natural Gas has identified 50 additional cities – with large vehicle populations and high pollution levels – to be included in the implementation of 50 ppm sulphur gasoline. This will be conducted in phases, with full completion expected by 2015. In accordance with the Strategic Plan for 2011–2017, 50 ppm sulphur gasoline will first be implemented in seven cities – Puducherry, Mathura, Vapi, Jamnagar, Ankaleshwar, Hisar and Bharatpur – from January-to-March 2012.

Significant gasoline quality specification improvements are also ongoing in other countries around the globe, particularly in Latin America, the Middle East and Russia, albeit from much softer existing requirements.

Diesel fuel specifications not only vary between countries and regions, but often between sectors. In the EU, the European Fuel Quality Directive (EFQD) has required on-road diesel fuel sulphur content to be set at 10 ppm since 2009, with off-road diesel sulphur reaching the same level in January 2011. Member states may also permit the continued placement – until the end of December this year – of gasoil containing up to 1,000 ppm sulphur for rail vehicles and agricultural/forestry tractors, provided that owners ensure that the proper functioning of emissions control systems is not compromised. Only two countries (Spain and France) make use of this derogation, in the rest of the EU the quality of off-road diesel is the same as the quality for on-road diesel.

Sulphur limits of 10 ppm for on-road diesel fuel are also in place in Japan, Hong Kong, Australia, New Zealand, South Korea and Taiwan. In the US, a move to 15 ppm sulphur for on-road diesel started in 2006 and was completed in 2010. Off-road diesel is planned to follow suit in 2012. California has been at a required 15 ppm for both on-road and off-road since June 2006. In Canada, a switch to 15 ppm for on-road diesel happened in June 2006 and off-road diesel was fully aligned at this level in October 2010.

Improvements have also been significant in a number of developing countries. China reduced its on-road diesel sulphur in January 2010, when the limit in automotive diesel was lowered to 350 ppm. In fact, this was China's first official differentiation between on-road and off-road diesel requirements. However, due to the country's size, the nationwide implementation of the 350 ppm limit is only expected to be fully achieved in 2011. The diesel sulphur limit for Beijing, Shanghai, Guangzhou and Shenzen is set at 50 ppm. Further reductions in on-road diesel quality in major Chinese cities are planned for 2012, when 10 ppm is expected to be imposed. On a national level, China is discussing the implementation of a

50 ppm sulphur diesel limit by 2015, although refiners have indicated it may not be possible until 2017.

India has also set two different diesel fuel specifications, one for nationwide supply and the other for 13 selected cities. The sulphur content specification for 13 urban centres is established at a 50 ppm maximum – implemented in September 2010 – and the national specification is 350 ppm. It is expected that further improvements in India will follow those of gasoline.

Elsewhere, in Latin America, Chile has been distributing 50 ppm diesel throughout the country since 2006, and by September 2011, the maximum sulphur limit for the Metropolitan Region of Santiago will be lowered to 15 ppm. The maximum sulphur limit in premium diesel in Argentina was lowered from 50 to 10 ppm in June 2011. Moreover, the tightening of on-road diesel quality specifications are also reported for other countries such as Indonesia, Malaysia, Philippines, Thailand, Russia, Kuwait, Qatar, South Africa, Brazil, Colombia and Mexico.

In most African 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. The exceptions are South Africa, and some countries in the North African sub-region.

Turning to projections for long-term quality requirements, future gasoline quality initiatives will continue to focus on sulphur, but increases in octane and reductions in benzene and aromatics are gaining traction around the world. Projected gasoline qualities for 2011–2030 are shown in Table 7.1.

While the expected reduction of gasoline's sulphur content will dictate some capacity additions to hydro-treating units, especially in developing countries, it is diesel sulphur that presents the sector's greater challenge. This is due mainly to the fact that it has a larger need for refinery processing additions and higher investment costs. Table 7.2 summarizes regional on-road diesel fuel quality requirements between 2011 and 2030. For Europe and North America, on-road (and off-road) ultra-low sulphur programmes require diesel sulphur to be at, or below 15 ppm, for most of the diesel market.

By 2015, a significant sulphur content reduction in on-road diesel is projected to be observed in the FSU, the Middle East and the Asia-Pacific, due to refinery modernization and construction. With the exception of Africa, all regions are projected to reach average on-road sulphur content of below 100 ppm by 2025.

It is evident that during the forecast period the major shift in fuel specifications for transportation will occur in developing countries. China and India, joined by

Table 7.1
Expected regional gasoline sulphur content*

ppm

Region	2011	2015	2020	2025	2030
US & Canada	30	30	10	10	10
Latin America	640	245	125	70	45
Europe	11	10	10	10	10
Middle East	770	280	45	20	20
FSU	450	110	50	20	15
Africa	810	470	290	160	100
Asia-Pacific	200	120	55	25	20

* *Estimated regional weighted average sulphur content is based on volumes of fuel corresponding to country specific legislated requirements, as well as expected market quality.*
Source: Hart Energy, World Refining & Fuels Services (WRFS) and IFQC.

several Latin American countries, are currently leading the introduction of clean fuels in the developing world. Plans have been announced to progressively adopt tighter standards for both diesel and gasoline. This includes constraints on benzene (gasoline), aromatics (both fuels), gravity (diesel), cetane (diesel), although the main focus is on sulphur content, which necessitates substantial investment in hydro-treating capacity. An increase in octane numbers is planned for some regions as well, which will be met by installing reforming, alkylation and isomerization units.

In addition to transportation fuels, other products, such as heating oil, jet kerosene and fuel oil, are becoming targets for tighter requirements. Sulphur content in Europe's distillate-based heating oil market was reduced from 2,000 to 1,000 ppm on 1 January 2008, and some countries, for example, Germany, provide tax incentives for 50 ppm heating oil production and use. Parts of North America plan to reduce the sulphur levels in heating oil to 15 ppm before 2020. Elsewhere, some progress is expected to be made in reducing the sulphur levels for heating oil, but not to very low levels, and only after the transition to low sulphur levels in transportation fuels is completed.

Current regulations on jet fuel allow for sulphur content as high as 3,000 ppm, although market products run well below this limit, at approximately 1,000 ppm. The general expectation is that jet fuel standards will be tightened to 350 ppm in industrialized regions by 2020, followed by other regions in 2025. In spite of the current lack of clear plans for global sulphur reduction in jet fuels, its levels in industrialized

Table 7.2
Expected regional on-road diesel sulphur content* *ppm*

Region	2011	2015	2020	2025	2030
US & Canada	15	15	15	10	10
Latin America	1,250	470	190	45	35
Europe	12	10	10	10	10
Middle East	2,500	370	150	70	30
FSU	490	130	45	15	10
Africa	4,200	1,860	1,020	550	210
Asia-Pacific	470	250	190	90	80

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

regions are assumed to be further reduced to 50 ppm by 2025. The quality developments for marine fuels are discussed in Box 5.2.

Fuel quality properties are also affected by increasing the volumes of bio-components blended to gasoline and diesel. In the US, these moves are regulated through Renewable Fuel Standards by the Environmental Protection Agency (EPA) on the basis of the EISA of 2007. Moreover, California's Low Carbon Fuel Standard aims to lessen GHG emissions by reducing the carbon intensity of transportation fuels by an average of 10% by 2020. In the EU, mandates for an increased proportion of biofuels in transport fuels are embedded in the EFQD.[10]

In Europe, as a consequence of its regulations, the minimum ethanol content of gasoline and the fatty-acid methyl ester (FAME) content of diesel have been increased from 5% (vol) to 10% (vol) for ethanol and from 5% (vol) to 7% (vol) for FAME as of 1 January 2011. However, member states are allowed to use a higher proportion of these blending components, which could lead to market fragmentation. Similarly, in the US, in order to help to meet the 36 billion gallons renewable fuel target required by 2022 under federal legislation, an increase of the ethanol content in conventional gasoline to a maximum 15% (vol) level (E15) was approved for vehicles manufactured in 2001 and later by the EPA in October 2010. However, there are multiple logistical, legal, and commercial hurdles to the immediate adoption of E15, and no such fuel has yet been introduced to the US market.

Box 7.1
Are boutique fuels emerging in Europe?

To promote the use of energy from renewable sources, the EU has adopted several directives. In April 2009, the European Commission passed the Renewables Energy Directive (RED 2009/28/EC) which establishes mandatory national targets consistent with a 20% share of overall energy from these sources and a 10% share of energy from renewable sources in transportation by 2020. How, and if, these targets are reached remains to be seen, but it is clear that this coming decade will witness changes in the make-up of fuels in the transportation sector. To support implementation of the RED, as of 1 January 2011, the minimum content of ethanol in gasoline and FAME in diesel was raised to 10% (vol) and 7% (vol), respectively. However, EU member states are allowed to use a higher proportion of these blending components.

This is leading some to ask the question: will this lead to boutique fuels emerging in the EU zone? To better understand this question, it is important to initially look at how biofuels have developed to ascertain the possible futures for boutique fuels.

Although a variety of renewable energies across all transport sectors are expected to contribute to the attainment of the mandated 10% target, the use of liquid biofuels in road transport is foreseen to make the highest contribution. The use of other renewable energies such as biogas, the role of electric cars with electricity generated from renewable sources, and the contribution of other transportation sectors such as aviation and marine, are going to be limited over the directive's timeframe due to technology and cost hurdles.

In addition, the need to modify and expand the distribution and logistics infrastructure for dispatching biofuels to market, as well as the need for recharging terminals for electric vehicles, will be a significant cost challenge.

Bio-ethanol and biodiesel have been developed and used as alternatives to fossil fuel-based gasoline and diesel in the road transport sector. The two types of biofuel used have been either high biofuel blends, such as E85 and B100, or low blends such as E10 and B7. EU member states were given the choice of using any composition of renewable and biofuel blends to meet the directive's 10% target.

The benefits of using high biofuel blends are that limited volumes are handled in full segregation from conventional fuels and used by a limited number of consumers driving vehicles that are specifically designed to use these types of fuels. The use of lower biofuel blends, on the other hand, requires more volumes to be produced and retailed. It should be noted that all retailed fuels should contain at least 10% biofuel content if the directive target is to be met solely by the use of biofuels.

Most of the vehicles made after 2005 are generally capable of using low biofuel blends. Older vehicles, however, which are still on the road in many member states, may not tolerate the use of biofuels at any concentration level. This means that there is a need to continue to supply conventional fuels (protection grades) in retail stations until all these vehicles are retired or upgraded.

In addition to the mentioned blends, any other biofuel blend can be formulated and used by EU countries, if automakers adapt and optimize their engine designs to meet these blends. In this regard, it should be stressed that if biofuel blends are not regulated by the EU through a standardization process and regulation is left to individual member states, EU fuel markets could become increasingly diverse and fragmented with numerous boutique fuels the likely outcome. This, however, is not an ideal outcome for consumers.

Unlike the standard fuels market where few transport fuels are sold, fragmented markets where numerous fuel grades with different biofuel content and varying specification are retailed, can introduce many inefficiencies. In addition to the inconvenience caused to cross-border drivers, particularly when thinking about transportation and trade, these fuels are costly to produce, segment the market and increase wholesale prices.

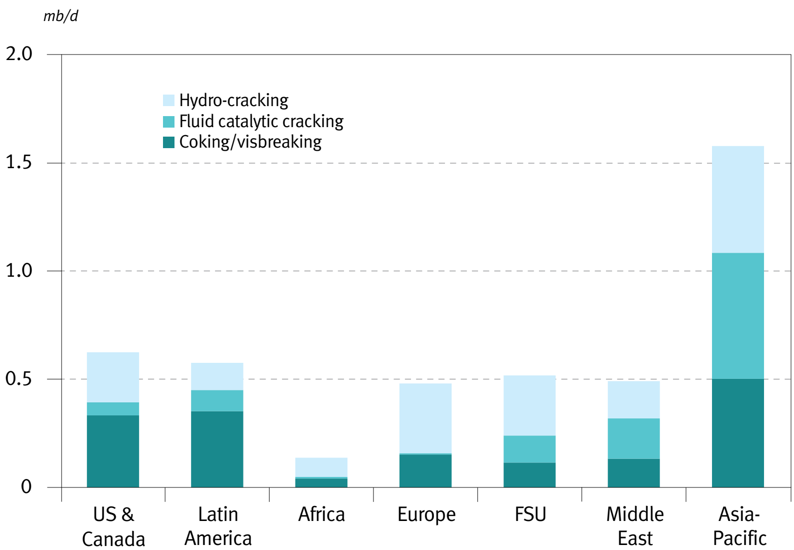
While boutique fuels may develop in some form, to prevent fuel market fragmentation these should at least be minimized. This can be done by regulating and limiting the number of biofuel grades that can be produced and retailed across Europe. How this is best achieved is down to the EU and its policy bodies, but the overall goal should be standard specifications for biofuel grades that can be enforced in all EU countries.

Capacity requirements

Medium-term outlook

To shed light on the impacts of continuing capacity additions to refined products supply, the assessment of refinery projects was extended – using available data – into a projection of medium-term incremental supply potential by major refined products groups. This was then compared with the projected incremental demands on a regional basis. As emphasized in Chapter 6, based on the announced or estimated

Figure 7.6
Conversion capacity additions from existing projects, 2010–2015



configuration of existing projects, Reference Case projections show a global total of 4.4 mb/d of new conversion capacity within the period 2010–2015. Most of this capacity (Figure 7.6) will come in the form of hydro-cracking units (1.7 mb/d), followed by coking (1.6 mb/d) and FCC units (1.1 mb/d).

To a large extent, the placement of these processes will mirror the location of distillation capacity since, in most instances, they come from the same expansion projects. However, some of the conversion capacity additions are components of projects more geared to altering refinery configuration than to expanding capacity. Projects in the US Midwest and Gulf Coast centre on either major expansions or revamps geared to processing heavy crude oils, mainly from Canadian oil sands. These projects embody the need for substantial coking capacity to deal with heavy crude oils, plus hydro-cracking to increase distillate yields. The shift away from a traditional US emphasis on FCC capacity means that distillate yields from these projects will comprise almost 50% of all products. However, they will still yield 40% gasoline in a region where demand for this product is flat and ethanol supplies are rising.

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

In Africa, the main conversion spotlight is on hydro-cracking, with projects underway in Egypt, Libya and potentially Angola. Similarly, European projects, predominantly in southern and eastern Europe, emphasize hydro-cracking, which is in line with the region's distillate deficit, as well as coking in a number of locations. Projects in the FSU are in general geared toward raising conversion capacity across the region. Again, the emphasis is on hydro-cracking, but also on appreciable FCC and coking additions.

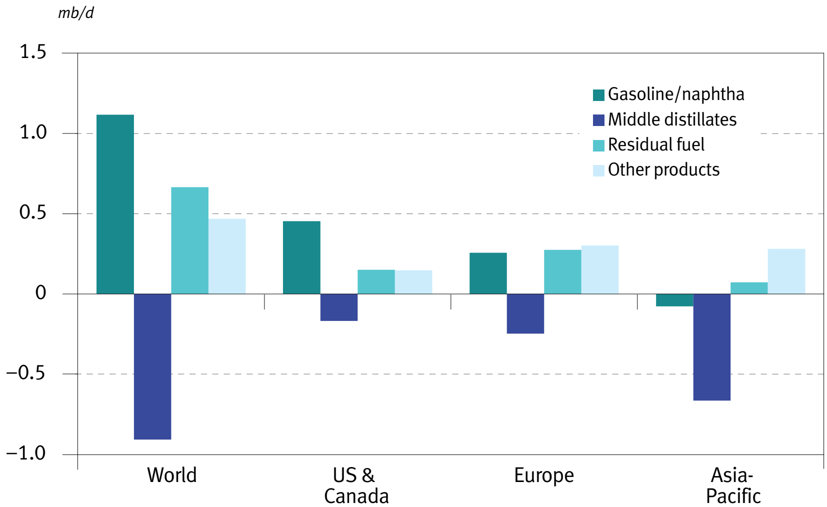
Conversion additions in the Middle East reflect a general move toward a lighter domestic and export product slate, as well as the region's gasoline deficit. Thus, the emphasis is on FCC capacity, alongside some hydro-cracking and coking. The main conversion additions are in the large Saudi Aramco projects (Jubail and Yanbu), plus projects in Iran and potentially the UAE.

The Asia-Pacific comprises the largest concentration of conversion projects. These reflect the general demand growth for light products, including gasoline, as well as the need to incrementally process mainly medium sour crude oils – hence, the relatively even distribution of additions across the three conversion processes. In line with distillation capacity additions, the majority of the conversion projects are located in China and India. Smaller scale conversion projects are also taking place in South Korea, Japan, Pakistan and Vietnam.

Figure 7.7 shows the results of comparing the potential additional regional output by major product group against projected incremental regional demand for the period 2010–2015. The results are presented as net surplus/deficits, by product group, by region and worldwide. It shows a continuation of the trend for refining projects to exceed incremental demand growth, as well as underscoring a persistent gasoline/naphtha, residual fuel and other products surplus, against a distillate deficit. A key issue is that essentially all refinery expansions tend to increase the capability to produce all four product groups, even if a project is, for example, labelled 'maximum distillate'.

Of the three main regions, the data indicates that only the Asia-Pacific will see a balance on incremental gasoline/naptha output, with the US & Canada and Europe witnessing a combined surplus of 0.7 mb/d. For the world as a whole, there is also a

Figure 7.7
Expected surplus/deficit of incremental product output from existing refining projects, 2010–2015



surplus of 1.1 mb/d over the five-year period. In contrast, all three main regions are projected to see a distillate deficit. The worst situation is expected to be found in the Asia-Pacific, which has a projected deficit of close to 0.7 mb/d, around 70% of the global total of 0.9 mb/d.

Thus, the medium-term outlook is for a continued imbalance. The Atlantic Basin has a gasoline/naphtha surplus and distillate deficit and the Pacific Basin, a significant distillate deficit. The implication is that distillate margins, relative to crude, are likely to remain strong and those for naphtha/gasoline weak. In addition, this analysis indicates that more medium-term investment is needed to cover incremental demand. Investments, in respect to conversion capacity, should focus on hydro-cracking to generate additional middle distillate volumes. To balance the market, required hydro-cracking additions above existing projects are estimated to be 1.3 mb/d.

Long-term outlook

Table 7.3 and Figures 7.8 through to 7.11 summarize projections for secondary processing to 2035. Similar to last year's Outlook, these projections highlight a sustained need for incremental hydro-cracking, some 10 mb/d out of 14 mb/d of conversion

Table 7.3
Global capacity requirements by process, 2010–2035 *mb/d*

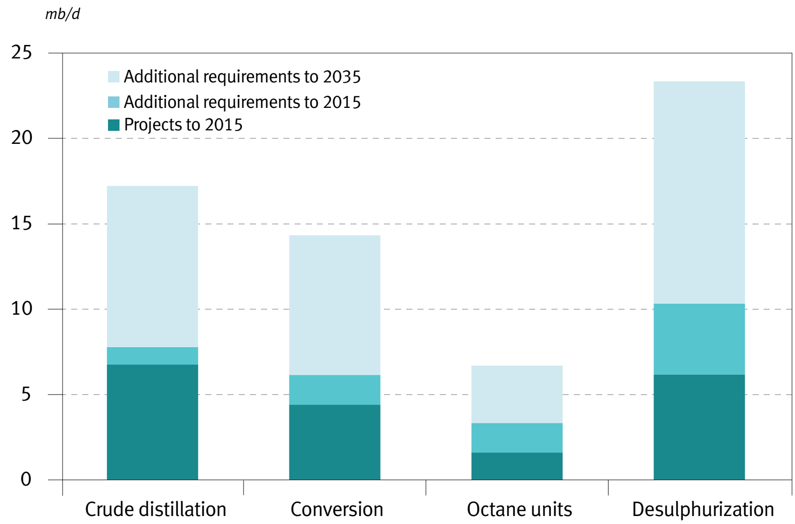
	Existing projects	Additional requirements		Total additions
	to 2015*	to 2015	2015-to-2030	to 2035
Crude distillation	**6.8**	**1.0**	**9.4**	**17.2**
Conversion	**4.4**	**1.7**	**8.2**	**14.3**
Coking/Visbreaking	1.6	0.1	0.9	2.6
Catalytic cracking	1.1	0.3	1.0	2.3
Hydro-cracking	1.7	1.3	6.3	9.4
Desulphurization	**6.2**	**4.2**	**13.0**	**23.3**
Vacuum gasoil/Resid	0.2	0.7	1.8	2.8
Distillate	4.5	2.7	8.1	15.3
Gasoline	1.4	0.7	3.1	5.3
Octane units	**1.6**	**1.7**	**3.4**	**6.7**
Catalytic reforming	1.2	1.6	2.0	4.8
Alkylation	0.2	0.1	0.2	0.4
Isomerization	0.2	0.1	1.1	1.5

* *Existing projects exclude additions resulting from capacity creep.*

capacity requirements. Hydro-cracking is the primary means to produce incremental distillate once straight run fractions from crude have been maximized. The need to keep investing in additional hydro-cracking capacity, with its high process energy and hydrogen costs, is expected to help support wide distillate margins relative to crude oil – and to other light products – into the future.

In contrast, recent substantial coking capacity additions, together with limited medium-term exports of heavy sour crudes, has led to a coking surplus, which is expected to further expand as new projects come on stream. This is evident in the absence of required capacity additions beyond projects to 2015. Moreover, between 2015 and 2035 less than 1 mb/d of further additions are projected. These are small relative to the more than 6 mb/d of projected hydro-cracking additions for the same period. The outlook for catalytic cracking is similar. It is adversely impacted by declining gasoline demand growth and rising ethanol supply in the Atlantic Basin. Consequently, projected increases beyond current projects are seen as minor until after 2015. They are then concentrated in non-OECD regions with gasoline demand growth, particularly in the Asia-Pacific.

Figure 7.8
Global capacity requirements by process type, 2010–2035



Generally, FCC and coking units suffer in the Outlook as they comprise 'swing' units for production of gasoline. Consequently, utilizations in these units are relatively depressed.

As Table 7.3 and Figure 7.8 illustrate, total conversion additions from projects to 2015 are 4.4 mb/d, which is almost two-thirds of the total crude unit additions. However, total conversion additions above ongoing projects, at close to 10 mb/d, are almost 100% of the distillation capacity additions. This reflects the need to increase production of light products for every barrel of crude processed. Moreover, the structure of this capacity emphasizes the continuing need to build more hydro-cracking, in order to produce incremental distillate which will at times effectively displace FCC units.

It should also be noted that this year's Reference Case outlook, unlike last year's, includes estimates for the impacts of MARPOL Annex VI on marine fuels. As discussed in Chapter 5, it is estimated that the effect of this will mean that 0.5 mb/d of residual type IFO fuel is switched to marine distillate by 2015, 1.7 mb/d by 2020 and 2.1 mb/d by 2035. These developments add significantly to projected conversion – as well as desulphurization – capacity and related units. They further the continuing trend to light products and distillates.

Figure 7.9
Conversion capacity requirements by region, 2010–2035

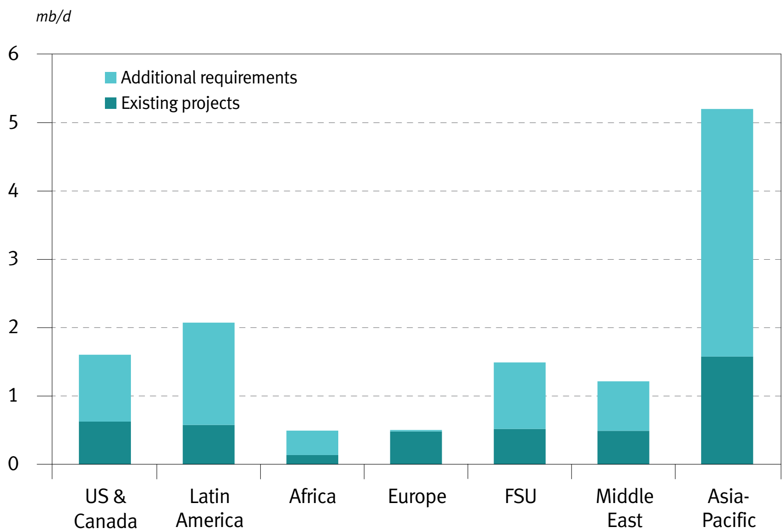
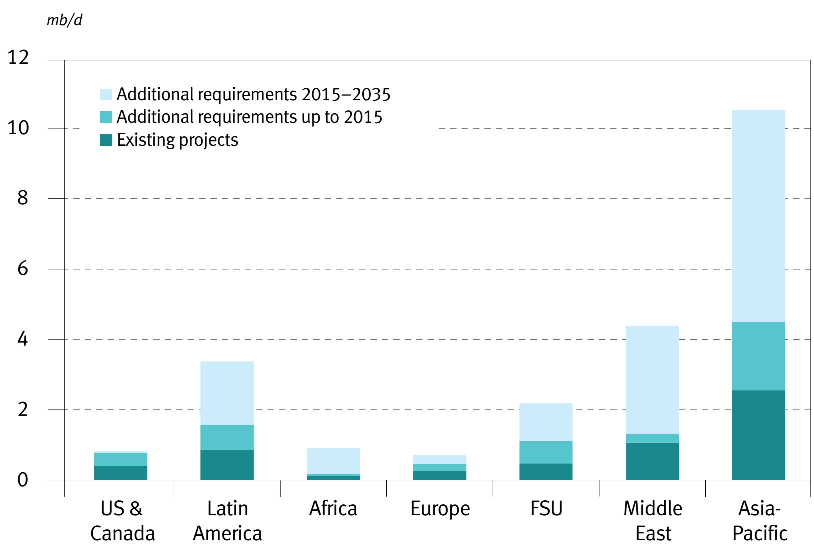


Figure 7.10
Desulphurization capacity requirements by region, 2010–2035

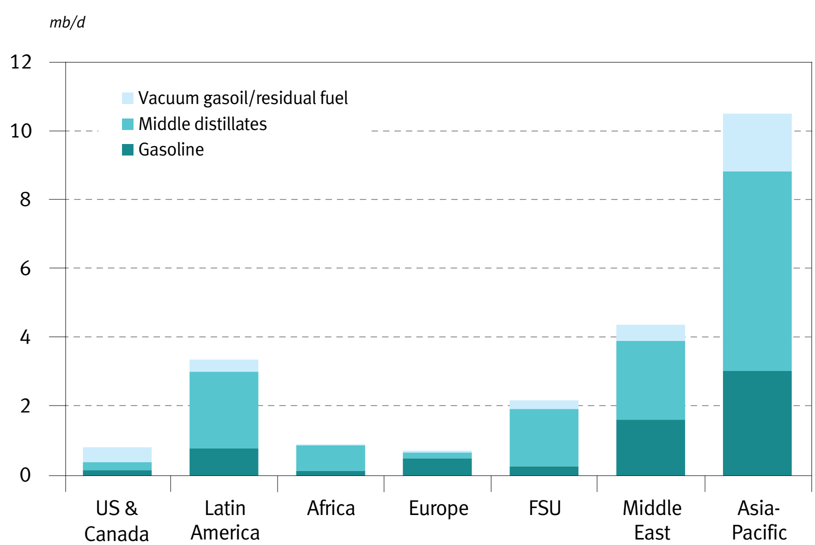


Moreover, continuing expansions are needed for catalytic reforming and isomerization units. These are driven in part by rising gasoline pool octanes. They also enable additional naphtha – including from condensates – to be blended into gasoline.

On a regional basis, conversion capacity requirements will be dominated by the Asia-Pacific, which sees over 40%, or 5.2 mb/d, of total future additions to 2035 (Figure 7.9). The proportion of required additions beyond existing projects in the Asia-Pacific is similar both up to, and after 2015. A significant increase should also take place in Latin America, at 2.1 mb/d, as light product demand and heavy crude supply in the region are both expected to grow.[11] Across essentially all regions, longer term conversion capacity additions are focused mainly on hydro-cracking.

Substantial desulphurization capacity additions will also be necessary to meet sulphur content specifications, as non-OECD regions in particular move progressively towards low and ultra-low sulphur standards for domestic fuels – often following Euro III/IV/V standards – and build export capacity to meet advanced ultra-low sulphur standards. Over and above existing projects of 5.8 mb/d, a further 4.2 mb/d is projected to be needed by 2015 and some 13 mb/d from 2015–2035 (Figure 7.10). Altogether this means a total of 23 mb/d by 2035, which compares to 17.2 mb/d of total distillation capacity over the same period.

Figure 7.11
Desulphurization capacity requirements by product and region, 2010–2035



Chapter 7

In short, the continued drive to tighter sulphur standards is expected to see desulphurization comprising the largest volume capacity additions in the period to 2035. The bulk of these units is projected in Asia (10.5 mb/d), followed by the Middle East (4.4 mb/d) and Latin America (3.4 mb/d). The lowest desulphurization capacity additions are projected for North America and Europe where almost all transport fuels are already at ultra-low sulphur standards. In other regions, due to limited existing capacity, even modest sulphur reduction implies considerable capacity additions.

In respect to products supply, of the 23 mb/d of global desulphurization capacity additions expected from 2010–2035, nearly 60%, or 13 mb/d, are for distillate desulphurization and the bulk of the remainder, 6.5 mb/d, for gasoline sulphur reduction (Figure 7.11).

Crude and product differentials

The model used to generate projections for crude and product pricing and differentials is based on an optimization technique. It balances the entire system in such a way that refining capacity is sufficient for demand over the forecast period and thus extreme differentials tend not to exist. Nevertheless, the effects of key trends, such as increasing distillates in total demand, tightening sulphur standards and lighter or heavier crude supplies are reflected in the projected differentials.

These, however, must only be considered as indicators of certain trends that reflect future market fundamentals, rather than actual projections. In other words, they represent future 'equilibrium levels' based on a longer term assumption that differentials, and thus margins and profitability, need to approximately average the long-run levels. Otherwise refiners would either make such small returns on capital that they would be out of business, or returns would be so high that arguably additional capacity would be attracted to the market.

In general, higher capital costs for process investments and higher crude prices drive in the direction of wider light/heavy and sweet/sour differentials for 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. Again, lower prices tend to reduce processing costs and hence light/heavy differentials. Higher prices for crude oil relative to natural gas and coal, hence, fuel grade petroleum coke,[12] on a Btu basis tend to make it relatively more attractive to add hydrogen from natural gas and less attractive to reject carbon via catalytic cracking and coking.[13] Again, the reverse is true.

In a similar vein, the sustained growth for distillates, requiring ongoing investments in hydro-crackers, widens the distillate premium relative to crude and other products. This reflects the associated high opportunity cost of producing incremental distillate barrels. The opposite trends are observed for products projected to remain in surplus, such as naphtha/gasoline. The price differentials for such products tend to narrow, or are even discounted relative to the crude price, reflecting the relative difficulty the industry has in finding markets for these products and streams.

These various effects can be observed in the crude and product price differentials, and hence, the outlook for refining economics and crack spreads. For lighter crude oils, at or above 40° API gravity, the projection is for future differentials versus Brent to weaken. The underlying basis is a reflection of the surplus NGL/naphtha/gasoline streams. Thus, since the very lightest crudes tend to contain the highest proportions of fractions in the gasoline and lighter boiling ranges, it is these crudes that suffer a decline in relative value.

For heavy crudes, it is also envisaged that there will be a weakening in the relative values, but for different reasons. Current pricing indicates a return to differentials versus Brent in the range of $6–8/b. In general, this indicates a gradual widening of these differentials, with a decline in relative values versus Brent over time. A key driver here is the WOO's Reference Case projection that demand for residual (inland) fuel oil will decline and that this trend will be reinforced by the need to convert a growing fraction of the world's heavy IFO type marine fuels to distillate. In addition, the on-going trend to low and ultra-low sulphur standards for transport and other fuels, makes high sulphur crude oils relatively less attractive.

For medium sour crudes, the story lies somewhere in between. Projections indicate only a slight widening of differentials versus Brent over time, somewhere in the range of $1/b. The relatively small shift arguably reflects the trend toward tightening sulphur specifications as sulphur content will increasingly play a role in setting differentials.

WTI crude is a special case. Unlike other crudes, WTI is a marker that is priced inland, at Cushing, Oklahoma, and Midland, Texas. It is not ocean-based with access to international markets as are Brent and others. Periodic 'disconnects' between WTI and Brent became structural at the end of 2010 and have led to sustained discounts for WTI in the range of $15–25/b. This is primarily due to the fact that the US crude oil logistics system is designed to carry crude oils into the interior, not out. Exacerbated by growing crude supplies from Canada, the inadequacy of pipelines to carry both Western Canadian crudes and an increasing Lower 48 domestic crude production to the Gulf Coast has created severe bottlenecks. The large crude price discounts reflect these.

Several pipeline projects have been proposed to relieve the situation and one or more of these is expected to be in service by late 2012/early 2013. Rail and barge movements are also playing a role. Therefore, the assumption in this WOO is that by 2015 sufficient pipeline and supporting capacity is in place, so that by then current market distortions will have dissipated. As a consequence, the projection for WTI-Brent differentials is a return to historical levels by 2015. Beyond 2015, a slight decline in the WTI value relative to Brent is expected. This is because WTI is lighter and has a higher yield of naphtha/gasoline and lighter fractions.

Overall, crude differentials remain moderate out to 2035 as low demand growth combined with a continued increase in non-crude supplies helps maintain moderate capacity utilizations, and hence, a surplus capacity in industrialized regions. This, however, will depend on the actual level of future refinery closures. A substantial level of rationalization and closure could have an appreciable impact on crude and product differentials and margins in both the short- and long-terms.

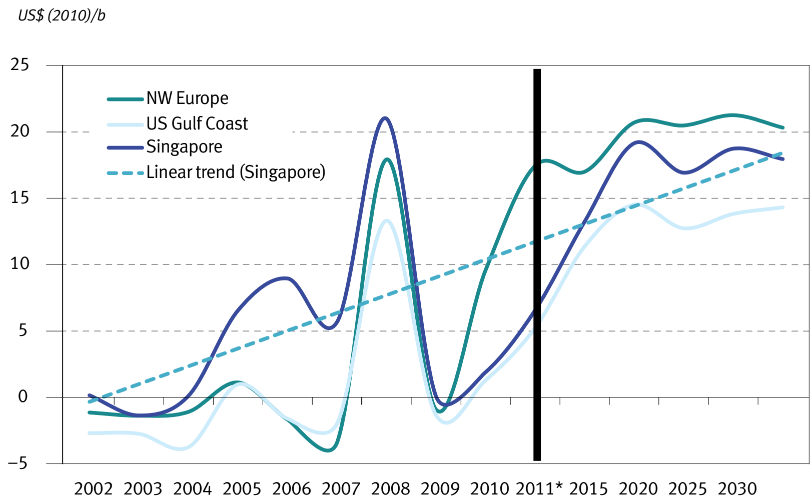
As already mentioned, bearing in mind that price differentials for time horizons more than ten years in the future must be regarded only as indicative, Figure 7.12 reflects what the WOO sees as the major global trends in product differentials. There is a continuing shift toward a gasoline surplus, as a result of increases in ex-refinery gasoline production capability, declining gasoline demand in the US, Europe and Japan, and rising supplies of ethanol, condensates and light sweet crudes. In parallel, distillate tightness, driven by sustained global growth, especially for diesel, is anticipated to lead to wider gasoil-gasoline differentials in all key markets.

Figure 7.12 shows gasoil/diesel minus gasoline price differentials for major markets, annually from 2002 to mid-2011 and projections for 2015–2035. The spike in the diesel premium over gasoline in 2008 reflected the refining tightness that was the result of continued economic growth and the refiners' ability to produce incremental diesel was limited and 'tight'. The 2009 collapse in the premium over gasoline – and crude – reflected the fact that distillate demand was particularly hard hit by the recession.

Data for 2010 and the first half of 2011 show a return to the pre-recession trend of strengthening distillate premiums relative to gasoline. Simulations indicate the recovery in these premiums will continue to 2015 and then start to plateau around 2020, at somewhere in the range of $10–20/b. This reflects the Reference Case outlook of continued distillates demand growth, the effects of the MARPOL Annex VI regulations and a sustained surplus for gasoline/naphtha.

These trends for products price differentials raise a number of questions. Are they sustainable over a period of 20 years? Will this change the behaviour of consumers? To what degree will governments and consumers respond over time to

Figure 7.12
Gasoil-gasoline price differentials in major markets, historical and projected



* *Year-to-date average week ending 22 July 2011.*

higher pump prices for diesel versus gasoline, in terms of shifting taxes/subsidies and/or vehicle ownership? In turn, could it shift demand back toward gasoline? To what extent will technology respond to eliminate the gap on both refinery yields and on gasoline/diesel demand? And, what may change in the downstream to moderate these effects?

It should be reiterated that these price differential outlooks are not predictions, but a signal of potential developments within the industry that are needed and likely to occur. It is anticipated that the industry will react to redress or reduce the imbalances foreseen in this and earlier outlooks, but major changes will take time.

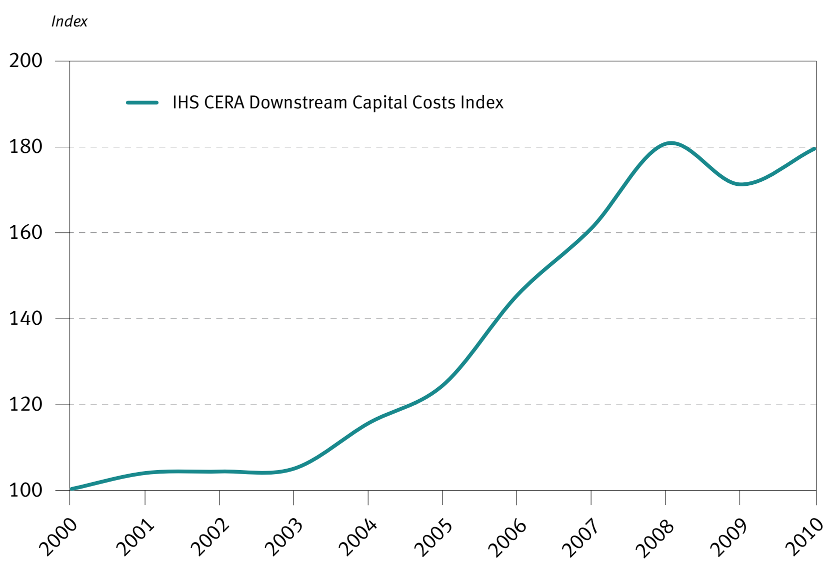
Chapter 8

Downstream investment requirements

Substantial capital investments are required to expand and provide maintenance to the global refining system. In the period to 2035, investments are estimated at around $1.2 trillion in the Reference Case. This excludes related infrastructure investments beyond the refinery gate, such as port facilities, storage and pipelines.

It should be noted that for the timeframe to 2030 – the forecast period for last year's WOO – overall investments are estimated to be around $1 trillion. This is higher than last year's estimate of around $860 billion. There are two reasons for this upward revision. The first is associated with higher average construction costs witnessed during 2010 and at the beginning of 2011 (Figure 8.1). Accordingly, the cost of building future new capacity is assumed to be moderately higher than last year's estimate. The second stems from a reassessment of the replacement value of the existing refining system, which leads to higher future maintenance costs.

Figure 8.1
Developments of downstream construction costs



Source: IHS Cambridge Energy Research Associates.

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Renewed interest in downstream capacity expansion is contributing to the upward movement in construction costs. As demonstrated in Figure 8.1, the IHS CERA downstream capital costs index (DCCI) increased during 2010 to its pre-economic crisis level of around 180, compared to the base year 2000. Increased downstream capital costs during 2010 not only reflect the rising price of raw materials, but also the higher labour costs and the premium price contractors needed to pay for construction equipment because of increased competition between various sectors during the post-crisis period.

If depicted on a quarterly basis, both indexes show a temporary decline in construction costs towards the end of 2008 and in the first half of 2009. By the second quarter of 2009, the IHS CERA DCCI index had lost around 10% from its third quarter 2008 peak, before returning to an upward trend. It is important to emphasize that the DCCI recorded an increase in 2010, albeit a much flatter increase than that which characterized the previous period of price escalation, especially during the period 2005–2008.

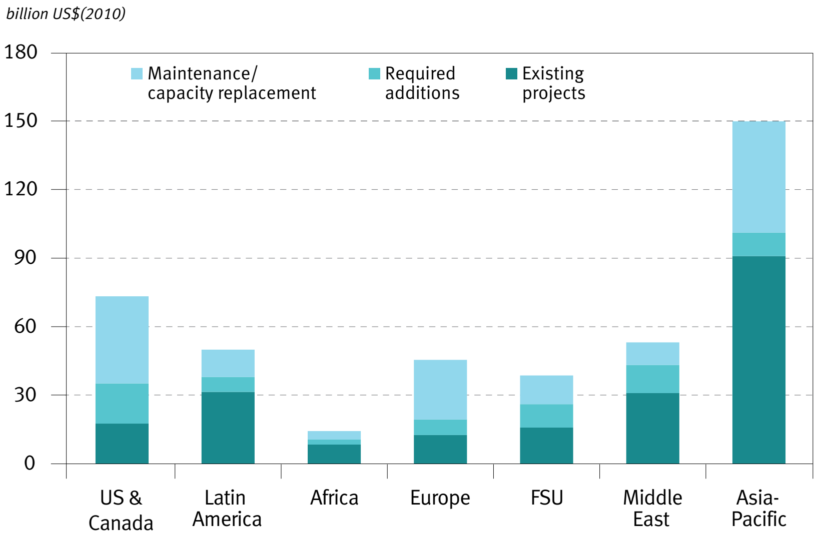
This leads us to a number of important questions. What are the expectations for future developments in downstream costs? Is the industry facing another period of cost acceleration and is 2010 the beginning of this trend? And if there is little chance for costs to remain flat or even move downwards, will future costs outpace inflation and increase significantly in real terms, as was the case during the period 2005–2008?

Estimations of future downstream investment requirements are based on the assumption that future costs will likely remain stable when expressed in real terms. This view is also shared by IHS CERA,[14] which expects the DCCI to increase gradually from 180 in 2010 to just over 220 by 2017.

There are three major components to investment requirements. The first category relates to identified projects that are judged to go ahead. The second category comprises capacity additions – over and above known projects – that are estimated to be required to provide adequate future refining capacity. The third category covers maintenance and capacity replacement. This relates to the ongoing annual investments needed 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 installed base. Thus, replacement investment is highest in regions that have the largest installed base of primary and secondary processing units. Moreover, since the installed refinery capacity base increases each year, so does the related replacement investment.

All these investment requirements are presented in Figures 8.2 and 8.3 for the periods to 2015 and 2035 respectively, over and above a 2010 base. Total required investment in refinery processing in the period to 2015 is projected to be $425 billion; almost $210 billion comprises the cost of known projects, $65 billion covers further

Figure 8.2
Refinery investments in the Reference Case, 2010–2015



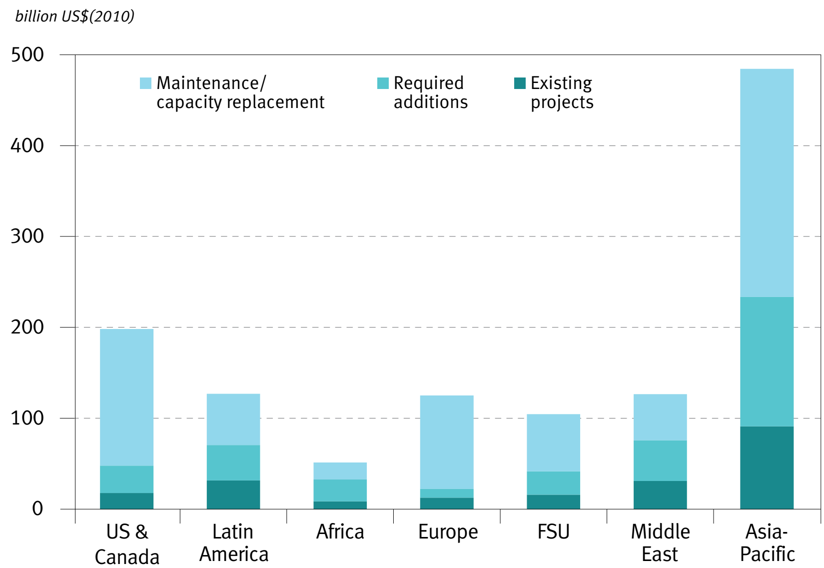
process unit additions – revamps and de-bottlenecking or creep, as well as major new units – and $150 billion is for ongoing maintenance.

Out of this, the Asia-Pacific is projected to require the highest level of investment in new units to 2015, with $90 billion for known projects and $10 billion for additional requirements. The region also sees $50 billion for capacity maintenance. China alone accounts for more than 60% of the Asia-Pacific total.

Following the Asia-Pacific is the US & Canada, which has a total requirement of around $70 billion. It should be noted, however, that around 50% is for capacity maintenance, stemming from the region's large installed base of complex refining capacity. In Europe, investment is mainly for maintenance and capacity replacement. New unit investments are limited and focused mainly on desulphurization for diesel and some expansion in conversion and distillation, mainly in South and Eastern Europe.

The Middle East is projected to require capital investments of around $50 billion, with much higher proportions of investment for new facilities than for replacement. A similar level of investment is required in Latin America. In both regions, existing projects will cost around $30 billion while required additions in the

Figure 8.3
Refinery investments in the Reference Case, 2010–2035



Middle East are somewhat higher than those in Latin America. In Latin America, these investments can be expected to expand the distillation base and desulphurization capacity. Somewhat lower investments – around $40 billion – are expected in the FSU. Here investment is more equally distributed to the expansion of all major process units. The lowest level of investment is projected for Africa, totalling close to $15 billion.

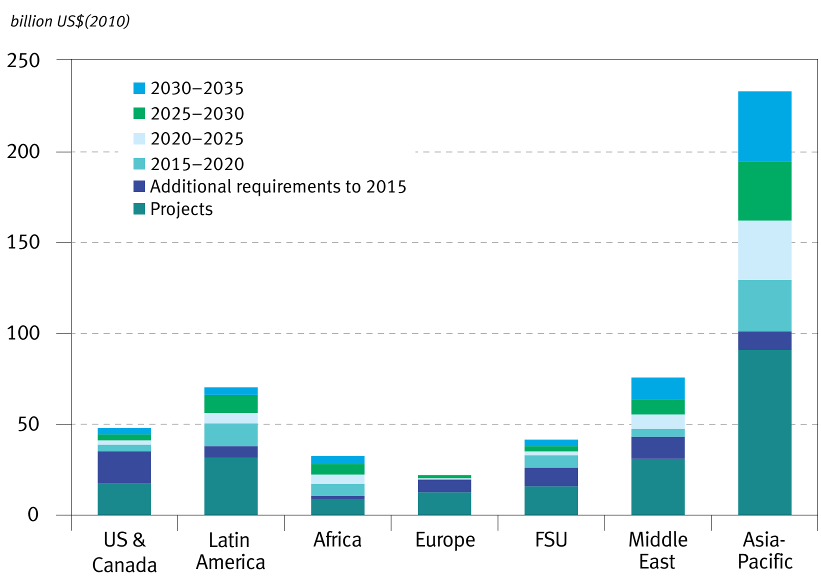
Turning to the long-term, as shown in Figure 8.3, global refining investments to 2035 are projected to reach $1.2 trillion, with $210 billion for investment in existing projects, $300 billion for required additions and close to $700 billion for maintenance and replacement.

Extending the time horizon to 2035 amplifies the significance of the Asia-Pacific as the region that should attract the highest portion of future downstream investments driven by the region's strong demand growth. From the $1.2 trillion required globally, almost 40%, or $480 billion should be in the Asia-Pacific. For other regions, the same breakdown for the period to 2015 is broadly maintained, especially when direct investments related to capacity expansion are considered.

Beyond existing projects, little investment to expand Europe's capacity base will be required. This is also true in the OECD part of Asia, which is not shown separately in Figure 8.3. The reasons for this are mainly related to quality compliance in regards to the growing distillates volumes. Fuel quality improvements are also driving US & Canada investments. Here, however, an important factor is the expanding production of heavy crudes that necessitate further investments in conversion capacity. Increasingly, projected investments in these regions are mainly for maintaining existing capacity.

In other regions, the ratio of investments for capacity expansion compared to maintenance is generally much higher. This is apparent in Africa, the Middle East, Latin America and the Asia-Pacific. To a lesser extent this is also true of the FSU. This striking difference in the structure of future investments becomes even more visible when comparing only projected investments for capacity expansion, as presented in Figure 8.4. This demonstrates how relatively little investment is required in the US & Canada and European refining systems as the timeline advances beyond 2015 and towards 2035 (the same is also true for Japan and Australasia). It is the developing regions, led by China and India in the Asia-Pacific, and followed by Latin America and the Middle East, that exhibit the need for sustained direct refining investments to 2035 to satisfy growing product demand.

Figure 8.4
Projected refinery direct investments*, 2010–2035



* *Excludes maintenance/replacement costs.*

Chapter 8

Chapter 9

Oil movements

In general, the economics of oil movements and refining gives preference for locating additional required capacity in consuming regions, because of the lower transport costs for crude oil, as opposed to oil products, unless construction costs for building the required capacity outweigh the advantages of the lower transport costs. Moreover, for consuming countries there is also the importance of securing a supply of required refined products, by emphasizing local refining over products imports, regardless of economic factors. On the other hand, however, many oil producing countries may look to increase their domestic refining capacity to benefit from the value-added of oil refining. Given these contradicting interests, and because oil is, to a large extent, a fungible commodity traded on global markets, there is a great level of uncertainty associated with any projections for future oil movements.

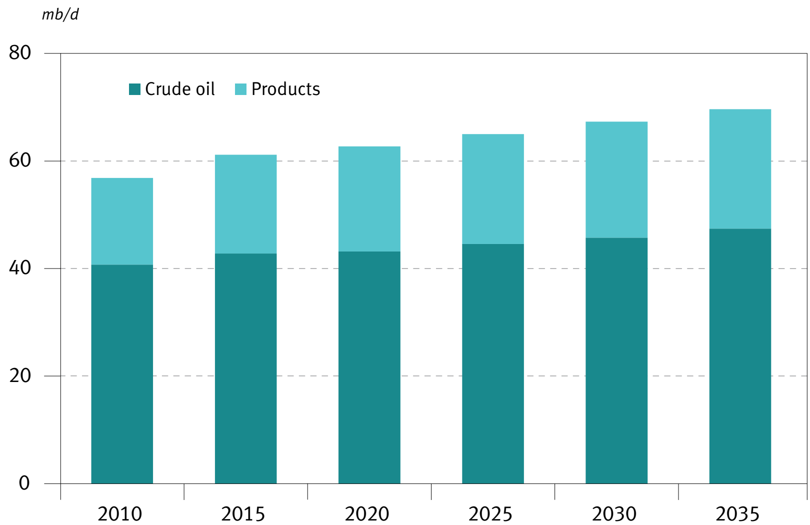
Moreover, reported trade volumes of crude oil and products depend on regional model groupings. A more detailed regional breakdown carries higher imports and exports than the one with more aggregated regions. Therefore, traded volumes presented in this Chapter should be considered as an indication of certain trends and future options for resolving regional supply and demand imbalances, rather than projections of specific movements.

At a disaggregated level, oil trade[15] between the considered 18 model regions is set to grow over the entire forecast period to 2035. As presented in Figure 9.1, oil trade will increase by around 4 mb/d in the period to 2015, compared to 2010 levels. Within this period, both crude oil and product exports are expected to increase by around 2 mb/d. In terms of growth, however, products are projected to grow almost three times faster than crude oil as their share of product trade in overall oil movements was less than 30% in 2010.

This trend represents a continuation of recent developments and is the result of a combination of factors. These include a projected increase in the refining capacity of crude producing regions, primarily the Middle East and Latin America, a demand decline in Europe, North America and the Pacific OECD regions, which makes refining capacity available for exports, and growing non-crude supplies.

Moreover, this medium-term trend is expected to continue in the long-term outlook. Between 2015 and 2035, total oil movements are projected to increase by more than 8 mb/d, although average overall growth will slow down to around

Figure 9.1
Inter-regional crude oil and products exports, 2010–2035



0.6% p.a. Product exports will grow faster than those for crude oil, although the difference will be much less than in the medium-term, 0.5% for crude oil versus 0.9% for products.

Crude oil export growth will primarily be driven by Asia-Pacific demand increases in the region associated with substantial refining capacity increases. By 2035, total crude exports will be almost 7 mb/d higher than in 2010. Exports of refined products are projected to witness a comparable volume increase, growing from around 16 mb/d in 2010 to slightly above 22 mb/d by 2035.

Combined, crude and product inter-regional trade between 2010 and 2035 increases by 13 mb/d, to a level close to 70 mb/d. Breaking this down, oil trade movements by 2020 will be around 63 mb/d, rising to 65 mb/d by 2025 and then above 67 mb/d by 2030.

Crude oil

In order to better distinguish key movements, only the seven major regions will be considered for the remainder of this Chapter. Since this means that some movements are eliminated, for example, between regions in the US and Canada, and intra-trade

Box 9.1
It's in the pipeline

It is clear that a growing proportion of future additional supply is expected to come from land-locked remote areas, such as Russia's Siberia, the Caspian region and the Canadian oil sands, which are often vast distances away from major consuming regions. The upshot is that these regions will require new transport routes to facilitate supply flows to global markets. So what is in the pipeline in terms of new transit routes?

Russia's large land mass, and the fact that its geology means that most of its oil reserves and the bulk of its production are located deep inland, underscores why the majority of its oil is moved by pipeline. It is also by far the most economical transportation option, with rail and water playing only supporting roles, mainly carrying refined products from processing plants to final consumers.

Currently, Russia has four principal routes to reach global markets – all operated by Russian state-owned pipeline company, Transneft. These are the Baltic Sea via Baltic Pipeline System (BPS-1); the Druzhba pipeline to a number of Central European countries; the Black Sea pipelines that move crude to four Black Sea terminals; and the East Siberia-Pacific Ocean (ESPO) pipeline in the direction of Russia's east coast and China. Going forward, however, the Russian Energy Ministry envisions a significant increase in Russia's overall crude oil export infrastructure capacity, from an estimated 6 mb/d in 2010 to 7.2 mb/d by 2015. The main focus is on two new transit routes: the ESPO-2 and BPS-2 projects.

Transneft has already embarked upon the second stage of the ESPO project, ESPO-2, which involves extending the original pipeline and expanding its capacity. According to Transneft President, the pipeline's capacity is slated to grow to 1 mb/d by 2012 and could potentially rise to as much as 1.6 mb/d at a later date.[16] According to Transneft, when the route is expanded to the planned maximum capacity, 0.3 mb/d is expected to go to China, 0.4 mb/d will be sent to a new refinery that Russia's Rosneft plans to build near Kozmino, and around 0.2–0.3 mb/d will be sent through the route to existing Far Eastern Russian refineries in Komsomolsk-on-Amur and Khabarovsk, according to Transneft. This implies that the remaining 0.6–0.7 mb/d will be exported from the Kozmino terminal on the Pacific coast. However, it is not yet currently clear when the route might be expanded to its maximum capacity.

Construction of BPS-2 began in June 2009 and the pipeline is set to run from the Unecha junction of the Druzhba Pipeline near the border of Russia and Belarus, to the Ust–Luga terminal on the Gulf of Finland. The pipeline will be constructed in two stages, the first of which is expected to be completed by September 2012, and the second by December 2013. It will have an initial capacity of 0.6 mb/d.

In the Caspian region, increasing crude oil production needs to go hand-in-hand with the development of new transport options to export the additional barrels to international markets. Nonetheless, given its general land-locked geography and geopolitics, finding options and securing solutions are proving to be difficult.

Among several proposals for new or expanded pipelines, at present it appears that only two projects are likely to go ahead in the coming years. The first is an expansion of the Caspian Pipeline Consortium[17] oil pipeline, which was first commissioned in 2001. It runs 1,580 km from the Tengiz oil field to the Russian Black Sea port of Novorossiysk. The $5.4-billion project is geared to increase the pipeline capacity from its current 0.56 mb/d, to around 1.34 mb/d by 2014.

The second project will extend Kazakhstan's link to China. In October 2009, CNPC and KazMunayGas (KMG) signed a framework agreement to construct the second phase of the Kazakhstan-China Oil Pipeline, doubling the pipeline capacity to 400,000 b/d by 2013. The expansion project is geared to carry oil from the huge Kashagan oil field.

Other major alternatives are under consideration, such as an expansion of the Baku-Tbilisi-Ceyhan (BTC) pipeline and the Kazakhstan Caspian Transportation System (KCTS). However, the timing and scope of these projects is uncertain. The need for them is expected to only arise towards the end of this decade, when the second phase of Kashagan's production is slated to come on stream.

In both Canada and the US, a combination of domestic crude oil production growth and a series of pipeline projects is leading to a situation that could have appreciable impacts on international crude oil markets and trade.

Declines in conventional production are projected to be more than offset by the substantial growth in oil sands streams. At the same time, rapid growth is occurring in US domestic crude oil production, and also NGLs, due to the swift spread of technologies to produce shale oil and shale gas reserves. The most pronounced growth is from the Bakken region, centred in North Dakota.

Concerned by a period between 2005 and 2007 when inadequate export pipelines led to significant price discounts, as well as shut-ins in WCSB production, Canadian producers, shippers and government authorities have been keen to develop export capacity. Here, it is important to note that for a country with such high exports, the WCSB crude oil export system is unusual in that it is currently overwhelmingly land-locked.

To relieve system stresses, several possible pipeline projects exist that would provide relief and enable the WCSB, as well as other crudes, to flow more freely to markets. The two most significant are the Enbridge Northern Gateway that would run from Edmonton to the deepwater port of Kitimat, British Columbia and the Trans-Canada Keystone XL pipeline that would run southeast from Hardisty Alberta, via Montana, to Steele City Nebraska. Taken together, these two projects would initially add over 1 mb/d of WCSB export capacity, and potentially over 1.5 mb/d.

Both of these projects are encountering substantial resistance. Whether either goes ahead in the near term – or at all – is uncertain. However, if they do, it will open up international markets for this crude, potentially changing the global crude trade outlook.

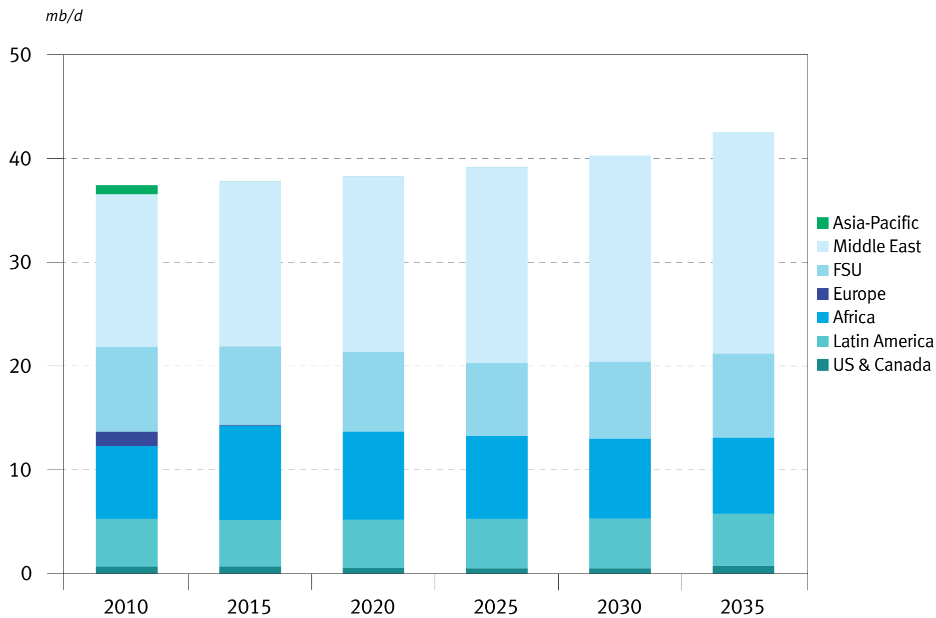
It is important to stress that this is not an exhaustive list of the global pipeline projects, just some of the major ones. Other large pipeline projects are expected to be constructed in the Middle East and China, with the latter playing a major role in developing pipelines to meet its growing oil demand. An example of the latter is the China-Myanmar pipeline, a 'demand driven' project to help China diversify its import sources. It should also be noted that pipelines are not the only major transit options being developed, with the current expansion of the Panama Canal and the possible opening of the Northwest Passage making waves in the shipping world.

in Latin America, Africa and Asia, total trade volumes are lower than reported earlier in this Chapter.

In the main, this regional configuration mirrors the key trends observed for crude oil movements between the more detailed regions, especially from the long-term perspective. In terms of total volumes, medium-term crude oil movements between the major regions are projected to increase marginally, but the growth will be stronger after 2020. This will lead to a total increase in crude oil exports of 5 mb/d by 2035, compared to the 2010 level. As presented in Figure 9.2, projections indicate that this volume could reach 38 mb/d in 2020, passing 40 mb/d by 2030 and approaching 43 mb/d by 2035.

Steady increases in global crude oil exports are a result of varying regional trends. The most obvious is the expanding importance of the Middle East as the key crude

Figure 9.2
Global crude oil exports by origin*, 2010–2035



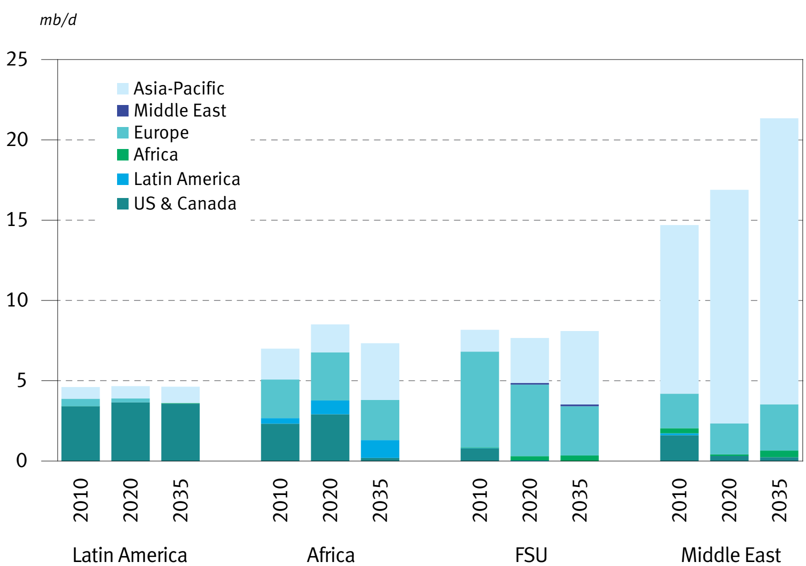
* *Only trade between major regions is considered.*

exporting region in the decades ahead. Indeed, crude oil exports from this region are set to grow continuously throughout the forecast period, reaching more than 21 mb/d by 2035, compared to just below 15 mb/d in 2010. In contrast to this are the rapidly diminishing crude exports from Europe and the Asia-Pacific. Growing demand in the Asia-Pacific will absorb the region's entire indigenous production by 2015. In the case of Europe, the key reason is declining North Sea production, although the net effect is similar to that for the Asia-Pacific.

The regions of Latin America and the FSU show declining exports in the period to 2020, but this is reversed in the years thereafter. This is due to a combination of increased refining capacity and growing local demand in the period to 2020, while additional barrels on the production side outweigh demand growth in the period after 2020, providing more crude oil available for export. In Africa, the pattern is reversed. Here, due to a lack of new refining capacity and increasing crude oil production, exports are expected to grow during the current decade. After 2020, however, as new refining capacity is expected to come on stream and domestic demand grows, the volumes of crude oil available for export will slowly decline. These fluctuations are limited to the range of 2 mb/d, however, as crude oil exports are moving between 7 mb/d and 9 mb/d across the entire forecast period. Fluctuations within a fairly narrow band of around 1 mb/d are also projected for the FSU region and Latin America.

Figure 9.3 details the key changes in crude oil flows from the perspective of major exporters from 2010–2020, and then to 2035. As already highlighted, it underscores the Middle East's future role as the major crude oil exporter. Moreover, it also highlights the region's major share in imports to the Asia-Pacific, as well as the increasing share of the Asia-Pacific in exports from Africa and Russia. In absolute numbers, the biggest change over the forecast period relates to crude oil exports from the Middle East to the Asia-Pacific; an increase of 7 mb/d from 2010–2035. In relative terms, however, Russia and Caspian countries will more than triple their crude exports to the Asia-Pacific, as new pipelines to China and Russia's Far East are assumed to be operational, and at the same time exports to Europe are expected to significantly reduce. Similarly, Africa will almost double its crude exports to the Asia-Pacific, mainly at the cost of reduced deliveries to the US & Canada. Contrary to these regions, crude oil exports from Latin America are projected to remain relatively stable in terms of both volume and structure.

Figure 9.3
Major crude exports by destination, 2010–2035



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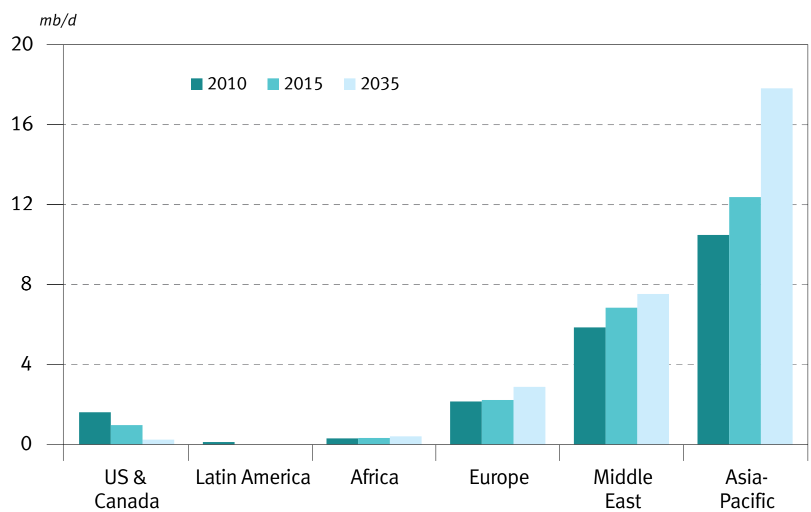
Another observation worth noting is the decline of crude oil imports to Europe and the US & Canada. In the case of the US & Canada, a combination of lower demand, the expansion of non-crude supplies and higher increases in synthetic crude production from Canada, offsetting declines in conventional crude, results in a reduction of around 4 mb/d in crude imports between 2010 and 2035. In the case of Europe, crude imports are projected to decline by almost 3 mb/d during the same period, as demand decreases and product imports more than outweigh declining domestic crude production.

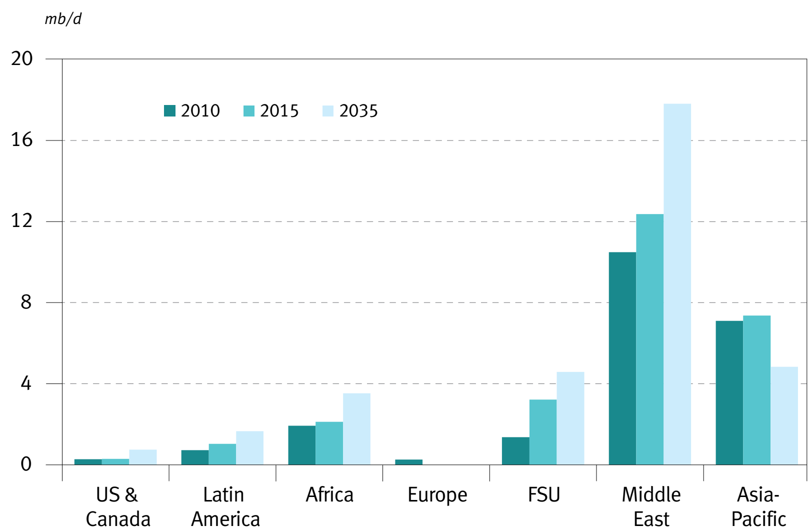
Total crude exports from the Middle East are projected to stand at almost 17 mb/d by 2020 and above 21 mb/d by 2035. This compares to 14.7 mb/d in 2010. Throughout the entire forecast period, the destination that receives the most crude oil exports from the Middle East is the Asia-Pacific (Figure 9.4). By 2035, this region accounts for almost 18 mb/d of exports from the Middle East. Another important partner for the Middle East will be Europe, with imports projected to be close to 3 mb/d by 2035, mostly in the category of medium sour although some will be light sour crude. With sufficient desulphurization capacity in Europe, the sour nature of Middle East crudes should not create problems for refiners. If demand in North America develops as projected, then crude exports from the Middle East to this region could almost be non-existent by 2035.

Figure 9.4
Destination of Middle East crude oil exports and local supply, 2010–2035



The Asia-Pacific's ever-expanding role in global crude oil imports is clearly demonstrated in Figure 9.5. By 2035, demand in the Asia-Pacific will increase by 17 mb/d, compared to 2010. However, crude production will decline by more than 2 mb/d over the same period. Therefore, the growing gap between demand and local production in these regions has to be filled by imports, primarily in the form of crude oil from all producing regions, but mainly from the Middle East and supplemented by Russian, Caspian, African and marginally crudes from the Americas (Figure 9.5). Expected trade between the Asia-Pacific and the Middle East has already been highlighted, and elsewhere, by 2035, the FSU will see almost 5 mb/d of crude exports to the Asia-Pacific and Africa 3.5 mb/d, predominantly from West Africa.

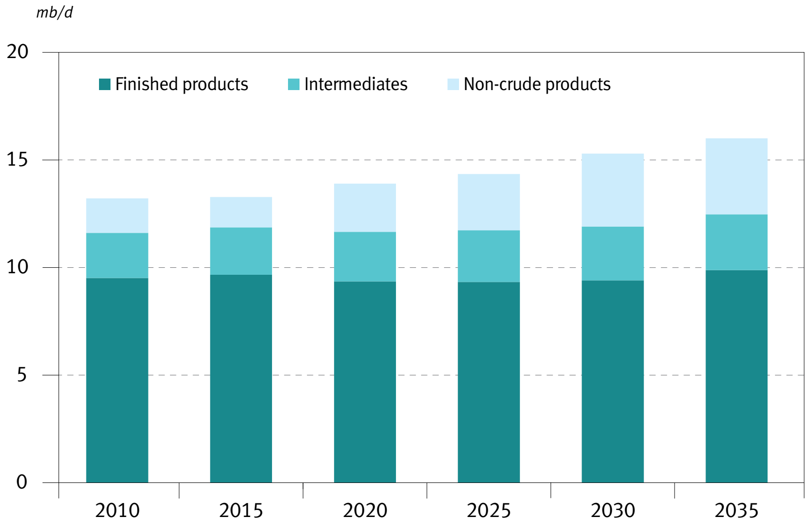
Figure 9.5
Asia-Pacific crude oil imports and local supply, 2010–2035



Products

As stated at the beginning of this Chapter, total exports for refined products, intermediates and non-crude based products is projected to reach a level of more than 22 mb/d by 2035, if trade between all the 18 model regions is considered. However, if product movements are restricted to the seven major regions then these inter-regional movements will account for 16 mb/d by 2035, an increase of more than 3 mb/d compared to 2010 (Figure 9.6). This increase represents only half of the product movement change projected for all 18 model regions, since refined products are typically

Figure 9.6
Global exports of liquid products, 2010–2035

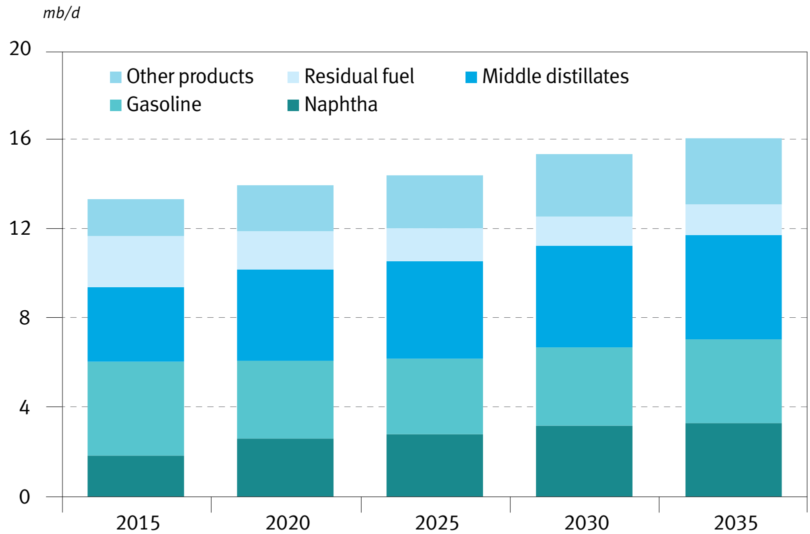


moved less on long haul routes due to their relatively high transport costs. Nevertheless, these movements constitute an integral part of the downstream sector as they contribute significantly to meeting regional demand for liquid products, as well as potentially solving regional product imbalances.

Total volumes traded on international markets are affected by a range of issues, such as the placement of new refining capacity, shifts in regional demand patterns and increasing spare refining capacity in regions with falling demand, in particular the US and Europe. Another important factor relates to the growing trade of non-crude based products, primarily due to the increasing production of NGLs (and product output from gas plants) supplemented by projected increases in GTLs. The global increase in this category of liquid products is projected to be almost 2 mb/d from 2010–2035, which sees it rising to 3.5 mb/d by the end of the forecast period. Production of the other two products in this category – CTLs and biofuels – is also projected to increase substantially, but this will materialize mainly in consuming regions. Thus, it will only marginally affect traded volumes.

Figure 9.7 provides the breakdown of the global inter-regional movements at the product level. This clearly demonstrates the expected changes in the make-up of future product movements, with growth in naphtha, middle distillates and the group of other products and a decline in gasoline and fuel oil. A dominant feature of

Figure 9.7
Global product imports by product type, 2015–2035



the expected future product trade is an expansion of middle distillates and naphtha, primarily for petrochemical use. Both products record an increase in the range of 1.5 mb/d between 2015 and 2035. However, while imports of middle distillates are spread among the Asia-Pacific, Europe, Africa and Latin America, naphtha will be almost entirely absorbed by the Asia-Pacific. This is driven by a rapid expansion of the petrochemical industry in China and India, as well as several other countries in the region.

Driven by the projected overall demand decline for fuel oil, due to falling inland use and marine bunker developments, trade in this product category drops off dramatically, especially around 2020, when tighter fuel specifications for marine bunkers are expected to be in place globally. The overall decline in fuel oil exports is expected to be around 1 mb/d by the end of the forecast period, compared to 2010.

Another product with a declining export trend is gasoline. Moreover, the regional pattern of gasoline flows is likely to change. There are two factors supporting this: a continued gasoline and diesel imbalance in the Atlantic Basin and increasing ethanol supplies, especially in the US. These factors will lead to increased competition in global gasoline markets, as Europe and the US face up to the problems of a gasoline surplus. This is due to the high installed capacity for gasoline production and the falling demand for crude-based gasoline, partly because of increased ethanol supplies. However, to what extent Europe and the US succeed in placing their gasoline surplus in other regions, as well as other products, depends very much on policies adopted in these other regions.

The regional pattern for product imports is depicted in Figure 9.8. It highlights several emerging trends. The most visible is that of the Asia-Pacific's rising product imports, to a level of almost 7 mb/d by 2035. These products will mainly come from Russia and the Middle East (Figure 9.9). The US & Canada will gradually reduce their product imports from levels of around 4 mb/d in 2015 to 3 mb/d by 2020, and then close to 2 mb/d by 2035. The region's net product imports will also decrease, by around 1 mb/d by 2035. A similar pattern of declining product imports is also expected in Europe. Here, the decline in net product imports is in the range of 1 mb/d. On the other hand, growing product imports are projected for Africa and Latin America. However, while Africa will likely remain a net product importer over the forecast period, Latin America is assumed to reverse its status and become a net products exporter by 2015, as new refining capacity becomes available.

Figure 9.8
Global product imports by region, 2010–2035

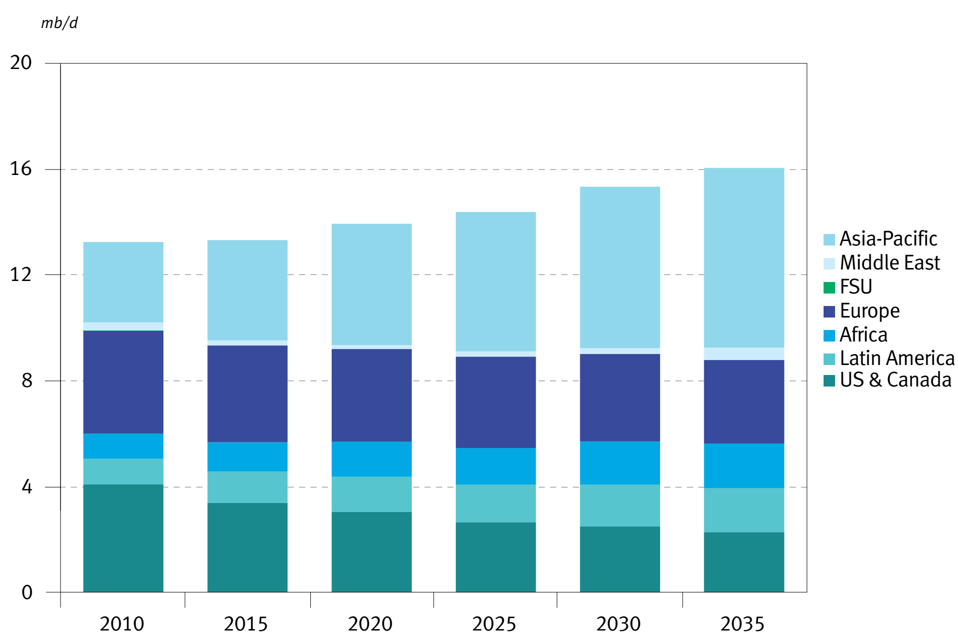
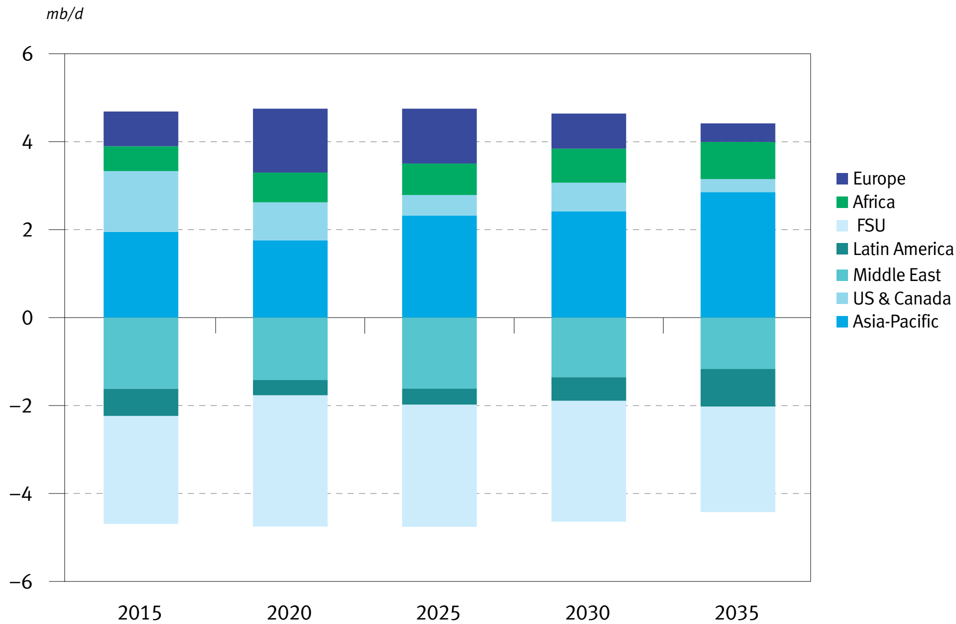


Figure 9.9
Net imports of liquid products by region, 2015–2035



The other two regions, the FSU and the Middle East, will keep their status as net products exporters. Their net exports will be relatively stable, moving within a range of 2.5-to-3 mb/d in the case of the FSU, and between 1 mb/d and 2 mb/d in the case of the Middle East. It should be stressed, however, that these volumes depend on the future policies of the countries in these regions, as they have the option to adding more refining capacity than projected in this outlook, thus, increasing their product exports.

Chapter 10

Downstream challenges

This Chapter brings together the key findings from Section Two and reviews the possible implications for the industry and the challenges ahead over the medium- and long-terms. It is apparent that some of industry's challenges are part of long-term trends, and as such, some of the themes and messages included here are similar in nature to last year.

A new downstream outlook

Since the middle of the last decade the refining industry has witnessed major highs and major lows. There was what many have described as the 'golden age' of refining that lasted from 2004 through to mid-2008. This was then followed by the global economic recession that cut demand severely and impacted the industry significantly.

From the overall oil market perspective, a major shift is the one between OECD and non-OECD regions. The latter are now delivering the bulk of the world's oil demand growth; conversely, OECD demand seems to have peaked. The long-term oil demand trend in the US & Canada, Europe and Japan is projected to follow a downward path. From a regional perspective, this situation has created a contrast between the Atlantic and Pacific Basins. Dominated by the US and Europe, the former is the centre of a significant refining capacity surplus, and the inherent challenges this brings, while the Asia-Pacific is the centre of growth. These shifts will serve to reshape the global downstream industry in the years ahead. The industry will have to readjust to this new environment.

Declining crude oil and refining share of the incremental demand barrel

The proportion of crude oil that needs to be refined per barrel of incremental product continues to decline, as the total proportion of biofuels, GTLs, CTLs, NGLs and other non-crudes continues to rise. The impact of non-crudes is significant. In the Reference Case, supply increases by nearly 23 mb/d between 2010 and 2035, from 86.8 to 109.7 mb/d. Of the increase, however, over 13 mb/d is projected to be met by growth in non-crudes and process gains. This equates to almost 60% of total supply growth. This leaves less than 10 mb/d of growth for crude oil, an average increase of around 400,000 b/d per year. Essentially, this translates into a similar growth rate for refining.

Capacity expansion competition – and closure

The demand decline now being witnessed in industrialized countries coincides with a period of substantial new capacity additions, approximately 7 mb/d by 2015. For many refiners, this is a significant cause of concern. In conjunction with recent demand losses caused by the recession, it is creating a situation where refinery throughputs and utilizations are expected to be under pressure for several years. Today is a post-'golden age' world of refinery surplus, concentrated in OECD regions.

Figure 6.6 (Chapter 6) illustrates the way 'effective spare capacity'[18] declined through the 1980s from the extreme levels early that decade, stayed relatively flat through the 1990s, dropped again to under 4 mb/d in the middle part of the last decade, and then increased sharply in 2009 due to the recession. Looking to the future, tellingly the graph shows the industry trending to further increases in spare capacity, at least until 2015.

Before the recession, smaller, older and less efficient refineries were already under pressure, unless they had the benefit of special circumstances, such as a local crude supply, protected local demand and/or specialty products. Following the recession, this pressure has now multiplied.

Moreover, in the current situation of capacity surplus, all refineries have to face the prospect of competing with a wave of new capacity, mainly large-scale, highly complex and increasingly efficient. The Reliance refineries in India have set new standards in all these dimensions. Expansions in the Middle East and, to some degree the US, are also raising the bar on what constitutes a 'world-scale' refinery. Much of the new capacity, such as in India and Saudi Arabia is export-oriented, geared to processing heavy and difficult crudes and to producing predominantly light products to advanced standards. At the same time, existing refineries in the US, Europe and Japan are facing reduced demand for their products.

Given the nature of the current market, it is expected that refineries in the US, Europe and Japan will be the ones that suffer the greatest number of closures. Although to date, however, there has been relatively little net closure. The emphasis at present is on selling – or at least attempting to sell – refineries. A major factor in OECD regions has been the shift by several major oil companies toward the divestment of refineries and disintegration, whereby a once integrated company is split into separate exploration and production, and downstream entities. It is evident that there could potentially be a substantial reshaping and re-ordering of refining capacity and refinery ownership over the next few years.

Nonetheless, it is not a simple matter of future closures in the OECD and new refineries elsewhere. Some OECD refineries will inevitably close, but others will have products available to put onto global markets.

Many US refineries, notably in the Gulf Coast, are well depreciated, highly complex and flexible, meaning they can put out products of advanced specifications. US refiners have been raising distillate yields and the exports of distillates, gasoline and other products have doubled in the last few years. European refineries are in general less complex than those in the US, but they need to produce gasoline and other co-products in order to keep producing profitable distillates. And in Japan, it can be expected that what remains after refinery closures are the more complex facilities that can compete on international markets. These OECD region refineries will join the new large-scale refineries in India, Brazil and the Middle East to compete for markets in Latin America, Africa and Asia.

Distillate deficit – gasoline surplus

This year's projections for distillates and gasoline demand follow the same trend outlined in last year's publication. The market is facing an imbalance, at least in the medium-term, characterized by a gasoline/naphtha surplus and a continuing distillate deficit. Thus, the mix of a refinery's products, in particular the proportions of distillate versus gasoline/naphtha, will be key factors affecting margins and profit. Similarly, distillate versus gasoline/naphtha fractions in crude oils are likely to have a marked impact on a crude's relative price, with crude oils containing a high distillate yield favoured. Very light crudes, as well as condensates, with their high yields of gasoline/naphtha, are expected to be disadvantaged.

Demand and technology responses?

The projected imbalance with respect to NGLs/naphtha/gasoline versus distillates poses processing and technology challenges for refiners. FCC yields are increasingly oriented to distillate and propylene, and away from gasoline, but while FCC capacity is substantial, the impact on distillates supply is potentially limited. Modern process technology to convert NGLs/naphtha/gasoline to distillates is needed, but as yet, commercial processes do not appear to be available. Nonetheless, modifications to current technologies and the development of new ones could become a feature of refineries as they adapt.

Moreover, distillate premiums relative to gasoline in the range of \$10–20/b, as indicated by model results in this Outlook, will likely prompt some response on the demand side too. However, the extent of this change depends primarily on policies adopted in consuming countries and, in any case, major changes will obviously take time.

Refining investments: trends and uncertainties

It is evident from this year's WOO that some current downstream trends and developments are largely set to continue as expected, whereas others are beset by some significant uncertainties.

While the continuing trend to distillates appears sound, the NGLs/naphtha/gasoline surplus and associated wide differentials versus gasoil/diesel could act to swing some demand back toward gasoline. The potential for more gasoline demand is also in evidence in the latest EU initiatives. The scope may be limited, however, as gasoil/diesel demand is driven more by commerce and economic growth, and marine fuels legislation will shift at least some portion of heavy IFO fuels to distillates. The upshot is that whereas in the past, particularly before 2006, it mattered little if a refinery emphasized gasoline or distillates, today, and in the future, it could make a significant difference to a refinery's viability.

On the basis that incremental distillate will continue to be required, in part via incremental hydro-cracking, and that this technology will remain capital, energy and hydrogen intensive, sustained distillate premiums look likely to remain. The caveat is future recessions, which have in the past, albeit temporarily, hit distillate demand hard. The same cannot be said for gasoline and naphtha. Although levels will of course fluctuate, it is difficult to avoid scenarios where premiums for these products are anything other than weak. However, sustained growth in Asia, even if some slow-downs occur, portends to sustained and solid refining margins and significant investment requirements in that region.

In other areas, however, the picture changes with some significant uncertainties at play. A refining sector that is being squeezed by the rising non-crude supply, could become even more pressured by further liquids supply growth, notably from NGLs, given the emergence of shale gas. While non-OECD demand looks robust, transportation efficiency measures in industrialized regions could lead to steeper declines there. In addition, biofuels represent a further 'wildcard'.

Overall, the general outlook is for severe competition, both across, and between regions, for refined products markets. It is an outlook where the role of refining in total liquids products supply gradually shrinks in proportionate terms, courtesy of the possibilities for rising biofuels and non-crude supplies. In turn, this trend, combined with ongoing project additions, reduces longer term requirements for further additions. In short, it is an outlook where there are many risks facing refiners.

Footnotes

Section One

1. From the G-20 Leader's Statement, Pittsburgh Summit, 24-25 September 2009: "All standardized OTC derivative contracts should be traded on exchanges or electronic trading platforms, where appropriate, and cleared through central counterparties by end-2012 at the latest. OTC derivative contracts should be reported to trade repositories. Non-centrally cleared contracts should be subject to higher capital requirements."
2. It was observed in the 'WOO 2010' that the price needed to support Canadian oil sands projects would exceed $70/b at internal rates of return above 10%.
3. It could be argued to some degree that part of these cyclical factors has become structural as the axis of economic growth shifts towards emerging economies, especially in Asia, with the concomitant steady and rising pressures upon demand for, and the price of, building materials.
4. IHS CERA, 'Costs of Building and Operating Upstream Oil and Gas Facilities Begin Measured Rise', December 2010, http://press.ihs.com.
5. OPEC, 'World Oil Outlook 2010', p.129.
6. Goldman Sachs, '230 Projects to Change the World', February 2009.
7. Michael C. Lynch, 'Upstream Costs: cycle or rising trend?', Strategic Energy & Economic Research, Inc., December 2009.
8. Paul Segal, 'Why do oil price shocks no longer shock?', Oxford Institute for Energy Studies, October 2007.
9. Ali Aissaoui, 'Fiscal break-even prices: what more could they tell us about OPEC policy behaviour?', APICORP, March 2011.
10. Carmen Reinhart and Kenneth Rogoff, 'This Time Is Different: Eight Centuries of Financial Folly', Princeton University Press, 11 September 2009.
11. It is worth noting that increased pessimism for growth prospects in some countries, notably the US, has emerged in the second half of 2011, after the model runs for this Outlook had been undertaken.
12. This is using the medium variant of projections from the UN Department of Economic and Social Affairs. There are, however, uncertainties, largely with regard to future fertility rates, with the UN also offering estimates for low and high variants, which suggest a global population by 2035 of 8 and 9.2 billion, respectively.
13. Defined as population aged 15–64.
14. There is no single definition used by the UN for what is designated as 'urban' since there are national differences that distinguish urban from rural areas. The traditional distinction has related to the higher standard of living in urban areas, but this is becoming blurred in developed countries. Typically, a population density of 1,000 persons per square mile (although this can be as low as 400, as with Canada, or even 200, as with Greenland and Norway) and/or population size (with this ranging between a minimum population of 2,000–5,000, although it can be as low as 200, as in the case of Iceland, or

as high as 20,000, as with Turkey) is used as a definition in censuses. See http://unstats.un.org/unsd/demographic/sconcerns/densurb/Defintion_of%20Urban.pdf.

15. Excluding non-commercial use of biomass.
16. Potential Gas Committee, Press Release, 27 April 2011, http://potentialgas.org.
17. Energy Information Administration, 'Review of emerging resources: US shale gas and shale oil plays,' July 2011, http://www.eia.gov/analysis/studies/usshalegas/.
18. Energy Information Administration, 'World Shale Gas Resources: An Initial Assessment of 14 Regions Outside the United States', April 2011, http://www.eia.gov/analysis/studies/ worldshalegas/pdf/fullreport.pdf.
19. http://www.eia.gov/pressroom/releases/pdf/shale_gas.pdf.
20. George E. King, 'Thirsty year of gas shale fracturing: what have we learned?', Society of Petroleum Engineers, Paper 131456, 2010.
21. Florence Geny, 'Can Unconventional Gas be a Game Changer in European Gas Markets', The Oxford Institute for Energy Studies, December 2010, http://www.oxfordenergy.org.
22. The Massachusetts Institute of Technology Energy Initiative, 'The Future of Natural Gas', 2011, http://web.mit.edu/mitei/research/studies/natural-gas-2011.shtml.
23. Stephen G. Osborn et al, 'Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing', Proceedings of the National Academy of Sciences, April 2011, http://www.pnas.org/ content/early/2011 /05/02/1100682108.
24. http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/index.cfm#curstud.
25. http://www.bbc.co.uk/news/world-europe-13592208.
26. http://world-nuclear.org/info/fukushima_accident_inf129.html.
27. http://www.neimagazine.com/story.asp?sectioncode=132&storyCode=2059858.
28. http://www.world-nuclear.org.
29. http://www.world-nuclear.org/info/inf17.html.
30. http://www.ifandp.com/wp-content/uploads/2011/03/032111-ORC-International-Japan-Nuclear-Reactor-survey-report-FINAL1.pdf.
31. http://www.nytimes.com/2011/03/25/us/25lobby.html?_r=1.
32. A significant portion of this change is due to revisions for short-term expectations for OECD regions.
33. Of course, even over the medium-term policies can play a significant role in changing demand patterns, such as with blending mandates.
34. Measured in terms of energy content.
35. This fall occurred at the same time that Indonesia was added to the definition of non-OPEC as it left the Organization in 2008. The revision was therefore even more emphatic than the figure shows.
36. Supply figures are slightly higher than those of demand due to the need for additional oil to satisfy stock build.
37. Same source used in this Chapter for subsequent depictions of historical oil use by sector.

38. Including sports utility vehicles.
39. Defined as lorries plus buses. Lorries are rigid motor vehicles designed, exclusively or primarily, to carry goods, and include vans and pick-ups. Buses are passenger road motor vehicles designed to seat more than nine persons, including the driver.
40. Defined as passenger-kilometres performed expressed as a percentage of seat-kilometres available.
41. Airbus, 'Global Market Forecast 2010'.
42. IATA is an international trade body representing two hundred and thirty airlines in 188 countries, and comprising 93% of scheduled international air traffic.
43. IATA 2008, http://www.iata.org/whatwedo/environment/Pages/fuel_efficiency.aspx.
44. International Civil Aviation Organization (ICAO), http://icaodata.com.
45. International air traffic applies to passengers, freight and mail disembarked at an airport located in a state other than that of the airport of embarkation, or vice versa.
46. 'Outlook for Air Transport to the Year 2025', ICAO, 2010.
47. Covers quantities delivered to ships of all flags that are engaged in international navigation.
48. Additionally, the following sources are used: IMF, World Economic Outlook; OECD, Economic Outlook; Economist Intelligence Unit; United Nations; national sources.
49. Oil use in diesel generators in factories is included in industrial oil use.
50. The prospects are not uniform across all Member Countries.
51. Prices by 2035 are 11% higher than in the Reference Case.
52. It should be noted that the effects of the ATTP and economic growth scenarios cannot be simply aggregated, as different driving forces are assumed to be at work.
53. Climate Change 2007: Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change, 2007. This report is often termed AR4.
54. Leon Clarke, Jae Edmonds, Volker Krey, Richard Richels, Steven Rose, Massimo Tavoni, 'International climate change policy architectures: Overview of the EMF 22 International Scenarios', Energy Economics 31 (2009).
55. Results presented to the January 2011 IEA-IEF-OPEC Symposium on Energy Outlooks, Riyadh, Saudi Arabia, using the CGE model of Charles River Associates confirm this. Such impacts are also corroborated by other assessments, including work at the OPEC Secretariat.
56. See www.ofid.org.
57. Data is for average water use relating to both raw materials and transformation.
58. Original source is: Stephen G. Osborn, Avner Vengosh, Nathaniel R. Warner, and Robert B. Jackson, 'Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing', April 2011, Proceedings of the National Academy of Sciences, available at http://www.pnas.org/content/108/20/8172.full.

Section Two

1. 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.
2. Heavy IFO fuels comprise the majority of marine fuel sold, especially for larger vessels. IFO fuels have primarily been distinguished based on their viscosity (Centistokes at 50°C). IFO380 has traditionally been the most used with IFO180 following second. Rising fuel costs and distillate/resid differentials are, however leading to the increasing use of IFO500 and even IFO700.
3. Initially, ECAs were established for sulphur/SOx only and so were called SECAs. Since broadening the emissions covered to include NOx and PM, the acronym has been changed to ECA.
4. Starting with the fiscal year 2012, some changes to the tax scheme for India's oil industry are being considered, potentially removing some of the benefits currently in place.
5. In fact, since fuel oil margins are negative on international markets, increased exports of fuel oil means value destruction compared to crude oil exports.
6. Construction of the pipeline was completed in June 2011.
7. A combination of finished gasolines and reformulated blendstock for oxygenate blending/conventional blendstock for oxygenate blending for final blending at terminals with ethanol.
8. Volumes of acidic 'high TAN' (total acid number) crudes are growing. These require additional pre-treating and/or processing in crude units with either metallurgy or additives to counter the acid's corrosive effects.
9. Percentage calculated on a weight basis.
10. Directive 98/70/EC as amended by two subsequent directives – Directive 2003/17/EC and Directive 2009/30/EC.
11. Note that all references to upgrading and conversion in this study exclude operations, capacity and requirements for upgraders associated with extra-heavy crude oil and oil sands (Venezuela and Canada). The analysis starts from the marketed streams (syncrudes, dilbit type blends, etc.) of such production and facilities.
12. In the model, the production of fuel grade coke is allowed to float as a by-product with prices based on those for coal, with which fuel grade coke competes.
13. On a weight basis, the coke yield on a coking unit can be in the range of 30%.
14. IHS CERA, 'OECD Refining: Lighter Supply Spells Lasting Trouble', October 2010.
15. Oil here includes crude oil, part of condensates and NGLs that are blended with crude oil, refined products, intermediates and non-crude based products.
16. Transneft's website: www.transneft.ru.
17. The consortium's four largest shareholders are: Transneft (24%), KMG (19%), Chevron (15%), and LukArco (12.5%).
18. Calculated as 90% of the difference between crude distillation capacity and required crude throughputs.

Footnotes

Annex A

Abbreviations

API	American Petroleum Institute
AR4	IPCC's Fourth Assessment Report
ATTP	Accelerated Transportation Technology and Policy
AWG-KP	Ad Hoc Working Group on Further Commitments for Annex I Parties under the Kyoto Protocol
AWG-LCA	Ad Hoc Working Group on Long-Term Cooperative Action under the Convention
b/d	Barrels per day
boe	Barrels of oil equivalent
BPS	Baltic Pipeline System
BTC	Baku-Tbilisi-Ceyhan (pipeline)
BTLs	Biomass-to-liquids
CCS	Carbon capture and storage
CFTC	Commodity Futures Trading Commission
CLSF	Carbon Sequestration Leadership Forum
CNG	Compressed natural gas
CNOOC	China National Offshore Oil Corporation
CNPC	China National Petroleum Corporation
CO_2	Carbon dioxide
CO_2-eq	Carbon dioxide equivalent
COP	Conference of the Parties
CTLs	Coal-to-liquids
DCCI	Downstream capital costs index
DCs	Developing countries
DOE/EIA	(US) Department of Energy/Energy Information Administration
dwt	Dead weight tonnes
EC	European Commission
ECAs	Emission control areas
EFQD	European Fuel Quality Directive
EIA	Energy Information Administration
EISA	(US) Energy Independence and Security Act
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency
EPRI	Electric Power Institute
ESPO	Eastern Siberia Pacific Ocean
EU	European Union
EU ETS	EU Emissions Trading Scheme

FAME	Fatty-acid methyl ester
FCC	Fluid catalytic cracking
FSU	Former Soviet Union
FYP	Five Year Plan
GCCSI	Global CCS Institute
GDP	Gross domestic product
GHG	Greenhouse gas
GSI	Global Subsidies Initiative
GTLs	Gas-to-liquids
GW	Gigawatt
IATA	International Air Transport Association
ICAO	International Civil Aviation Organization
ICE	Intercontinental Exchange
IEA	International Energy Agency
IEA GHG	International Energy Agency Greenhouse Gas Programme
IEF	International Energy Forum
IFO	Intermediate fuel oil
IFQC	International Fuel Quality Centre
IHS CERA	IHS Cambridge Energy Research Associates
IMF	International Monetary Fund
IMO	International Maritime Organization
IOCs	International oil companies
IPCC	Intergovernmental Panel on Climate Change
JODI	Joint Oil Data Initiative
JVETS	Japan's Voluntary Emissions Trading Scheme
KCTS	Kazakhstan Caspian Transportation System
KMG	KazMunayGas
kpg	Kilometres per hour
LCFS	Low Carbon Fuel Standard
LNG	Liquefied natural gas
LPG	Liquefied petroleum gas
MARPOL	International Convention for the Prevention of Pollution from Ships
mb/d	Million barrels per day
mboe	Million barrels of oil equivalent
mBtu	Million British thermal units

MDGs	Millennium Development Goals
MDO	Marine diesel
MEPC	Marine Environmental Protection Committee
METI	Ministry of Economy, Trade & Industry
MGO	Marine gasoil
MOMR	(OPEC's) Monthly Oil Market Report
mpg	Miles per gallon
MR1	General Purpose Vessels (16,500–24,999 dwt)
MR2	Medium Range Vessels (25,000–49,999 dwt)
MTBE	Methyl tetra-butyl ether
MW	Megawatt
NDRC	National Development and Reform Commission
NEI	Nuclear Energy Institute
NGLs	Natural gas liquids
NOCs	National oil companies
NOx	Nitrogen oxide
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
PM	Particulate matters
ppm	Parts per million
R&D	Research and development
RED	(EU) Renewable Energy Directive
R/P	Reserves-to-production
Sinopec	China Petrochemical Corporation
SOx	Sulphur oxide
TAN	Total acid number
Tcf	Trillion cubic feet
toe	Tons of oil equivalent
UN	United Nations

UNCTAD	United Nations Conference on Trade and Development
UNFCCC	United Nations Framework Convention on Climate Change
URR	Ultimately recoverable reserves
USGS	United States Geological Survey
WCSB	Western Canadian Sedimentary Basin
WHO	World Health Organization
WNA	World Nuclear Association
WOO	World Oil Outlook
WORLD	World Oil Refining Logistics Demand Model
WRFS	World Refining & Fuels Services
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
Libya
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
Georgia
Kazakhstan
Kyrgyzstan
Latvia
Lithuania
Malta
Moldova
Montenegro
Romania
Serbia
Slovenia
Tajikistan
The Former Yugoslav Republic of Macedonia

Turkmenistan
Ukraine
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
Libya
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

Airbus, Global Market Forecasts 2010

American Petroleum Institute

APICORP

Baker Hughes

Bank of International Settlements, Semiannual Over-The-Counter (OTC) Derivatives Markets Statistics, http://www.bis.org/statistics/derstats.htm

BP Statistical Review of World Energy

Central Banks' reports

C1 Energy Limited

Canadian Energy Research Institute

Cedigaz

Consensus forecasts

Direct Communications to the OPEC Secretariat

The Economist

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