Organization of the Petroleum Exporting Countries

World Oil Outlook

2012

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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.

Acknowledgements

Director, Research Division
Hasan M Qabazard

Head, Energy Studies Department
Oswaldo Tapia Solis

Senior Adviser
Mohamed Hamel

Contributors
Mohammad Taeb, Mehdi Asali, Odalis Lopez Gonzalez, Benny Lubiantara, Esam Al-Khalifa, Haidar Khadadeh, Taher Najah, Julio Arboleda Larrea, Elio Rodriguez Medina, Amal Alawami, Eissa Alzerma, Mehrzad Zamani, Mohamed El-Shahati, Nadir Guerer, Garry Brennand, Aziz Yahyai, Jan Ban, Joerg Spitzy, Ralf Vogel, Douglas Linton, Pantelis Christodoulides, James Griffin, Klaus Stoeger, Martin Tallett, Petr Steiner

Editors
James Griffin, Alvino-Mario Fantini

Senior Editing Assistant
Anne Rechbach

Secretarial support
Khedoudja Zeghdoud, Yi Wen Huang, Marie Brearley

Layout and typesetting
Alaa Al-Saigh, Andrea Birnbach

Additional support was provided by
Hojatollah Ghanimi Fard, Ulunma Agoawike, Puguh Irawan, Ramadan Janan, Kurt Zach, Hannes Windholz, Mouhamad Moudassir, Harvir Kalirai

OPEC's Economic Commission Board
Yamina Hamdi, Luís Neves, Diego Armijos-Hidalgo, Safar Ali Keramati, Adel Al-Taee,
Nawal Al-Fuzaia, Imad Ben Rajab, Suleman Ademola Raji, Sultan Al-Binali, Nasser Al-Dossary,
Hamdan Mubarak Al Akbari, Fadi Kabboul

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Foreword

Ongoing geopolitical tensions, continuing excessive speculation in oil markets, a fragile financial and banking system, an anaemic economic recovery despite the extraordinary fiscal and monetary support, persistent high unemployment and social unrest in a number of countries have all made 2012 a challenging year for oil producers and consumers everywhere.

The biggest hurdle facing the global oil market in 2012 remained the uncertainty surrounding the global economy. Risks stemming from the Euro-zone have heightened as a result of expanding public deficits, weakening economic growth, deleveraging in the banking system, as well as policy indecisiveness. The US appears more resilient, but its economic indicators throughout the year have been mixed. And in developing countries, economic growth is slowing, feeding concerns as to whether the difficulties in industrialized nations will spill over into their economies.

Looking ahead, it is thus important to remain vigilant. The uncertainties regarding the prospects for the world's major economies, as well as the potential adverse impacts of the enduring weaknesses of the international financial system, evidently constitute significant downside risk for oil markets. Yet, possible upside potential also exists and could have a sizable impact on oil prices and investment needs. The OPEC World Oil Outlook (WOO) aims to cover such a comprehensive view, in a balanced way.

This past year has also seen prolonged instability and tensions in a number of countries. These events, in turn, have impacted the oil market. There have been supply disruptions in South Sudan, Syria and Yemen. And, in addition, geopolitical-related problems have continued to impact parts of the Middle East and North Africa.

Volatility and excessive speculation were also present in 2012. Crude prices showed an upward trend during the first quarter of 2012, followed by a drop during the second quarter, before recovering in the third. These price fluctuations were a reflection of divergent factors, including global economic prospects, supply disruptions, refinery outages and other downstream bottlenecks, as well as geopolitical concerns.

It is recognized that speculative investment flows can, if excessive, contribute to a distortion of the price of crude, and detach it from the physical realities of supply and demand. It is essential to keep trying to mitigate price extremes. Important moves to address this issue are underway, and are covered in this WOO.

It should be stressed, however, that the oil market in 2012 has been well-supplied and there have been no shortages of oil. The market has been able to quickly adjust to unforeseen and sudden events. OPEC Member Countries have continued to invest in existing fields, in the development of new upstream capacity, the rehabilitation of older infrastructure, the laying of pipelines, and the construction and expansion of refineries, as well as oil terminals. These huge efforts demonstrate the commitment of OPEC Member Countries to satisfy the needs of consumers in a timely manner.

OPEC's focus remains on bringing stability to the market, given that oil is expected to satisfy the largest share of the world's energy needs for the foreseeable future. In this spirit, the WOO 2012 – the publication's sixth edition – consistently provides a detailed breakdown and analysis of the key issues that might shape the global energy future, particularly in relation to the oil market.

From a supply perspective, the world has more than enough oil resources to satisfy consumer demand for many decades. The US Geological Survey estimate of ultimately recoverable oil resources continues to be revised upward. It is now approaching four trillion barrels. Technological advances have improved the recovery from producing fields and extended the reach of the industry to explore and produce from frontier areas and new plays. Moreover, there remain many areas, both OPEC and non-OPEC, that still have not been explored. Technology has also helped deliver cleaner petroleum-fuels and reduced the environmental footprint of industry operations.

While there are clearly enough resources, many uncertainties remain, particularly in regard to how different challenges might impact oil demand in the short- and long-term. These challenges include the ongoing global economic situation and the possibility of more future liquids supply than has been projected. Thus, as in previous editions, the WOO 2012 evaluates various possible future scenarios to determine the potential impact of a number of these issues.

This year's WOO also examines, in more detail, the emergence of shale oil and gas. It is evident that this resource will contribute to the overall energy mix, but when looking outside of the US, shale resources remain in the early stages of development. A diversity of factors such as costs, water and well services availability, regulation, concerns over potential environmental impacts and energy prices, will shape the future of shale oil and gas.

The WOO echoes the concern about the worldwide shortage of skilled labour, which are absolutely essential for the future growth of the industry. And in the downstream, there persists the challenge of rationalizing the over-capacity, from which the industry still suffers, as well as the need to re-balance the diesel and gasoline mix, with the former expected to see the greater demand increase.

In terms of transportation – a key sector to global oil demand growth – the WOO considers several changing global trends. The growing numbers of automobile users in large emerging economies, such as China and India, is a significant source for future demand growth. However, there are also substantial uncertainties surrounding the potential impact of evolving energy and environmental policies, non-petroleum fuels, as well as new technologies, on this sector's projected demand patterns.

Another challenge facing the industry is climate change, with the forthcoming United Nations Climate Change Conference taking place in Doha later this year. It is important that these negotiations succeed in ensuring the full implementation of the United Nations Framework Convention on Climate Change, particularly in respect to its principles and provisions, including the principles of 'equity' and 'common but differentiated responsibilities', and that economic development and poverty eradication are the overriding priorities of developing countries.

Global environmental efforts also should not come at the cost of leaving people in developing countries trapped in energy poverty. As the Rio+20 Summit held in June this year fully acknowledged, energy poverty remains widespread, despite the efforts of many countries. It is, therefore, important for the world to increasingly work together to find sustainable solutions that do not impede the growth of developing countries, and which allow poor communities to earn an income – and, thus, escape the poverty trap.

Once again, the WOO 2012 illustrates OPEC's constantly-evolving analysis of the global oil market. It serves to provide interested readers with a wide variety of data, as well as the analysis that informs the OPEC Secretariat's work and which further reinforces the Organization's commitment to market stability.

Neither the WOO nor our Organization have ever tried to make predictions. But we always strive to make sure the industry has at its disposal an analytical consideration of the many varied challenges that producers face, and of the numerous factors that may come into play in the upstream and downstream sides of the industry.

Additionally, to complement our efforts, ensuring data transparency and working to maintain ongoing dialogue with other energy stakeholders is vital. OPEC has long recognized the importance of a cooperative approach to dialogue with all stakeholders aimed at fostering market stability in both the short- and long-term.

All of this serves to underscore the need for a prudent approach when offering insights into trends and possible future developments. In this context, we believe the WOO is an important reference tool – and we hope it makes a useful contribution to a better global understanding of the outlook for energy and oil.

Abdalla Salem El-Badri
Secretary General

Executive summary

This year's World Oil Outlook (WOO) demonstrates that oil will continue to play a major role in satisfying world energy needs. It also stresses the demand uncertainties that blur the future of oil in the medium- to long-term.

Five years after the onset of the financial crisis, and despite the extraordinary fiscal and monetary support, the economic recovery remains fragile, the risks stemming from the Euro-zone debt crisis appear to be heightening, economic growth in major developing countries is facing strong headwinds, and many financial institutions are under stress and in a deep process of deleveraging. World economic prospects are thus highly uncertain.

Policy and technology are affecting demand for oil, in particular the transportation sector. While oil resources are recognized as amply sufficient to satisfy future needs, shale gas and tight oil are changing future prospects in the long-term. The refining system needs to go through a profound rationalization and adaptation process, given the future product mix and more stringent quality specifications. The Durban United Nations Climate Change Conference in 2011 and the Rio+20 Summit in June 2012 launched important multilateral processes, the outcome of which, although still to be agreed, will be of great significance. Geopolitical tensions add another layer of uncertainty, when looking to the future.

The WOO calls for serious monitoring of future developments in the energy scene and to remain alert to various possible outcomes.

Oil price assumption slightly higher than in the previous WOO

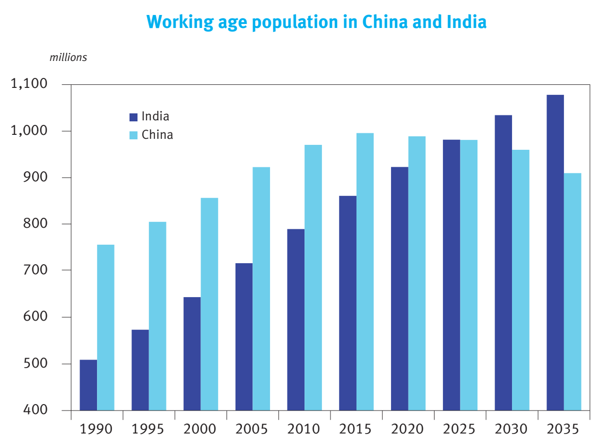
This year it is assumed that the OPEC Reference Basket (ORB) nominal price remains at an average of $100/b over the medium-term, before rising with inflation to reach $120/b by 2025. Longer term, real prices are set to rise slightly and nominal prices thereby reach $155/b by 2035. The key basis for making such assumptions for the Reference Case's medium- to long-term outlook remains the perception of how the costs of supplying the marginal barrel might evolve, as well as taking into account the effects of depletion, an increasing supply of oil from more remote and harsher environments, and the impacts of stricter environmental protection on costs. The extent, to which these costs rise, is tempered by the impacts of continued technological developments.

Short- and medium-term economic growth assumptions reflect Euro-zone crisis

Short-term economic growth rates see a downward adjustment compared to the WOO 2011. The estimate for the 2012 global economic growth rate is around 1% lower than assumed previously. OECD Europe gross domestic product (GDP) remains approximately flat in 2012, compared to the WOO 2011 expected growth rate of 1.9%. The impact of the Euro-zone crisis is expected to continue to be felt in Europe in 2013, which has led to an assumed growth rate of just 0.5% for OECD Europe in that year. The impact is also felt elsewhere. The European Union (EU) contributes to around a fifth of global GDP and is the most important trading partner to many large emerging economies, such as China. However, it is assumed that monetary and fiscal measures, accompanied by budget-deficit reduction measures, including austerity, as well as growth-inducing incentives, will help the Euro-zone to gradually improve its economic prospects and by 2015 return to more normal growth patterns, with positive impacts on the global stage.

Growing global population, but shrinking working-age strata in many countries

Demographics is a key driver for economic growth, as well as energy demand. It is important in terms of changes to the total number of people and in changing age structures, with the latter having significant implications for the size of the working-age population. Global population rises from 6.9 billion in 2010 to 8.6 billion in 2035. This increase comes predominantly from developing countries, which accounts for 92% of the rise. By 2022, India will have overtaken China to become the most populous country on the planet. And there is a significant shift occurring in age structures: while the past has seen labour forces consistently grow across all regions, this is now becoming a shrinking trend in many cases. This is a strong dynamic for economic growth potential. The Chinese working-age population, for example, is expected to start declining within three years. This contrasts with demographic trends in India, where higher birth rates feed into a steadily rising working-age population.



Long-term economic growth averages 3.4% per annum

Long-term economic growth rate assumptions reflect demographic trends, as well as progressively smaller rates of productivity improvement. Over the period 2012–2035, long-term economic growth rates average 3.4% per annum (p.a.). By 2035, the Chinese economy will be larger than any other country and even larger than entire regions within the OECD, such as America and Europe. India, which in 2010 accounted for 5% of global GDP, rises to 11% by 2035 and will then have a larger economy than the whole OECD Asia-Pacific region. Within ten years, India is expected to be growing faster than China, partly due to demographic trends that reduce the dependency rate and raise the savings ratio, thus supporting investment. The share of developing Asian countries in the world's economic activity rises in the Reference Case from 26% in 2010 to 43% by 2035. OECD regions will nevertheless continue to benefit from higher GDP per capita. Poverty, though retreating, unfortunately remains widespread in the developing world.

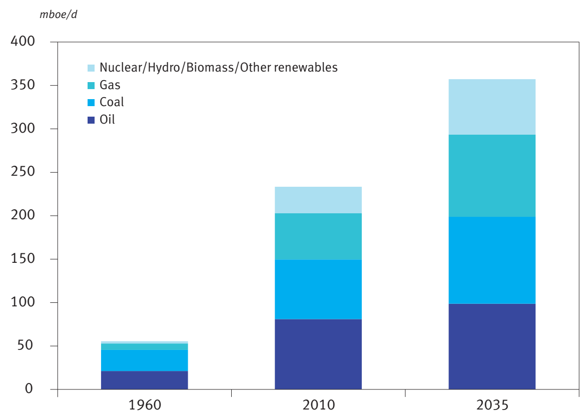
The Reference Case considers only current policies

The WOO has consistently presented a Reference Case based on policies already in place. Recent policies that have been factored in include the EU package of measures for climate change and renewable objectives, and the US Energy Independence and Security Act (EISA). The Reference Case does not, however, include effects from policies that are currently being proposed or that may be thought to be more likely in the longer term. This is left for scenario analysis.

Energy demand in the Reference Case increases by 54% over the period 2010–2035

Over the period 2010–2035, primary energy demand in the Reference Case increases by 54%. Fossil fuels, currently accounting for 87% of this, 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, towards the end of the projection period, coal use in the Reference Case reaches similar levels as that of oil, with oil's share having fallen from 35% in 2010 to 27% by 2035. Natural gas use will rise at faster rates than either coal or oil, both in percentage terms and quantities, with its share rising from 23% to 26%.

World supply of primary energy by fuel type



Shale gas has large potential, but mainly in the US for now

There is clearly potential for shale gas on the world energy scene. The main use of this gas in the foreseeable future will be to replace coal in electricity generation, and as a feedstock in the petrochemicals sector. However, shale gas development is in its infancy, and there are considerable uncertainties about the size of the resources, the economics of development and the potential contribution to future supply. Currently, shale gas production is coming primarily from North America (mainly the US).

Total shale gas production in the US jumped from 15 billion cubic feet a day (bcf/d) in 2010 to 25 bcf/d in 2012. Replicating the success of US shale gas development internationally requires addressing many key challenges including water shortages, a lack of infrastructure, higher population densities, a shortage of skilled labour and the NIMBY effect.

Substantial coal reserves, but prospects could be affected by carbon constraints

In terms of calorific value, there are more coal reserves than the sum of oil and gas reserves. At the end of 2010, the highest level of reserves by far was in the US, which, together with Russia, China, India and Australia, account for three-quarters of global reserves. Coal was the fastest growing fossil fuel over the last ten years. In addition to the health of the economy, its future prospects hinge on the competition from other sources of electricity generation, primarily gas and nuclear, as well as the stringency of future carbon emissions reduction policies, the price of carbon permits and energy security.

Fukushima impact on nuclear limited to some OECD countries

The current use of nuclear energy is dominated by OECD America, OECD Europe and Asia. The Fukushima accident continues to reverberate on Japan's energy map, with the closure of nuclear plants. By May 2012, Japan was without electricity from nuclear power for the first time in over four decades. Outside of Japan, several OECD countries, such as Germany, Switzerland and Italy, have decided not to replace retiring nuclear plants with new ones, reversing earlier plans. More stringent safety regulations are also likely to affect the future economics of nuclear power, but the consequences beyond the OECD appear to be negligible. Global nuclear energy expands in the Reference Case at an average rate of 1.7% p.a., with a share of 6% in 2035, similar to today.

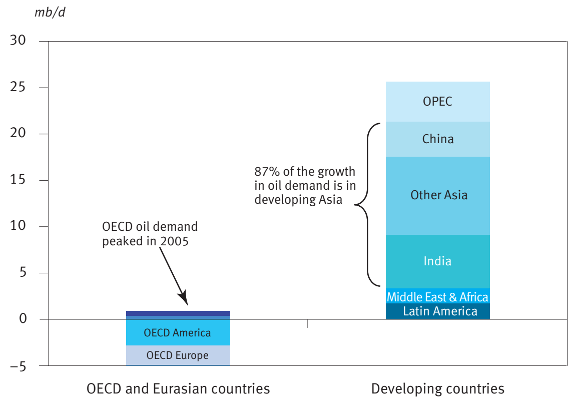
Medium-term oil demand projections revised downwards

Medium-term projections in earlier WOOs were revised downwards as the recession unravelled and GDP forecasts were amended down. The last two publications took into account the extraordinary monetary and fiscal stimulus that were put in place and considered a more positive view on how quickly a recovery would occur, leading to upward revisions in medium-term oil demand prospects. This year, however, there is growing concern about immediate prospects for economic growth, particularly in the Euro-zone. In this publication, 2012 demand is already 820,000 b/d lower than in the WOO 2011. The medium-term outlook for oil demand, therefore, reflects a corresponding revision from last year's publication. The Reference Case now foresees demand reaching 92.9 mb/d by 2016, a downward revision of over 1 mb/d compared to the WOO 2011. Over the period 2011–2016, OECD oil demand declines each year, having peaked in 2005. Around 70% of the medium-term increase of 5.1 mb/d comes from developing Asia.

Long-term to 2035, oil demand grows to 107.3 mb/d

Long-term oil demand prospects have not only been affected by the medium-term downward revisions, but by higher oil prices too. Additionally, the implications of technological developments and deployment, especially in the transportation sector, also contribute to some downward long-term revision. In the Reference Case, demand increases by over 20 mb/d for the period 2010–2035, reaching 107.3 mb/d by 2035. The long-term sees a steady decline in demand in all OECD regions. Fully 87% of the global demand increase is in developing Asia, where demand reaches 90% of that of the OECD by 2035. Global demand in 2035 is more than 2 mb/d lower than in the WOO 2011.

Growth in oil demand, 2010–2035



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

	2010	2015	2020	2025	2030	2035
OECD	46.8	45.8	45.2	44.0	42.6	41.1
Developing countries	35.4	40.8	46.3	51.3	56.0	60.6
Eurasia	4.8	5.2	5.4	5.5	5.6	5.6
World	87.0	91.8	96.9	100.9	104.2	107.3

Transportation sector is the main source of growth

Growth in oil demand since 1980 has been dominated by transportation use – mainly road transportation, but also aviation, internal waterways and international marine. Over the past three decades, the average annual growth in OECD and non-OECD countries has been very similar, each around 0.3 mboe/d. At the global level, transportation is expected to continue to dominate growth over the projected period. Nonetheless, this increase will come only from non-OECD countries, three-quarters of which stem from the transportation sector. In contrast to both OECD and Eurasian countries, developing countries also see a rise in oil use in other sectors (petrochemicals, residential/commercial/agriculture, other industrial uses). However, all regions will see the small amount of oil that is still used for electricity generation decline in the future.

Demand for OPEC crude stays essentially flat over the medium-term

Turning to supply, the medium-term Reference Case outlook sees growth in non-OPEC liquids supply over 2011–2016. It rises by over 4 mb/d, mainly from shale oil in the US, Canadian oil sands, and crude oil from the Caspian and Brazil. These compensate for expected declines elsewhere. For example, combined supply from OECD Europe and Mexico falls by close to 1 mb/d over this period. As with earlier Reference Cases, a rise in OPEC natural gas liquids (NGLs) is expected over the medium-term, increasing from 5.2 mb/d in 2011 to 6.4 mb/d in 2016. These supply projections, along with those already outlined for demand, imply that the amount of OPEC crude required over the medium-term will stay essentially flat. However, total OPEC liquids supply rises. OPEC crude oil spare capacity is expected to exceed 5 mb/d as early as 2013/14.

OPEC is investing heavily

Even in the face of uncertainties about future oil demand, OPEC Member Countries continue to invest heavily in exploration, development, refining and transport in order to maintain and expand supply capacities. According to the latest list of upstream projects in the OPEC Secretariat's database, Member Countries are undertaking or planning around 116 development projects during the five-year period 2012–2016. This corresponds to an estimated investment of about $270 billion, and demonstrates the scale of OPEC's portfolio of projects. It is estimated, given Reference Case assumptions and projections, as well as natural declines in existing fields, that total OPEC liquids capacity will rise by 5 mb/d over this period, although investment decisions and plans will obviously be influenced by various factors, such as the global economic situation, policies and the price of oil.

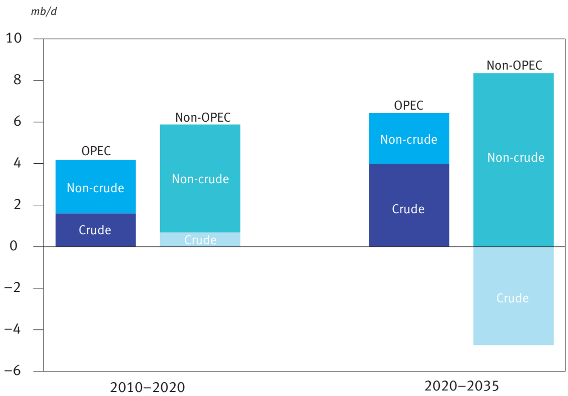
Large diversity of liquids supply sources over the long-term

A central result that emerges from the assessment of long-term liquids supply is that resources are plentiful, and the sources of supply are diverse. Total non-OPEC liquids supply in the long-term increases strongly, by more than 10 mb/d over these years: supply increases in crude and NGLs from the Caspian, Russia, Brazil and US shale oil, as

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

	2010	2015	2020	2025	2030	2035
OECD	20.0	21.8	22.6	23.3	24.1	24.9
Developing countries, excl. OPEC	16.9	17.8	19.2	19.3	19.1	19.3
Eurasia	13.4	13.9	14.3	14.7	15.1	15.5
Processing gains	2.1	2.4	2.6	2.7	2.9	3.0
Total non-OPEC	52.3	55.8	58.6	60.1	61.1	62.7
OPEC NGLs	4.9	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	29.6	30.9	32.5	33.8	34.9

Incremental OPEC and non-OPEC supply in the Reference Case



well as steady increases in biofuels and oil sands, are far stronger than declines elsewhere. Non-OPEC supply from Canadian oil sands and biofuels in the US, Europe and Brazil continues to grow strongly, by close to 11 mb/d. Global NGLs supply rises by close to 7 mb/d over these years. These developments mean that OPEC crude supply needs to rise in the Reference Case, but at a modest rate: by 2035, it would need to be just 35 mb/d, around 5 mb/d higher than in 2010. It means the share of OPEC crude in global liquids supply remains approximately constant, at around 32%, throughout the whole period.

Shale oil represents a large change to the supply picture

In previous WOO Reference Cases, no significant shale oil contribution to liquids supply was envisaged. This year a rise in the importance of shale oil is expected. However, it should be noted that future production is likely to be beset by several constraints and challenges, such as environmental concerns, questions over the availability of equipment and skilled labour, rising costs and steep well-production declines. Nevertheless, resource development is moving rapidly in the US and production has markedly increased: supply from Bakken, Eagle Ford and Niobrara in the US is already over 1 mb/d, and despite severe decline rates, emerging forecasts now see oil shale supply rising rapidly. In the Reference Case, an estimate of 2 mb/d and 3 mb/d for shale oil is assumed to emerge by 2020 and 2035, respectively. Lower growth after 2020 is justified by the fact that the best shale oil plays will be tapped first. Their contribution in the medium-term will continue to come only from North America. In the longer term, however, modest contributions might also come from other parts of the world.

Huge investments for additional net capacity, but not markedly different from past

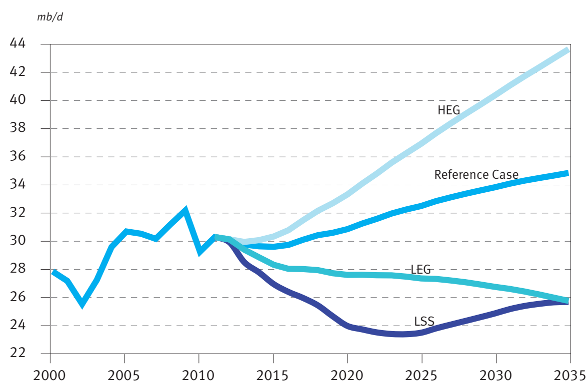
Over the period 2011–2035, upstream investment requirements for additional capacity amount to \$4.2 trillion in 2011 dollars. Much of the investment needed is to compensate for natural declines in fields that are currently producing oil. However, it should be noted this need compares to the performance of the oil industry in compensating for past declines. For example, over the period 1980–2011, a similar natural decline had to be compensated for – and it was.

Alternative scenarios stress major demand uncertainties for OPEC crude

The Reference Case outlook is not a forecast of how the future will evolve, but an internally consistent and feasible benchmark derived from a set of Reference Case assumptions and current policies. It is self-evident that different patterns of oil and energy demand and supply could emerge, with plausible alternative sets of assumptions.

Accordingly, scenarios have been developed for future OPEC crude oil demand. The first scenario, Lower Economic Growth (LEG), looks at the impact of lower economic growth, both in the medium-term, largely as a result of the on-going Euro-zone debt crisis and the Chinese growth slowdown, but also in the longer term. A second scenario, Higher Economic Growth (HEG), acknowledges that there is indeed upside potential for economic growth and explores what this could imply for OPEC oil. And the third scenario, Liquids Supply Surge (LSS), estimates the possible impact upon OPEC crude if the overall supply of liquids other than OPEC crude is higher than estimated in the Reference Case. The change in expectations relative to the Reference Case is startling in all three cases. On the one hand, they demonstrate genuine concern over security of demand; on the other, they underscore that circumstances could arise where considerably more OPEC crude oil will be needed than the Reference Case suggests. The two downside risk cases involve either a stagnant call on OPEC crude, or a falling one, while the HEG scenario sees substantially higher production levels. By 2035, the expectations for OPEC crude are very similar across the downside risk scenarios, at 25–26 mb/d, while the HEG scenario sees the need for OPEC crude at over 43 mb/d.

OPEC crude oil supply in the three scenarios



Naturally, the feasibility of the OPEC supply paths in the three scenarios needs to be questioned. The dramatic supply fall in the downside scenarios, as well as the rapid increase in the HEG scenario may not be sustainable. In which case, the behaviour of the drivers in these scenarios would point to alternative price paths to those assumed in the Reference Case. Hence, uncertainties over these key drivers are intrinsically linked to large uncertainties, both upside and downside, regarding future oil price developments. Close attention needs to be continually paid to all these elements in order to understand what pressures might be expected upon oil prices in the coming years.

Challenges exist also in the downstream, where transport fuels drive future demand structure

Gasoil/diesel is expected to witness the largest volume gain, increasing by more than 10 mb/d between 2011 and 2035, mainly due to the growing transport sector, including marine bunkers. However, on a percentage basis, naphtha is anticipated to be the fastest growing product in the long-term, especially in developing Asian countries. Another product witnessing demand expansion is gasoline, with demand increasing by almost 5 mb/d between 2011 and 2035. This, however, is less than half of the diesel/gasoil increase for the same period. Residual fuel oil is the only product that is set to decline globally in the coming years. Its use in industry, mainly for electricity generation and refineries, has faced competition from natural gas in most regions for decades, with the upshot being a demand drop. Moreover, this demand decline will accelerate due to the expected shift from fuel oil to diesel in marine bunkers stemming from International Maritime Organisation (IMO) regulations.

Global product demand, 2011–2035 *mb/d*

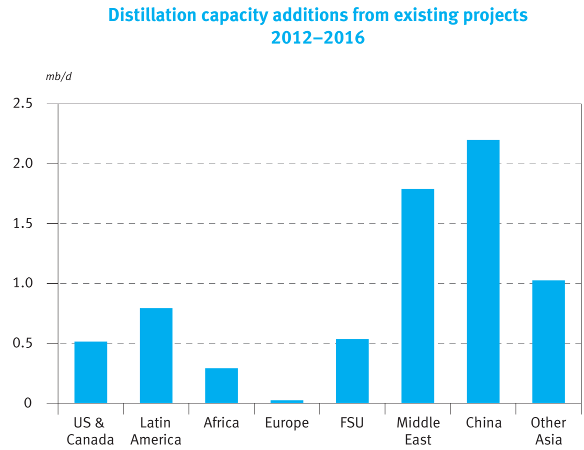
	2011	2016	2020	2025	2030	2035
Light products						
Ethane/LPG	9.2	9.8	10.2	10.5	10.8	11.0
Naphtha	6.0	6.5	7.1	7.7	8.3	8.8
Gasoline	21.5	22.5	23.4	24.5	25.3	26.1
Middle distillates						
Jet/Kerosene	6.5	6.8	7.1	7.5	7.7	8.0
Diesel/Gasoil	26.0	28.9	31.3	33.2	34.7	36.0
Heavy products						
Residual fuel*	8.8	8.2	7.5	7.0	6.7	6.3
Other**	9.8	10.2	10.2	10.4	10.7	11.0
Total	**87.8**	**92.9**	**96.9**	**100.9**	**104.2**	**107.3**

* *Includes refinery fuel oil.*

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

Shift of refining capacity to developing countries will accelerate

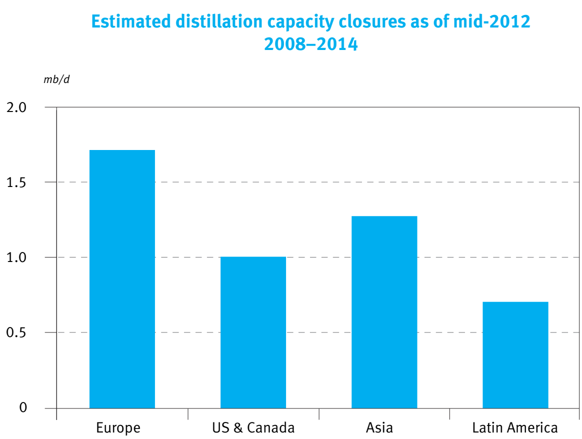
It is estimated that around 7.2 mb/d of new crude distillation capacity will be added to the global refining system from assessed projects in the period to 2016. Additions to global conversion units and desulphurization capacity are estimated to be almost 5 mb/d and more than 6 mb/d, respectively, over the same period. Most of the new capacity will be realized in Asia, mainly China and India, followed by the Middle East, Latin America and the Former Soviet Union (FSU).



By adding in the effect of capacity creep, crude distillation capacity increases 8 mb/d by 2016, from the 2011 base level.

Refinery closures offset part of the capacity increase from new projects…

The cascade of refinery closures indicated as inevitable in previous WOOs arrived in 2012. At the global level, closures have already reached 4 mb/d and are heading to the 5 mb/d mark, affecting not only small and simple plants, but large and fairly complex refineries too.

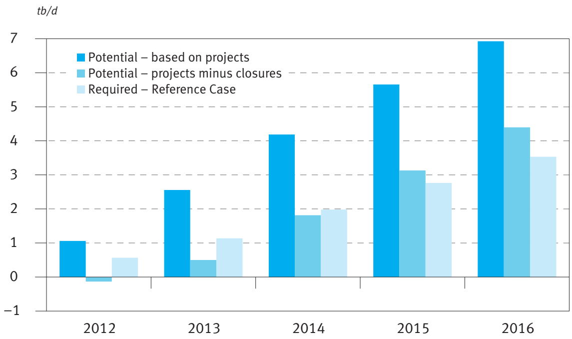


The largest proportion of closures – around 1.7 mb/d – has so far occurred in Europe. Developments in the Asia-Pacific are driven by Japan, where more than 0.8 mb/d of distillation capacity has already been closed, or is scheduled to be closed. The wave of closures has also hit the US & Canada, including refineries located in US territories in the Caribbean.

…but the net effect remains a growing capacity surplus unless more closures take place

There will likely be a marginal decline in potential crude runs in 2012 – compared to 2011 – as closed refineries during the year exceed newly built capacity. Set against required incremental crude runs for 2012 of 0.6 mb/d, this leads to a gap (deficit) of 0.7 mb/d, which will help to increase the average utilization rate for 2012, albeit

Additional cumulative refinery crude runs required and potential*



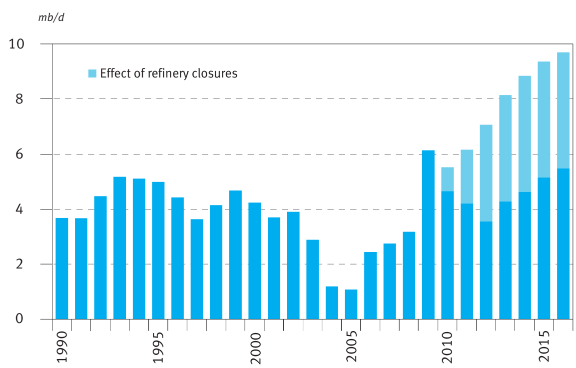
*Potential: based on expected capacity expansion and closures.
*Required: based on projected demand increases.

by less than 1%. In 2013, unless more refineries close than are currently on the list, the cumulative gap will be broadly maintained, before narrowing somewhat in 2014 and then emerging as a surplus only in 2015. In total, by the end of the medium-term horizon, the industry will continue to experience a capacity surplus, one that has been gradually building since 2009.

Further scope (and need) for more capacity rationalization

Refinery closures in 2011 and 2012 – primarily in OECD regions – reduced spare capacity levels below 4 mb/d, but unless more refineries are closed, new refining projects in developing countries should bring it back above 5 mb/d towards the end of the medium-term. This indicates that there is scope (and need) for more capacity rationalization to improve refinery utilizations and margins.

Global spare distillation capacity*, 1990–2016



*Equal to 85% distillation capacity less crude runs.

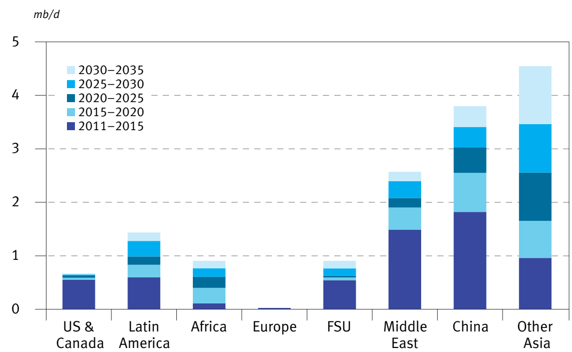
Current refining projects represent a substantial proportion of future capacity requirements

Cumulative total additions to crude distillation capacity are projected to reach 14.9 mb/d by 2035, compared to the 2011 base. Significantly, almost 50% of these additions are projected to be onstream by 2016. Therefore, the industry is witnessing a capacity surge in the short- to medium-term, which results in a much slower rate of additions being needed thereafter, through to 2035.

In terms of the regional breakdown, the vast majority of the refining capacity expansions to 2035 are projected for the Asia-Pacific and the Middle East, with 8.3 and

2.6 mb/d, respectively. In the period to 2015, capacity additions in China are almost double those in 'Other Asia'. Beyond the medium-term, however, capacity additions in China will gradually slow, while Other Asia, mainly India, will retain momentum and expand by around 1 mb/d in every five-year period. Capacity additions in Latin America are seen at 1.4 mb/d, and both the FSU and Africa are projected to rise by around 1 mb/d by 2035.

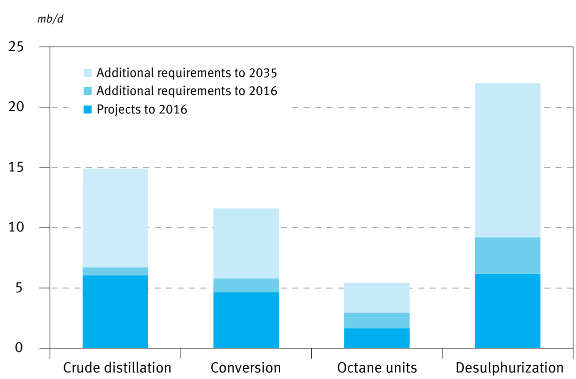
Crude distillation capacity additions in the Reference Case 2011–2035



Refining sector set to increase its complexity

In the entire forecast period to 2035, total conversion additions of 11.6 mb/d represent 85% of the distillation capacity additions. This sustained high ratio reflects the requirement to increase light products yields, as well as the continuing need to build hydro-cracking (almost 8 mb/d) to produce incremental distillate. Recent and current substantial coking capacity additions, together with the limited export supply of heavy sour crudes in the medium-term, are leading to a coking surplus.

Global capacity requirements bry process type 2011–20235



It is estimated that 22 mb/d of additional desulphurization capacity will be required globally by 2035. The drive to continued tighter fuels sulphur standards will lead to desulphurization comprising the largest volume of capacity additions to 2035, nearly 1.5 times those for distillation.

Future oil movements increasingly heading east

Inter-regional trade of crude and liquid products increases by around 14 mb/d to a level of 73 mb/d by 2035, from 59 mb/d in 2011.

In the medium-term, the key factor is refining capacity expansion, primarily in the Middle East and Latin America, which will make more products available for export. This is supported by developments in the US & Canada region, with its declining demand and growing supply. The net result is a higher volume of product exports, with a relatively stagnant crude oil trade.

In the long-term, growth in product exports will slow, as regional refining capacity is projected to grow more proportionally with regional demand after 2016. The majority of the oil export increase will be directed towards expanding Asian markets.

Projected trade movements also emphasize the growing importance of the Middle East as the key crude exporting region in the decades ahead. Indeed, after a decline between 2011 and 2015, and then a minor increase between 2015 and 2020 (although, increased products exports partially compensate for a reduction in the first period and result in higher oil exports in the second period), crude oil exports from this region are set to grow by around 1 mb/d every five years, reaching almost 20 mb/d by 2035, compared to 17 mb/d in 2011.

Oil-related investments between 2011 and 2035 estimated in the range of $6 to $7 trillion

In the period to 2035, global refining investments are estimated to be around $1.3 trillion, out of which $230 billion will be needed for existing projects, $300 billion for required additions and around $750 billion for maintenance and replacement. The key components of the additional investments needed beyond the refinery gate – typically referred to as the midstream sector – relate to the necessary expansions in regional pipeline systems and tanker capacity that are required to move volumes of crude oil and liquid products. In addition to this, some investments will be necessary for loading and receiving ports, related storage capacity, and to expand the retail distribution network. Combined, midstream investment costs for the period to 2035 are estimated to be close to $1 trillion.

Adding in upstream investment needs results in an estimated oil-related investment requirement in the Reference Case of somewhere in the range of $6 to $7 trillion, between 2011 and 2035.

Human resource shortage remains a potential constraint

With the oil industry continuing to expand, and the need to increasingly tap into resources in more frontier and challenging areas, the industry needs more skilled people. For a number of years, however, it has increasingly been observed that there is a shortage of human resources entering the industry. The issue can be traced back to the 1980s and 1990s when large scale downsizing led to a lack of recruitment into the energy sector. At that time many universities also cut back drastically on the number of people taking energy disciplines. Pressures on the industry's technical workforce now appear to threaten the timely completion of projects. The key is making the industry more appealing; to make it accepted as an inclusive and forward looking workplace. The industry needs to be sure it is well presented as a prime employment choice; a high-tech and diverse sector with great prospects. It is important for the industry to be significantly involved in fostering and supporting new graduates and its potential workforce at an early stage. The focus is on further developing a better relationship between prospective employees, universities and the industry. This includes making sure that energy-related courses are open to all students from across the world, as well as furthering cooperation between universities across the globe, in terms of helping to facilitate the transfer of technologies and know-how. Moreover, it is also essential to underscore the issue of local content and the utilization of domestic companies.

Energy poverty alleviation is paramount

The large extent of energy poverty across the developing world is a challenge that requires international cooperation. The core issue is making energy services available to those who are identified as energy-poor. While access to electricity for lighting has been identified as a priority, sustaining access to this and providing other similar services in the long-term are matters that underscore the need to empower the poor to be able to earn an adequate and sustainable level of income so that they may pay for such services in the long-term. Thus, the successful eradication of energy poverty in the long-term must rely on creating employment and income generating opportunities. In this context, an important area for international cooperation is assisting the poor in transforming subsistence agriculture into income-generating agriculture. This requires that attention be given to two areas: shifting toward more productive mechanized agriculture and facilitating access to international markets for agricultural products by removing agricultural subsidies in developed countries that hinder such market access. In this context, the eventual conclusion of the Doha Round of trade negotiations, which may include the removal of such agricultural subsidies in developed countries, could be one important step in supporting multilateral efforts to provide income generating opportunities for the poor and enable them to benefit from expanded energy services.

Importance of dialogue and cooperation will continue to grow

In an increasingly globalized and interdependent world, dialogue and cooperation is becoming ever more crucial. Closer stakeholder engagement at various levels is conducive to better understanding each other's viewpoints, developing common understandings, building confidence and finding the right balance in handling the uncertainties and challenges before the industry in a manner that takes into account the interests of all. Throughout 2012, OPEC has been actively involved in a number of dialogues, including the global producer-consumer dialogue, under the auspices of the International Energy Forum (IEF), the EU-OPEC Energy dialogue, the OPEC-Russia Energy dialogue, as well as working with other international institutions, such as the International Energy Agency (IEA), the International Monetary Fund, the World Bank, the Gas Exporting Countries Forum and the G-20, in terms of energy-related issues. In Kuwait, in March 2012, the 13th IEF Ministerial Meeting took place. OPEC, which has been active in this dialogue since its inception, collaborates closely with the IEF on a number of issues. In 2012, OPEC continued to cooperate with the IEF on the IEA-IEF-OPEC dialogue, G-20 energy-related issues and the Joint Organisations Data Initiative. The latter has proved to be an effective vehicle for improving energy data transparency at the global level. In February 2012, the IEA and OPEC also held a joint workshop in Kuwait on CO_2-enhanced oil recovery with carbon capture and storage. All of this demonstrates how OPEC has long recognized the importance of a cooperative approach to dialogue aimed at fostering market stability in both the short- and long-term. It is essential that the industry continues to evolve, and looks to expand cooperation, as and when appropriate, in the years ahead.

Section One

Oil supply and demand outlook to 2035

Chapter 1

World oil trends: overview of the Reference Case

Section One of this Outlook, prepared using OPEC's World Energy Model (OWEM), develops projections for medium- and long-term energy supply and demand to 2035. It is complemented by downstream analysis, based on the World Oil Refining Logistics and Demand (WORLD) model, in Section Two.

The changing dynamics of the global energy scene are continually monitored and assessed at the OPEC Secretariat, and feed into this annual publication. Developments in the global economy and policy announcements are considered, as are key drivers and potential technological patterns that may emerge. It will be seen that major uncertainties lie ahead.

Country groupings have been redefined in this year's World Oil Outlook (WOO) compared to 2011. India is now analyzed as a separate country (previously it was part of a region termed 'South Asia', which included, *inter alia*, Bangladesh, Pakistan and Sri Lanka); a new region, 'Other Asia', includes other countries previously in South Asia, as well as what was previously termed 'Southeast Asia'; different OECD regions now incorporate the new members that have joined that organization in recent years, accordingly, OECD regions have been renamed 'OECD America', 'OECD Europe' and 'OECD Asia Oceania'; and the expression 'Transition Economies' has been replaced with the term 'Eurasia'.

After presenting an overview of the Reference Case in this Chapter, the following Chapter looks at sectoral demand prospects, while Chapter 3 considers the supply outlook in detail. Chapter 4 concentrates on various upstream challenges, particularly, the uncertainties that pervade the Outlook under a number of scenarios. These uncertainties relate to future oil supply and demand but also to oil prices. It will be seen that they lead to a genuine concern over security of demand, which is far more tangible than security of supply.

Main assumptions

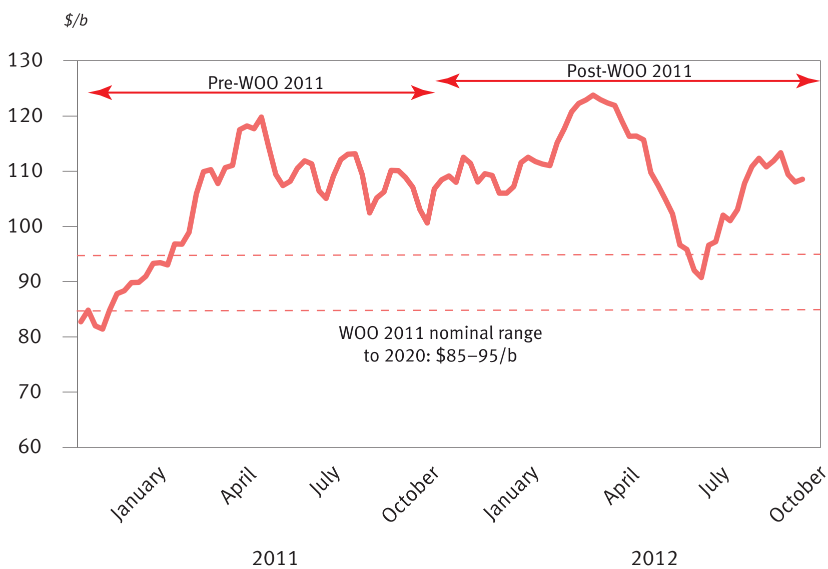
Oil price

For the WOO 2011, published in November 2011, the assumption for the OPEC Reference Basket (ORB)[1] price, in nominal terms, was to remain in the range

$85–95/b to 2020, rising thereafter to $133/b by 2035. This assumption was consistent with a real price of $80/b in 2010 prices. This represented an upward revision of around $10/b compared to the previous year's report, and was made in the midst of considerable turbulence in prices: between late November 2010 and the end of April 2011, the ORB rose from $81/b to almost $120/b before declining to $103/b by the beginning of August 2011 (Figure 1.1).

The reasons for the oil market being in a constant state of flux in 2011 were manifold: the ups and downs of the global economic recovery, Japan's multiple disasters, and unrest in parts of North Africa and the Middle East. But speculation remained a major driving force in the price rise, with increasing investor interest in the crude oil paper market. Speculative activities persist as an issue in the current market. This can be seen in the respective size of the paper and physical markets. Since 2005, there has been a sharp increase in the number of open interest futures and options contracts. At times, it has surpassed three million contracts per day, which is equivalent to 3 billion b/d. This is 35 times the size of actual world oil demand. Box 1.1, which explores this subject in detail, shows how current moves to tighten regulation in the paper markets clearly reflect the concern over the impact that speculation can have on market stability.

Figure 1.1
OPEC Reference Basket price before and after WOO 2011



Box 1.1
Regulatory reform: swap derivatives market beginning to take shape

Since the emergence of oil as an asset class in 2005, speculative activities on the financial markets have become a key factor behind the increased volatility of crude oil prices. The resulting influence of excessive speculation has, at times, decoupled price movements from fundamentals and thus sent confusing signals to the market.

Policymakers at the highest levels have recognized the need for oversight and regulation in the financial derivatives markets. This includes the organized futures exchanges, such as the New York Mercantile Exchange (Nymex) and the Intercontinental Exchange (ICE), as well as the over-the-counter (OTC) derivatives markets.

The previously unregulated OTC derivative market is receiving particular attention. The OTC market is massive and includes not only commodity derivatives, but also foreign exchange, interest rate and equity-linked derivatives, as well as credit default swaps. At end-2011, the total amounts outstanding amounted to \$648 trillion.[2] Oil-based derivatives represent only a tiny fraction of the overall OTC market – less than 1% in terms of outstanding amounts. However, relative to the crude futures market, the swaps market for oil is considerably larger.

As in other commodity markets, swaps are used in the crude oil market to hedge against price risk. The buyer of the crude swap contract typically pays to guarantee a fixed price for either the buying or selling of crude, while the seller of the contract assumes exposure to the future price risk at the expiration of the contract by agreeing to make up the eventual difference, if any. If, however, the market moves in the other direction, the seller keeps both the resulting profits and the fee for writing the contract.

There are two distinct yet interrelated sets of drivers behind on-going efforts to strengthen regulation and oversight in the financial markets. The first are regulatory initiatives to address commodity price volatility, particularly high oil prices. The second are initiatives aimed at addressing the considerable shortcomings of the existing regulatory framework as revealed by the 2007/2008 financial crisis.

Before 2006, regulators had almost no information about activities on the swap derivatives market. Data from the Bank of International Settlements was of limited use as it was only provided twice-yearly and with a considerable time lag. It also had little disaggregation.

During the 2007/2008 oil price spike, it became clear to policymakers that in order to understand the factors driving oil prices, it was necessary to know what was going on in the swap derivatives market. Regulators were also concerned that the lack of oversight in the swaps market could allow market manipulation and a distortion of the price discovery process. This led to a push on the commodity side for improved transparency and oversight.

On the financial side, the risks associated with widespread ignorance about swaps activities were even more dramatically illustrated during the financial crisis with the near-bankruptcy of insurance giant AIG. A division of the company had been a major seller of credit default swaps in the OTC market. When the downturn in the US housing market led to widespread defaults, the insurer's collateral obligations and debt losses mounted, and the US government was forced to step in with a massive $182 billion taxpayer-funded bail-out to prevent AIG's collapse. Therefore, another central driver behind efforts to regulate the swaps market is to prevent a repeat of a systemic, AIG-like event.

At their Pittsburgh Summit in 2009, the G-20 industrialized and emerging economies committed to implement reforms in the OTC derivatives markets. The Pittsburgh Communiqué[3] states that "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." G-20 leaders further agreed that all OTC derivative contracts would be reported to trade repositories, which would allow the data to be made available to regulators for oversight, as well as released in aggregate form to the general public, similar to the existing reports on trader's activities issued by the US Commodity Futures Trading Commission (CFTC).

In response to these commitments, regulators in the world's derivatives trading centres have been busy establishing the necessary rules and guidelines to facilitate the shift in swaps trading from private, bilaterally-negotiated deals to standardized agreements executed on electronic platforms, with established clearing houses and trade repositories.

Extending regulation and oversight to the swaps market is likely to impact the commodity markets in two ways: enhancing transparency and increasing costs for speculative activity.

With regard to transparency, for the first time, regulators will have detailed data on the activities of financial firms in the swap derivatives market for oil. For example, the large financial firms active in swaps trading will be required to maintain a daily record of swaps, as well as a complete audit trail, to allow for a reconstruction of any trades. Such data will give regulators the necessary tools to pursue cases of suspected market manipulation. Moreover, since it is planned that some of this data will be published in 'commitment of trading' reports similar to those published for the futures exchanges, the market as a whole will have a more complete picture of swaps activities in the oil market and, thus, a better understanding of the factors driving crude oil prices.

In terms of speculative costs, increased capital and margin requirements will make speculative activities more expensive. In addition to other costs associated with investing in commodity markets, this could diminish some of the attractiveness of commodities as an asset class (relative to other asset classes) and it could thereby dampen some speculative inflows. Some critics of the new regulatory push warn that this would lead to lower liquidity and therefore unintentionally push up hedging costs.

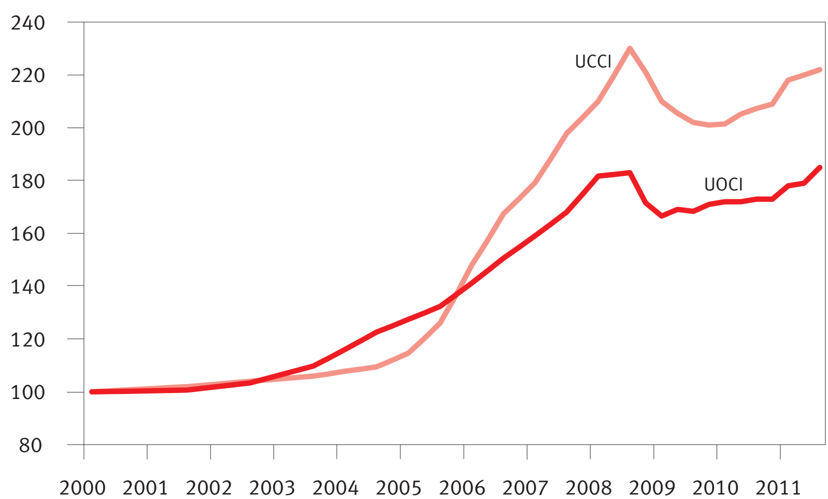
It bears remembering that the development of a spot market for crude oil and products historically led to increased volatility. This, in turn, increased the need for financial instruments to hedge against the resulting price risk. Combined with financial deregulation and the emergence of oil as an asset class, the sharp increase in investment flows into commodity derivatives markets further exacerbated oil price volatility.

The current push to strengthen the regulation and oversight of the paper markets is, therefore, a clear recognition of the harmful impact that excessive speculation can have on stability in the commodity markets, including oil. Regulators are working at both national and international levels to put these new rules in place by the end of 2012. However, given the evolving developments in investment flows, regulation and the continued role of oil as an asset class, the impact of financial markets on the oil price is likely to remain a key uncertainty in the years ahead.

However, the key basis for making assumptions for the Reference Case's medium- to long-term outlook remains the perception of how the costs of supplying the marginal barrel might evolve. Costs had initially fallen during the second half of 2008 as what has become termed 'the Great Recession' took hold and bottomed out towards the end of 2009. However, both capital and operating costs have since started to rise once more as oil supply activity has picked up following the recovery from the recession (Figure 1.2).

These cost developments lie behind earlier upward revisions in oil price assumptions. The continuation of the rise suggests that a revision to these assumptions is again warranted. However, the current revision also focuses on sustainability issues, taking into account the possible longer term responsiveness of oil supply and demand to prices. The Reference Case oil price assumption has indeed been revised to be consistent with cost perceptions, yet without portraying either an exaggerated escalation of future costs or assuming minimal price responsiveness of supply and demand. The assumption is that the nominal ORB price remains at an average of $100/b over the medium-term, before rising with inflation to reach $120/b by 2025. Longer term real prices rise slightly to reflect the effects of depletion, as well as increasing dependence on oil from harsher environments, the impacts of environmental protection on costs, and rising competition for capital and human resources. The extent to which these costs rise is tempered by the effect of continued technological developments. In real terms, this means that the ORB eventually reaches $95/b at today's prices by 2035. The ORB price typically lies somewhat below dated Brent (on average around $4/b higher than the ORB in 2011). Comparisons with the WTI price are, at present, misleading: while WTI traditionally has held a premium over Brent, growing production in the land-locked US mid-continent from shale oils and the increasing inflows from Canadian pooled oil in the US Midwest has created a glut and depressed the price of the US benchmark. Over 2011, the average WTI price was more than $12/b below the ORB. (The emergence of, and prospects for, these differentials is explored further in Section Two.)

Figure 1.2
IHS CERA upstream capital and operating cost indices (UCCI and UOCI), 2000=100



Source: IHS CERA.

Medium-term economic growth

This WOO incorporates a downward adjustment to short-term economic growth rates compared to the WOO 2011. For 2012, the Euro-zone crisis has forced a major downward revision for OECD Europe, which is now expected to remain approximately flat in 2012, compared to the former expected growth rate of 1.9%. Downward revisions have also occurred elsewhere. These revisions lead to an assumed global growth rate for 2012 of just 3.3%, down 0.8% from the previous year's publication. Global growth in 2011 also sees downward revisions compared to the figures used in the WOO 2011, particularly for OECD America. The net result is that the estimated growth rate for the global economy in 2012 is around 1% lower than assumed in the WOO 2011. As can be seen later in this Chapter, this translates into lower baseline oil demand estimates, upon which the medium-term and long-term projections are based.

The medium-term economic growth rates appear in Table 1.1 and are not significantly changed from WOO 2011 assumptions, although the figures have been revised in three specific cases:

1. The impact of the Euro-zone crisis is expected to continue to be felt in Europe in 2013, which has led to an assumed growth rate of just 0.5% for OECD Europe in that year. (The implications of the Euro-zone debt crisis are further explored in Box 1.2.);
2. The forecast for the growth rate of India over the medium-term has been increased. This reflects the difference in historical growth rates between India and the South Asia grouping that had been used formerly; and a reassessment of the impact of demographics and factor productivity; and
3. Estimates of Russia's medium-term growth rates have also been slightly raised, reflecting in part that concerns over economic growth have replaced worries over inflation, the fact that Russia is now a member of the World Trade Organization (WTO), and the potential impacts from higher oil prices assumed in this Reference Case.

In the medium-term, over the 2013–2016 period, average global growth is therefore expected to average 3.6% per annum (p.a.).

The WOO 2011 paid close attention to the extent to which China's 12th Five Year Plan (FYP) should be factored into assumptions. It should be recalled that the Plan includes a reduced target for China's GDP growth rate, down to 7% p.a., compared to 7.5% in the previous Plan. It was noted that earlier targets, such as the 7.5% example of the 11th FYP, were considerably below what actually transpired (with Chinese growth averaging 10.2% p.a. between 2006 and 2011). The Reference Case

Table 1.1
Real GDP growth assumptions in the medium-term

% p.a.

	2013	2014	2015	2016
OECD America	2.1	2.3	2.4	2.5
OECD Europe	0.5	1.2	1.6	1.8
OECD Asia Oceania	1.8	1.8	1.8	1.8
OECD	**1.4**	**1.8**	**2.0**	**2.1**
Latin America	3.3	3.5	3.5	3.5
Middle East & Africa	2.7	3.4	3.4	3.4
India	6.6	6.8	6.8	6.8
China	8.0	8.0	8.0	7.9
Other Asia	4.0	3.9	3.9	3.9
OPEC	3.9	3.9	3.9	3.6
Developing countries	**5.6**	**5.7**	**5.7**	**5.7**
Russia	3.4	3.6	3.6	3.5
Other Eurasia	2.7	3.1	3.1	3.0
Eurasia	**3.1**	**3.4**	**3.4**	**3.3**
World	**3.2**	**3.5**	**3.7**	**3.8**

Box 1.2
The Euro-zone debt crisis: one year after the 2011 Greece bailout

The past year has again been a turbulent period for the Euro-zone. After the governmental changes in Italy and Greece at the end of 2011, the single currency zone has had to establish a framework for greater integration and go through several key-elections and votes on the newly established support mechanism; the European Central Bank (ECB) has had to continue providing support to the financial system at unprecedented levels; and ailing Euro-zone economies have had to manage the difficulties of severe short-term austerity measures, including deep budgetary cuts, while at the same time find ways to stimulate growth again in the medium-term.

Moreover, the EU, together with its Euro-zone member states, have started discussions, which yet have to be finalized, on significant steps designed to move the economic region towards closer integration. This issue has increasingly come to the fore given the increasing economic worries surrounding Italy and Spain. While Greece constitutes only around 3% of the Euro-zone's Gross

Domestic Product (GDP), Italy and Spain combine for almost 30%, and globally close to 5%.

Two major institutional initiatives can be viewed as important in preventing a further deterioration of the crisis.

Firstly, a proposal for a tighter integrative approach, including more burden sharing, was delivered by the European Council in June. This blueprint for EU integration relies on four major building blocks: financial integration, budgetary integration, economic integration, and democratic accountability and legitimacy. It has been acknowledged, however, that this integrative approach would require modifications to the EU's founding treaties and that full implementation of this approach would require a timeframe of around 10 years.

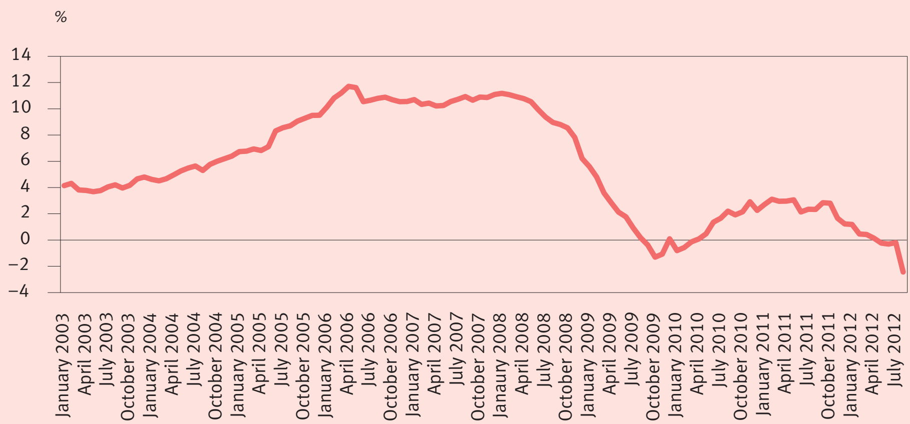
A more specific and time-bound roadmap for achieving a genuine economic and monetary union is currently in the works by the European Council. While the agenda put in place improved the sentiment of sovereign debt investors to some degree, it is still at the very beginning of its implementation. This agenda is a prerequisite towards a sounder and deeper economic integration of the still heterogeneous Euro-zone structure. However, a major challenge could be garnering broader political support as these changes will require referenda in several Euro-zone economies. Eurosceptic movements have gained some momentum in 2012, which could potentially put the project at risk. As a major focus and building block of the blueprint, it has been acknowledged by the European Council that greater democratic legitimacy and accountability is required to win a broad consent for decisions that are being deployed from Brussels to Member States.

The four building blocks of the political integration for the EU are designed to create a banking union with a centralized banking supervision, including a deposit guarantee scheme (financial integration); common decision making on national budgets (budgetary integration), with the ultimate goal of introducing Euro-bonds and a common treasury; a coordinated economic policy (economic integration); and advancing the involvement of member states in decision making at the supranational level (democratic accountability and legitimacy).

The launch of the European Stability Mechanism (ESM) in October 2012 constitutes a significant step towards this integrative approach, with the ESM set to act as a fiscal back-stop and deposit guarantee authority. The ESM will replace the European Financial Stability Facility (EFSF) by 2014, when the ESM is expected to have reached its total funding capability. The EFSF will continue to provide an additional €240 billion in the intervening period.

The second major institutional development has seen the ECB move its focus away somewhat from its primary mandate of keeping price stability, to providing monetary resources to a strained financial system. This was made obvious, when it injected more than a trillion euros in two extraordinary supply operations, called long-term refinancing operations, at the end of 2011 and again at the beginning of 2012. This focus on supporting the financial system most recently culminated in the ECB's announcement of conditional, but unlimited buying of sovereign debt from ailing economies in its newly created outright monetary transaction programme.

Figure 1
Monetary financial institution lending to private sector, year-on-year growth

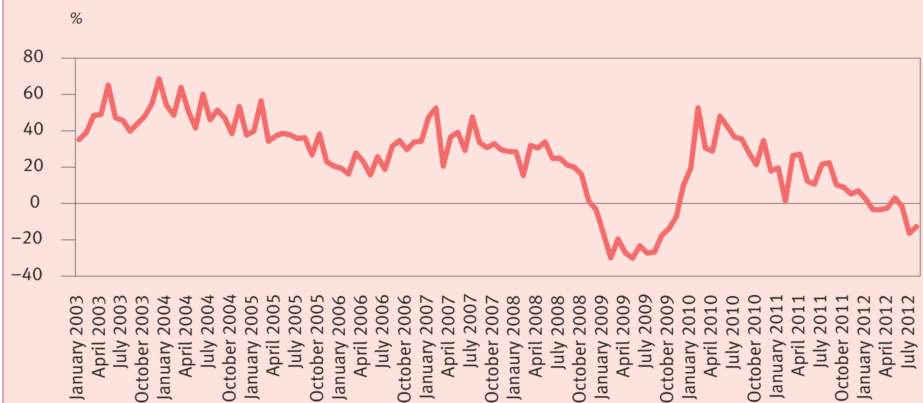


Source: Haver Analytics.

This structural shift has been requested by many of the ECB's stakeholders as the ultimate backstop for avoiding major disruptions in the Euro-zone's financial system, as well as an important addition to the fiscal support mechanism to help refinance ailing economies. This also shifts the monetary system of the Euro-zone more towards a scheme of burden-sharing. Germany's Bundesbank has openly dissented with this shift, however, and it is expected to cause further debates about the purpose of the ECB and its legitimacy for bailing out member states. Thus, it remains to be seen whether this policy shift will continue over the coming years, or if it is scaled back and the focus is placed on inflation fighting again.

The Euro-zone's economic health, and the wider EU, is vital to the global economy, given that it provides around a fifth of global GDP. It is also the most

Figure 2
Exports from China to the European Union, year-on-year growth



Source: *Haver Analytics.*

important trading partner to many developing and emerging market economies, such as China, although exports from China to Europe fell overall in the first half of 2012 (Figure 2).

The Euro-zone's problems are evidently having a knock-on impact elsewhere. It is the second most important global reserve currency, therefore, any shift in its economy and financial system, in real terms, or even only perceived by investors, will be felt at the global level. With capacity utilization at below 80%, an unemployment rate of more than 11% and unprecedented financial support from the ECB, the Euro-zone's unused capacity has never been so large.

By unlocking these currently unused resources, continuing to provide the necessary financial support via its monetary system to resolve the current debt issues and having growth policies as a priority for the economy, the Euro-zone would not only be able to gradually reduce its debt burden, but also support future economic growth at home, and on the global stage.

assumption amounts to an easing of Chinese growth, with an average of 8.2% growth over the 2011–2016 period. This reflects the notion that a 'cooling' of the economy is a serious policy objective and that the Plan's structural targets emphasize quality of growth versus quantity; but it also reflects the low likelihood that has been given to actually reaching the 7% target.

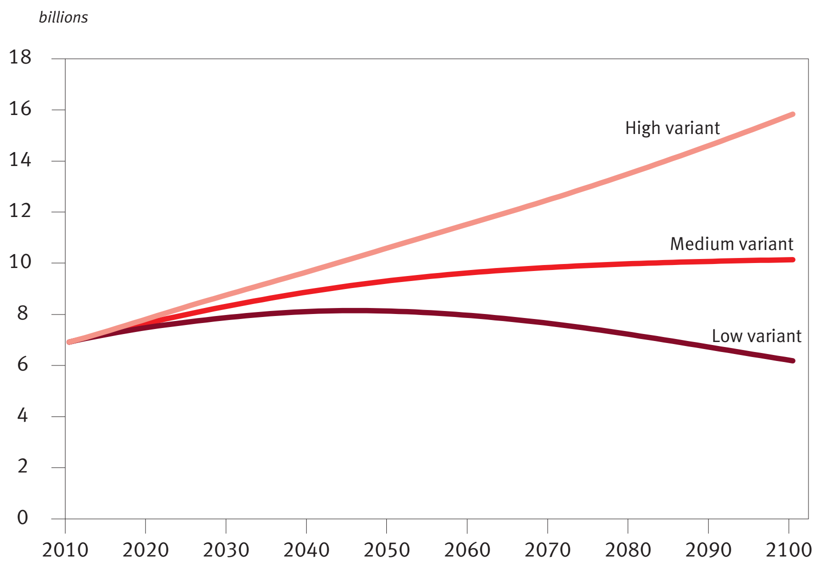
Long-term economic growth

Demographics

Population dynamics are a key element in making long-term energy projections. They affect the potential for economic growth, both in terms of the changes in the total number of people in the world and in terms of changing age structures, since this also has significant implications for the size of the working age population – and thus the potential size of the labour force. Population dynamics clearly also have a direct impact on the prospects for energy demand growth.

The United Nations (UN) is the key source for world population prospects. The 2010 revisions to these estimates, released in 2011, have been used in developing the current OPEC Reference Case.[4] This latest revision is the first to extend projections to the year 2100, instead of to 2050. It relies on national population censuses, specialized surveys, and an assessment of trends at global, regional and national levels. Central to these projections are future fertility patterns. The UN develops a 'medium variant' in

Figure 1.3
Population of the world in three variants



Source: 'World Population Prospects: The 2010 Revision', Department of Economic and Social Affairs of the United Nations Secretariat, Population Division.

which average global fertility declines from 2.5 children per woman in 2005–2010 to just under 2.2 per woman by 2050. It is this variant that is used in the Reference Case projections. The UN also develops 'high' and 'low' variants which have substantial impacts on future population prospects.

Figure 1.3 portrays the projected global population over the period to 2100. While this is well beyond the projection period of the Reference Case, it serves to demonstrate the uncertainties surrounding future population levels. By the end of the UN projections, the low variant sees a world population that actually declines to 6.2 billion while the high variant foresees an increase to close to 16 billion by 2100. Even by 2035, the high variant sees a world population that is 15% higher than in the low variant.

The question to ask is: how significant is this uncertainty for the oil outlook? At one level, the impact is minor. Most of the people of driving licence age have already

Table 1.2
Population levels and growth, 2010–2035

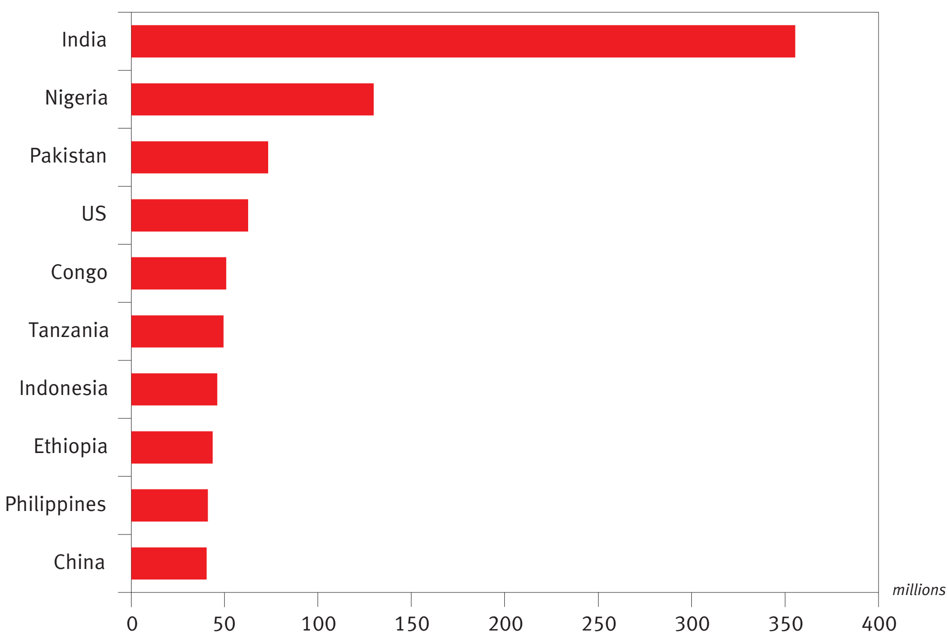
	Levels *millions*		Growth *millions*	Growth *% p.a.*		
	2010	**2035**	**2010–2035**	**2010–2035**	**2010–2020**	**2020–2035**
OECD America	484	583	99	0.7	0.9	0.7
OECD Europe	551	588	37	0.3	0.4	0.2
OECD Asia Oceania	209	212	3	0.1	0.2	0.0
OECD	**1,244**	**1,383**	**139**	**0.4**	**0.5**	**0.3**
Latin America	414	503	89	0.8	1.0	0.7
Middle East & Africa	874	1,435	561	2.0	2.2	1.8
India	1,215	1,567	352	1.0	1.2	0.9
China	1,353	1,392	40	0.1	0.3	0.0
Other Asia	1,082	1,374	292	1.0	1.2	0.8
OPEC	408	637	230	1.8	2.0	1.7
Developing countries	**5,345**	**6,909**	**1,564**	**1.0**	**1.2**	**0.9**
Russia	142	133	-9	-0.3	-0.1	-0.4
Other Eurasia	196	201	5	0.1	0.2	0.0
Eurasia	**338**	**334**	**-4**	**-0.1**	**0.1**	**-0.1**
World	**6,926**	**8,625**	**1,699**	**0.9**	**1.0**	**0.8**

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

been born, signifying little probable impact on road transportation demand. Similarly, working age population figures will not be hugely affected by these uncertainties, which in turn signifies little impact of this source of uncertainty upon growth potential due to changes in the size of the labour force. To this extent, fertility uncertainties have little bearing on the outlook for energy and oil, in particular. However, other complex dynamics from alternative growth rates are also likely, such as the change in the ratio of working to non-working populations. But this is beyond the scope of this Reference Case and it is assumed that such population uncertainties are not a key factor to be included in the analysis.

Population levels and growth rates in the UN medium variant for 2010 and 2035 are shown in Table 1.2. Global population rises from 6.9 billion in 2010 to 8.6 billion in 2035. The table clearly shows that this increase comes predominantly from developing countries, accounting for 92% of the rise. The UN's latest revision has seen a slight upward revision to longer term expectations for global population, but the patterns remain essentially unchanged from the WOO 2011. The greatest re-

Figure 1.4
Top ten increases in population, 2010–2035

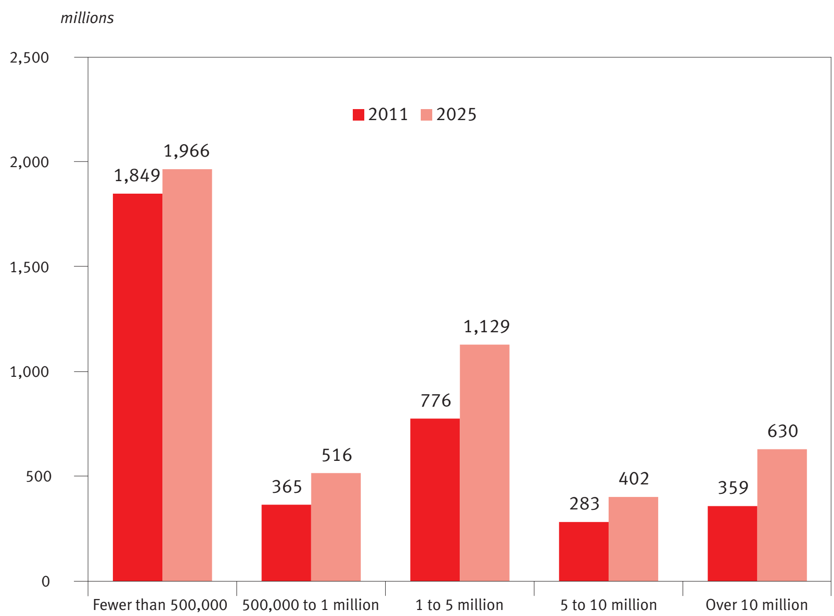


Source: 'World Population Prospects: The 2010 Revision', Department of Economic and Social Affairs of the United Nations Secretariat, Population Division.

gional increase continues to be in Sub-Saharan Africa, but India registers the greatest population growth of all countries over this period, with more than one-fifth of the global total. This increase is almost three times that of the country with the next largest growth, Nigeria (Figure 1.4). By 2022, India will have already overtaken China to become the most populous country on the planet.

Changes in the age structure of the population also influence the energy outlook. Mention has already been made of the impact upon the size of the labour force for any given total population, as well as the number of people of driving-licence age. In fact, there is a significant shift occurring in population trends: while the past has seen labour forces consistently grow across all regions, this is now becoming a shrinking trend in many cases. This is a strong dynamic for economic growth potential. The Chinese working-age population, for example, is expected to peak within three years and then start declining. There are also other factors at play, such as the known trend that the average distance driven for any given year falls with age.

Figure 1.5
Total population by city class size



Source: 'World Urbanization Prospects: The 2011 Revision', Department of Economic and Social Affairs of the United Nations Secretariat, Population Division.

Earlier WOOs have also emphasized the relevance of population movements from rural to urban areas. The urbanization trend in developing countries in particular is set to continue at a swift pace. Figure 1.5 shows the expected rise by city class size. Almost three-quarters of the population increase to 2025 will be in cities with more than 1 million inhabitants; and, by 2025, the number of cities with a population greater than 10 million will rise from 23 to 37, with nine of these in developing Asia. (The number of such cities in China and India alone will go from seven to 12.) Energy demand patterns will be strongly associated with these developments, as urbanization is usually associated with improved access to commercial energy and reductions in energy poverty. The implications for oil use are mixed, as growing urban road transportation needs are increasingly brought into conflict with attendant congestion and local pollution concerns.

Economic growth

The long-term economic growth rate assumptions appear in Table 1.3. The slowing growth over time reflects both the demographic trends already identified, as well as progressively smaller rates of productivity growth. Over the period 2012–2035, long-term economic growth rates average 3.4% p.a.

Table 1.3
Long-term economic growth rates in the Reference Case *% p.a.*

	2012–2020	2021–2035	2012–2035
OECD America	2.4	2.3	2.3
OECD Europe	1.4	1.6	1.5
OECD Asia Oceania	1.9	1.4	1.6
OECD	**1.9**	**1.9**	**1.9**
Latin America	3.3	2.8	3.0
Middle East & Africa	3.2	3.1	3.1
India	6.6	5.9	6.2
China	7.6	5.4	6.2
Other Asia	3.8	3.0	3.3
OPEC	3.8	3.2	3.4
Developing countries	**5.5**	**4.5**	**4.9**
Russia	3.4	2.5	2.8
Other Eurasia	2.8	2.3	2.5
Eurasia	**3.1**	**2.4**	**2.7**
World	**3.6**	**3.3**	**3.4**

Figure 1.6
Real GDP by region in 2010 and 2035

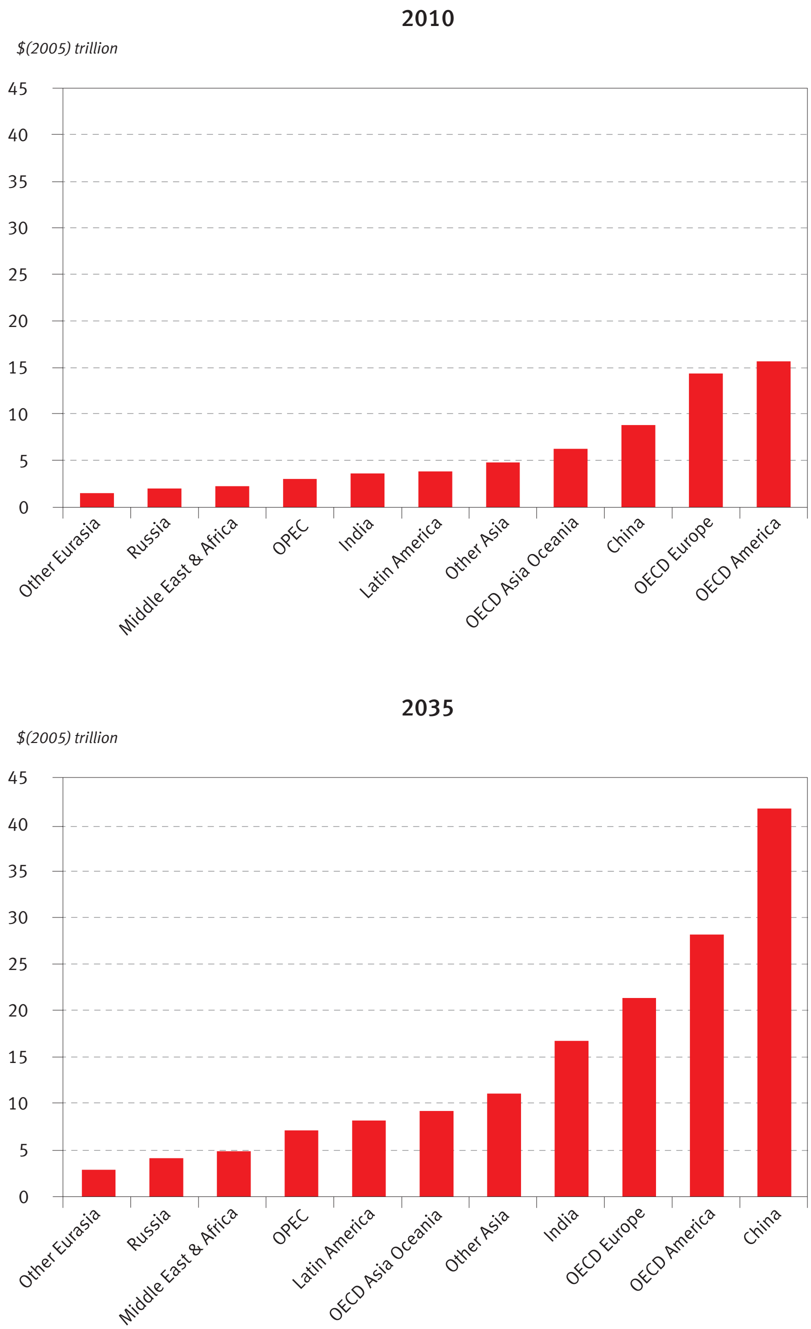


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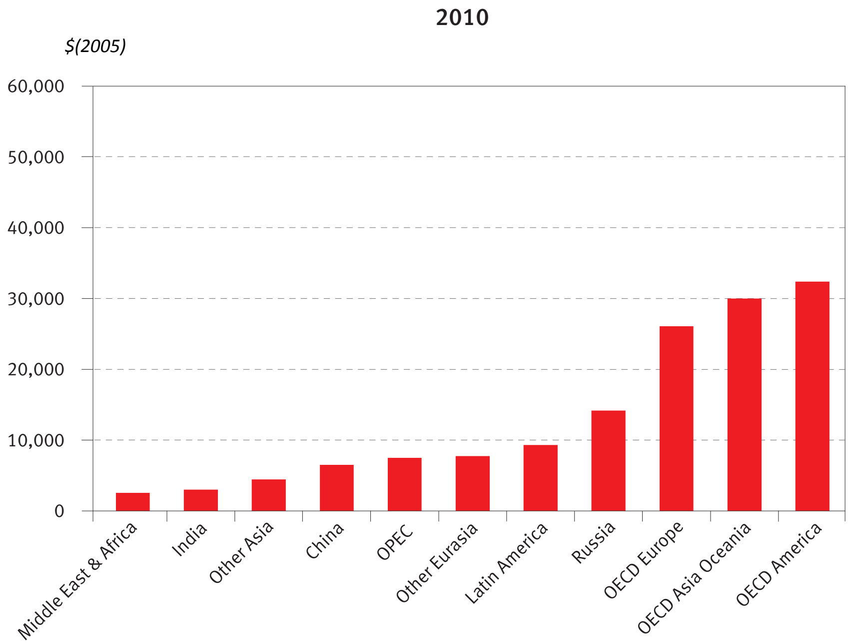
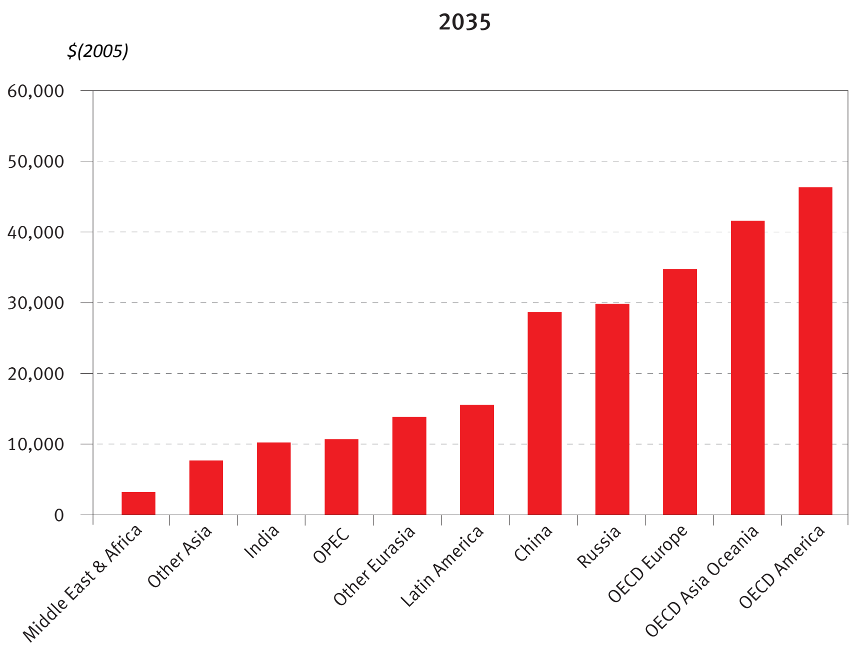
Figure 1.7
Real GDP per capita in 2010 and 2035





By 2035, the Chinese economy will be larger than any other country and even larger than entire regions within the OECD (Figure 1.6). India, which in 2010 accounted for 5% of global GDP, rises to 11% by 2035 and will have a larger economy than the whole OECD Asia Oceania region. Within ten years, India is expected to be growing faster than China (Box 1.3). The share of developing Asian countries in the world's economic activity rises in the Reference Case from 26% in 2010 to 43% by 2035.

As shown in Figure 1.7, by 2035, OECD regions will remain in the dominant position in terms of GDP per capita. In today's prices, OECD America will approach $50,000 per capita, while China's growing economy sees per capita income approach that of Russia at $30,000, above current average levels for OECD Europe. Other Asia still averages just $8,000 per capita by 2035. In the Reference Case, Africa (which, in the WOO's nomenclature, is combined with non-OPEC Middle East countries) remains the poorest region with GDP per capita of just $3,400.

Box 1.3
India to overtake China in economic growth

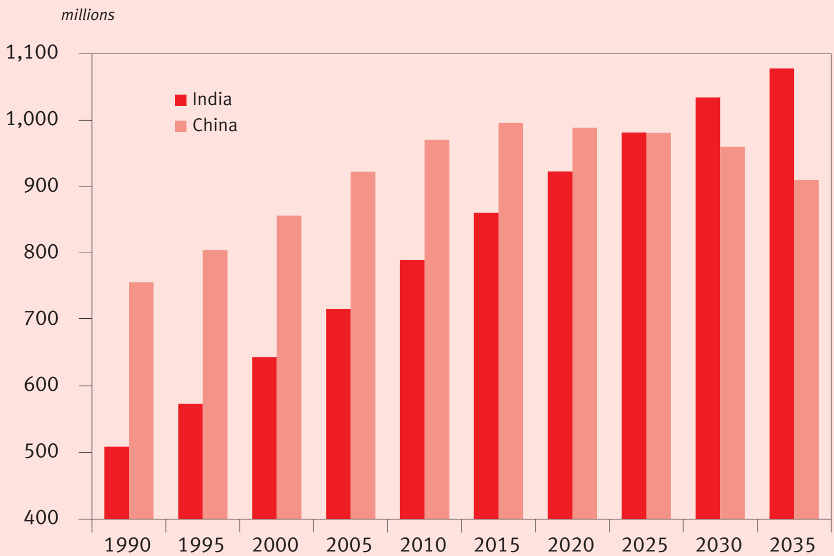
Over the period 1990–2011, the Chinese economy grew at an average rate of 10.2% p.a., while India's GDP grew at an average rate of 6.7% p.a. What these averages disguise, however, is that the difference in growth rate has become less in recent years, certainly compared to the 1990s when Indian growth rates were at least 5% below those of China for half of the decade.

A key issue to note is the markedly different demographic trends between the two countries. India's total population is expected to increase at an average rate of 1% p.a. over the years 2010–2035, thereby increasing by more than 350 million people, in contrast to China's net increase of just 40 million over this period. What is particularly relevant for the country's economic potential, however, is not just aggregate population growth, but also changes in the age structure, which in turn have impacts on the size of the working age population. The key difference between the two countries has been in respect to crude birth rates. While they were similar in the early 1950s, at just over 40 births per 1,000, the rate in China fell to just over half the rate of India by the beginning of the 21st century.

While the UN expects this gap to gradually narrow over this century, for the purposes of projections to 2035, the variances in birth rates translate directly into the relative share of age groups in total populations in the Reference Case. Figure 1 demonstrates how the share of the working age population in China has been rising over the past decades, on the back of earlier high birth rates. However, the 'peak' appears to have almost been reached: throughout the projection period to 2035, the share of working age population is expected to steadily decline after 2015, from a peak of around 72% to just 63% in 2035.

This is in contrast to the situation in India where higher birth rates feed into a steadily rising share of the labour force throughout the years to 2035. This means that the benefit China has enjoyed in terms of surplus in the labour force will disappear and, very likely, this will lead to increased wages and a loss in labour-cost comparative advantage.

Figure 1
Working-age population in China and India



The average annual population growth rate in India over the projection period, which is 1.1% p.a., is 1.6% p.a. higher than the 0.5% p.a. decline in China. This is one important factor to consider in making any economic growth assumptions.

The second key element is trends in Total Factor Productivity (TFP), defined in this context as economic output per head of the labour force. China has reached a stage in its economic development where the impact of external demand on economic growth has started to diminish. Moreover, there are the diminished impacts of the previous structural reforms that shifted resources from agriculture to industry, the exhausted gains from first generation policy reforms and the absorption of imported technologies. Trends in TFP for India, on the other hand, have become increasingly optimistic in light of recent economic reforms. Part of the support for strong TFP growth in India comes from the demographic trends already outlined. The strong expansion in the country's working-age population not only provides an impetus for growth through the sheer size of the labour force, but also reduces the dependency ratio (the working age population divided by total population). This, in turn, raises the savings ratio, which supports investment, as well as internal demand for goods and services. The performance of the services sector in India has tremendous implications for growth, too, given that it is the largest sector of the economy. It is export-intensive, employment-oriented and attractive to foreign direct investment. Therefore, the sustainability of the growth of the services sector is vital to the Indian economy.

Despite these strong supportive elements for continued robust growth, there are some constraints to Indian growth. The benefits of reforms were rapid, as the country moved from a state-controlled economy to a more competitive economy over the last two decades or so. However, there is considerable uncertainty over the speed of implementation of the next phase of planned reforms, and progress appears to be slow within the current ruling coalition. There is also a potential drag on growth if educational standards are not improved.

Nevertheless, this Reference Case assigns an optimistic view of Indian TFP growth. As a result, within 10 years, India is assumed to have a higher economic growth rate than China.

Demand side policies

The WOO has consistently presented a Reference Case based on policies already in place. Recent key policies that have been factored in include the EU package of measures for climate change and renewable objectives, and the US Energy Independence and Security Act (EISA). This year, however, the WOO also introduces implications for the new measures that were reported in the WOO 2011 concerning international marine bunker fuel, the standards for which are administered by the International Maritime Organization (IMO), a UN agency, under the International Convention for the Prevention of Pollution from Ships (MARPOL[5]). The July 2011 meeting of the IMO Marine Environmental Protection Committee (MEPC62) resulted in significant new regulations, namely, the first-ever greenhouse gas (GHG) emission regulations for new ships. There is evidently uncertainty over how the volumes of fuel used will be impacted, but the 2012 Reference Case reflects the downward pressure on oil demand resulting from these new regulations. In particular, the IMO regulations on efficiency in marine bunkers use leads to lower demand growth in the latter stages of the Reference Case projections.

The Reference Case does not, however, include potential downward pressures upon demand from policies that are currently being proposed or that may be thought to be more likely in the longer term. This is left for scenario analysis. A key example of this approach concerns the December 2011 proposals from the US Environmental Protection Agency (EPA) to dramatically increase efficiency standards for cars and light trucks over the period 2017–2025. The approach taken will initially study scenarios of the potential outcomes of the concrete proposals and then implement into a future Reference Case the estimated impact of the new standards once they are passed into law. In this Reference Case, no such impact has been introduced.

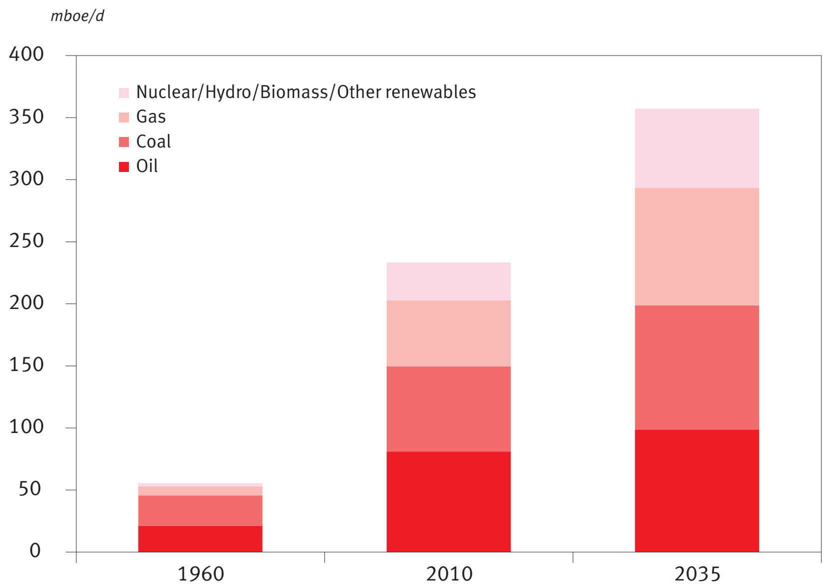
Energy demand

Over the period 2010–2035, primary energy demand[6] in the Reference Case increases by 54% (see Table 1.4). Fossil fuels, currently accounting for 87% of energy demand, 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, towards the end of the projection period, in the Reference Case, coal use reaches similar levels to that of oil,

Table 1.4
World supply of primary energy in the Reference Case

	Levels *mboe/d*				Growth *% p.a.*	Fuel shares *%*			
	2009	**2010**	**2020**	**2035**	**2009–35**	**2009**	**2010**	**2020**	**2035**
Oil	79.0	81.0	89.7	97.8	0.8	35.0	34.7	32.1	27.2
Coal	66.3	68.8	84.3	102.9	1.7	29.3	29.5	30.1	28.6
Gas	51.0	53.1	66.5	94.8	2.4	22.6	22.8	23.8	26.0
Nuclear	14.1	14.3	16.0	21.6	1.7	6.3	6.1	5.7	6.0
Hydro	5.6	5.8	7.4	10.4	2.4	2.5	2.5	2.6	2.9
Biomass	8.2	8.5	12.0	19.3	3.4	3.6	3.7	4.3	5.4
Other renewables	1.6	1.8	3.8	12.5	8.1	0.7	0.8	1.4	3.5
Total	**225.9**	**233.2**	**279.7**	**359.2**	**1.8**	**100.0**	**100.0**	**100.0**	**100.0**

Figure 1.8
World supply of primary energy by fuel type



with the oil share having fallen from 35% in 2010 to 27% by 2035. Natural gas use will rise at faster rates, both in percentage terms and quantities, than either coal or oil, with its share rising from 23% to 26%.

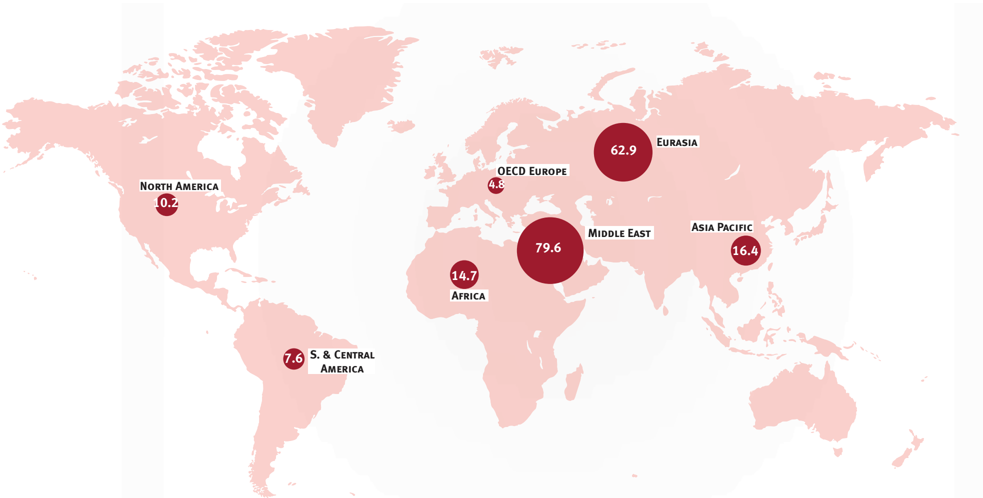
There is clearly potential for shale gas on the world energy scene. Figure 1.9 shows the volume of natural gas reserves, excluding shale gas, but adding estimates for shale gas reserves to these figures would further emphasize the potential of natural gas. Two main themes for exploring the possible significance of shale gas will be its possible future role in the transportation sector, particularly for freight vehicles (Box 2.1), and the size of recoverable reserves of shale gas (Box 3.1).

The principal use of this gas in the foreseeable future will be to replace coal in electricity generation, as well as increased use in the petrochemicals sector. Some GTL projects are also being considered. In addition, it should be noted that the rise in gas demand on the back of rising shale gas supply will likely put upward pressure on gas prices in the future which would dampen demand prospects.

In terms of calorific value, there are more coal reserves than the sum of oil and gas reserves. At the end of 2010, the US, Russia, China, India and Australia account

Figure 1.9
Natural gas: proven reserves at end 2011

trillion cubic metres



Source: OPEC Annual Statistical Bulletin, 2012 edition.

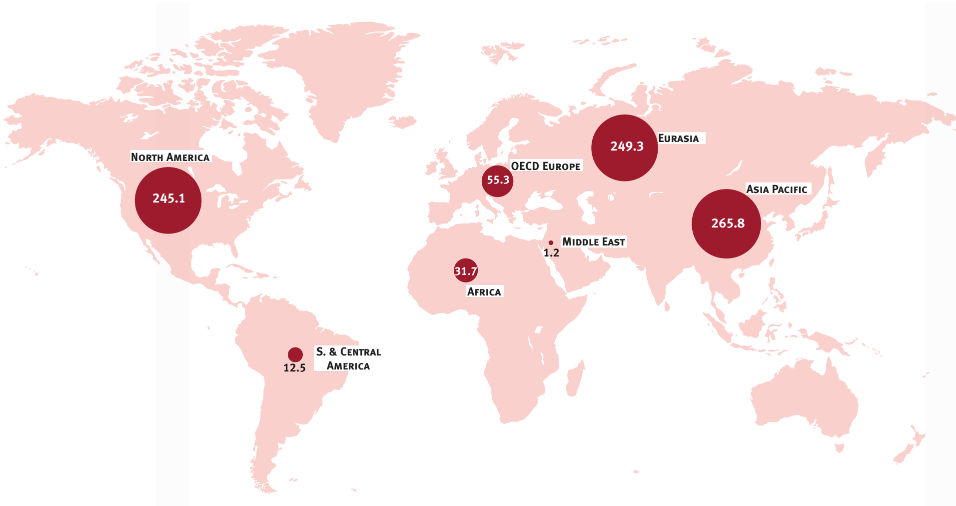
for three-quarters of global reserves (Figure 1.10). The abundance of coal is reflected in the fact that the R/P ratio currently stands at close to 120 years, although this ratio has been steadily falling, down from 200 years just a decade ago. At this rate of decline, the ratio could fall to under 40 years by the end of the projection period.

The future prospects for coal use will be related to the extent to which costs are attached to carbon emissions, as well as the competition from other sources of electricity generation, primarily gas and nuclear. The contribution of carbon capture and storage (CCS) to climate change mitigation measures will play an important role in determining the sustainability of coal use in a more carbon-constrained world.

The current use of nuclear energy is dominated by OECD America, OECD Europe and Asia (Figure 1.11). The accident at Fukushima continues to reverberate on Japan's energy scene and, indeed, elsewhere. The Fukushima units directly affected by the earthquake and tsunami of March 2011 have, of course, been permanently closed. But on top of this, the accident eventually resulted in the closing of many other nuclear plants. Following a policy review on nuclear power, all remaining Japanese plants were shut down, so that by May 2012 Japan was without electricity from nuclear power for the first time in over four decades. There is considerable uncertainty about the potential for restarting these facilities, but public opinion is currently strongly against this.

Figure 1.10
Coal: proven reserves at end 2011

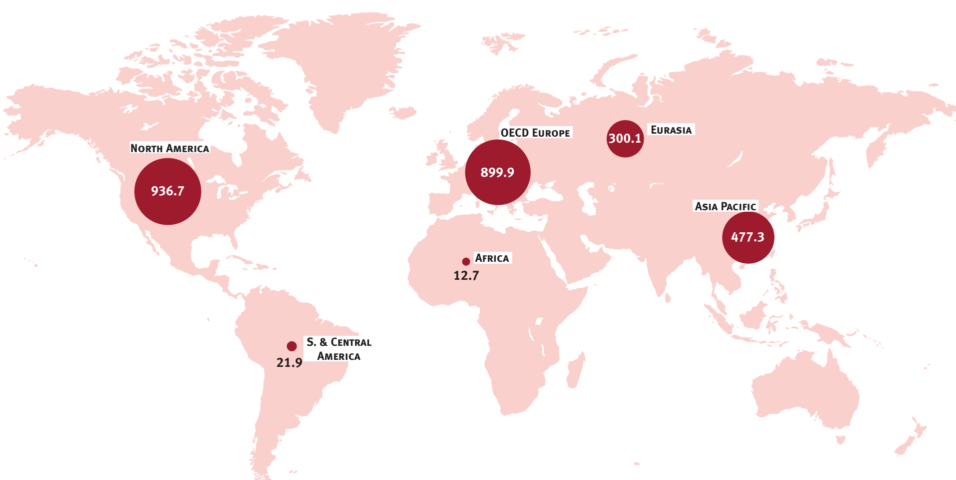
million tonnes



Source: BP Statistical Review of World Energy 2012.

Figure 1.11
Nuclear energy consumption at end 2011

Terrawatt hours



Source: BP Statistical Review of World Energy 2012.

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One of the reasons for the shrinking of Japanese oil consumption during the period 1979–1985 was the construction of several nuclear plants for electricity generation. This led to the substitution of crude and fuel oil, and caused a drop in demand of around 1.2 mb/d for the whole period. Although direct fuel burning was still declining prior to the earthquake and tsunami of March 2011, the natural disaster may have significantly changed the country's energy map, at least for the short- and medium-term. Following the shutdown of its nuclear reactors, the country switched to other forms of fuel to produce electricity. Consequently, if and when nuclear power plants are returned to service, this should impact total oil demand prospects in Japan over the short- and medium-term.

Outside of Japan, several OECD countries (particularly Germany, but also Switzerland and Italy) have decided not to replace retiring nuclear plants with new ones, reversing earlier plans. In March 2011, Germany shut down half of its nuclear plants; it then passed legislation in June to phase out the remainder of its nuclear power stations by 2022. In Switzerland, the final nuclear power plant is expected to have closed by the end of this WOO's projection period. And a referendum in Italy has rejected any move back towards nuclear power. More stringent safety regulations are also likely to affect the future economics of nuclear power, but the consequences beyond the OECD appear to be negligible, with pre-Fukushima plans elsewhere generally going ahead as intended.

The Reference Case reflects the potential long-term effects of these developments on the prospects for nuclear power in Japan and some European countries. As a result, the contribution of nuclear to the energy mix has been reduced. However, as the impacts are assumed to be negligible elsewhere, the overall impact is seen to be modest. Nuclear energy expands in the Reference Case at an average rate of 1.7% p.a. in total, with a share in the mix of 6% in 2035, similar to today.

Of the other non-fossil fuels, commercial biomass has the next largest share in the energy mix. Its use expands rapidly and its contribution to total supply approaches that of nuclear by 2035. Almost 40% of the commercial use of biomass in the OECD is in the electricity generation sector, where its use has doubled over the past two decades. It is important to note that the energy supply figures in Table 1.4 do not include non-commercial biomass. The shift from non-commercial to commercial energy use in developing countries is reflected in the Reference Case as an impact on energy demand growth.

The use of renewable energy, other than hydropower and biomass, predominates in America, Europe and Asia (Figure 1.12). This has been rising at close to 5% p.a. globally over the past twenty years. In the Reference Case, this increase is set to accelerate, averaging more than 8% p.a. over the period 2010–2035, the fastest growth of all energy types. Growth in non-OECD countries will be more rapid than in the OECD, particularly in China and India (Figure 1.13). Starting from a low base, however, means that the share of this group of renewables is just 3.5% by 2035. Hydropower is also expected to grow strongly, primarily in developing countries, which account for over 80% of the increase to 2035. Asia is already the largest user of hydropower (Figure 1.14). More than half of the global increase will be in China alone. However, as with other renewables, the global share of hydropower remains modest since it starts from a relatively low base.

Increases in energy demand by fuel type for OECD and non-OECD countries are shown in Figure 1.15. As in earlier projections, the dominant growth is in fossil fuel use in non-OECD countries. In this year's Reference Case, however, it has become apparent that the single biggest demand increase is for gas use in non-OECD countries.

The prevalence of energy poverty in developing countries and the consequent requirement to satisfy future development needs with higher energy use is reflected in the Reference Case projections. Figure 1.16 shows that by 2035, the OECD will still

Figure 1.12
Other renewables consumption at end 2011

Terawatt hours

Source: BP Statistical Review of World Energy 2012.

Figure 1.13
Increase in the use of renewables other than hydropower and biomass, 2010–2035

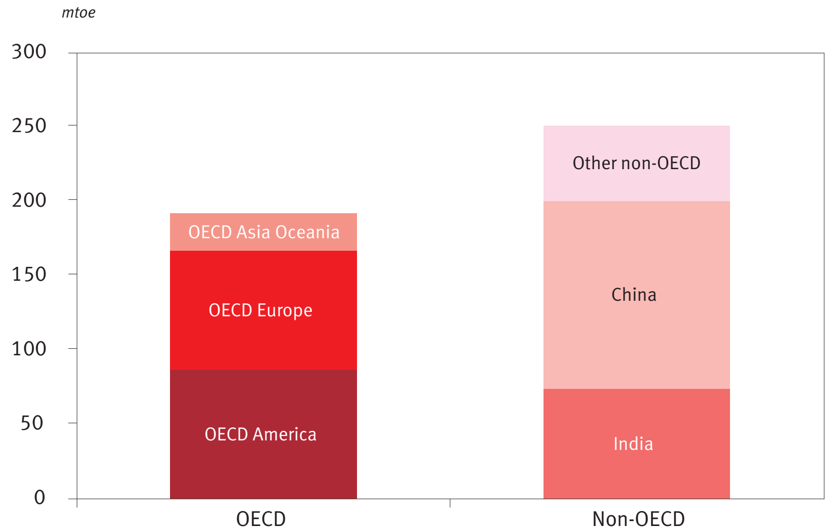
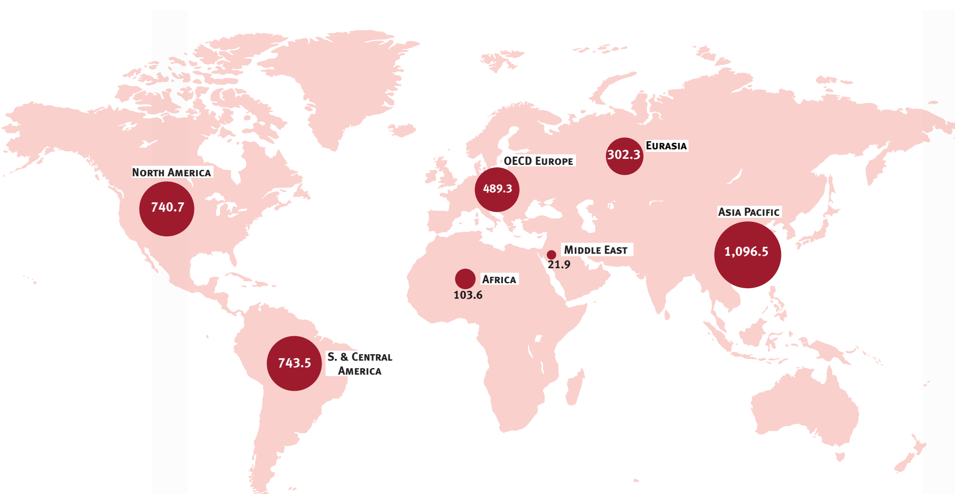


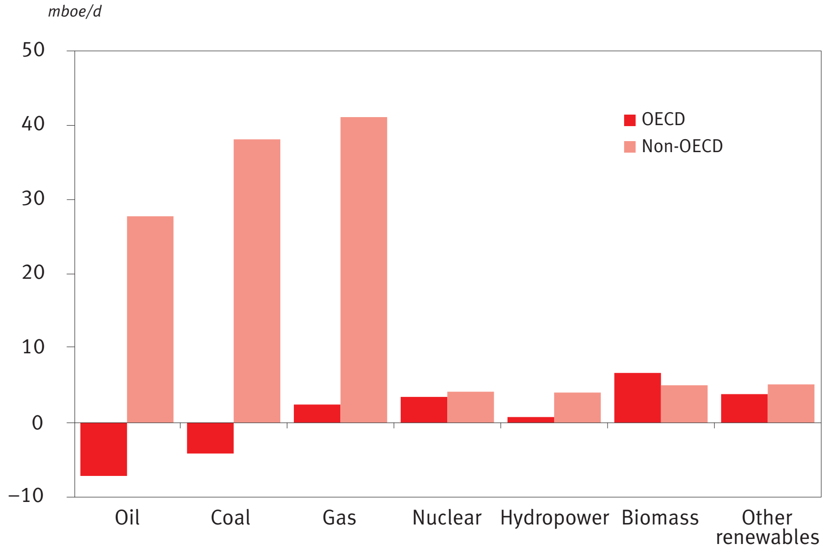
Figure 1.14
Hydropower consumption at end 2011

Terawatt hours



Source: BP Statistical Review of World Energy 2012.

Figure 1.15
Evolution of energy demand, 2010–2035, by fuel type, OECD versus non-OECD



be consuming around three times more energy per capita than developing countries. Although the gap in per capita energy use is closing, it is doing so slowly.

These Reference Case developments involve a steady decline in energy intensities (energy use divided by real GDP measured at purchasing power parity) for both OECD and non-OECD countries (Figure 1.17). Following an average decline of 1.2% p.a. globally over the period 1990–2010, this ratio is set to fall even faster over the projection period, at an average of 1.6% p.a. The reasons for these higher rates of decline in global energy intensities in the Reference Case compared to the period 1990–2010 include:

- The incorporation of new policies geared to improving efficiencies in all sectors, but particularly in the transportation sector;
- Saturation effects in OECD countries continue to be a natural downward force upon intensities;
- Many developing countries are generally on the cusp of changing from rising energy intensities to falling intensities;
- Intensity declines come not only from improved energy efficiencies but also from structural changes in the global economy;

Figure 1.16
Energy use per capita

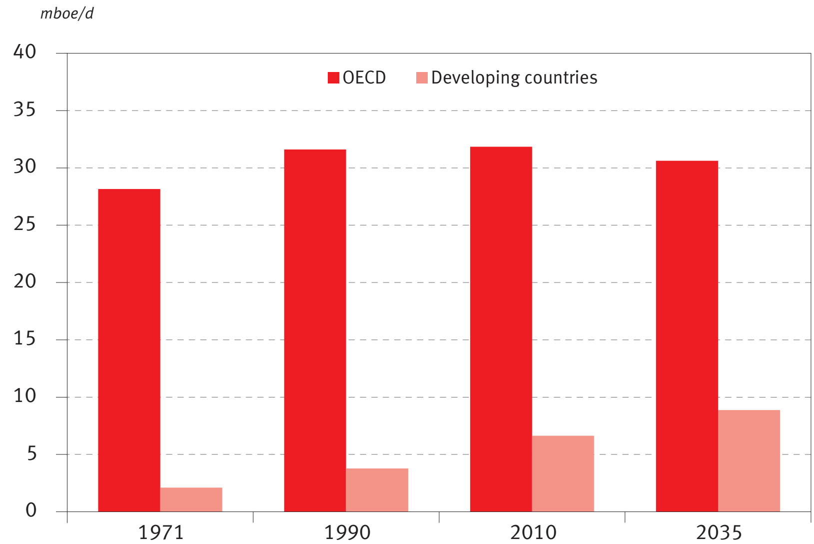
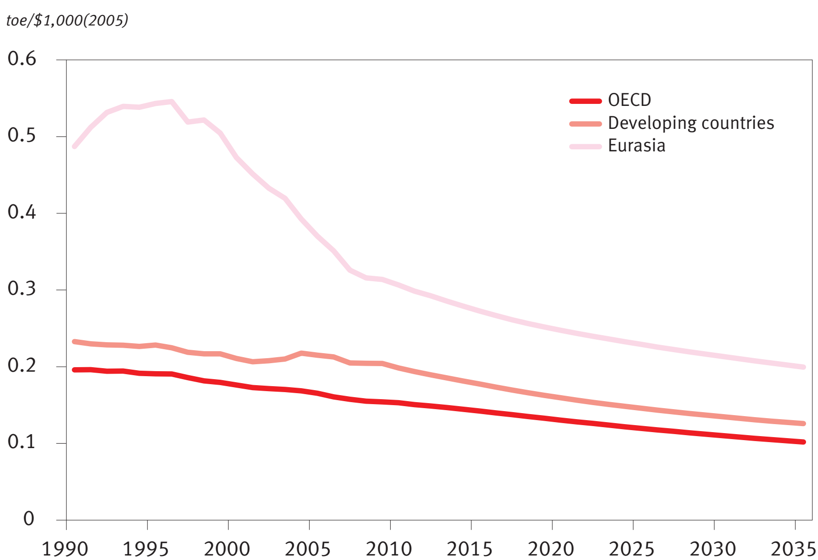


Figure 1.17
Energy intensities in the Reference Case



- The Reference Case assumes higher oil prices compared to historical averages; and
- Declines in non-OECD intensities have increasingly had an impact on global averages as their share of energy consumption increases.

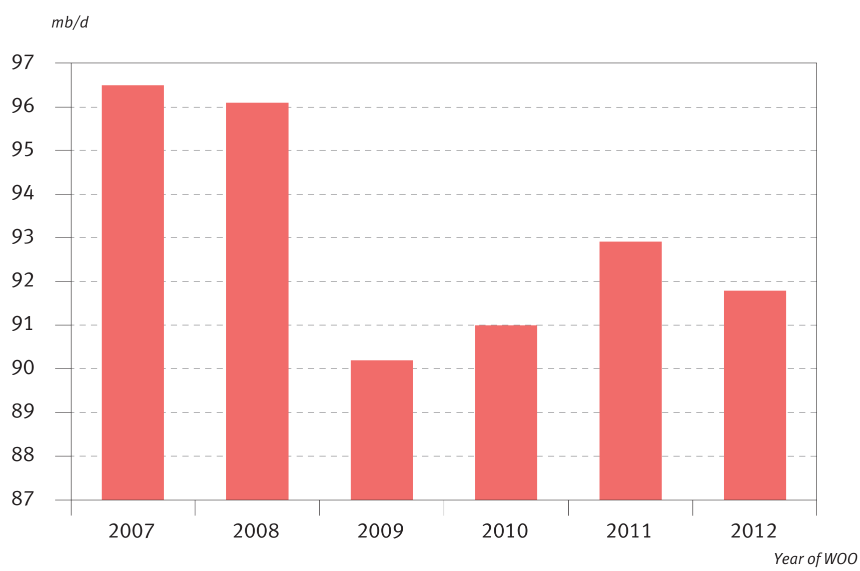
Oil demand

Oil demand in the medium-term

Chapter 1

It has already been documented in earlier Outlooks how the global financial crisis and 'Great Recession' had significant implications for oil demand projections in the short- and medium-term. Figure 1.18 shows how the medium-term projections to 2015 were revised downwards in the WOO 2009 as the recession unravelled and GDP forecasts for 2009 were revised down. The next two WOOs (2010 and 2011) took into account the extraordinary monetary and fiscal stimulus that were put in place and considered a more positive view on how quickly a recovery would occur, leading to upward revisions in medium-term oil demand prospects. This year, as discussed already, there is growing concern about immediate prospects for economic growth, particularly in the Euro-zone. For 2012, demand in this publication is already 820,000 b/d lower than in the WOO 2011.

Figure 1.18
World Oil Outlook projections for global oil demand in 2015



The medium-term oil demand outlook, therefore, reflects a corresponding downward revision from last year's report. As can be seen in Table 1.5, the Reference Case now foresees demand reaching 92.9 mb/d by 2016, a downward revision of over 1 mb/d compared to the WOO 2011.

Table 1.5
Medium-term oil demand outlook in the Reference Case *mb/d*

	2011	2012	2013	2014	2015	2016
OECD America	23.8	23.7	23.7	23.7	23.7	23.7
OECD Europe	14.4	14.0	13.8	13.7	13.7	13.6
OECD Asia Oceania	8.1	8.4	8.5	8.5	8.4	8.4
OECD	**46.3**	**46.1**	**46.0**	**45.9**	**45.8**	**45.7**
Latin America	5.0	5.1	5.2	5.3	5.4	5.5
Middle East & Africa	3.4	3.5	3.6	3.7	3.8	3.8
India	3.4	3.6	3.7	3.8	4.0	4.2
China	9.4	9.8	10.2	10.6	11.1	11.5
Other Asia	7.0	7.1	7.2	7.4	7.5	7.7
OPEC	8.3	8.5	8.6	8.8	9.0	9.2
Developing countries	**36.6**	**37.5**	**38.5**	**39.6**	**40.8**	**42.0**
Russia	3.3	3.4	3.4	3.4	3.5	3.5
Other Eurasia	1.6	1.6	1.7	1.7	1.7	1.7
Eurasia	**4.9**	**5.0**	**5.1**	**5.1**	**5.2**	**5.2**
World	**87.8**	**88.7**	**89.5**	**90.7**	**91.8**	**92.9**

Over the period 2011–2016, OECD oil demand declines each year, having peaked in 2005. Although demand in Eurasia is expected to continue to grow slowly, the medium-term increase of 5.1 mb/d over the years 2011–2016 comes essentially from developing countries, with 70% of that increase occurring in developing Asia.

Oil demand in the long-term

Long-term oil demand prospects have been affected by several factors that are different from the WOO 2011:

- New policies since WOO 2011, specifically IMO regulations on ships' efficiency and marine bunkers quality specifications, lead to lower oil demand growth in the latter stages of the forecast;
- Higher oil prices cause some degree of demand reduction by 2035, when compared to the WOO 2011. Although price elasticities are low, they are not zero. A key reason for a limited impact is that crude oil price movements are not felt very strongly at the consumer level in countries with high levels of taxation;
- The implications of technological developments and implementation, especially in the transportation sector, also point to further downward pressures upon demand compared to WOO 2011;
- The observed medium-term downward revisions noted also contribute to some downward long-term revisions; and
- Some upward pressures on demand are, however, channelled through slightly higher economic growth rate assumptions for India and Russia.

The outlook for long-term oil demand in the Reference Case is presented in Table 1.6. Demand increases by over 20 mb/d over the period 2010–2035, reaching 107.3 mb/d by 2035. As previously mentioned, OECD demand peaked in 2005 and

Table 1.6
World oil demand outlook in the Reference Case *mb/d*

	2010	2015	2020	2025	2030	2035
OECD America	24.1	23.7	23.5	23.0	22.4	21.7
OECD Europe	14.7	13.7	13.4	13.0	12.6	12.1
OECD Asia Oceania	8.1	8.4	8.2	8.0	7.6	7.3
OECD	**46.8**	**45.8**	**45.2**	**44.0**	**42.6**	**41.1**
Latin America	4.9	5.4	5.8	6.1	6.4	6.6
Middle East & Africa	3.3	3.8	4.1	4.5	4.8	5.1
India	3.3	4.0	4.9	6.0	7.4	9.0
China	9.0	11.1	13.2	15.0	16.4	17.6
Other Asia	6.8	7.5	8.4	9.1	9.7	10.3
OPEC	8.1	9.0	9.8	10.6	11.4	12.0
Developing countries	**35.4**	**40.8**	**46.3**	**51.3**	**56.0**	**60.6**
Russia	3.2	3.5	3.6	3.6	3.6	3.6
Other Eurasia	1.6	1.7	1.8	1.9	2.0	2.1
Eurasia	**4.8**	**5.2**	**5.4**	**5.5**	**5.6**	**5.6**
World	**87.0**	**91.8**	**96.9**	**100.9**	**104.2**	**107.3**

the longer term sees a steady decline in demand in all OECD regions. Fully 87% of the increase in global demand is in developing Asia, where demand reaches 90% of that of the OECD by 2035 (Figure 1.19). Global demand in 2035 is more than 2 mb/d lower than in the WOO 2011, due to the impacts outlined.

Per capita oil use in developing countries will stay relatively low and definitely below the average levels in OECD countries (Figure 1.21). By 2035, oil use per capita in developing countries will average just three barrels, compared to close to an average of 11 barrels in the OECD. By 2035, while more than 13 barrels per person will be consumed annually in OECD America, this ratio will still be less than two barrels per head in India and only a little over one barrel in the Middle East & Africa region.

Growth in oil demand since 1980 has been dominated by transportation use – mainly road transportation, but also aviation, internal waterways and international marine (Figures 1.22–1.25). Over the past three decades, the average annual growth in OECD and non-OECD countries has been very similar, each at around 0.3 mboe/d. At the global level, transportation is expected to continue to dominate growth over the projected period. However, this increase will come only from non-OECD

Figure 1.19
Growth in oil demand, 2010–2035

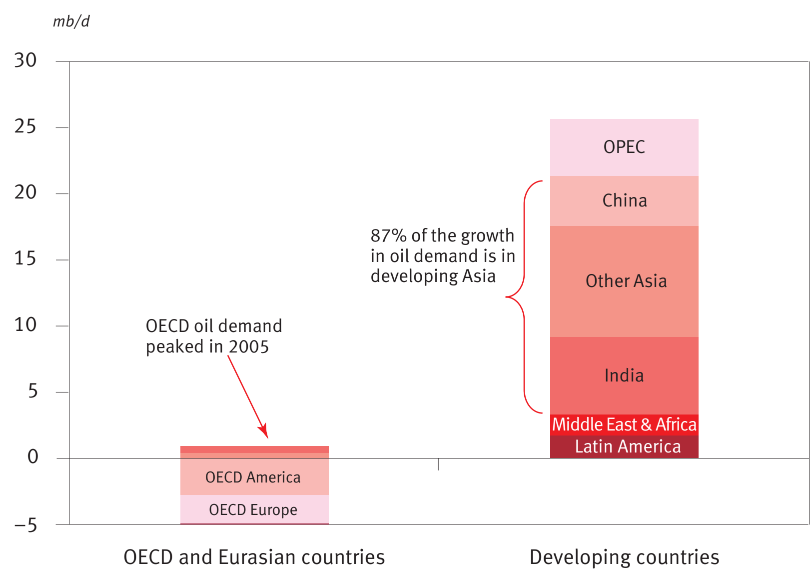


Figure 1.20
OECD and non-OECD oil demand

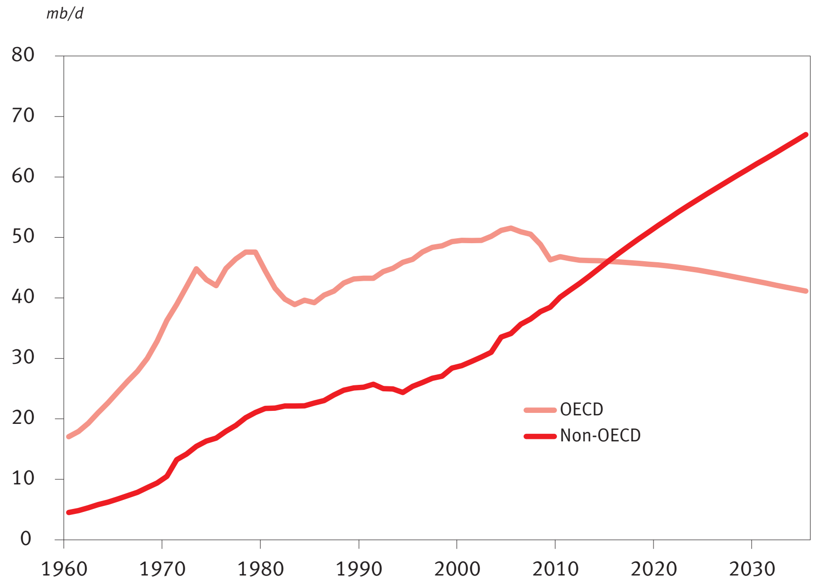
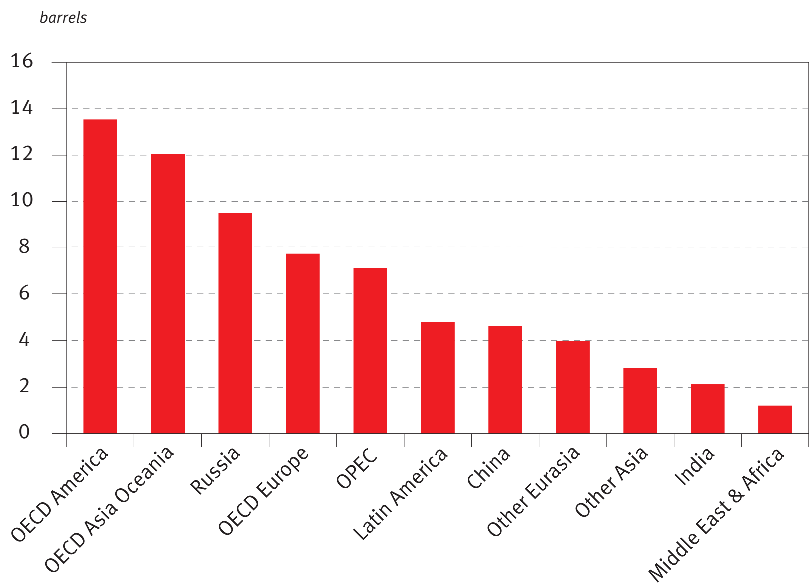


Figure 1.21
Oil use per capita in 2035



Chapter 1

Figure 1.22
Average annual global growth in oil demand by sector

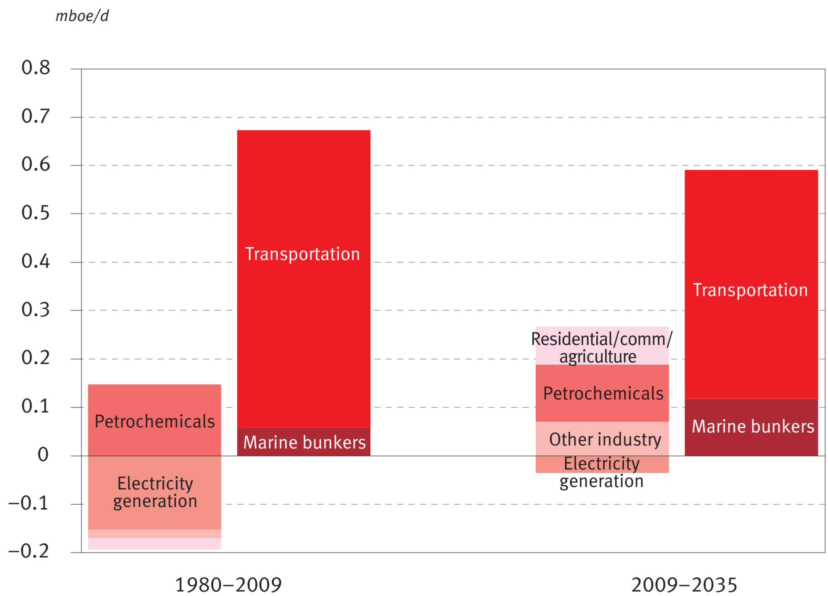


Figure 1.23
Average annual global growth in oil demand in OECD countries

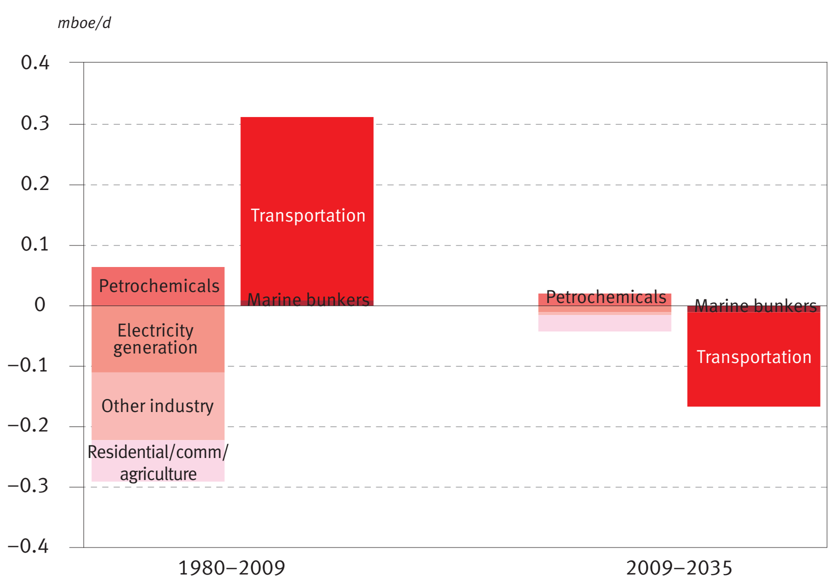


Figure 1.24
Average annual global growth in oil demand in Developing countries

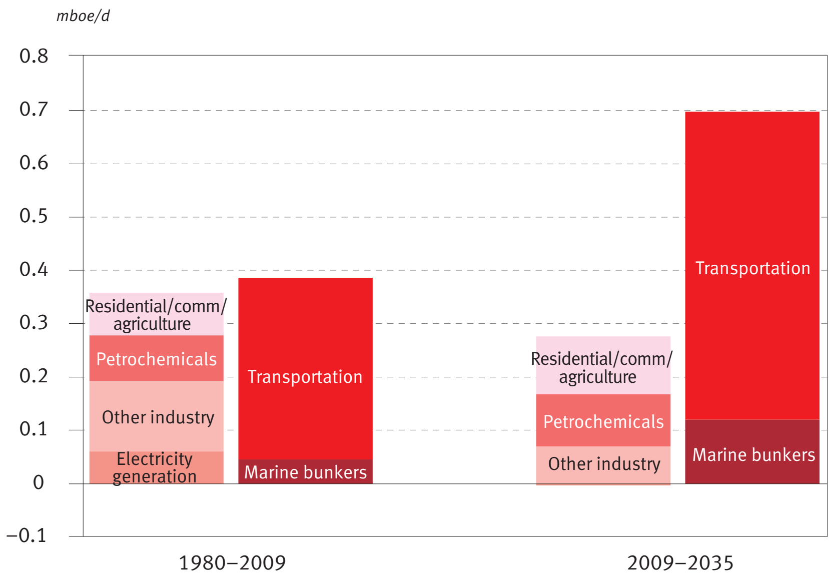
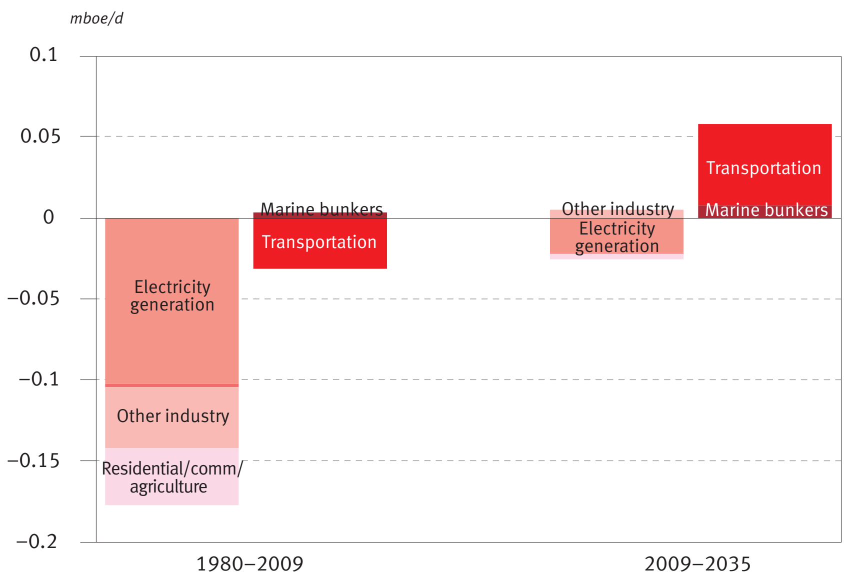


Figure 1.25
Average annual global growth in oil demand in Eurasia



countries. The key to future demand growth is in transportation in non-OECD countries, which accounts for close to three-quarters of the increase in oil demand in the period to 2035. In contrast to both OECD and Eurasian countries, developing countries also see a rise in oil use in other sectors (petrochemicals, household/commercial/agriculture, other industrial uses). But all regions will see the small amount of oil that is still used for electricity generation decline in the future.

Liquids supply

Liquids supply in the medium-term

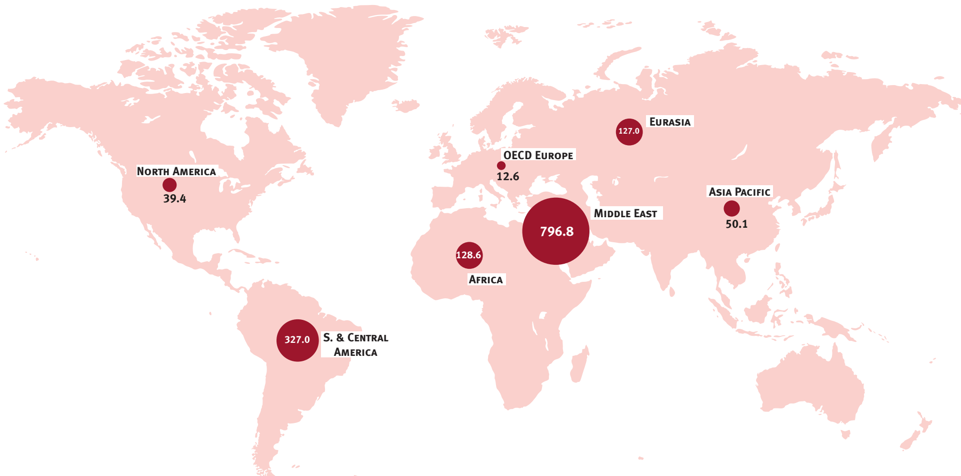
The development of medium-term Reference Case figures for non-OPEC liquids supply relies on a bottom-up approach that uses data from producing fields, upstream development projects and proven reserves. (For longer term projections, the total resource base is a key input to the assessment.) The approach involves a 'risking' process, which considers both estimated declines from fields currently in production and an assessment of new oil that is expected to appear over the medium-term from fields either under development or which are expected to be developed over the next five years. In much the same way, medium-term paths for biofuels and other forms of liquid supply are estimated based on currently producing plants and projects, but are also influenced by legislation targeting minimum levels of certain fuels. Details of these assessments are explored in Chapter 3.

OPEC's Annual Statistical Bulletin (ASB) documents that OPEC Member Countries account for 81% of the world's proven crude oil reserves. At the regional level, 54% of this oil is contained in the Middle East, 22% in Latin America, 8.5% in Africa, while only 3% is found in North America (Figure 1.26).

In previous WOO Reference Cases, no significant contribution of shale oil to liquids supply was envisaged. In this year's Outlook, a rise in the importance of shale oil is expected, as described in more detail in Chapter 3. However, it should be noted that production in the future is likely to be beset with several constraints and challenges, such as environmental concerns, questions over the availability of equipment and trained staff, rising costs and steep decline rates. Nevertheless, the development of this resource is moving rapidly in the US and even since the preparation of the previous WOO, production levels have markedly increased: supply from Bakken, Eagle Ford and Niobrara in the US is already over 1 mb/d, and despite severe decline rates, emerging forecasts now see supply from oil shale rising rapidly. In the previous WOO Reference Case, crude oil plus Natural Gas Liquids (NGLs) supply in the US & Canada fell from 9.4 mb/d in 2010 to 6.8 mb/d by 2035. By including significant additions from shale oil, this decline in crude supply will be far slower. With this in

Figure 1.26
Proven oil reserves at end 2011

billion barrels



Source: OPEC Annual Statistical Bulletin, 2012 edition.

mind, an assumption of between 2 mb/d and 3 mb/d of shale oil is assumed to emerge by 2020 and 2035, respectively. The lower growth after 2020 is justified by the fact that the best shale oil plays will be tapped first.

Short-term data revisions for non-OPEC crude and NGLs supply in OECD Europe, OECD Asia Oceania, Middle East & Africa, Asia and the Caspian have shifted the 2011 base down by almost 700,000 b/d. The medium-term expectations for crude supply from Middle East and Africa and the Caspian region (other Eurasia) have become somewhat more pessimistic due to new data on investment projects.

Regarding biofuels, since the WOO 2011, growing debt burdens across many countries are now thought to represent a hurdle, given the reduced willingness and ability to subsidize biofuels. Moreover, experience has already shown the difficulties in achieving established targets (for example, due to the introduction of waivers, delays in the implementation of directives, on-going concerns over the implications for land use changes, concerns over capital availability, high feedstock prices, and growing perceptions that targets for second-generation biofuels are clearly over-ambitious). The biofuels outlook has, therefore, been slightly adjusted downwards to reflect these insights and their impact on medium-term projections, but also to reflect the realization that cellulosic biofuels may take longer to become commercially available than previously thought.

The Reference Case also takes into account a more bullish view of the prospects for Canadian oil sands supply, particularly with the higher price assumption in this WOO.

Following the recent progressive upward revisions to total non-OPEC liquids supply, the new Reference Case sees a continuation of this process, with the total in 2015 now increased by a further 500,000 b/d.

The medium-term Reference Case outlook for non-OPEC supply, as well as for OPEC crude, OPEC Gas-to-Liquids (GTLs) and OPEC NGLs, appears in

Table 1.7
Medium-term liquids supply outlook in the Reference Case *mb/d*

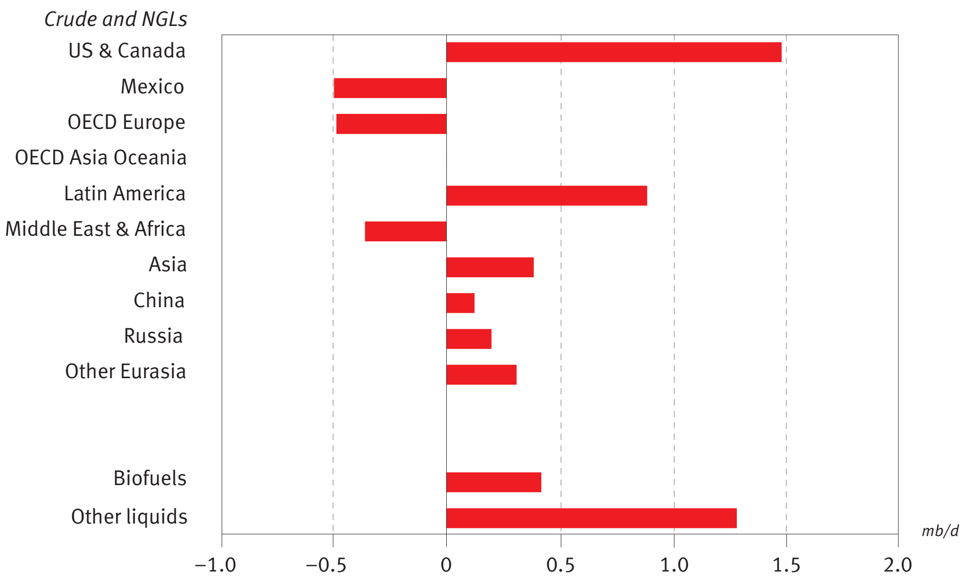
	2011	2012	2013	2014	2015	2016
US & Canada	12.6	13.5	14.0	14.5	14.8	15.2
Mexico & Chile	2.9	2.9	2.8	2.7	2.6	2.4
OECD Europe	4.1	3.9	3.8	3.8	3.8	3.8
OECD Asia Oceania	0.5	0.5	0.5	0.6	0.6	0.6
OECD	**20.1**	**20.8**	**21.2**	**21.5**	**21.8**	**22.0**
Latin America	4.7	4.9	5.1	5.3	5.6	5.8
Middle East & Africa	4.3	3.8	3.9	3.9	3.9	3.9
Asia	3.6	3.7	3.7	3.8	4.0	4.1
China	4.1	4.2	4.3	4.3	4.3	4.4
DCs, excl. OPEC	**16.8**	**16.6**	**17.0**	**17.4**	**17.8**	**18.2**
Russia	10.3	10.3	10.4	10.4	10.5	10.5
Other Eurasia	3.1	3.2	3.3	3.4	3.4	3.5
Eurasia	**13.4**	**13.5**	**13.7**	**13.8**	**13.9**	**14.0**
Processing gains	2.1	2.2	2.3	2.3	2.4	2.4
Non-OPEC	**52.4**	**53.1**	**54.1**	**55.1**	**55.8**	**56.6**
OPEC NGLs	**5.2**	**5.4**	**5.7**	**5.9**	**6.2**	**6.4**
OPEC GTLs*	**0.2**	**0.2**	**0.2**	**0.3**	**0.3**	**0.3**
OPEC crude	**29.8**	**31.1**	**30.1**	**29.6**	**29.6**	**29.7**
World supply	**87.5**	**89.9**	**90.0**	**90.9**	**92.0**	**93.1**

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

Table 1.7.[7] The growth in non-OPEC supply over 2011–2016 is portrayed in Figure 1.27. Total non-OPEC supply increases steadily over the medium-term, rising by over 4 mb/d over the 2011–2016 period. The key sources of supply driving this growth are rising levels of shale oil from the US, Canadian oil sands, and crude oil from the Caspian and Brazil. These compensate for expected declines elsewhere. For example, combined supply from OECD Europe and Mexico falls by close to 1 mb/d over this medium-term period.

Table 1.7 also indicates that, as with earlier Reference Cases, a rise in OPEC NGLs is expected over the medium-term, increasing from 5.2 mb/d in 2011 to 6.4 mb/d in 2016. All of these projections, including those already outlined for demand, imply that the amount of OPEC crude required over the medium-term will stay essentially flat. This represents a fall of more than 1.6 mb/d by 2015, when compared to the WOO 2011, due to the combined effects of lower demand and higher non-OPEC liquids supply. This downward revision, together with updated estimates of OPEC production capacity over the medium-term, implies that OPEC crude oil spare capacity is expected to rise beyond 5 mb/d as early as 2013/2014.

Figure 1.27
Growth in non-OPEC supply, 2011–2016



Liquids supply in the long-term

A central result that emerges from the assessment of the long-term supply of liquids is that resources are plentiful and that the sources of this supply are extremely diverse. Crude oil and NGL projections to 2035 are based on the resource base estimates from the US Geological Survey (USGS)[8] of ultimately recoverable resources (URR) of crude oil and NGLs. As described in Chapter 4, adjustments to these figures have been made in the past to account for countries that plainly have a resource base of crude and/or NGLs, given that production is underway, but for which the USGS data contains no estimated URR value. But recently a new assessment has become available from the USGS which supersedes earlier estimates.

It should be stressed that estimates by the USGS for crude resources do not include shale oil resources. As we have seen in the medium-term Reference Case, a rapid revision to expectations for the contribution of this source of crude oil to the liquids supply has been taking place. The long-term potential for shale oil is, therefore, also reflected in this Reference Case. However, because of the rapid decline rates experienced with this form of supply and the considerable infrastructural challenges (particularly those related to transportation), as well as the fact that the best plays are tapped first, it is not expected that the rapid acceleration of supply growth over this decade will continue indefinitely. A slower build-up of shale oil supply is, therefore, incorporated into the post-2020 outlook.

The non-OPEC liquids supply outlook is completed by the assessment of the long-term potential for biofuels and other liquids. These are expected to be important sources of additional oil over the projection period, although they remain subject to their own constraints and challenges. These are examined further in Chapter 3.

Total non-OPEC liquids supply increases strongly in the long-term, as shown in Table 1.8, by more than 10 mb/d: increases in crude and NGLs supply from the Caspian, Russia, Brazil and shale oil in the US, as well as steady increases in biofuels and oil sands, are far stronger than decreases elsewhere. Non-OPEC supply from Canadian oil sands and biofuels in the US, Europe and Brazil continues to grow strongly, by close to 11 mb/d. Global NGLs supply rises by close to 7 mb/d over these years.

These developments mean that OPEC crude supply needs to rise in the Reference Case, but at a modest rate. By 2035, it would need to be just 35 mb/d, around 5 mb/d higher than in 2010. This would mean that the share of OPEC crude in global liquids supply remains approximately constant, at around 32%, throughout the whole forecast period (Figure 1.28).

The total increase of non-crude liquids supply will satisfy more than 90% of the increase in demand to 2035. In the 2020–2035 period, non-crude supply increases from non-OPEC regions will account for more than 80% of all increases in liquids supply. However, non-OPEC crude is set to decline over the projection period. It also becomes evident that crude supply in the Reference Case would at no point in the projection need to exceed 73 mb/d (Figures 1.29, 1.30 and 1.31).

Figures 1.32 to 1.34 show the regional liquids supply paths in the Reference Case.

Table 1.8
World liquids supply outlook in the Reference Case *mb/d*

	2010	2015	2020	2025	2030	2035
US & Canada	12.0	14.8	16.0	17.1	17.9	18.9
Mexico & Chile	3.0	2.6	2.3	2.1	2.0	1.8
OECD Europe	4.4	3.8	3.6	3.5	3.5	3.5
OECD Asia Oceania	0.6	0.6	0.6	0.6	0.7	0.7
OECD	**20.0**	**21.8**	**22.6**	**23.3**	**24.1**	**24.9**
Latin America	4.7	5.6	6.6	7.1	7.2	7.3
Middle East & Africa	4.4	3.9	3.8	3.7	3.5	3.4
Asia	3.7	4.0	4.3	4.1	3.8	3.6
China	4.1	4.3	4.4	4.4	4.5	5.0
DCs, excl. OPEC	**16.9**	**17.8**	**19.2**	**19.3**	**19.1**	**19.3**
Russia	10.1	10.5	10.7	10.7	10.7	10.7
Other Eurasia	3.2	3.4	3.7	4.0	4.3	4.7
Eurasia	**13.4**	**13.9**	**14.3**	**14.7**	**15.1**	**15.5**
Processing gains	2.1	2.4	2.6	2.7	2.9	3.0
Non–OPEC	**52.3**	**55.8**	**58.6**	**60.1**	**61.1**	**62.7**
OPEC (incl. NGLs)	**34.2**	**36.1**	**38.4**	**41.0**	**43.3**	**44.9**
OPEC NGLs	**4.9**	**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**	**29.6**	**30.9**	**32.5**	**33.8**	**34.9**
World supply	**86.5**	**92.0**	**97.1**	**101.1**	**104.4**	**107.5**

* *Future growth of other liquids in OPEC is expected to be dominated by GTLs. This item includes other non-crude streams, such as MTBE.*

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

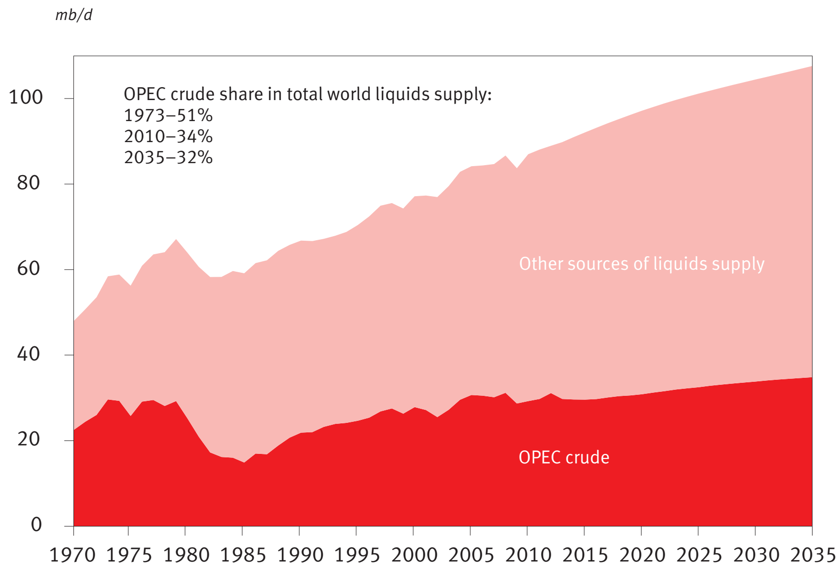


Figure 1.29
Incremental crude and non-crude oil supply in the Reference Case

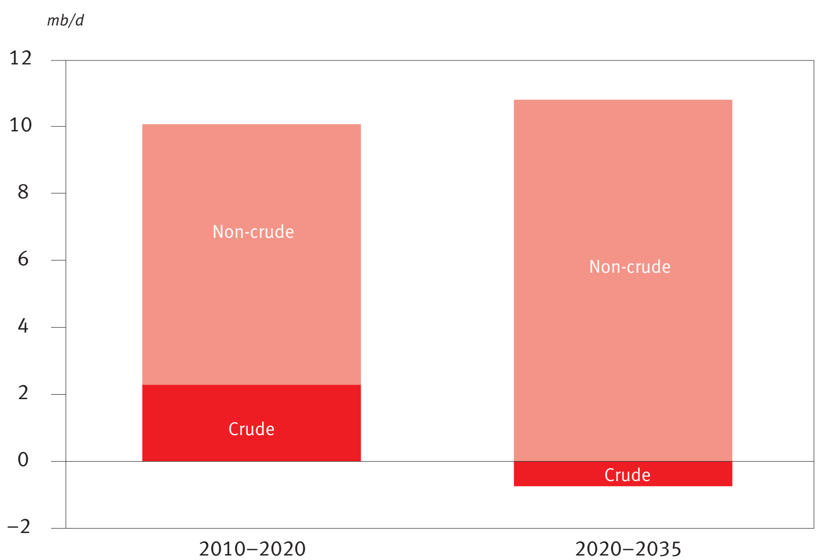


Figure 1.30
Incremental OPEC and non-OPEC supply in the Reference Case

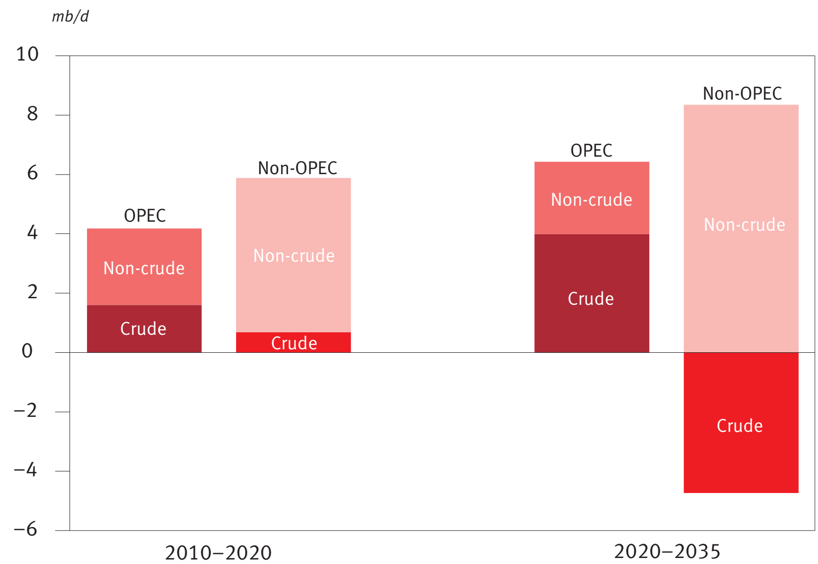


Figure 1.31
World liquids supply 1970–2035: crude and other sources

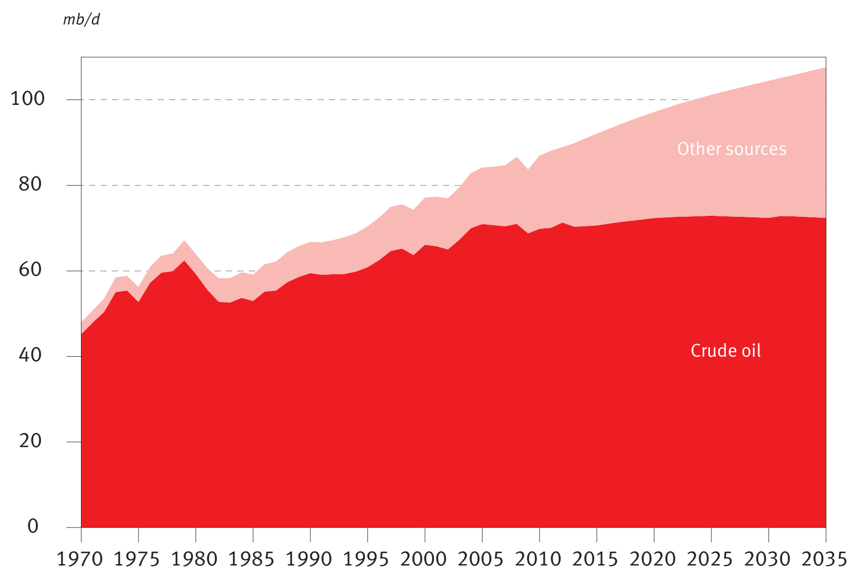


Figure 1.32
Non-OPEC liquids supply, OECD regions

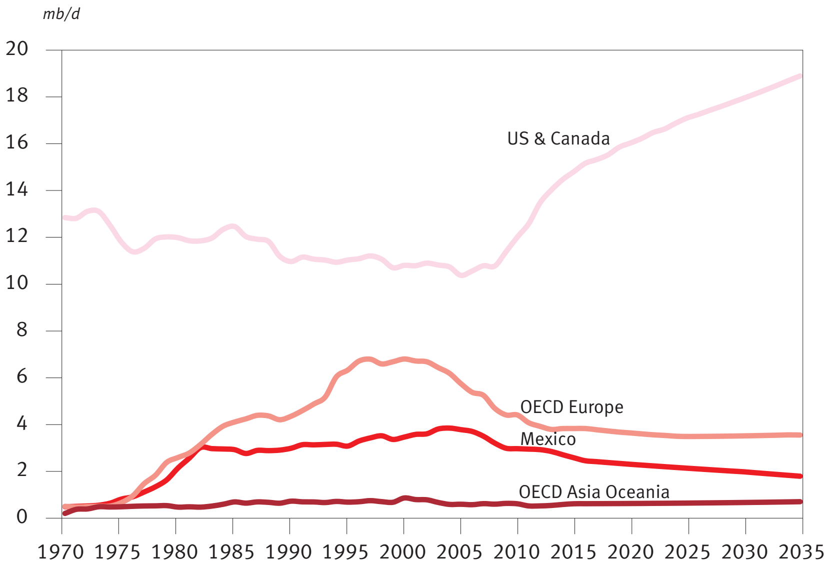


Figure 1.33
Non-OPEC liquids supply, Developing country regions

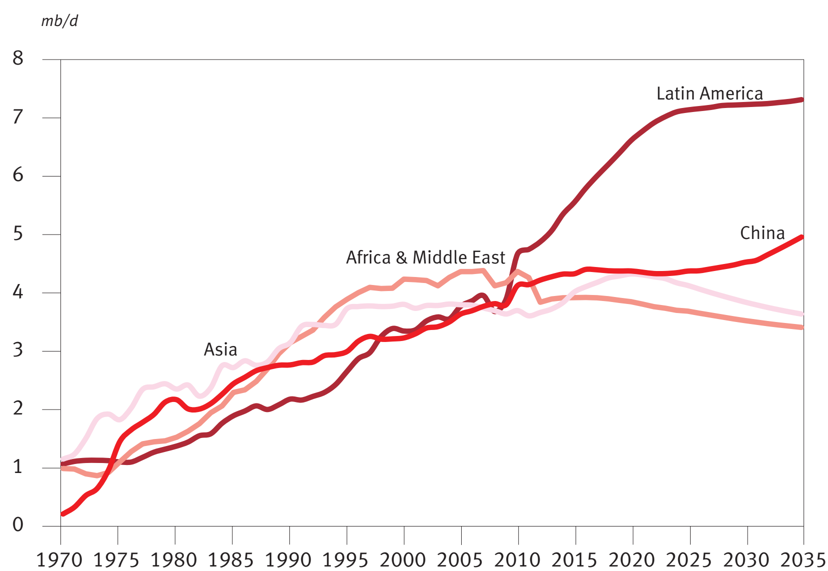
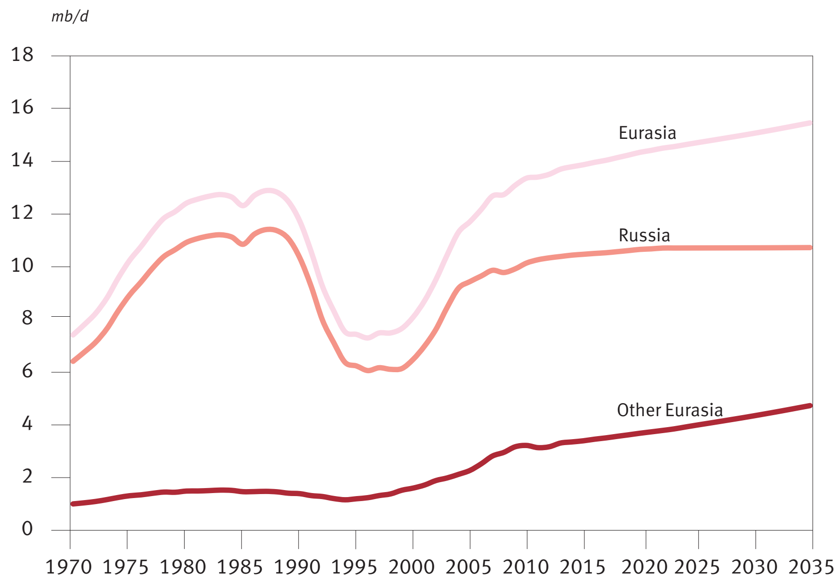


Figure 1.34
Non-OPEC liquids supply, Eurasia

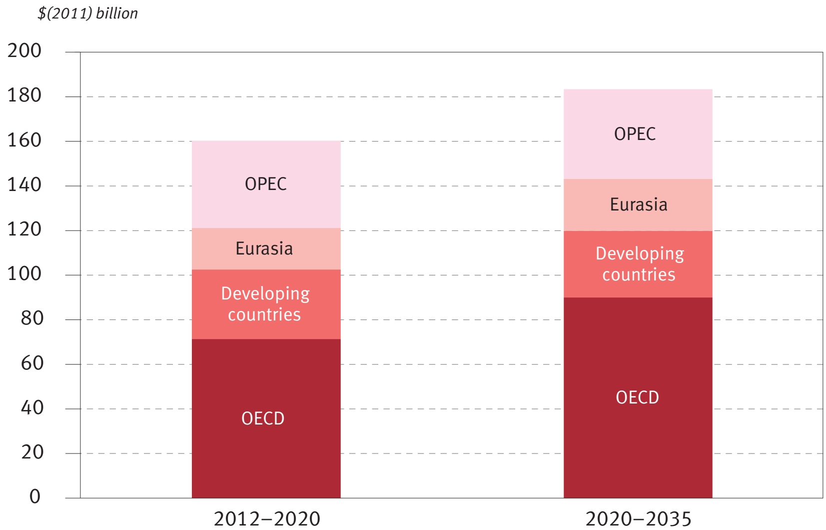


Upstream investment

Over the period 2011–2035, upstream investment requirements for additional capacity amount to \$4.2 trillion in 2011 dollars. Most of this investment will be made in non-OPEC countries: over the medium-term, non-OPEC will need to invest an average of \$95 billion each year and in the long-term, this rises to over \$110 billion annually. OPEC, on the other hand, would need to invest an average of \$45 billion annually (Figure 1.35). The OECD's share in global investment will be at 35% given the high costs and decline rates in this region. Adding estimated mid-stream and downstream investment requirements (see Section Two), overall oil investment needs to 2035 reach \$6–7 trillion in the Reference Case.

Much of the investment needed is to compensate for natural declines in fields that are currently producing oil. Because of this decline, the volumes of crude required for compensating loss of capacity are indeed very large. However, it should be noted this need compares to the performance of the oil industry in compensating for past declines. For example, over the period 1980–2011, a similar natural decline had to be compensated for – and it was.

Figure 1.35
Annual upstream investment requirements for capacity additions in the Reference Case, 2012–2035



CO_2 emissions

The Reference Case sees fossil fuels contributing the largest share to the energy mix over the entire projection period, with coal eventually becoming the fuel type with the highest share. These developments can be interpreted in terms of CO_2 emissions: in 2011, non-Annex I emissions exceeded those of the Annex I group for the first time (Figure 1.36). By the end of the projection period, non-Annex I emissions will account for 67% of the global total. It should be noted, however, that like energy use, the per capita situation for CO_2 emissions paints a different picture: by 2035, Annex I countries emit double the CO_2 emissions of non-Annex I countries per capita.

Moreover, cumulative emissions from Annex I countries 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 1.37).[9]

Figure 1.36
Per capita CO_2 emissions in the Reference Case

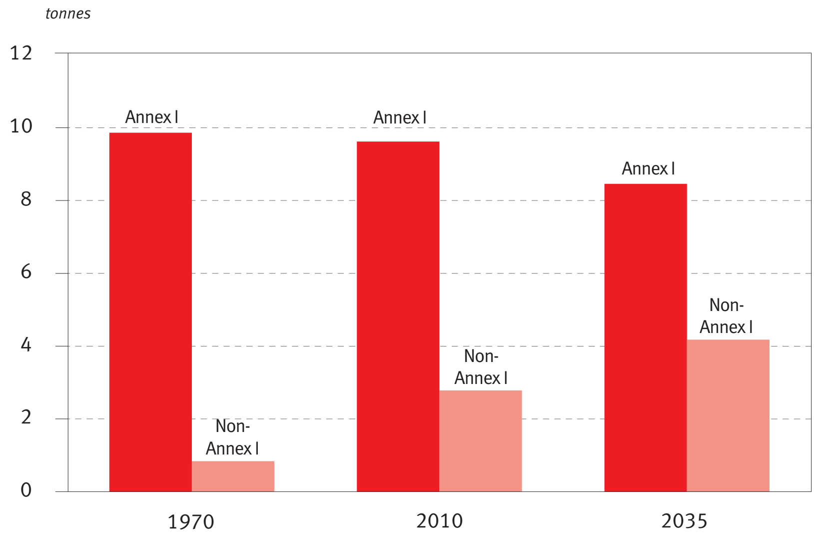
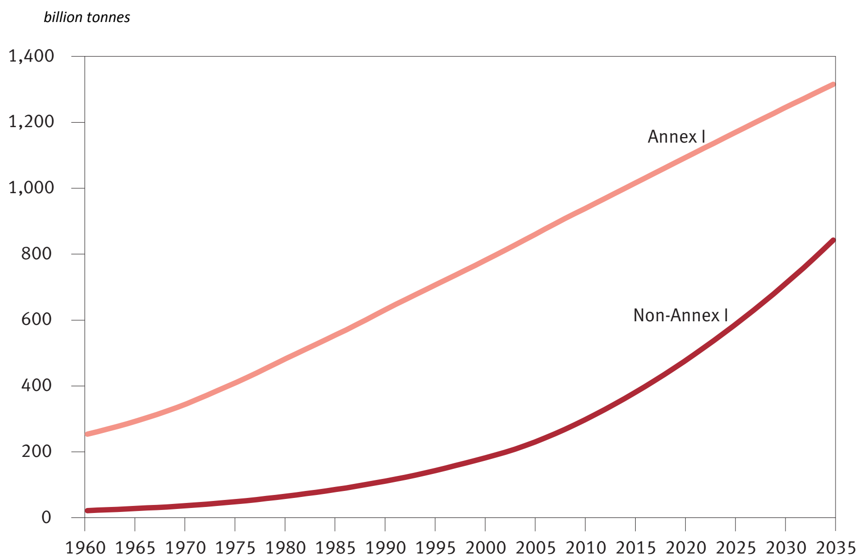


Figure 1.37
Cumulative CO_2 emissions from 1900, 1960–2035



Chapter 2
Oil demand by sector

This Chapter explores in detail the sectoral oil consumption patterns that underpin the Reference Case demand figures presented in Chapter 1.

Transportation, consisting of road, aviation, internal waterways, rail and international bunkers, accounted for 57% of global oil use in 2009. This is set to increase to 61% by 2035. This demonstrates the importance of focusing upon the many drivers that affect oil demand in the transportation sector, including policies and technological development.

The petrochemical industry and other industrial usage accounts for more than one-quarter of all oil consumed, while households and agriculture, together with some consumption in the commercial sector, contribute around 10%. Globally, little oil is used to produce electricity, although in some countries this remains an important fuel, such as in Greece, Italy, Japan and Mexico, as well as some OPEC countries.

Road transportation

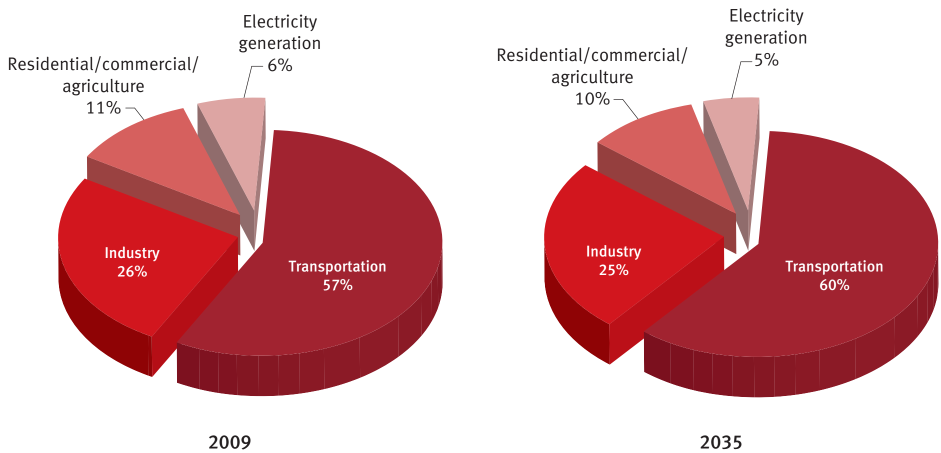
All previous WOOs have pointed to the transportation sector as the key to future oil demand growth. This is unsurprising, given the limited fuel switching possibilities in this sector, and the expected continued demand growth for mobility. The low price elasticity, together with, in many countries, the presence of a large tax buffer, limit the impact upon demand of the higher oil price assumptions outlined in Chapter 1.

With the on-going significance of this sector for oil demand growth, it is vital to improve understanding of the dynamics of this sector's growth, and identify possible constraints and uncertainties. A key distinction is the growth potential for passenger cars and commercial vehicles.[10] The importance of this disaggregation derives from the marked differences in the key growth drivers for these two types of vehicles. In particular, while the concept of saturation is important for the ownership of passenger cars, at least at higher income levels, it is the nature and pace of economic growth and trade that is of more relevance to the expansion of the stock of commercial vehicles.

Passenger car ownership

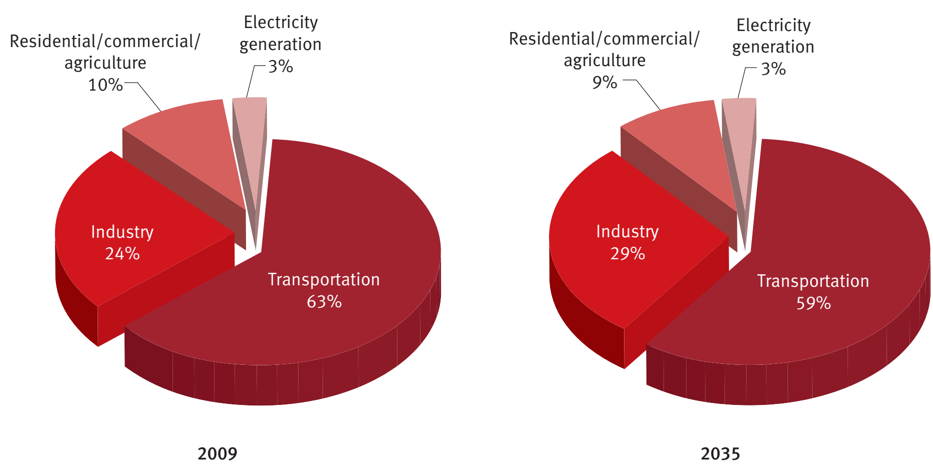
Table 2.1 shows the levels of passenger car ownership in 2009 across the various regions, as well as for many countries in those regions. In this year, there were more than

Figure 2.1
Percentage shares of oil demand by sector in 2009, 2035 – World



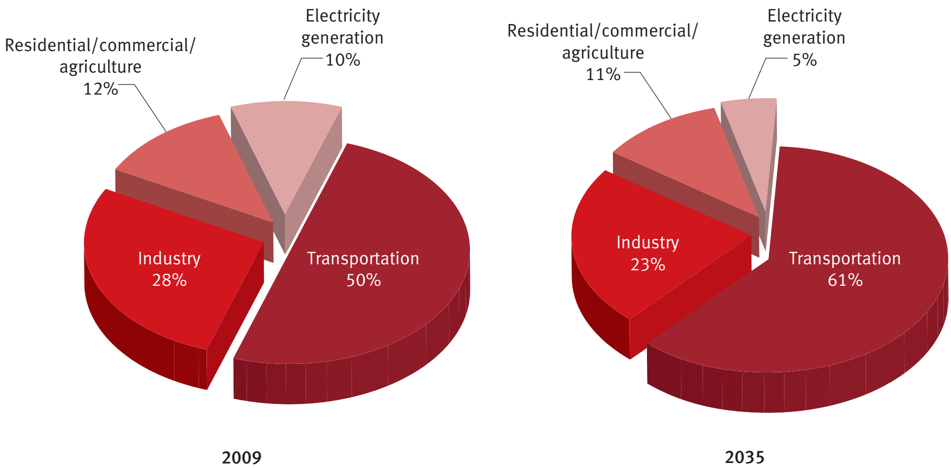
Source: *OECD/IEA Energy Balances of OECD/non-OECD countries, 2011.*

Figure 2.2
Percentage shares of oil demand by sector in 2009, 2035 – OECD



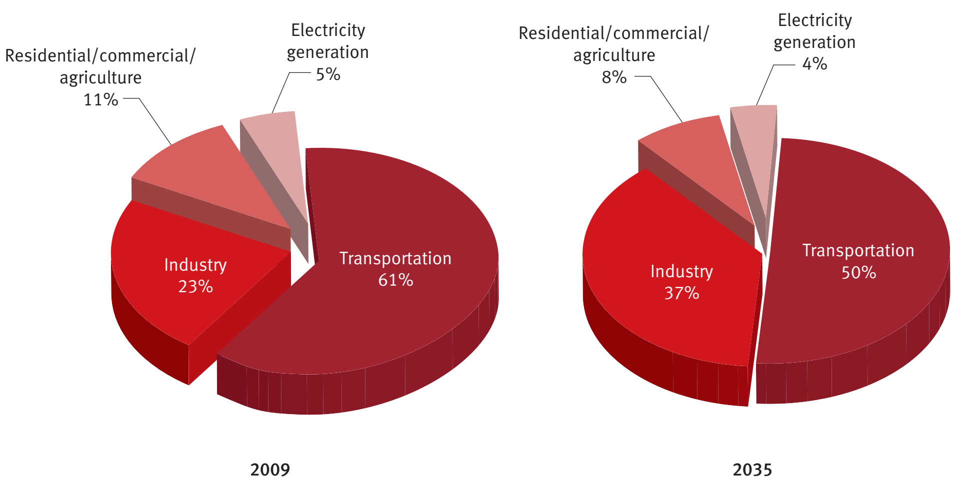
Source: *OECD/IEA Energy Balances of OECD/non-OECD countries, 2011.*

Figure 2.3
Percentage shares of oil demand by sector in 2009, 2035 – Developing countries



Source: OECD/IEA Energy Balances of OECD/non-OECD countries, 2011.

Figure 2.4
Percentage shares of oil demand by sector in 2009, 2035 – Eurasia



Source: OECD/IEA Energy Balances of OECD/non-OECD countries, 2011.

870 million cars across the globe, an increase of over 22 million compared to 2008. More than two-thirds of cars are in OECD countries. Over the past few decades, however, the percentage shares between developed and developing countries have shifted rapidly. Figure 2.5 shows how the percentage of cars in developing countries went from under 6% in 1970 to more than 24% in 2009.

It is expected that this trend will continue. By 2035, the developing country share will have more than doubled, reaching 52% of all passenger cars globally.

Nowhere is the recent car ownership increase as dramatic as in China. As can be viewed in Figure 2.6, the rise in the number of cars over the past decade has been unique: from 2000-2009, the number of cars on Chinese roads expanded by 37 million on the back of strong increases in income levels and the rapid economic development. The rise was close to three times greater than in Russia, which saw the next largest increase.

However, despite this rapid rise in car ownership in developing countries, there remain significantly lower levels of car ownership per capita compared to the developed world. Car ownership in OECD countries in 2009 averaged 478 per 1,000 people, while in developing countries it was just 40 per 1,000. Table 2.1 and Figure 2.7 document this difference in car ownership per capita. For example, while levels of around one car per two people are typical in OECD countries, the level is as low as just one car per 1,000 in parts of Africa and Asia.

Car ownership saturation is already visible in the developed world: perhaps the most notable example is the US. Car ownership increased rapidly from below 500 per 1,000 people in the early 1970s to over 700 per 1,000 at the start of this century, although it should be noted that car ownership ratios in 2009 are the same as 2002.

Of course, saturation levels vary between countries, due to alternative demographic structures, geographical and cultural differences, or even variances in income distribution. What is clear, however, is that saturation is of limited relevance for the developing world, especially for countries at low levels of car ownership. As emphasized in previous WOOs, the main constraints limiting the growth of car ownership in the developing world revolve around such areas as congestion, infrastructure, the rates of expansion in automobile manufacturing, steel production capacities and local pollution concerns.

Reference Case projections for passenger car ownership are shown in Table 2.2. The number of passenger cars double by 2035, compared to 2009 levels,

Table 2.1
Vehicle and passenger car ownership in 2009

	Population *millions*	Cars *millions*	Cars *per 1,000*
OECD America	479.1	263.5	549.9
Canada	33.6	14.2	422.2
Chile	17.0	2.0	118.3
Mexico	109.6	20.5	187.2
USA	314.7	224.4	713.2
OECD Europe	548.1	240.2	438.2
Austria	8.4	4.4	521.5
Belgium	10.7	5.2	488.9
France	62.3	31.1	498.1
Germany	82.2	41.7	507.9
Greece	11.2	5.1	459.9
Hungary	10.0	3.0	301.7
Italy	59.9	35.9	599.2
Luxembourg	0.5	0.3	676.6
Netherlands	16.6	7.9	474.3
Poland	38.1	16.5	433.3
Portugal	10.7	5.6	520.2
Spain	44.9	22.0	489.6
Turkey	74.8	7.1	94.8
UK	61.6	28.5	462.2
OECD Asia Oceania	208.2	87.5	420.3
Australia	21.3	12.0	564.7
Japan	127.2	57.9	455.4
New Zealand	4.3	2.6	609.6
South Korea	48.3	13.0	269.5
OECD	**1,235.4**	**591.2**	**478.5**
Latin America	409.4	60.1	146.7
Argentina	40.3	11.6	287.0
Brazil	193.7	33.9	175.1
Colombia	45.7	2.4	52.5
Peru	29.2	1.2	41.2
Uruguay	3.4	0.6	178.6
Middle East & Africa	835.8	21.9	25.6
Egypt	83.0	2.7	33.1
Ethiopia	82.8	0.1	0.9
Ghana	23.8	0.4	18.4
Jordan	6.3	0.7	106.5
Kenya	39.8	0.5	12.6
Morocco	32.0	1.8	57.0

Table 2.1 (continued)
Vehicle and passenger car ownership in 2009

	Population *millions*	Cars *millions*	Cars *per 1,000*
South Africa	50.1	5.4	108.0
Sudan	42.3	0.9	21.8
Syria	21.9	0.6	29.1
India	1,198.0	13.7	11.4
China	1,345.8	45.9	34.1
Other Asia	1,069.3	38.6	36.1
Bangladesh	162.2	0.3	1.7
Indonesia	230.0	10.4	45.1
Malaysia	27.5	8.6	313.1
Pakistan	180.8	1.8	9.8
Philippines	92.0	0.8	8.5
Singapore	4.7	0.6	127.4
Sri Lanka	20.2	0.4	19.1
Taiwan	23.1	5.7	246.7
OPEC	398.4	30.1	75.4
Algeria	35.6	2.6	72.8
Angola	18.5	0.8	41.7
Ecuador	14.0	0.5	34.8
Iran	74.1	9.4	126.3
Iraq	31.5	0.8	25.7
Kuwait	3.5	1.2	329.8
Libya	6.4	1.4	221.2
Nigeria	154.7	3.8	24.7
Qatar	1.6	0.5	299.0
Saudi Arabia	25.4	6.8	267.6
United Arab Emirates	4.6	1.5	326.0
Venezuela	28.4	3.3	117.3
Developing countries	**5,256.7**	**210.2**	**40.0**
Russia	141.8	33.1	233.3
Other Eurasia	195.9	34.5	176.1
Belarus	9.6	3.3	338.1
Bulgaria	7.6	2.5	331.4
Kazakhstan	15.9	2.7	167.4
Romania	21.3	4.2	199.5
Ukraine	45.7	6.5	142.6
Eurasia	**337.7**	**67.6**	**200.1**
World	**6,829.7**	**868.9**	**127.2**

Sources: *International Road Federation (IRF), World Road Statistics (WRS), various editions, OPEC Secretariat database.*

Figure 2.5
Passenger cars, 1970–2009

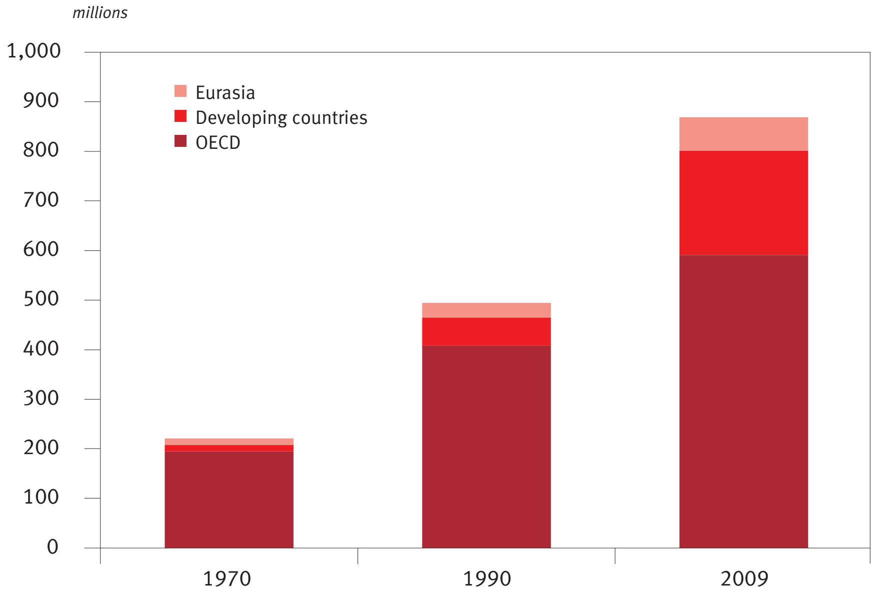


Figure 2.6
Growth in passenger cars, 2000–2009

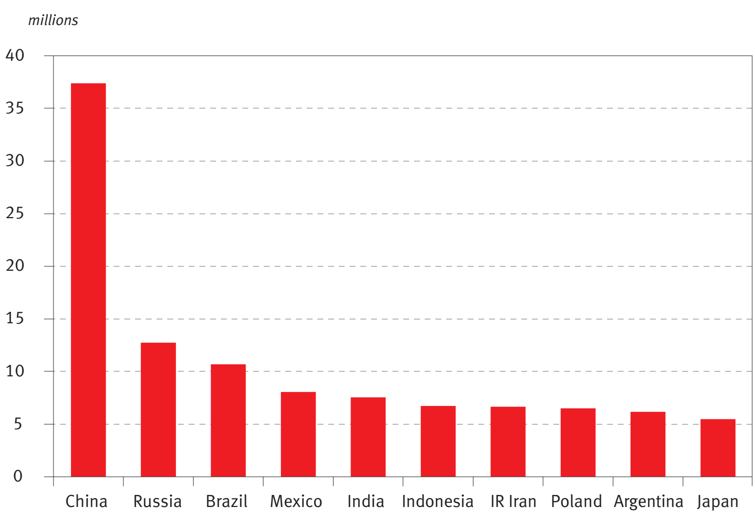


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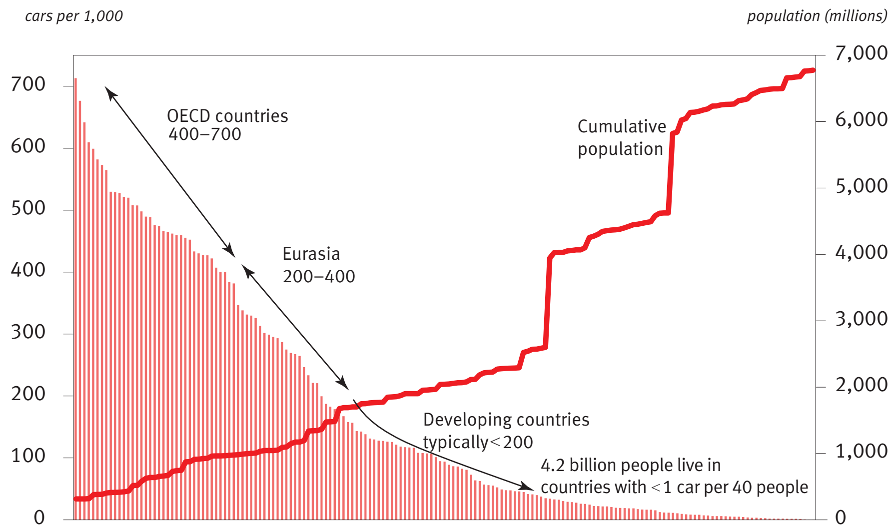
Figure 2.7
Passenger car ownership per 1,000, 2009



Sources: IRF, WRS, various editions, OPEC Secretariat database.

reaching more than 1.7 billion cars. Over this period an additional 140 million cars are accounted for by OECD countries. Of course, the impact in developing countries is more dramatic, with an extra 700 million cars over this timeframe (Figure 2.8). With these developments, by 2030 there will be more cars in developing countries than in the OECD. And 59% of the increase in cars will be in developing Asia.

Rapid car ownership growth in developing countries means that per capita car ownership is also expected to change quite dramatically: China moves from just 34 cars per 1,000 people in 2009 to 213 per 1,000 by 2035, higher than the rate seen in South Korea at the turn of this century and similar to the rate seen in Japan in the early 1980s. The rate of growth of car ownership is at its greatest in India. It witnesses an average annual growth of more than 10%, a massive movement from around just one car per 100 people in 2009 to slightly over one in 10 people by 2035, about the same as Taiwan in 1990. Other Asia rises to a similar level. Ownership in the Middle East & Africa will remain less than one car per 20 people by 2035. OPEC car ownership rates more than double, from 75 to 180 per 1,000, involving a significant increase of over 80 million cars.

Table 2.2
Projections of passenger car ownership rates to 2035

	Cars *per 1,000*			Cars *million*			Car growth *% p.a.*
	2009	**2020**	**2035**	**2009**	**2020**	**2035**	**2009–2035**
OECD America	550	572	602	263	302	351	1.1
OECD Europe	438	451	477	240	258	280	0.6
OECD Asia Oceania	420	449	479	88	96	102	0.6
OECD	**479**	**499**	**530**	**591**	**655**	**732**	**0.8**
Latin America	147	174	213	60	79	107	2.3
Middle East & Africa	26	34	47	22	37	68	4.5
India	11	31	115	14	43	180	10.4
China	34	93	213	46	130	297	7.4
Other Asia	36	65	106	39	79	145	5.2
OPEC	75	102	180	30	51	114	5.3
Developing countries	**40**	**70**	**132**	**210**	**420**	**911**	**5.8**
Russia	233	268	327	33	37	43	1.0
Other Eurasia	176	255	363	34	51	73	2.9
Eurasia	**200**	**260**	**349**	**68**	**88**	**116**	**2.1**
World	**127**	**151**	**206**	**869**	**1,163**	**1,760**	**2.8**

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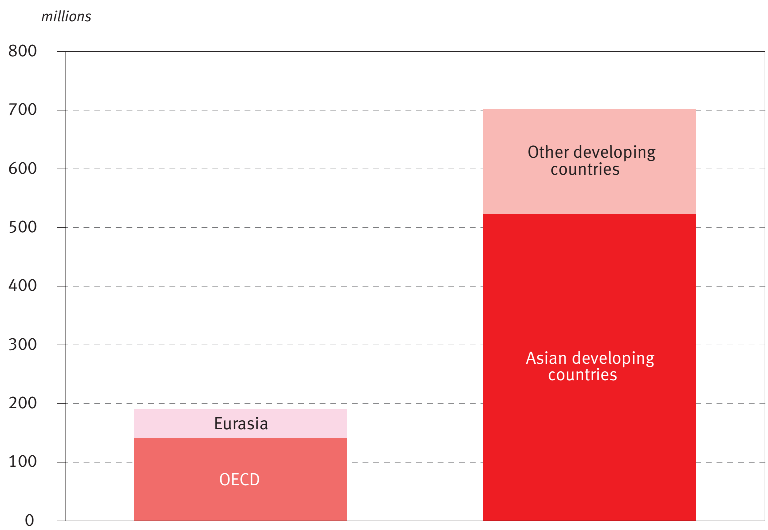
Figure 2.8
Increase in number of passenger cars, 2009–2035



Commercial vehicles

The projections of the number of commercial vehicles in the Reference Case are shown in Table 2.3. Over 480 million commercial vehicles are expected to be on the roads by 2035. This reflects an average increase of 3.8% p.a. from 2009, higher than the expected annual average rate of global economic growth. Developing Asia is the key source of the increase, accounting for 58% globally (Figure 2.9). By 2030, India has as many trucks as China and, by 2035 it will have more than any of the three highlighted OECD regions (Table 2.3).

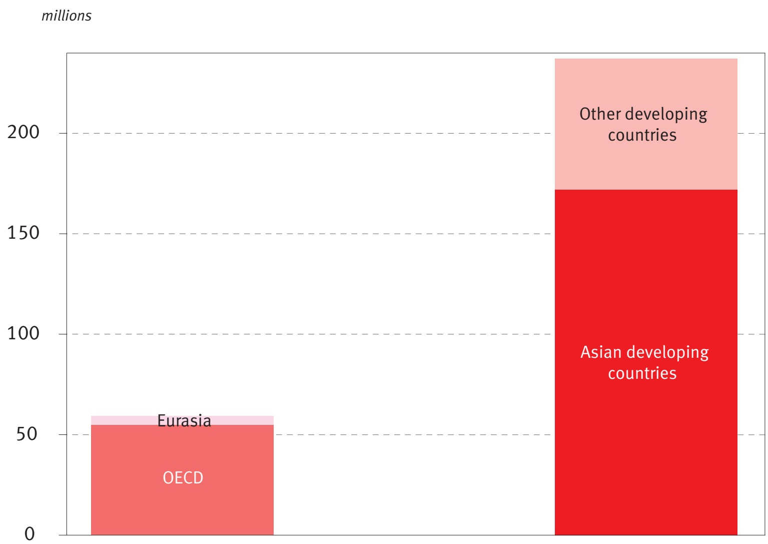
Table 2.3
Commercial vehicles in the Reference Case *millions*

	2009	2010	2015	2020	2025	2030	2035	Lorry growth *% p.a.* 2009–2035
OECD America	33	34	37	40	43	46	50	1.6
OECD Europe	38	39	42	47	53	60	67	2.2
OECD Asia Oceania	25	28	29	31	32	34	35	1.2
OECD	**96**	**101**	**108**	**118**	**129**	**140**	**151**	**1.7**
Latin America	15	19	22	26	30	34	39	3.7
Middle East & Africa	10	10	14	17	22	27	34	4.9
India	8	10	15	23	34	50	72	9.1
China	16	17	23	31	40	50	62	5.3
Other Asia	20	23	31	41	52	65	82	5.6
OPEC	10	12	14	17	20	24	28	3.8
Developing countries	**79**	**90**	**119**	**155**	**198**	**251**	**316**	**5.5**
Russia	5	6	6	6	6	6	7	0.8
Other Eurasia	3	3	4	5	5	6	7	2.5
Eurasia	**9**	**9**	**10**	**11**	**12**	**12**	**13**	**1.6**
World	**184**	**201**	**237**	**284**	**339**	**403**	**481**	**3.8**

Oil use per vehicle

Key to oil demand patterns in the road transportation sector, in addition to the actual projected quantities of vehicles in the future, is the amount of oil that is used on average across the fleet of cars and commercial vehicles. This, in turn, is determined

Figure 2.9
Increase in volume of commercial vehicles, 2009–2035



by usage patterns, the efficiency of the fleet of vehicles using the internal combustion engine (ICE), and the pace of development and penetration of vehicle technologies, including non-petroleum-based engines.

Usage patterns, in terms of the average distance travelled per vehicle varies over time, between countries, and between individual in these countries. The major factors affecting usage are:

- Wealth levels, with high income countries that have high levels of car ownership per capita typically experiencing saturation in usage rates;
- Incomes can also affect usage in the opposite direction, with driving related to the ability to pay, not only for the vehicle, but also for fuel;
- The age and gender structure of the population, with average annual miles per driver tending to be lower for older, as well as female drivers;[11]
- Infrastructure and public transport availability;
- Congestion;
- Consumer behaviour, for example, the effects of a rise in telecommuting; and
- Commercial vehicle usage, which is affected by a number of factors, such as geography, economic conditions and vehicle size.

In terms of the ICE vehicle efficiencies, these will be determined by:

- The efficiencies of new vehicles, which is affected by several factors, specifically policies, technological developments and consumer preferences;
- Government policies, which are central to the future development of new car efficiencies;[12]
- Another element of policy is related to climate change, and the extent to which efficiency targets and alternative fuels are linked to CO_2 emissions;
- It is also important to stress that technological evolution is an innate feature of any competitive industry, whether mandated by legislation or not;
- The impacts of new-vehicle efficiency on the average oil used per vehicle will depend upon the rate at which old vehicles are scrapped, as well as the size of the fleet;
- The mix between gasoline and diesel will affect average car efficiencies; and
- The scope for efficiency improvements in commercial vehicles is more limited than for passenger cars, and fuel economy targets are generally not applied. However, this may change over time.

The list of alternative technologies in the transportation sector has grown in recent years, and all options clearly carry implications for average oil use per vehicle. Some of the possibilities are highlighted below:

- Hybrids: this technology is seen as the most likely to emerge as over the projection period to 2035. It includes both the ICE hybrid and plug-in hybrid;
- Electric vehicles: currently hindered by cost, low driving range, long charging time and the low availability of charging stations. It is a technology that may emerge as an alternative to ICEs for specific usages, such as over short-distances;
- Natural gas: the potential future role for natural gas in the transportation sector is attracting increasing attention, particularly in the US (Box 2.1). Low natural gas prices compared to gasoline in the US, and the rising importance of shale gas production in the country, may see natural gas vehicles (NGVs) play a greater role in the transportation sector, in particular for freight and the urban large vehicle fleet. Over recent years, the worldwide growth for NGVs has been over 25% p.a., and many predict a further steep rise in market share. Perhaps the key prospect is for LNG long-haul truck companies to switch from diesel, although the availability of fuelling infrastructure constitutes a key obstacle that needs to be overcome;
- Other alternatives, such as fuel cells, will probably remain insignificant over the Reference Case projection period to 2035.

Despite these possibilities, the traditional ICE vehicle will continue to be the main road transportation mean for the foreseeable future. Many conveniences such as reliability, global service network, mobility, range independence and relative cost, as well as the unmatched petroleum energy-density and ease of transport and storage will guarantee continued demand for petroleum-powered cars.

All of the oil usage highlighted elements demonstrate that the average rate of oil use per vehicle is sensitive to a wide range of factors. Yet this is a central variable in the assessment of oil demand prospects. It shows, at the qualitative level, the very large uncertainties associated with oil demand projections. Some of these uncertainties are explored in more detail in scenario analyses in Chapter 4.

Table 2.4 documents the assumptions made for oil use per vehicle in the Reference Case. For the entire world, average efficiency improvements occur at 2% p.a. for the period 2009-2035, higher than in the previous WOO. OECD countries see an average decline of just under 2% p.a. in oil use per vehicle, a more rapid fall than assumed in the previous WOO. Developing countries see an average decline of 2.3% p.a., while the slowest rate of change is in Eurasia.

As already emphasized, these assumptions are subject to enormous uncertainty, but what they do reflect is the continued dominance of the ICE as the key technology in this sector over the projection period, albeit with a more rapid take-off of alternative technologies in the post-2025 period.

Table 2.4
Average growth in oil use per vehicle *% p.a.*

	1971–1980	1980–1990	1990–2009	2009–2035
OECD	–1.3	–0.4	–0.5	–1.9
Developing countries	–1.6	–1.9	–2.0	–2.3
Eurasia	2.0	–2.1	–5.3	–0.7
World	–1.1	–0.8	–0.8	–2.0

Box 2.1
Natural gas for America's highways: how long is the road?

With the availability of abundant gas supplies in the US, and the present benefit of a hefty price premium to oil, new applications and markets are being sought for natural gas. Both, electricity generation and petrochemicals are obvious sectors, but a key question concerns the extent to which the captive road transport sector, may also develop into a significant market for natural gas use.

Natural gas is already present in the road transportation sector, but only marginally. Today, half of all natural gas vehicles registered globally can be found in three countries: Pakistan, Iran and Argentina. This is due to a large advantage in pricing, constraints in gasoline supply, and the availability of a substantial network of natural gas fuel stations, for instance in Pakistan about 40% of cars are powered by natural gas.

In the US, heavy, long-haul trucks in particular, have recently become the focus for natural gas. Fuel contributes to about 37% of a truck's total[13] operating costs and from this perspective a switch to natural gas could become attractive for truck owners, given the low natural gas price in the US compared to diesel. A few truck operators have already switched to natural gas, but due to a lack of available public natural gas stations they are maintaining their own private refuelling network. Proposed US legislation suggests additional US$ tax incentives for the purchase of new and the conversion of older trucks to natural gas.[14] Extra incentives may be provided for enhancing the fuelling infrastructure in order to assure public availability of natural gas.

Vehicles powered by natural gas have been around for some time; the technology is mature and reliable, natural gas in the US is cheap and for new vehicles most safety concerns have been resolved. In addition, the price premium to be paid for new factory built natural gas cars has narrowed to about 10%, compared to diesel powered sister models. Natural gas engines for road vehicles are built on conventional four-stroke spark ignition architecture, similar to petrol engines, but with a higher compression ratio. They can be operated by compressed natural gas (CNG) or LNG, or petrol. Many CNG vehicles are equipped with an additional small tank for gasoline: in case they run out of natural gas a seamless switch to petrol is possible, enhancing range and flexibility. Although, in gasoline mode some sacrifices in efficiencies and performance have to be accepted. In contrast to retrofits, new natural gas vehicles with dedicated, turbocharged engines offer competitive efficiencies and driving performance. Fewer emissions, and reduced oil change intervals add to the basket of benefits.

Unfortunately, the energy density of retail CNG compares to only 20% of conventional liquid fuels. This effectively requires tanks five times larger than needed for traditional fuels. Consumers, especially commercial operators do not appreciate such bulky tanks because it increases weight, and reduces the effective payload and cargo space. LNG offers a 'half way' out of this dilemma, by freezing the gas into liquid form below its boiling point of -162°C. Compared to CNG, LNG thermostatic fuel tanks are compact, but still more than twice the size of diesel tanks and relatively expensive due to the utilization of special materials and advanced technology. Nevertheless, in the US, LNG has emerged as an attractive option for commercial long-haul trucks, where it is important to carry large amounts of fuel and where payload requirement and the economies of scale for a big tank plays in favour of LNG.

Despite all the benefits, the biggest obstacle and key question prior to adopting CNG or LNG as a common road transport fuel, especially in the US, will remain the availability of a widespread network of natural gas stations. In September 2012, there were 1,166 natural gas stations in the US, less than 1% of the total number; about half of them are open to the public and only 59 outlets offer LNG.

Developing a viable natural gas logistics and retail sector is very capital intensive, and without a solid customer base does not appeal as an attractive business model.

The existing US tax credit for natural gas fuelling infrastructure expired at the end of 2011, with limited success. A new legislation is proposed, but its outcome at this point remains unclear.

Moves to develop more public LNG stations strategically located at major interstate corridors across the US are underway, or have been announced.[15] Together with tax incentives, this could encourage a broader natural gas technology adoption for the commercial heavy-duty trucking sector, and in the longer term, for CNG light trucks and cars.

However, such developments will take considerable time. It will be an evolutionary process and for natural gas to become a major fuel, the road to success will be long.

Road transportation demand projections

Reference Case projections for road transportation oil demand levels and growth rates are shown in Tables 2.5 and 2.6. World demand increases by slightly more than 9 mboe/d over the period 2009–2035. OECD road transportation demand falls steadily from 2010 onwards as the decline in oil use per vehicle, from efficiency gains, the rising importance of alternative fuels, and a variety of other factors also highlighted earlier in this Chapter, combine to more than compensate for the growth in the number of vehicles.

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

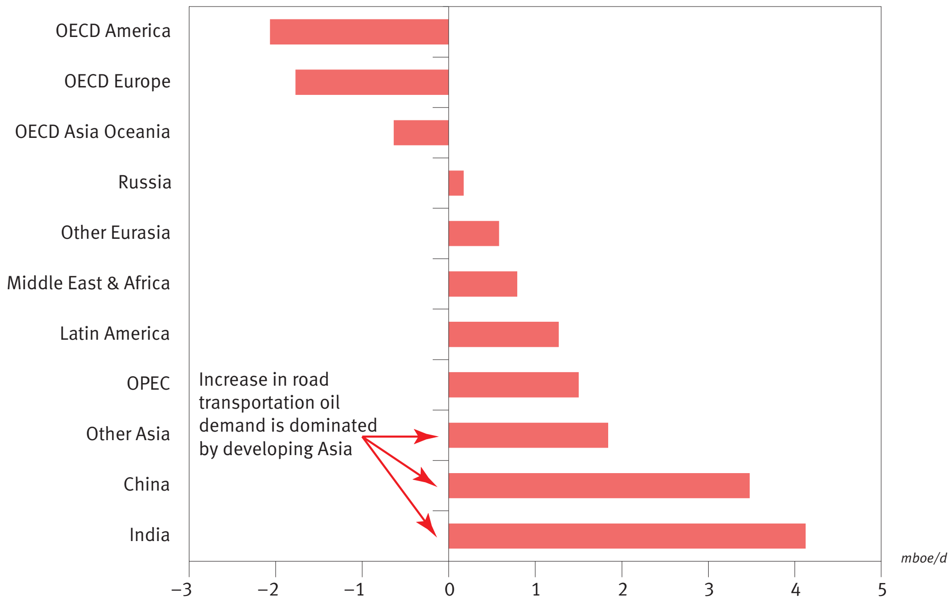
	Levels				Growth
	2009	2010	2020	2035	2009–2035
OECD America	12.1	12.5	11.9	10.1	–1.9
OECD Europe	6.2	6.0	5.1	4.2	–2.0
OECD Asia Oceania	2.6	2.7	2.8	2.1	–0.5
OECD	**20.9**	**21.2**	**19.7**	**16.4**	**–4.4**
Latin America	1.9	2.5	2.9	3.1	1.3
Middle East & Africa	1.3	1.3	1.8	2.2	0.9
India	0.9	0.9	1.9	4.8	4.0
China	2.5	2.5	4.6	5.8	3.4
Other Asia	2.2	2.4	3.3	3.9	1.8
OPEC	2.8	2.6	3.6	4.5	1.7
Developing countries	**11.4**	**12.2**	**18.1**	**24.5**	**13.1**
Russia	0.8	1.0	1.2	1.1	0.3
Other Eurasia	0.7	0.6	0.8	1.0	0.3
Eurasia	**1.5**	**1.6**	**2.0**	**2.1**	**0.6**
World	**33.9**	**35.0**	**39.8**	**43.0**	**9.1**

Table 2.6
Growth in oil demand in road transportation in the Reference Case *% p.a.*

	1990–2009	2009–2020	2020–2035
OECD America	1.5	–0.2	–1.1
OECD Europe	1.3	–1.8	–1.2
OECD Asia Oceania	1.5	0.6	–1.8
OECD	**1.4**	**–0.5**	**–1.2**
Latin America	2.9	4.1	0.6
Middle East & Africa	3.9	3.0	1.5
India	3.7	7.6	6.3
China	9.7	5.9	1.6
Other Asia	4.6	3.8	1.2
OPEC	4.3	2.3	1.6
Developing countries	**4.8**	**4.3**	**2.0**
Russia	–0.5	2.4	–0.9
Other Eurasia	–1.2	0.8	2.0
Eurasia	**–0.8**	**1.7**	**0.4**
World	**2.2**	**1.5**	**0.5**

Figure 2.10 shows that by 2020, non-OECD oil use in road transportation will be greater than in the OECD. Moreover, the increase in road transportation oil demand is dominated by developing Asia.

Figure 2.10
Growth in oil consumption in road transportation, 2009–2035



Aviation

Global oil use in the aviation sector grew at an average of 1.4% p.a. over the years 1990–2009. In 2009, it accounted for 6% of global oil demand. Over this period, the fastest growth was in developing countries, at 4.6% p.a. While in the early 1970s developing countries accounted for just 16% of demand in this sector, it has now risen to close to one-third, and this share is set to rise further. Nevertheless, the OECD will maintain its central position in oil use in air passenger and freight services over the projection period.

Since the turn of the century, passenger-kilometres flown have risen by an average of 5% p.a. globally, with developing countries rising at double that rate. There were over 30 million scheduled commercial flights in 2010, more than one-third of these in North America.[16] Asia and Europe together accounted for one-half of departures.

Oil demand growth in this sector is very closely linked to economic activity but efficiency gains act to limit increases in fuel use. On top of this, the sector is sensitive to higher jet fuel prices.

A potentially important change in this sector since the release of the WOO 2011 – and one which makes this price sensitivity all the more significant – is the move by the European Union (EU) to include the aviation sector in its emissions trading scheme (ETS) at the beginning of 2012. This effectively imposes a tax on carbon emissions from flights within EU airspace. This measure covers all EU states, plus Norway, Iceland and Liechtenstein, and eventually Croatia, which totals (ultimately) 31 countries.

Initial impacts are expected to be limited, since the start of the scheme foresees airlines operators receiving 85% of the total quantity of emissions allowances for free, and then 82% over the period 2013–2020. Nevertheless, since the total quantity of allowances is set as 95% of historical aviation emissions, and 15% of allowances will be assigned by auctioning, costs are set to rise, and passenger tickets and freight unit costs will be affected.

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

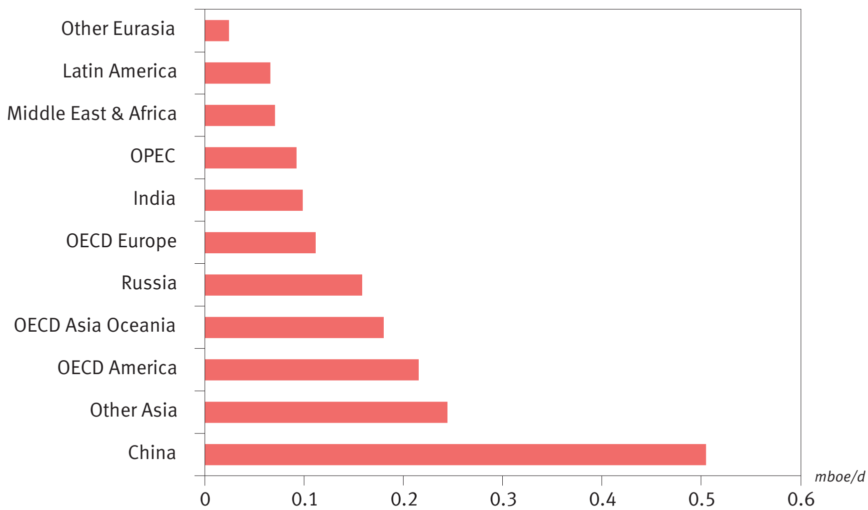
	Levels				Growth
	2009	**2010**	**2020**	**2035**	**2009–2035**
OECD America	1.6	1.6	1.7	1.8	0.2
OECD Europe	1.1	1.1	1.1	1.2	0.1
OECD Asia Oceania	0.4	0.4	0.5	0.6	0.2
OECD	**3.0**	**3.1**	**3.3**	**3.5**	**0.5**
Latin America	0.2	0.2	0.2	0.2	0.1
Middle East & Africa	0.2	0.2	0.2	0.3	0.1
India	0.1	0.1	0.1	0.2	0.1
China	0.3	0.3	0.5	0.8	0.5
Other Asia	0.5	0.5	0.6	0.7	0.2
OPEC	0.3	0.3	0.3	0.3	0.1
Developing countries	**1.5**	**1.5**	**2.0**	**2.6**	**1.1**
Russia	0.2	0.2	0.3	0.4	0.2
Other Eurasia	0.1	0.1	0.1	0.1	0.0
Eurasia	**0.3**	**0.3**	**0.3**	**0.5**	**0.2**
World	**4.8**	**4.9**	**5.6**	**6.6**	**1.8**

Table 2.8
Growth in oil demand in aviation in the Reference Case

% p.a.

	1990–2009	2009–2020	2020–2035
OECD America	–0.3	0.8	0.3
OECD Europe	3.0	0.5	0.3
OECD Asia Oceania	2.2	1.6	1.3
OECD	**0.9**	**0.8**	**0.5**
Latin America	2.8	1.7	0.9
Middle East & Africa	3.7	1.1	1.3
India	5.5	2.5	2.8
China	15.9	5.4	3.0
Other Asia	4.8	1.9	1.5
OPEC	1.9	1.8	0.8
Developing countries	**4.6**	**2.6**	**1.8**
Russia	–2.7	2.5	1.9
Other Eurasia	–3.8	1.8	1.1
Eurasia	**–3.0**	**2.4**	**1.8**
World	**1.4**	**1.5**	**1.0**

Figure 2.11
Growth in aviation oil demand, 2009–2035



Chapter 2

The measure may lead to the introduction of more efficient aircraft, but with the slow turnover of capital stock this initial effect will be minimal: it has been estimated that by 2020 only 1% of aviation-kilometres flown will come from new planes.[17]

Tables 2.7 and 2.8 show the Reference Case levels and growth rates for oil demand in this sector for the Reference Case. Over the period 2009–2035 average global growth of 1% p.a. sees demand increase by close to 2 mboe/d. The fastest growth rates are in China and India, both around 3% p.a., but China registers the highest absolute growth, as it starts from a higher base. Indeed, developing Asia accounts for 48% of the global increase (Figure 2.11).

Rail and domestic navigation

When looking at the overall demand picture, a relatively insignificant contribution to oil demand comes from trains and domestic waterways navigation. This sector accounted for less than 2 mboe/d in 2009, with three-quarters of the oil use in the OECD or China. Demand in this sector in OECD countries has been steadily falling, and this is set to continue, while use in developing countries has been rising,

Figure 2.12
Oil use in rail and domestic navigation, 1970–2035

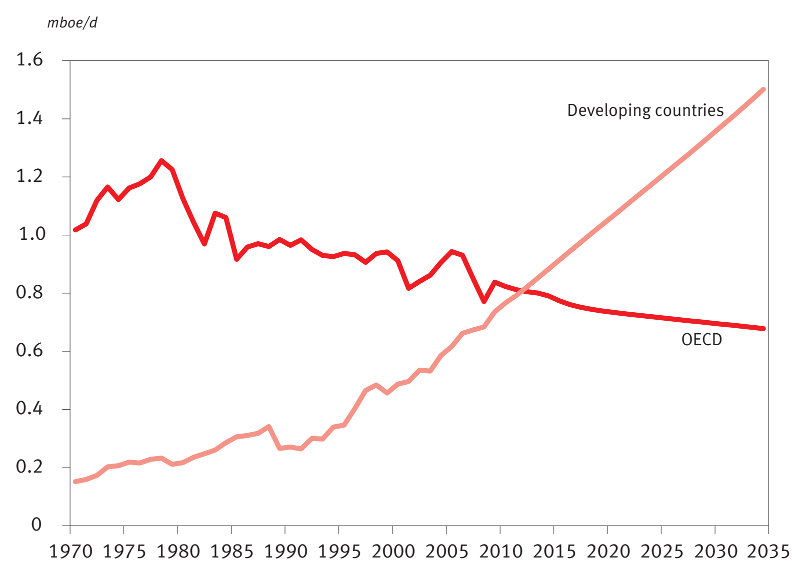


Table 2.9
Oil demand in rail and domestic navigation in the Reference Case *mboe/d*

	Levels				Growth
	2009	2010	2020	2035	2009–2035
OECD America	0.4	0.4	0.4	0.3	0.0
OECD Europe	0.3	0.3	0.2	0.2	0.0
OECD Asia Oceania	0.2	0.2	0.1	0.1	0.0
OECD	**0.8**	**0.8**	**0.7**	**0.7**	**–0.1**
Latin America	0.1	0.1	0.1	0.2	0.1
Middle East & Africa	0.0	0.0	0.0	0.0	0.0
India	0.1	0.1	0.1	0.2	0.1
China	0.4	0.5	0.7	1.0	0.6
Other Asia	0.1	0.1	0.1	0.2	0.1
OPEC	0.0	0.0	0.0	0.0	0.0
Developing countries	**0.7**	**0.7**	**1.0**	**1.5**	**0.8**
Russia	0.1	0.1	0.1	0.1	0.0
Other Eurasia	0.0	0.0	0.0	0.0	0.0
Eurasia	**0.3**	**0.3**	**0.3**	**0.5**	**0.2**
World	**1.6**	**1.7**	**1.9**	**2.3**	**0.7**

Table 2.10
Growth in oil demand in rail and domestic navigation in the Reference Case *% p.a.*

	1990–2009	2009–2020	2020–2035
OECD America	–2.1	0.2	–0.8
OECD Europe	–0.3	–0.8	–0.4
OECD Asia Oceania	–0.6	–1.5	–0.2
OECD	**–1.3**	**–0.4**	**–0.6**
Latin America	1.9	3.1	2.8
Middle East & Africa	6.9	0.0	0.0
India	3.1	2.6	2.9
China	7.8	4.7	2.5
Other Asia	2.6	2.4	2.3
OPEC	1.6	2.0	1.5
Developing countries	**5.1**	**3.8**	**2.5**
Russia	–6.6	1.8	1.5
Other Eurasia	–4.5	–0.5	–1.0
Eurasia	**–6.0**	**1.1**	**0.9**
World	**–0.1**	**1.7**	**1.3**

particularly due to the movement of goods on China's waterways. By 2013, developing country use for this sector will exceed that of the OECD (Figure 2.12).

Tables 2.9 and 2.10 show the Reference Case outlook for oil demand levels and growth rates for trains and domestic waterways navigation.

Marine bunkers

Last year's WOO discussed at length the regulation of fuel quality specifications for the marine bunker sector. The key change has been a lowering of sulphur levels from 4.5% to 3.5%, although this is thought to have had little impact, given the fact that most fuels in use in the sector already satisfy this requirement. Although implications will be more significant if far more stringent standards are introduced as proposed in the longer term, it is expected that this will affect the refining sector more than the level of demand.

An exception to this idea is the possibility of switching to LNG to satisfy these requirements, which would displace some oil in the marine bunkers sector. This is

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

	Levels				Growth
	2009	2010	2020	2035	2009–2035
OECD America	0.5	0.6	0.6	0.6	0.1
OECD Europe	0.9	0.8	0.8	0.8	–0.2
OECD Asia Oceania	0.3	0.2	0.1	0.1	–0.2
OECD	**1.8**	**1.6**	**1.5**	**1.5**	**–0.3**
Latin America	0.2	0.2	0.3	0.4	0.3
Middle East & Africa	0.1	0.1	0.1	0.2	0.0
India	0.0	0.0	0.0	0.0	0.0
China	0.2	0.3	0.6	1.9	1.7
Other Asia	1.0	1.0	1.3	1.9	0.9
OPEC	0.4	0.4	0.5	0.7	0.2
Developing countries	**1.9**	**2.0**	**2.8**	**5.0**	**3.1**
Russia	0.0	0.0	0.1	0.2	0.2
Other Eurasia	0.1	0.1	0.1	0.1	0.0
Eurasia	**0.1**	**0.1**	**0.2**	**0.3**	**0.2**
World	**3.8**	**3.6**	**4.5**	**6.8**	**3.1**

Table 2.12
Growth in oil demand in marine bunkers in the Reference Case *% p.a.*

	1990–2009	2009–2020	2020–2035
OECD America	–0.7	1.1	–0.2
OECD Europe	1.5	–1.2	–0.3
OECD Asia Oceania	3.0	–7.3	–0.5
OECD	**1.0**	**–1.2**	**–0.3**
Latin America	4.6	4.7	2.8
Middle East & Africa	–0.3	1.9	1.1
India	0.4	–13.2	0.0
China	10.5	11.6	7.3
Other Asia	6.4	2.2	2.8
OPEC	4.0	1.6	1.8
Developing countries	**5.1**	**3.7**	**3.9**
Russia	0.5	6.7	6.1
Other Eurasia	5.4	1.3	2.3
Eurasia	**2.9**	**3.8**	**4.6**
World	**2.7**	**1.7**	**2.8**

discussed in Section Two. However, as described in the WOO 2011, safety concerns and infrastructure constraints are likely to limit this effect.

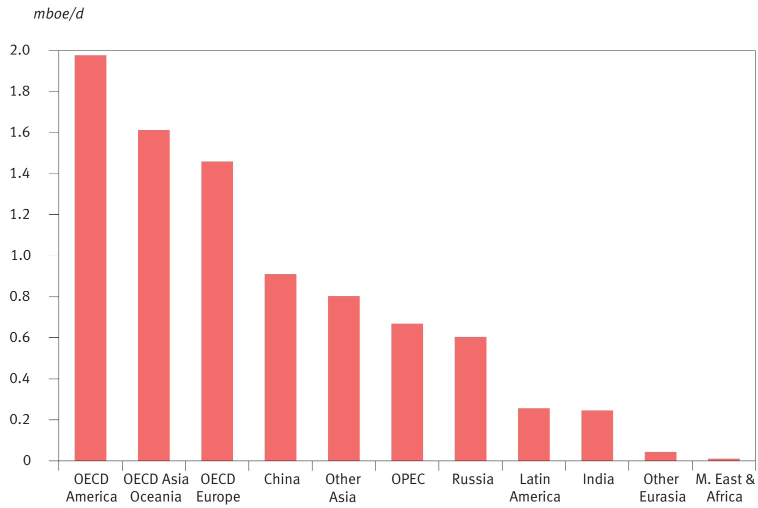
Taking all this into account, it is assumed in the Reference Case that only minor downward pressures emerge on the overall volume of oil used in this sector. The outlook continues to see growth in international trade affecting shipping activity, with on-going efficiency improvements playing a role in limiting oil demand growth. Tables 2.11 and 2.12 show the Reference Case projections for the increase in oil demand in marine bunkers, which is 3.1 mboe/d over the years 2009–2035. The biggest increase, as in the previous WOO, is in China and Other Asia, which account for 85% of the demand growth. Total OECD oil demand in this sector falls over the projection period.

Other sectors

Petrochemicals

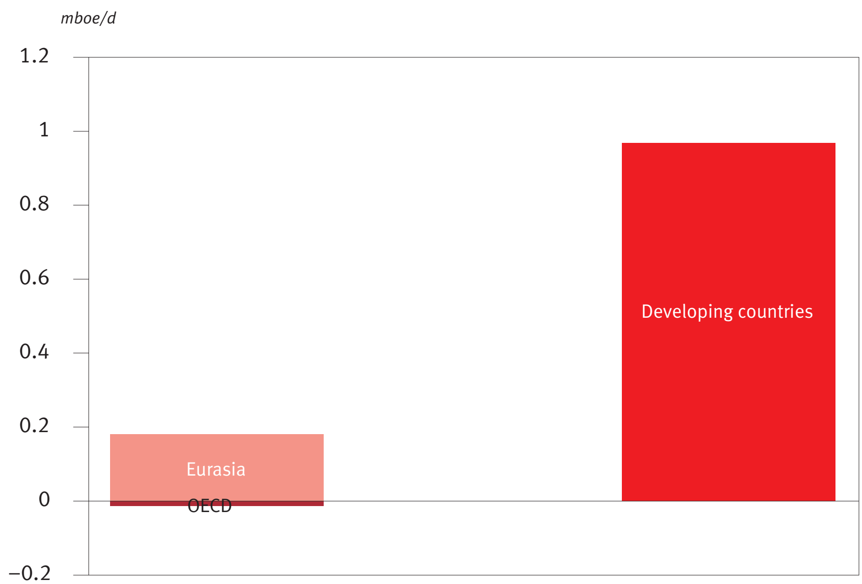
After the transportation sector, the next largest user of oil is 'industry'. In the Reference Case this sector is split into two distinct categories: petrochemicals and other

Figure 2.13
Oil use in the petrochemical sector in 2009



Source: *OECD/IEA Energy Balances of OECD/non-OECD countries, 2011.*

Figure 2.14
Growth in oil use in the petrochemical sector, 2000–2009



Source: *OECD/IEA Energy Balances of OECD/non-OECD countries, 2011.*

industry. Total 'industry' oil usage in 2009 accounted for 28% of the global figure. Petrochemicals alone accounted for almost 11%, as a feedstock and as energy to transform feedstocks into end products. Over 60% of petrochemical oil use is in OECD countries (Figure 2.13). Among developing countries, more than 90% of oil use is in OPEC or Asia. However, what these relative rates of usage disguise, is that the increase in oil use in the petrochemicals sector over the past decade has been predominantly in developing countries (Figure 2.14).

The Reference Case outlook for oil use in the petrochemical sector is presented in Tables 2.13 and 2.14. Demand in developing countries increases to 5.5 mboe/d by 2035, similar to the level in OECD countries by that year. By 2030, non-OECD oil use in the petrochemicals sector will exceed that of OECD countries. The key to demand growth is in OPEC and developing Asia, which together account for three-quarters of the global increase. The closure of steam crackers operating in OECD countries is likely, particularly in the US. A key uncertainty over the growth in oil demand for this sector concerns competition from natural gas, which currently benefits from a favourable large price spread.

Table 2.13
Oil demand in the petrochemical sector in the Reference Case *mboe/d*

	Levels				Growth
	2009	2010	2020	2035	2009–2035
OECD America	2.0	2.0	2.1	2.3	0.3
OECD Europe	1.5	1.5	1.5	1.6	0.1
OECD Asia Oceania	1.6	1.6	1.7	1.7	0.1
OECD	**5.1**	**5.1**	**5.3**	**5.6**	**0.5**
Latin America	0.3	0.3	0.3	0.4	0.1
Middle East & Africa	0.0	0.0	0.0	0.0	0.0
India	0.2	0.2	0.3	0.4	0.2
China	0.9	1.0	1.2	1.3	0.4
Other Asia	0.8	0.8	1.0	1.2	0.4
OPEC	0.7	0.7	1.1	2.2	1.5
Developing countries	**2.9**	**3.0**	**3.9**	**5.5**	**2.6**
Russia	0.6	0.6	0.7	0.7	0.1
Other Eurasia	0.0	0.0	0.1	0.1	0.0
Eurasia	**0.6**	**0.7**	**0.8**	**0.8**	**0.1**
World	**8.6**	**8.8**	**9.9**	**11.9**	**3.3**

Table 2.14
Growth in oil demand in the petrochemical sector in the Reference Case *% p.a.*

	1990–2009	2009–2020	2020–2035
OECD America	1.8	0.6	0.6
OECD Europe	0.7	0.2	0.4
OECD Asia Oceania	3.1	0.3	0.0
OECD	**1.8**	**0.4**	**0.4**
Latin America	1.7	2.1	1.2
Middle East & Africa	–6.2	0.5	0.5
India	3.7	1.9	1.9
China	5.3	2.4	0.5
Other Asia	8.6	1.7	1.5
OPEC	6.4	4.9	4.6
Developing countries	**5.4**	**2.8**	**2.3**
Russia	2.3	1.3	0.2
Other Eurasia	–1.8	1.3	0.8
Eurasia	**1.9**	**1.3**	**0.3**
World	**2.8**	**1.3**	**1.2**

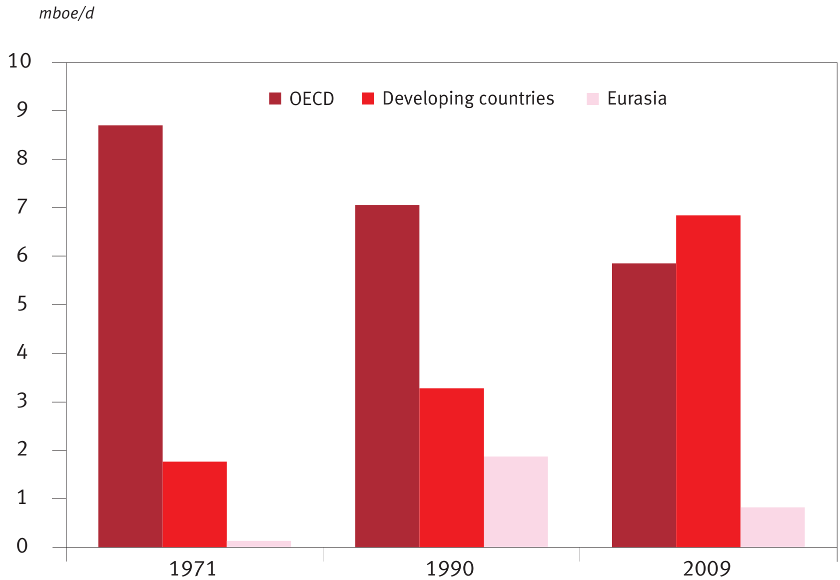
Other industry sector

Removing petrochemicals from industrial oil use leaves what is termed the 'other industry' sector. This is primarily iron and steel, glass and cement production, construction and mining, where diesel and heavy fuel oil are the main products in use. OECD countries have seen oil use fall in these areas, whereas developing countries continue to see growth. In fact, developing countries now use more oil in this sector than the OECD (Figure 2.15).

The prospects for future oil use in this sector across the regions are driven by expected developments in this sector's share of economic activity; the absolute rate of economic growth; oil prices, especially relative to the main competing fuel, natural gas; and the pace of on-going efficiency improvements. The share of industry value-added in GDP has risen markedly for all developing Asian groupings (Figure 2.16). On the other hand, the share of industry in OECD GDP has fallen steadily, with this trend set to continue.

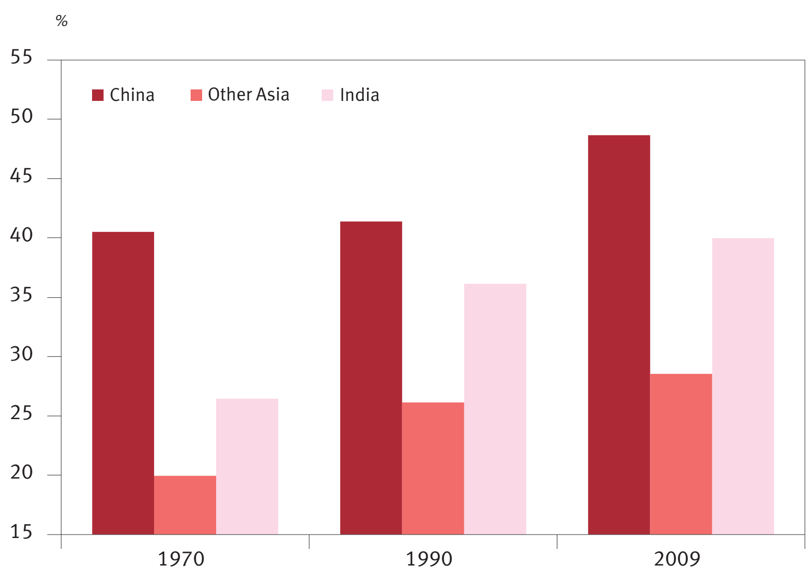
Tables 2.15 and 2.16 summarize the Reference Case projections for oil consumption in this sector. Developing countries see a rise in demand, increasing by close to 2 mboe/d by 2035, compared to 2009. The strongest increase is in India and

Figure 2.15
Oil use in other industry



Source: OECD/IEA Energy Balances of OECD/non-OECD countries, 2011.

Figure 2.16
The share of industry value added in developing Asian economies



Source: OECD/IEA Energy Balances of OECD/non-OECD countries, 2011.

Table 2.15
Oil demand in other industry in the Reference Case *mboe/d*

	Levels				Growth
	2009	2010	2020	2035	2009–2035
OECD America	2.9	3.1	3.0	3.1	0.1
OECD Europe	1.9	1.9	1.8	1.7	–0.2
OECD Asia Oceania	1.0	1.0	1.0	0.9	–0.1
OECD	**5.9**	**6.0**	**5.9**	**5.7**	**–0.1**
Latin America	0.8	0.8	0.9	1.0	0.2
Middle East & Africa	0.6	0.6	0.7	0.8	0.2
India	1.0	1.0	1.2	1.6	0.6
China	2.1	2.2	2.4	2.6	0.5
Other Asia	0.9	0.9	1.0	1.0	0.2
OPEC	1.5	1.5	1.6	1.7	0.2
Developing countries	**6.8**	**7.0**	**7.8**	**8.7**	**1.8**
Russia	0.5	0.5	0.6	0.6	0.1
Other Eurasia	0.4	0.4	0.4	0.4	0.1
Eurasia	**0.6**	**0.7**	**0.8**	**0.8**	**0.1**
World	**13.5**	**13.9**	**14.7**	**15.4**	**1.9**

Table 2.16
Growth in oil demand in other industry in the Reference Case *% p.a.*

	1990–2009	2009–2020	2020–2035
OECD America	–0.9	0.3	0.1
OECD Europe	–0.9	–0.3	–0.5
OECD Asia Oceania	–1.5	0.0	–0.4
OECD	**–1.0**	**0.0**	**–0.2**
Latin America	2.3	1.4	0.2
Middle East & Africa	2.1	0.9	1.0
India	7.4	1.7	1.7
China	6.5	1.3	0.6
Other Asia	1.4	0.9	0.4
OPEC	3.2	0.9	0.4
Developing countries	**3.9**	**1.2**	**0.7**
Russia	–2.4	1.9	0.2
Other Eurasia	–5.9	1.2	0.3
Eurasia	**–4.2**	**1.6**	**0.3**
World	**0.5**	**0.7**	**0.3**

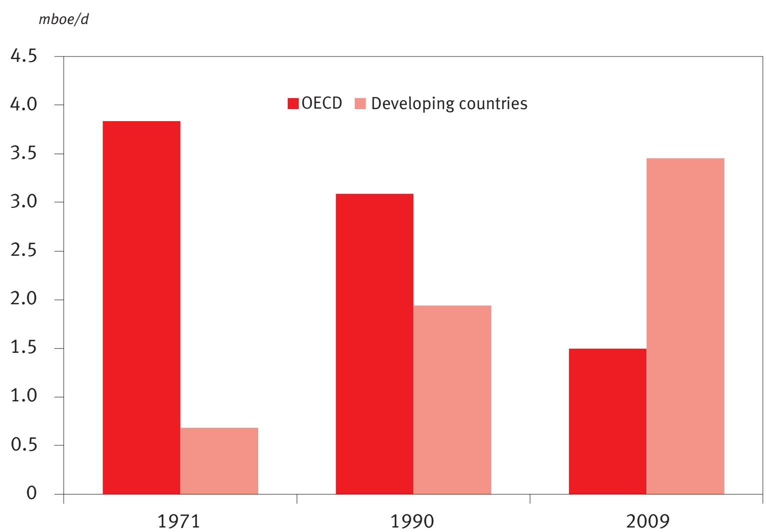
China. Oil use in this sector in the OECD and Eurasia remains essentially flat, as efficiency improvements, fuel switching and the continued declining importance of the sector for economic growth cancel out upward pressures upon oil demand given the aggregate rise in economic activity.

Residential/commercial/agriculture

Of the residential, commercial and public services, agriculture/forestry and fishing sector, it is the residential sector that accounts for close to half of the oil consumption in this grouping. According to the OECD, the treatment of these sectors as one is essentially driven by the difficulties in distinguishing consumption between each of the components. Thus, the sum of the sectors is a more accurate figure than the individual components.

The historical patterns for oil use in these sectors have differed significantly between OECD and developing countries. As can be viewed in Figure 2.17, there has been a strong upward movement in oil use in developing countries partly due to rising levels of income, but also because of the gradual switch to commercial energy use from traditional fuels. While in 1971, OECD use was more than seven times that of

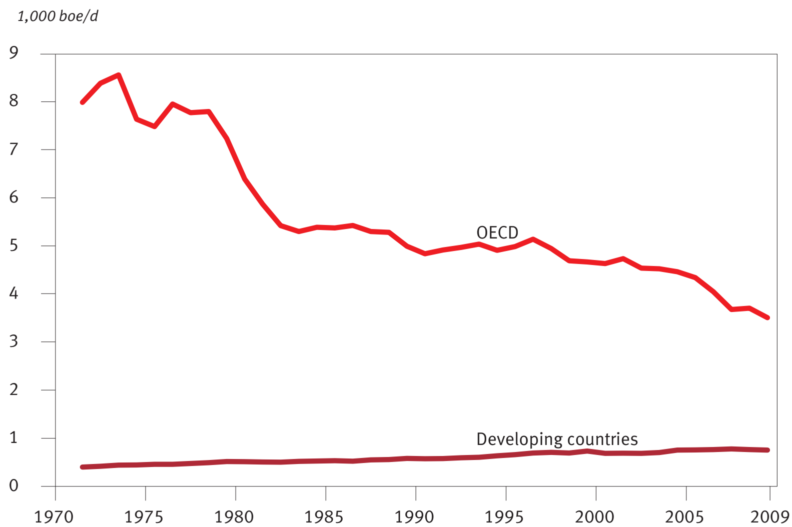
Figure 2.17
Oil use in residential/commercial/agriculture



Source: OECD/IEA Energy Balances of OECD/non-OECD countries, 2011.

developing countries, by 2009 it was just 9% higher. What this disguises, however, is the immense difference in per capita use, as shown in Figure 2.18. While oil use per head has steadily declined in the OECD and increased in developing countries, figures show that the OECD still has around a five times higher per capita use than developing countries in this sector. This is a clear demonstration of the persistence of energy poverty.

Figure 2.18
Per capita oil use in residential/commercial/agriculture



Source: OECD/IEA Energy Balances of OECD/non-OECD countries, 2011.

The Reference Case outlook for oil demand in the residential/commercial/agriculture sectors is presented in Tables 2.17 and 2.18. Demand in developing countries rises by close to 3 mboe/d over the projection period 2009–2035. The downward trends in the OECD continue, and demand falls by a total of 0.7 mboe/d over these years. Global oil use in the sector rises by 2 mboe/d by 2035.

Electricity generation

The electricity generation sector represents an exception to the dominance of developing Asia in oil demand growth patterns. In 2009, less than 18% of the oil used in

Table 2.17
Oil demand in residential/commercial/agriculture in the Reference Case *mboe/d*

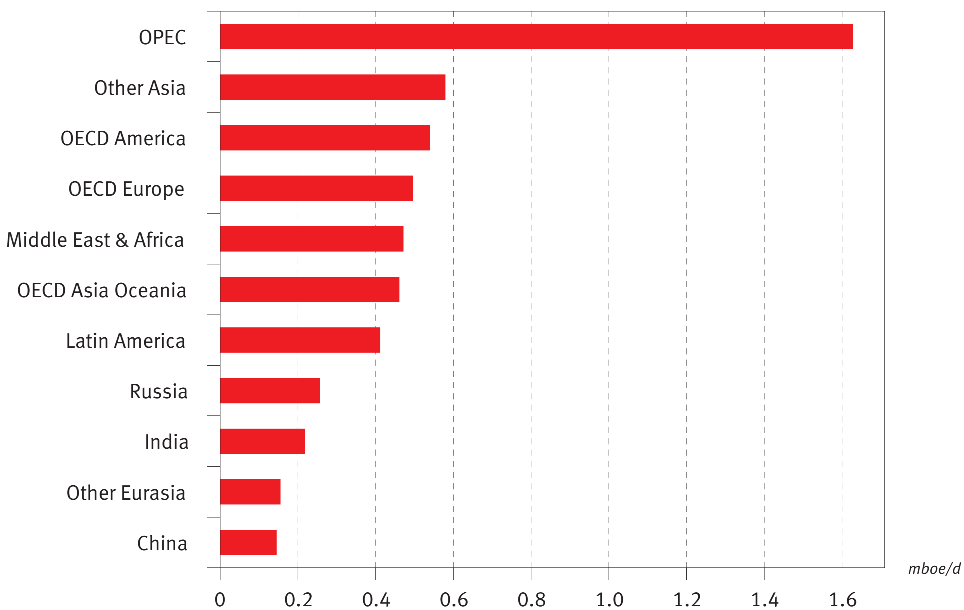
	Levels				Growth
	2009	2010	2020	2035	2009–2035
OECD America	1.6	1.6	1.5	1.3	–0.3
OECD Europe	1.8	1.8	1.6	1.4	–0.4
OECD Asia Oceania	1.0	1.0	1.0	0.9	–0.1
OECD	**4.3**	**4.4**	**4.1**	**3.6**	**–0.7**
Latin America	0.5	0.5	0.7	1.0	0.5
Middle East & Africa	0.5	0.5	0.6	0.8	0.3
India	0.6	0.6	0.8	1.2	0.5
China	1.2	1.2	1.7	2.3	1.1
Other Asia	0.6	0.6	0.7	0.7	0.1
OPEC	0.5	0.6	0.6	0.7	0.2
Developing countries	**4.0**	**4.1**	**5.2**	**6.8**	**2.8**
Russia	0.2	0.2	0.2	0.2	0.0
Other Eurasia	0.3	0.3	0.3	0.2	0.0
Eurasia	**0.5**	**0.5**	**0.5**	**0.4**	**–0.1**
World	**8.8**	**8.9**	**9.8**	**10.8**	**2.0**

Table 2.18
Growth in oil demand in residential/commercial/agriculture in the Reference Case *% p.a.*

	1990–2009	2009–2020	2020–2035
OECD America	–0.3	–0.5	–0.8
OECD Europe	–1.5	–0.8	–1.1
OECD Asia Oceania	–1.0	0.3	–0.7
OECD	**–0.9**	**–0.4**	**–0.9**
Latin America	0.7	3.4	2.3
Middle East & Africa	3.5	1.4	1.8
India	5.0	2.5	2.4
China	6.5	3.5	2.0
Other Asia	2.2	0.9	0.6
OPEC	0.3	1.7	0.9
Developing countries	**3.1**	**2.5**	**1.8**
Russia	–5.4	–0.2	–1.5
Other Eurasia	–5.4	0.0	–0.7
Eurasia	**–5.4**	**–0.1**	**–1.0**
World	**0.0**	**1.0**	**0.7**

this sector was in these countries, and India and China together account for less than 16% of demand growth over the past decade. OPEC is by far the largest user of oil to generate electricity, with more than 30% of global use in Member Countries (Figure 2.19). There has been a steady decline of oil use in this sector in all OECD regions, while developing country use has grown (OPEC accounted for 55% of the increase in developing country use over the years 1971–2009). The year 2000 saw OECD oil use in this sector fall below that of developing countries for the first time, and by 2009 it was just 43% of the total in developing countries (Figure 2.20). Globally, the use of oil in this sector is in steady decline, falling by close to 30% over the years 1990–2009, with a particularly swift reduction in Eurasia.

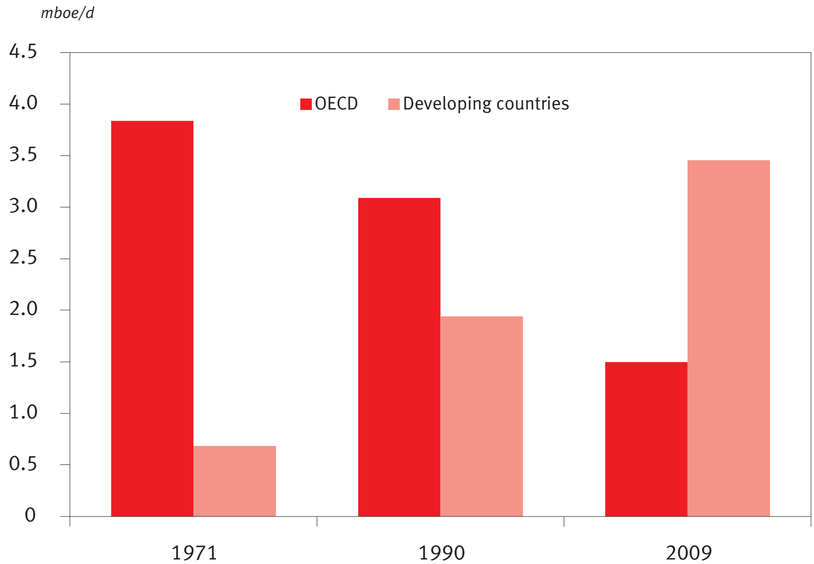
Figure 2.19
Oil use in electricity generation in 2009



Source: OECD/IEA Energy Balances of OECD/non-OECD countries, 2011.

Coal is the dominant fuel in this sector. Fuel switching towards high efficiency combined-cycle gas plants is likely, if severe GHG policies emerge that penalise carbon emissions. US shale gas developments points to an even greater potential for gas in this sector, and while this will mainly compete with coal, it is likely that gas-driven

Figure 2.20
Oil use in electricity generation in OECD and Developing countries



Source: OECD/IEA Energy Balances of OECD/non-OECD countries, 2011.

capacity will continue to replace oil-fired turbines. Some short- to medium-term support for oil use in the sector will come from Japan, as the shut-in of its nuclear power plants following the Fukushima disaster is compensated for, in part, by the use of some oil-based generators. In 2011, this led to a small increase in Japanese oil demand, following a previous period of steady decline. However, the dominant alternative fuel has been LNG.[18] Prospects for future continued increases in oil use in OPEC Member Countries will be limited by the increased availability of natural gas, and the introduction of nuclear power over the longer term. Tables 2.19 and 2.20 show the Reference Case projections for this sector. The only growth comes from Africa and India.

Table 2.19
Oil demand in electricity generation in the Reference Case *mboe/d*

	Levels				Growth
	2009	2010	2020	2035	2009–2035
OECD America	0.5	0.6	0.6	0.6	0.0
OECD Europe	0.5	0.5	0.4	0.3	–0.2
OECD Asia Oceania	0.5	0.5	0.5	0.4	–0.1
OECD	**1.5**	**1.5**	**1.5**	**1.2**	**–0.3**
Latin America	0.4	0.4	0.4	0.4	0.0
Middle East & Africa	0.5	0.5	0.6	0.8	0.3
India	0.2	0.2	0.3	0.4	0.2
China	0.1	0.1	0.1	0.1	0.0
Other Asia	0.6	0.6	0.6	0.5	–0.1
OPEC	1.6	1.6	1.6	1.2	–0.4
Developing countries	**3.5**	**3.5**	**3.5**	**3.4**	**–0.1**
Russia	0.3	0.3	0.2	0.1	–0.1
Other Eurasia	0.2	0.2	0.1	0.1	–0.1
Eurasia	**0.4**	**0.4**	**0.3**	**0.2**	**–0.2**
World	**5.4**	**5.4**	**5.3**	**4.8**	**–0.6**

Table 2.20
Growth in oil demand in electricity generation in the Reference Case *% p.a.*

	1990–2009	2009–2020	2020–2035
OECD America	–2.9	0.6	–0.1
OECD Europe	–3.5	–1.6	–2.4
OECD Asia Oceania	–4.8	1.0	–2.4
OECD	**–3.7**	**0.1**	**–1.4**
Latin America	3.1	0.0	–0.8
Middle East & Africa	3.8	1.6	2.0
India	6.0	2.3	2.5
China	–4.1	–1.2	–1.5
Other Asia	0.7	–0.3	–0.5
OPEC	5.6	–0.4	–1.5
Developing countries	**33.1**	**0.1**	**–0.2**
Russia	–8.0	–2.5	–3.0
Other Eurasia	–10.6	–2.4	–3.0
Eurasia	**–9.1**	**–2.4**	**–3.0**
World	**–1.8**	**–0.1**	**–0.7**

Chapter 3

Liquids supply

Chapter 1 briefly described how total non-OPEC liquids supply continues to rise over the projection period in the Reference Case. This Chapter examines this conclusion in detail from both the medium- and long-term perspectives. The section covering the medium-term to 2016 considers, on the basis of an extensive dataset of currently producing fields and upstream projects, the prospects for non-OPEC crude and NGLs, and other liquids supply, including biofuels and oil sands. This is then extended to the long-term to 2035.

As with the oil demand projections, there is a need to constantly revisit potential supply developments. With demand, it is important to react to changing economic growth expectations for the short-, medium- and long-term, changes to oil price expectations, emerging policies, and the development and penetration of newer technologies. Similarly, on the supply side, there are often changes to expectations, even over the course of the year since the last report. For example, there have been significant revisions to the expected prospects of shale oil supply. This chapter considers the detailed outlook for all forms of liquids supply and also highlights where major changes in expectations have occurred.

Medium-term outlook for liquids supply

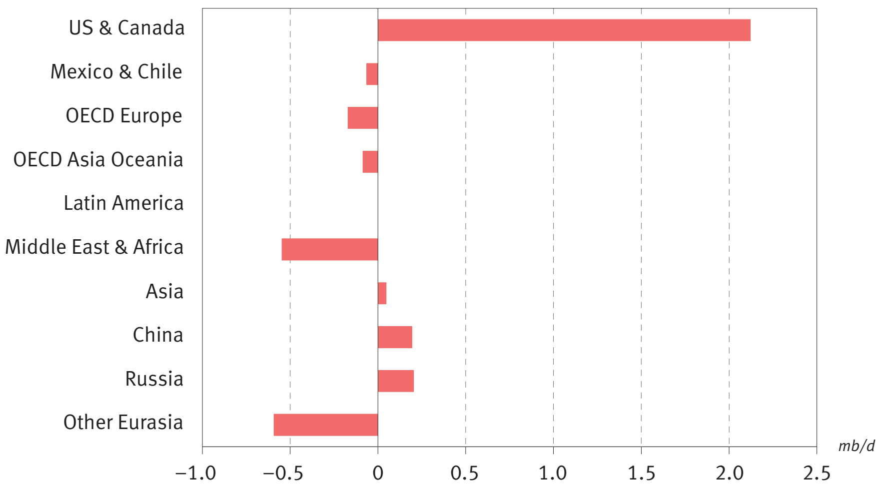
Non-OPEC crude and NGLs

The most dramatic change for the medium-term outlook for crude and NGLs supply relates to rising US shale oil production. Last year's WOO identified the huge shale oil potential, but questioned the extent to which the massive deposits could be translated into supply, given constraints that included acquiring the necessary equipment and skilled labour, dealing with rising costs and environmental concerns.

This year's expanded oil shale supply projections are driven by the fact that production levels are already accelerating: total supply from the Bakken, Eagle Ford and Niobrara shale oil plays is already over 1 mb/d. And despite severe decline rates, US shale oil supply is expected to rise rapidly over the medium-term.

Figure 3.1 shows how the non-OPEC liquids supply expectations for 2015 have risen by more than 2 mb/d compared to the WOO 2011. Medium-term US crude oil and NGLs production is projected to increase from 7.8 mb/d in 2011 to 9.3 mb/d

Figure 3.1
Changes to non-OPEC crude and NGLs supply in Reference Case projections for 2015 compared to WOO 2011



in 2016. In addition to the increased production from shale oil plays, many existing and new ultra-deep water projects are either being developed or are planned to come onstream between now and 2016. Projects such as Cascade & Chinook, Galapagos, Thunder Bird, Cardamom, Jack & St. Malo, Lucius, Knotty Head, Puma, Big Foot and Mars B are expected to bring more than 1 mb/d of net additional capacity in the medium-term, even accounting for natural declines in existing fields.

In Canada, in the medium-term, modest supply growth from onshore western Canada will be offset by declines in the onshore East Coast. Canada's crude oil plus NGLs production is projected to decline from 1.9 mb/d in 2011 to 1.7 mb/d by 2016.

Thus, whereas last year's WOO figures for crude and NGLs production in the US & Canada fell from 9.4 mb/d in 2010 to 9.1 mb/d by 2015, as the region's mature areas experienced declines that could not be fully compensated by increases elsewhere, the significant additions to the crude figures introduced in this Reference Case means that crude and NGLs supply from this region grows substantially, from 9.8 mb/d in 2011, to 11.2 mb/d in 2016.

Elsewhere, there are increases in Latin America, mainly Brazil, as well as from the Caspian region.

Non-OPEC Latin America's production of crude and NGLs is expected to grow strongly, from 4.2 mb/d in 2011 to 5.1 mb/d in 2016. Brazil, the dominant non-OPEC Latin America producer, is the main growth source. The fields Baleia Zaul, Lara, Bauna/Piracaba, Aruana, Lula NE Pilot, Tubarao Azul, Roncador Module 3 P-55 and Tubarao Martelo are all under development and set to add around 750,000 b/d of capacity by the end of 2013. A further 18 projects – Saphinhoa 1 (Pilot 3), Papa-Terra, Whale Park P-58, Roncador Module 4 P-62, Cernambi Sul, Saphinhoa (Norte), Badejo (Siri), Cavalo Marinho, Coral & Estrela do Mar, Maromba, Lula (P-66), Marimba, Lula (P-67), Wahoo, Franco, Carioca, Tambuata, BS-004 (Oliva & Atlanta) and Marlim Sul Module 4 – are all in the planning phase, and are expected to further contribute to medium-term growth. In the Reference Case, Brazil's production grows steadily from 2.2 mb/d in 2011 to 2.7 mb/d in 2016, a one-year delay compared to last year's projections. Elsewhere, in non-OPEC Latin America, Colombia and Argentina crude oil and NGLs production is anticipated to remain flat, at about 900,000 b/d and 700,000 b/d, respectively.

In the Caspian region, Azerbaijan and Kazakhstan exhibit medium-term growth in the Reference Case, albeit at a slower rate than in last year's WOO. This is mainly due to the slower-than-expected growth in 2011 and 2012.

In Azerbaijan, growth in the medium-term will be supported 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 mb/d in 2011 to 1.2 mb/d in 2016.

In Kazakhstan, oil production reached 1.6 mb/d in 2011 and is expected to grow further, supported by expansions at the Tengiz, Kashagan, Akote and Karachaganak Phase III fields. Initial production from Phase 1 of the giant Kashagan field is slated to begin in 2013 at a level of 0.11 mb/d. It is anticipated to result in additional capacity of 450,000 b/d over the medium-term. First production from the Tengiz expansion is also expected to start in 2013 and is projected to add another 250,000 b/d. Karachaganak Phase III is anticipated to come onstream in 2014 and add 100,000 b/d. It is important to stress, however, that risks associated with transport infrastructure challenges remain, which augments the uncertainty in these projections. Crude oil and NGLs production in Kazakhstan is projected to increase from 1.6 mb/d in 2011 to 2.1 mb/d in 2016.

In Russia, production grew by about 130,000 b/d in 2011 to reach a level of 10.3 mb/d. This growth trend is expected to continue in the medium-term. A number of major projects are planned for the next few years. These include Prirazlomnoye (Pechora Sea), Pyakyakhinskoye, Kuyumbinskoye, Yurubcheno-Tokhomskoye (Phase

I), Russkoye (Yamal-Nenets), Suzunskoye, Novoportovsoye, Naulskoye, Sakhalin 1 Arkutun-Dagi and Vladimir Filanovsky. These are anticipated to add a total production capacity of more than 1.5 mb/d. These additional volumes will most probably offset the expected decline in other mature fields, particularly in the Volga-Urals and West Siberia regions. Russia's production in the medium-term remains relatively flat, going from 10.3 mb/d in 2011 to 10.5 mb/d in 2016.

Total crude oil and NGLs production in Eurasia is anticipated to grow from around 13.4 mb/d in 2011 to 13.9 mb/d by 2016.

Crude oil and NGLs production in non-OPEC Asian countries, excluding China, is also expected to see healthy growth, reaching around 3.9 mb/d by 2016, from 3.5 mb/d in 2011. As in last year's Outlook, India is anticipated to be the main growth area. New projects including the Bhagyam, Aishwariya, Saraswati/Raageshwari, Heera & South Heera and the Krishna-Godavari Cluster expansion are anticipated to add production capacity of about 230,000 b/d by 2016. In the Reference Case, Indian crude oil and NGLs production increases from 890,000 b/d in 2011 to about 1 mb/d in 2016.

Elsewhere, Malaysia's medium-term production is projected to stay flat at about 700,000 b/d. Vietnam's production will show some modest growth, increasing from 350,000 b/d in 2011 to around 400,000 b/d in 2016, due to projects such as the Su Tu Trang, Gau Trang, Hai Thach, Hai Su Trang/Hai Su Den, Amethyst Southwest, Dua and Su Tu Nau coming onstream. Supply in Indonesia, Brunei, Papua New Guinea, Pakistan and Thailand is expected to stay fairly consistent in the medium-term.

As for China, its current level of production of 4.1 mb/d is expected to be maintained till 2013, with growth then expected in 2014. Additional volumes of more than 300,000 b/d are expected to come from new projects over the medium-term, such as Weizhou, Chunxiao and other phases of Nanpu. These are anticipated to offset production declines from the Daqing, Shengli and Liaohe giant fields. In the Reference Case, China's medium-term crude oil and NGLs production is projected to grow by about 100,000 b/d, from 4.1 mb/d in 2011 to 4.2 mb/d in 2016.

OECD Europe production sees a fall of around 500,000 b/d over the medium-term, due mainly to sharp declines in the North Sea. Mexico sees a similar drop in its production over this timeframe. And non-OPEC Middle East & Africa also witnesses a fall.

In OECD Europe, due to declines in North Sea output, crude and NGLs production fell by about 360,000 b/d in 2011. This trend is expected to continue in the coming years, with the OECD Europe's crude oil and NGLs production projected to fall from 3.7 mb/d in 2011 to 3.2 mb/d in 2016.

Breaking down the North Sea figures further, Norway sees a fall of 0.3 mb/d for the period 2011-2016 and the UK a drop of 0.2 mb/d for the same period. In Norway, planned and under development projects such as Skarv & Idun, Skuld, Goliat, Ekofisk South, Knarr, Trestakk, Yme, Katla, Jardbaer, Bream, Froy, Edvard Grieg and Eldfisk II are expected to translate into additional supply over the medium-term, but this is not expected to be sufficient to offset declines in mature fields. Norwegian crude and NGLs production fell 100,000 b/d in 2011, to 2 mb/d. Over the medium-term, it is expected to decline at a slower annual rate of around 50,000 b/d, reaching 1.8 mb/d by 2016.

In the UK, crude oil and NGLs production fell by around 250,000 b/d during 2011. This downward trend, which began a decade ago, is expected to continue in 2012 and beyond. The complexity of maintaining production in the UK's mature field tends to reduce investment levels and lower the anticipated output from planned and under-development projects, such as Huntington, Kinnoull, Cheviot, Golden Eagle, Kraken and Clair Phase II. In this year's Reference Case, UK crude oil and NGLs production is expected to fall from around 1.1 mb/d in 2011 to 0.9 mb/d in 2016.

Mexico's production has been declining since 2004. It is anticipated that this will continue over the medium-term. Due to the rapid decline in the giant Cantarell field, a peak in production from Ku-Maloob-Zaap complex and the fact that additional production from Chicontepec will be insufficient to offset declines in other fields, Mexico's crude oil and NGLs production is projected to fall by almost 0.5 mb/d over the medium-term, from 2.9 mb/d in 2011 to 2.4 mb/d in 2016.

Non-OPEC Middle East & Africa crude oil and NGLs production is expected to decline sharply from 4.1 mb/d in 2011 to 3.7 mb/d in 2016. This is mainly due to declines in the non-OPEC Middle East region. While Oman's production is projected to stay flat at about 0.9 mb/d, medium-term production from Yemen and Syria is expected to decline significantly. In the Reference Case, crude oil and NGLs production in the non-OPEC Middle East is expected to fall from 1.7 mb/d in 2011 to 1.3 mb/d in 2016.

In non-OPEC Africa, the planned modest growth from new projects in Congo, Equatorial Guinea, Ghana, and Uganda will not be enough to offset the anticipated declines in Sudan and South Sudan, Egypt and other countries. In the medium-term, crude oil and NGLs production in non-OPEC Africa is projected to stabilize at about 2.5 mb/d from 2013 onwards.

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

	2011	2012	2013	2014	2015	2016
United States	7.9	8.6	9.0	9.3	9.4	9.5
Canada	1.9	1.9	1.9	1.8	1.8	1.7
US & Canada	**9.8**	**10.5**	**10.9**	**11.1**	**11.2**	**11.2**
Mexico & Chile	**2.9**	**2.9**	**2.8**	**2.7**	**2.6**	**2.4**
Norway	2.1	2.0	1.9	1.9	1.9	1.8
United Kingdom	1.1	1.0	1.0	1.0	0.9	0.9
Denmark	0.2	0.2	0.2	0.2	0.2	0.2
OECD Europe	**3.7**	**3.5**	**3.3**	**3.3**	**3.2**	**3.2**
Australia	0.5	0.5	0.5	0.5	0.5	0.5
OECD Asia Oceania	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**	**0.5**
OECD	**16.9**	**17.4**	**17.6**	**17.5**	**17.5**	**17.4**
Argentina	0.7	0.7	0.7	0.7	0.7	0.7
Brazil	2.2	2.3	2.3	2.4	2.6	2.7
Colombia	0.9	0.9	0.9	0.9	0.9	0.9
Latin America	**4.2**	**4.3**	**4.5**	**4.8**	**4.9**	**5.1**
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	0.2	0.2	0.2	0.2	0.2
Yemen	0.2	0.2	0.2	0.2	0.2	0.2
Middle East	**1.7**	**1.4**	**1.4**	**1.3**	**1.3**	**1.3**
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	0.4	0.2	0.3	0.3	0.3	0.3
Africa	**2.4**	**2.4**	**2.5**	**2.5**	**2.5**	**2.5**
Middle East & Africa	**4.1**	**3.7**	**3.7**	**3.7**	**3.7**	**3.7**
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	1.0	1.0	1.0	1.0
Malaysia	0.6	0.6	0.7	0.7	0.7	0.7
Thailand	0.3	0.3	0.3	0.3	0.3	0.3
Viet Nam	0.4	0.4	0.4	0.4	0.4	0.4
Asia	**3.5**	**3.6**	**3.6**	**3.7**	**3.9**	**3.9**
China	**4.1**	**4.1**	**4.1**	**4.2**	**4.2**	**4.2**
DCs, excl. OPEC	**15.9**	**15.7**	**16.0**	**16.4**	**16.6**	**17.0**
Russia	**10.3**	**10.3**	**10.4**	**10.4**	**10.4**	**10.5**
Kazakhstan	1.6	1.6	1.7	1.8	2.0	2.1
Azerbaijan	1.0	1.0	1.0	1.1	1.2	1.2
Other Eurasia	**3.1**	**3.2**	**3.3**	**3.3**	**3.4**	**3.4**
Eurasia	**13.4**	**13.5**	**13.7**	**13.7**	**13.8**	**13.9**
Total non-OPEC crude & NGLs	**46.2**	**46.6**	**47.2**	**47.7**	**47.9**	**48.2**

What is interesting to note is that because of the upward revision to the importance of shale oil in the US, by 2016, the total OECD supply of crude and NGLs remains higher than in developing countries. This is a change from the previous year's figures. Overall, the medium-term supply outlook for total non-OPEC crude oil and NGLs is for a rise, from 46.2 mb/d in 2011 to 48.2 mb/d in 2016 (Table 3.1).

Other liquids (excluding biofuels)

In terms of other liquids, the oil sands in Alberta, Canada, account for the majority of current production, representing over 80% of the world's total for other liquids supply. There are some slight downward revisions to short-term expectations, compared to last year, which partly reflect the potential for future oil supply from this source to be negatively affected by rising development and production costs in the coming years. In contrast, however, medium-term expectations have risen as several new projects appear.

The next most important source of other liquids are coal-to-liquids (CTL) and gas-to-liquids (GTL). The figures also include increases in oil shale (a different recovery process to shale oil, involving the heating of kerogen – see WOO 2011). The Reference Case sees supply of these other liquid fuels continuing to increase over the medium-term.

Table 3.2
Non-OPEC other liquids supply outlook (excluding biofuels) in the Reference Case

mb/d

	2011	2012	2013	2014	2015	2016
US & Canada	1.8	2.1	2.2	2.4	2.6	2.9
OECD Europe	0.1	0.2	0.2	0.2	0.2	0.2
OECD Asia Oceania	0.0	0.0	0.0	0.1	0.1	0.1
OECD	**2.0**	**2.3**	**2.5**	**2.7**	**2.9**	**3.2**
Middle East & Africa	0.2	0.2	0.2	0.2	0.2	0.2
Asia	0.0	0.0	0.0	0.0	0.1	0.1
China	0.0	0.1	0.1	0.1	0.1	0.1
Developing countries, excl. OPEC	**0.2**	**0.2**	**0.3**	**0.3**	**0.4**	**0.4**
Non-OPEC	**2.2**	**2.5**	**2.7**	**3.0**	**3.3**	**3.6**

The medium-term Reference Case outlook appears in Table 3.2. The combined growth of these fuels result in non-OPEC supply of other liquids increasing in the medium-term Reference Case, from 2.2 mb/d in 2011 to 3.6 mb/d in 2016.

Biofuels

For biofuels medium-term supply, it is expected that there will continue to be a supply growth from first generation biofuels, supported by policy incentives and fiscal support that, although probably over-ambitious in many cases, provide momentum for medium-term biofuels growth.

Even over this period, however, some constraints to growth are already appearing. The economic debt burdens in many countries are now thought to represent a hurdle for biofuels, given the reduced willingness and ability to subsidize biofuels. This is likely to have some impact upon medium-term prospects. On top of this, sustainability issues are increasingly placing a limitation on how much first-generation biofuels can produce.

Other emerging constraints include the difficulties in achieving established targets, leading to the introduction of waivers; delays in the implementation of directives; concerns over capital availability; and high feedstock prices.

With these emerging constraints in mind, the medium-term outlook for biofuels is slightly softer than in the WOO 2011. Supply rises from 1.9 mb/d in 2011 to

Table 3.3
Non-OPEC biofuel supply outlook in the Reference Case *mb/d*

	2011	2012	2013	2014	2015	2016
US & Canada	1.0	0.9	0.9	0.9	1.0	1.0
OECD Europe	0.3	0.2	0.3	0.4	0.4	0.4
OECD	**1.3**	**1.1**	**1.2**	**1.3**	**1.4**	**1.5**
Latin America	0.5	0.5	0.5	0.6	0.6	0.7
Asia	0.1	0.1	0.1	0.1	0.1	0.1
China	0.0	0.0	0.1	0.1	0.1	0.1
Developing countries, excl. OPEC	**0.6**	**0.6**	**0.7**	**0.7**	**0.8**	**0.9**
Non-OPEC	**1.9**	**1.8**	**1.9**	**2.1**	**2.3**	**2.4**

2.4 mb/d in 2016, a reduction of 0.4 mb/d from last year's estimate, although this should still be viewed as a significant amount of additional liquids supply over the medium-term (Table 3.3). The largest suppliers of biofuels continue to be the US, Europe and Brazil.

Non-OPEC supply from crude and NGLs, biofuels and other liquids together contribute to a medium-term increase of 4.3 mb/d from 2011–2016, with 48% coming from crude and NGLs, 33% from other liquids excluding biofuels and 12% from biofuels (the remainder stems from rises in processing gains).

Long-term outlook for liquids supply

Non-OPEC crude and NGLs

While the medium-term outlook for non-OPEC crude and NGLs supply is driven by a database covering fields in production and under development, beyond the medium-term this approach becomes less viable. The further we move into the future, the more important those investment decisions yet to be made become, including with regard to resources that have yet to be turned into proven reserves. Thus, long-term projections rely on estimates of the available resource base. Ultimately recoverable resources (URR) are based upon estimates by the US Geological Survey (USGS).

The USGS has recently released the results of a complete reassessment of the world oil and NGLs resource base, with the USGS World Petroleum Resources Project, undertaken between 2009 and 2011. What has been particularly revealing about the results is that the mean estimate of undiscovered resources is now set at 732 billion barrels. This is an increase of more than 30% compared to figures reported in WOO 2011, which was based upon the amended USGS 2000 assessment.[19,20] Moreover, the new estimate still does not cover all potential oil-bearing provinces. New estimates of cumulative production to 2010, proven reserves and the reserves to be added ultimately, are documented in Table 3.4. This shows that the new estimate for URR is over 3.8 trillion barrels. It is a further reflection of the on-going upward revision process to the oil resource base.

This trend is reflected in Figure 3.2. Moreover, this estimate does not include shale oil deposit estimates, nor does it cover other liquids and the potential supply from biofuels. It is another clear indication that resource availability will not impose a limiting factor to oil supply. There are sufficient resources for the foreseeable future.

Table 3.4
Estimates of world crude oil and NGLs resources *billion barrels*

	OPEC	Non-OPEC	Total world
Cumulative production to 2010 (a)	446	695	1,142
Proved reserves (b)	1,197	270	1,467
Reserves to be added ultimately (c)	**617**	**620**	**1,237**
Of which:			
Reserves growth	342	163	505
Discoveries yet to be made	275	457	732
Original Endowment (a) + (b) + (c)	2,260	1,585	3,846

Sources: *USGS World Petroleum Assessment 2000; 'An estimate of undiscovered conventional oil and gas resources of the world, 2012', US Geological Survey, April 2012; OPEC Annual Statistical Bulletin, 2010/2011 edition, IHS PEPS database, OPEC Secretariat estimates.*

Turning to the reserves situation, in Chapter 1 it was stated that OPEC's Annual Statistical Bulletin 2012 shows that OPEC accounts for the majority of proven reserves. The figure in 2011 is 81%.[21] The USGS analysis also points to OPEC having considerably higher expectations for reserve growth compared to non-OPEC. Moreover, as can be seen in Figure 3.3, global proven reserves have steadily increased over the past five decades, despite growing cumulative production, and this boost has come mainly from OPEC Member Countries.

Global oil supply has been greatly impacted by the application of new exploration and production technologies that increase recovery factors and exploit new reservoirs. New technologies have made it possible to explore frontier basins and operate in harsher environments, increase exploration success ratio (the number of dry wells has fallen by more than 30% over the last decade), achieve higher recovery rates through a greater reservoirs knowledge and management, and drill and produce more economically and efficiently. Today, important and evolving technologies include: 3D seismic, directional and multilateral drilling, hydraulic fracturing, enhanced oil recovery and CO_2 injection. And of course, many of these technological developments are linked to advances in computing power, digital communication and information management systems.

As has already been mentioned, estimates by the USGS for crude and NGLs resources do not include shale oil. The long-term implication of these additional shale

Figure 3.2
USGS estimates of Ultimately Recoverable Resources

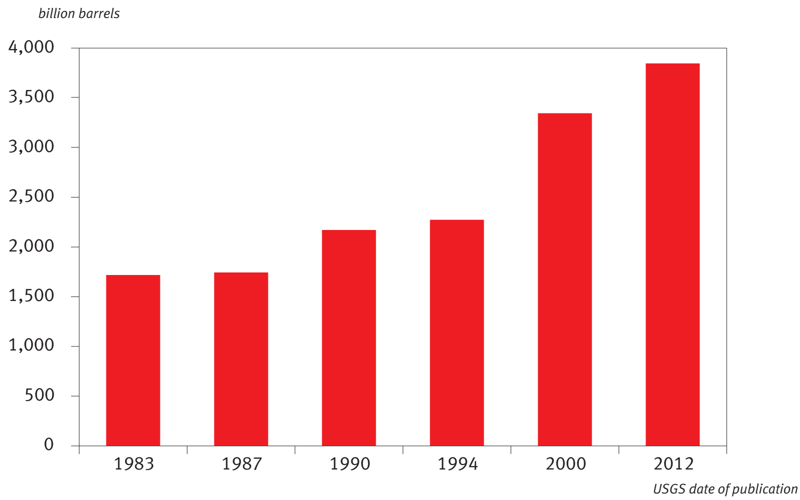
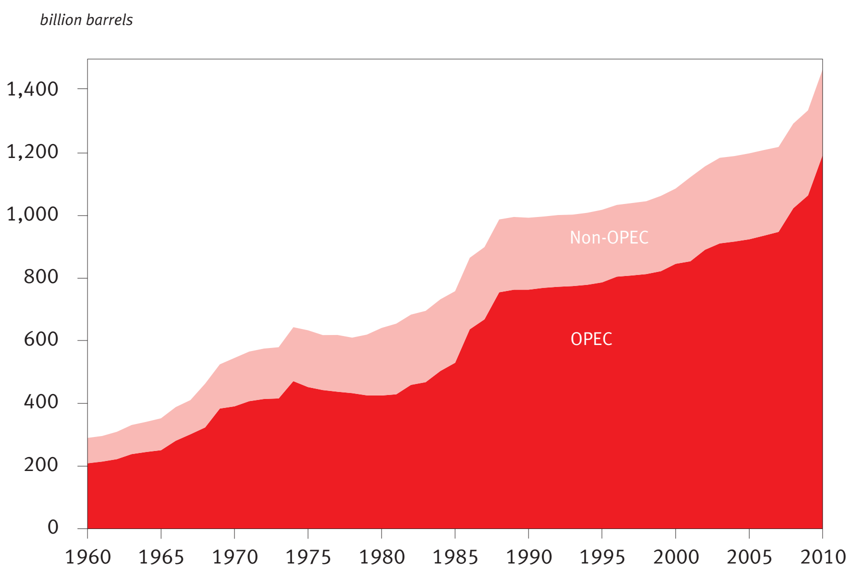


Figure 3.3
Evolution of world proven crude reserves



Source: OPEC Annual Statistical Bulletin, 2012 edition.

oil resources, particularly given the rapid expansion of supply that is already underway, is reflected in the Reference Case.

Looking ahead, it is important to understand the potential infrastructure challenges for shale oil, particularly with regard to transportation (the expanded use of rail to transport this oil in the US has been notable but has its limitations) and the specific capital needs to develop these resources, both human and physical. Moreover, environmental concerns are a further constraint to the future development of shale oil (see Box 3.1). For example, hydraulic fracturing, required for the development of shale oil, involves large volumes of water, and associated concerns about possible pollution, as well as a number of other environmental impacts, such as heavy equipment traffic, noise and air pollution.

It is, therefore, estimated in the Reference Case that shale oil supply will rapidly rise in the US during this decade to reach 2 mb/d by 2020, but the pace will slow down afterward, with shale oil supply expected to be at a level of 3 mb/d by 2035.

Table 3.5
Non-OPEC crude oil and NGLs supply outlook in the Reference Case *mb/d*

	2010	2015	2020	2025	2030	2035
US & Canada	9.4	11.2	11.2	10.7	10.2	9.7
Mexico & Chile	3.0	2.6	2.3	2.1	2.0	1.8
OECD Europe	4.0	3.2	2.9	2.5	2.2	2.0
OECD Asia Oceania	0.6	0.5	0.5	0.5	0.5	0.5
OECD	**17.0**	**17.5**	**16.9**	**15.8**	**14.9**	**13.9**
Latin America	4.1	4.9	5.8	6.1	5.9	5.7
Middle East & Africa	4.2	3.7	3.6	3.4	3.2	3.0
Asia	3.6	3.9	4.1	3.8	3.5	3.1
China	4.1	4.2	4.0	3.8	3.5	3.3
DCs, excl. OPEC	**16.0**	**16.6**	**17.6**	**17.1**	**16.2**	**15.2**
Russia	10.1	10.4	10.6	10.6	10.6	10.6
Other Eurasia	3.2	3.4	3.7	4.0	4.3	4.7
Eurasia	**13.4**	**13.8**	**14.3**	**14.6**	**14.9**	**15.3**
Non-OPEC	**46.4**	**47.9**	**48.7**	**47.5**	**45.9**	**44.5**

The long-term Reference Case projections for non-OPEC crude oil plus NGLs supply up to 2035 are shown in Table 3.5. Output from all OECD regions continues to fall. By 2035, the decline in OECD supply from these sources is more than 3 mb/d compared to 2010. The fall, however, is considerably less than in the previous outlook, due to the reassessment of the importance of shale oil and the new, more optimistic USGS assessment of the resource base.

Overall non-OPEC supply of crude plus NGLs rises over this decade, before entering a phase of decline post-2020. Even in North America, where shale oil is

Box 3.1
Shale: on the rise, but challenges remain

Given recent significant increases in North American shale oil and shale gas production, it is now clear that these resources might play an increasingly important role in non-OPEC medium- and long-term supply prospects.

It begs the questions: what is the potential contribution of shale oil and shale gas resources to the future global energy supply? Will the high development costs, and environmental impacts and challenges, affect this potential? And will it be possible to replicate the US success story globally?

Currently, shale production is primarily coming from North America (mainly the US), with production and market data mainly available from the following shale plays: Bakken, Barnett, Cardium, Eagle Ford, Fayetteville, Granite Wash, Haynesville-Bossier, Horn River, Marcellus, Montney, Niobrara, Permian, Utica and Woodford. Globally, shale oil and gas development is in its infancy, and there are thus considerable uncertainties about the size of the resources, the economics of development and the potential contribution to future supply. In regard to the overall shale oil resource base, although no serious attempts have been made yet to analyze its size, it seems that even if the in-place volumes are large, reserves will not be as high, due to very low recovery factors, presently in the range of 1% to 10%, with few exceptions.

According to the Energy Information Administration's (EIA) 2012 Energy Outlook, the unproved technically recoverable tight oil resources in the US as of 1 January 2010 were estimated to be 33 billion barrels, with the recoverable shale gas resources about 480 trillion cubic feet (tcf). For the latter, it is worth mentioning that this level is almost half that reported (827 tcf) the previous year. It is a further indication of the large uncertainties still still associated with recoverable resource estimates. Globally, the estimates are even more uncertain.

As to shale oil's current production and future supply prospects, total US production from known 'main' plays is projected to increase from about 1 mb/d in 2012 to 2 mb/d in 2020, before reaching 3 mb/d from 2025 onward. Eagle Ford and Bakken are the most prolific basins. Outside the US, there is shale oil potential in 85 basins around the world.[22] Some projections show that tight oil production will increase from less than 2% of global oil capacity in 2012 to more than 4% in 2020.[23]

Total shale gas production in the US jumped from about 15 bcf/d in 2010 to 25 bcf/d in 2012. This is projected to increase to more than 35 bcf/d in 2015 and 45 bcf/d in 2020.[24] Despite the challenges, there are several plays outside North America where market conditions and the quality of the shale formation could result in some shale gas development.

In regard to the economics of shale oil development in the US, the drilling and completion costs for a horizontal shale well currently ranges from \$4 to \$6 million. Drilling and completion costs required to fully develop a shale oil play will typically amount to \$50,000–\$75,000 per flowing barrel at plateau. This relatively high cost arises from the steep first year decline rate (70% to 90%) for the wells. Nevertheless, a break-even oil price of \$50–\$60 suggests that most US shale oil plays are profitable at current oil price levels.[24]

Breakeven gas prices for most US shale gas plays have improved greatly over the years and most are now profitable at the current US gas price range. Of course, costs will increase if the government introduces new environmental regulations related to hydraulic fracturing.

Many of the environmental impacts associated with shale oil and gas development are directly or indirectly related to hydraulic fracturing (or 'fracking'). This process requires large volumes of water and has many environmental impacts, such as heavy truck traffic, noise and air pollution.

While there remain obstacles for US shale oil production, including bottlenecks in domestic oil transportation systems and the environmental impacts of hydraulic fracturing, it is clear that progress is being made. The US experience, however, will not be easy to replicate in the rest of the world. Globally, the main constraints come from the lack of geological analyses of prospective shales, the shortage of well-trained crews to perform hydraulic fracturing, insufficient drilling rigs and fracturing equipment and the NIMBY effect.

In summary, global shale oil and gas resources seem to be significant enough to play an important role in the future global energy supply. Their contribution in the medium-term will continue to come only from North America. In the longer term, however, modest contributions might also come from other parts of the world. Shale gas and shale oil are also likely to play a role in OPEC Member Countries.

expected to expand significantly, maturing production regions lead to a steady decline in overall production, which, together with declines in the North Sea and Mexico, see OECD supply start to fall already from the middle of this decade.

Declines are also expected in developing countries, though not as swift. Brazil is anticipated to see increases in output for at least the next 10 years, and future declines over the long-term projection period will only be gradual. Russia is seen in the Reference Case to reach a plateau of between 10 and 11 mb/d. The Caspian region is the one non-OPEC grouping that is thought to be able to sustain a gradual increase in supply over the long-term.

Other liquids (excluding biofuels)

Turning to the long-term outlook for other liquids (excluding biofuels), the largest supply increase in the Reference Case will come from Canadian oil sands, with supply expected to rise by more than 4 mb/d over the years 2010–2035. Although oil sands resources are substantial, the nature of the extraction and processing of the oil suggests a long plateau of supply. Moreover, there are several question marks over the environmental credentials of oil sands mining, which may limit long-term potential; these include related greenhouse gas emissions, impacts upon wildlife, and effects upon water availability and quality.

In terms of other sources of other liquids supply, CTLs are expected to witness growth, particularly in regions with substantial coal resources. These include the US, Australia and China, which together are expected to see an increase in liquids supply from this source of around 1 mb/d over the period 2010-2035. GTLs are also seen as possibly an increasingly important source of other liquids supply, especially where cheap and plentiful supplies of natural gas exist, such as in the US, where supply could rise to 300,000 b/d by 2035.

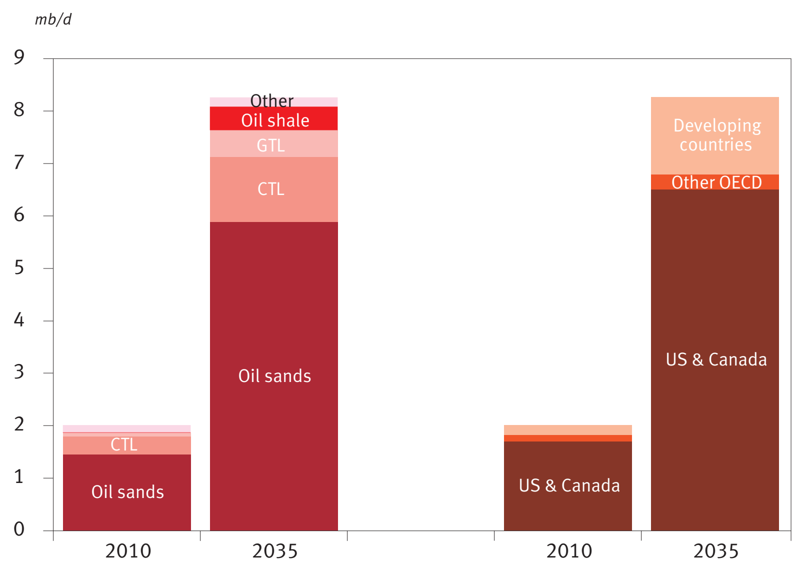
Altogether, supply from other liquids in the Reference Case, excluding biofuels, increases by close to 7 mb/d in the long-term, reaching almost 9 mb/d by 2035

Table 3.6
Non-OPEC other liquids supply outlook (excluding biofuels) in the Reference Case

mb/d

	2010	2015	2020	2025	2030	2035
US & Canada	1.7	2.6	3.6	4.9	5.9	6.9
OECD Europe	0.1	0.2	0.2	0.2	0.2	0.2
OECD Asia Oceania	0.0	0.1	0.1	0.1	0.1	0.1
OECD	**1.8**	**2.9**	**3.9**	**5.2**	**6.2**	**7.2**
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	0.1	0.2	0.4	0.6	1.1
DCs, excl. OPEC	**0.2**	**0.4**	**0.5**	**0.7**	**1.0**	**1.4**
Russia	0.0	0.0	0.0	0.1	0.1	0.1
Non-OPEC	**2.0**	**3.3**	**4.4**	**6.0**	**7.2**	**8.7**

Figure 3.4
Other liquids supply by type and region, 2010 and 2035



(Table 3.6). Figure 3.4 emphasizes the expectation that Canadian oil sands are likely to be the key to the increase.

Biofuels

In developing the long-term prospects for biofuels in the Reference Case, it is necessary to address the question as to whether the medium-term surge is sustainable, as the implications for land use and the consequent competition for food production becomes a real constraint to production growth. This became particularly apparent during the drought that hit the US midwest farming regions in the summer of 2012, with subsequent calls for ethanol production to be reduced in response to rising corn prices.[25]

Moreover, looking ahead, there is an apparent growing realization that cellulosic biofuels may take longer than previously thought to become commercially available. Very little is currently being produced from cellulosic biofuels, even at a demonstration phase.[26] Although in the longer term these second generation technologies – and third generation biofuels technology, such as algae-based fuels – may become commercial, the pace of their emergence has been revised downwards in this Reference Case compared to last year's WOO. In turn, this suggests that targets for second generation biofuels are over-ambitious.

Chapter 3

Table 3.7
Non-OPEC biofuel supply outlook in the Reference Case *mb/d*

	2010	2015	2020	2025	2030	2035
US & Canada	0.9	1.0	1.2	1.5	1.9	2.3
Western Europe	0.3	0.4	0.6	0.8	1.1	1.4
OECD Asia Oceania	0.0	0.0	0.0	0.0	0.0	0.1
OECD	**1.2**	**1.4**	**1.8**	**2.3**	**3.0**	**3.8**
Latin America	0.6	0.6	0.8	1.0	1.2	1.5
Middle East & Africa	0.0	0.0	0.0	0.1	0.1	0.2
Asia	0.0	0.1	0.1	0.2	0.3	0.4
China	0.0	0.1	0.1	0.3	0.4	0.6
DCs, excl. OPEC	**0.7**	**0.8**	**1.1**	**1.5**	**2.0**	**2.7**
Other Europe	0.0	0.0	0.0	0.0	0.0	0.1
Non-OPEC	**1.8**	**2.3**	**3.0**	**3.9**	**5.1**	**6.6**

The Reference Case sees biofuels supply increase by close to 5 mb/d from 2010, to reach 6.6 mb/d by 2035 (Table 3.7). The future economics of second and third generation biofuels, however, represent a large degree of uncertainty as to what extent biofuels may contribute to supply. One key variable that may affect these developments is oil prices: major departures from the Reference Case assumption, either higher or lower, could result in relatively large impacts upon biofuels supply levels in the future.

OPEC upstream investment

OPEC Member Countries have continuously played a positive key role in satisfying the world's energy needs, in supporting oil market stability, and investing along the whole oil supply chain in an adequate and timely manner. Even in the face of large uncertainties about future oil demand, OPEC Member Countries continue to invest heavily in exploration, development, refining and transport in order to maintain and expand supply capacities. This is a clear reflection of their objective to support stability in oil markets, as has been clearly stated in OPEC's Statute and Long Term Strategy.

As was indicated in Chapter 1, OPEC crude oil spare capacity is expected to rise to beyond 5 mb/d as early as 2013/2014. In 2011, total OPEC sustained capacity averaged over 34 mb/d, while the total supply averaged to 29.79 mb/d. This rising trend is expected to continue over the medium-term, especially given that the call on OPEC crude is foreseen to remain approximately flat.

According to the latest list of upstream projects in OPEC's database, Member Countries are undertaking or planning around 116 development projects during the five-year period 2012–2016. This corresponds to an estimated investment of about $270 billion, and demonstrates the scale of OPEC's portfolio of projects. It is estimated, given Reference Case assumptions and projections, as well as the natural decline in existing fields, that total OPEC liquids capacity will rise by 5 mb/d over the period 2012–2016, although investment decisions and plans will obviously be influenced by various factors, such as the the global economic situation, policies and the price of oil. Accordingly, OPEC's spare capacity will stay at healthy levels.

It is important to stress, however, that given the nature of the industry, particularly in terms of the often long-lead times for projects and high upfront costs, striking the right balance for investments will continue to be a major challenge.

Chapter 4
Upstream challenges

In looking ahead, there are many challenges for the oil industry, and it is clearly important to continually gain a better understanding as to how these might evolve.

Clearly the economic environment is today particularly challenging and a source of major uncertainties for the future. How the global economy will evolve in the coming years is thus a key question, with huge impacts on the oil industry.

There are oil price fluctuations – as discussed in Chapter One – and the role of speculation in this. There is clearly a convergence of views on the need to mitigate extreme volatility and dampen excessive speculation.

The industry has also recently seen how quickly perspectives for energy supply can change. For example, the Fukushima disaster changed nuclear prospects in some regions, impacting in the short-term oil and gas markets, and changing country energy policies in the longer term; and shale oil and gas have rapidly reversed the decline of oil and gas production in the US, with dramatic consequences on gas, LNG, and coal trade and prices. Energy policies have also become increasingly far-reaching in their scope, with a number of countries and regions looking to significantly alter their energy mix in the medium- to long-term.

In addition, skilled labour availability continues to be seen as a potential constraint to the expansion of the industry. In past years, this publication has repeatedly called for moves to address this.

And there is also the pressing issue of the environment and climate change, and how this might impact the industry and future technological developments. In fact, when looking at technology, in general, it can perhaps be viewed as the source of the greatest uncertainty in terms of the long-term oil and energy outlook.

This is not an exhaustive list of challenges, but it does underscore some of the uncertainties facing the industry. And this is further brought home when looking at how much investment is required.

Investment needs in the petroleum industry are massive. For OPEC, and its Member Countries, offering spare capacity in a climate of uncertainty (over how much OPEC oil will be needed) generates a substantial risk of making large investments in capacity that may not be needed, nor utilized.

This Chapter brings together some of the key strands that constitute future petroleum industry challenges. The uncertainties, stress points and unknowns that cannot be fully reflected in a modeling framework are as important as quantitative assessments. Addressing these challenges is a broad and all-inclusive task. It will require constructive flexibility from all.

Uncertainty scenarios

The previous chapters in this publication have concentrated upon the Reference Case outlook. This is not a forecast of how the future will evolve but an internally consistent feasible benchmark that is derived from the set of Reference Case assumptions described in Chapter 1.

It is self-evident that alternative patterns of oil and energy demand and supply could emerge, with plausible alternative sets of assumptions. Often, given the nature of the drivers of demand, the uncertainties are skewed to the downside: policies and technology are oriented to reducing consumption, and the current economic climate is obviously a major cause of concern. And on the supply side, there are differing opinions as to how this might evolve, particularly regarding some of the new forms of liquid supply. However, there is also upside potential that needs to be considered, for example, from the perspective of future economic growth potential or mobility needs.

Accordingly, scenarios have been developed for the future demand for OPEC crude oil. The first scenario, Lower Economic Growth (LEG), looks at the impact of lower economic growth, both in the medium-term, largely as a result of the on-going Euro-zone debt crisis and Chinese growth slowdown, but also in the longer term. A second scenario, Higher Economic Growth (HEG), acknowledges that there is indeed upside potential for economic growth and explores what this could imply for OPEC oil. And the final scenario, Liquids Supply Surge (LSS), estimates the possible impact upon OPEC crude if the overall supply of liquids is higher than estimated in the Reference Case.

The Lower Economic Growth scenario

The LEG scenario deals with the uncertainties surrounding a key driver of energy and oil demand: the global economy.

In developing the Reference Case, growth rates over time for each region were developed, consistent with estimates of demographics and factor productivity.

However, the UN publishes not only mean assessments for future population growth, which were used for the Reference Case, but also low and high variants. These show that by 2035, global population could be as low as 8 billion or as high as 9.2 billion, compared to the mean level of 8.6 billion. Thus, in terms of economic growth rates, the high and low variants see an uncertainty of +/-0.3% p.a., relative to the Reference Case. This feeds directly into economic growth uncertainty in the long-term.

Of course, uncertainty over the future for global economic growth relates to issues that go beyond population growth rates. Long-term growth potential from factor productivity increases are typically the focus for economic growth scenarios. Thus attention must be paid to possible alternative trade patterns, investment, consumption, savings rates,[27] sectoral shifts in economies, economic reforms that affect the investment climate, income distribution, dependency ratios, technological development and diffusion, government expenditure, levels of education, political stability, (target) levels of inflation, exchange rate movements, monetary and fiscal policies, interest rates, commodity prices, constraints from debt circumstances and credit availability. Downside risks to growth are often stressed, rather than the upside potential.[28]

The immediate outlook is dominated by the aftermath of the financial crisis and the on-going struggles related the global economic recovery. The main focus is currently on the Euro-zone debt crisis. The uncertainty over the future of the Euro, especially given the political turnaround in some countries regarding the acceptability of austerity measures, is one of the factors that play into the assessment. While debt levels and budget deficits are generally falling,[29] growth expectations are being repeatedly revised downwards and doubts remain as to the ability of the region to manage its sovereign debt. The severe austerity measures put in place have also adversely impacted growth prospects, with the risk of entering into a vicious circle and snowballing effect. It should also be noted that the debt crisis in the Euro-zone has negative implications for growth prospects elsewhere, in particular through strong trade interlinkages.

In developing the LEG scenario, the short- to medium-term prospects of a persistent dampening of growth from the Euro-zone debt crisis is combined with longer term downside factors. The assumptions for global economic growth are such that, on average, the world economy grows at a 0.5% p.a. lower rate than in the Reference Case. However, the lower rates are skewed to the short- and medium-term, when the largest downside risk is reflected in the OECD Europe region, which grows at an average of just 0.7% p.a. for the rest of this decade. Lower growth in this scenario is nevertheless experienced in all regions.

Table 4.1
Oil demand in the LEG scenario *mb/d*

	2015	2020	2025	2030	2035
OECD	45.0	43.4	41.6	39.4	37.3
Developing countries	40.3	44.8	48.7	52.1	55.3
Transition economies	5.1	5.3	5.3	5.3	5.3
World	**90.5**	**93.5**	**95.6**	**96.9**	**98.0**
Difference from Reference Case					
OECD	–0.8	–1.7	–2.5	–3.1	–3.8
Developing countries	–0.5	–1.5	–2.7	–3.9	–5.3
Transition economies	0.0	–0.1	–0.2	–0.2	–0.3
World	**–1.3**	**–3.3**	**–5.3**	**–7.3**	**–9.3**

Table 4.2
OPEC crude oil supply in the LEG scenario *mb/d*

	2015	2020	2025	2030	2035
OPEC crude	28.3	27.6	27.4	26.8	25.8
Difference from Reference Case					
OPEC crude	–1.3	–3.3	–5.2	–7.1	–9.1

The results for oil demand and supply are presented in Tables 4.1 and 4.2. It should be stressed that these numbers initially assume that oil prices remain at Reference Case levels, so that the demand decrease relative to the Reference Case is fully absorbed by lower OPEC production.[30] By 2035, oil demand is 9.5 mb/d lower than in the Reference Case. The scenario thereby sees OPEC crude supply falling throughout the entire projection period: by 2035, it has fallen to 26 mb/d.

The Higher Economic Growth scenario

Although the recession and on-going concern for the global recovery has highlighted concerns for downside risks to the prospects for economic expansion over both the medium- and long-term, there is also a need to consider, moving forward, the possible upside potential for the global economy. This could rapidly materialize if, for example, emerging markets expand more quickly than assumed in the Reference

Table 4.3
Oil demand in the HEG scenario *mb/d*

	2015	2020	2025	2030	2035
OECD	46.2	46.4	46.1	45.5	44.8
Developing countries	41.2	47.6	53.7	59.6	65.7
Transition economies	5.2	5.5	5.6	5.8	6.0
World	**92.5**	**99.4**	**105.4**	**110.9**	**116.4**
Difference from Reference Case					
OECD	0.4	1.2	2.1	2.9	3.7
Developing countries	0.3	1.2	2.3	3.6	5.1
Transition economies	0.0	0.1	0.2	0.2	0.3
World	**0.7**	**2.5**	**4.5**	**6.7**	**9.1**

Table 4.2
OPEC crude oil supply in the HEG scenario *mb/d*

	2015	2020	2025	2030	2035
OPEC crude	30.3	33.3	36.9	40.4	43.7
Difference from Reference Case					
OPEC crude	0.7	2.5	4.4	6.5	8.8

Case, particularly as their financial constraints do not mirror those of most OECD countries.

An alternative set of economic growth rates have, therefore, been developed for the HEG scenario. On average, over the projection period to 2035, global economic growth rates are assumed to be 0.5% p.a. higher than in the Reference Case. As with the previous scenario, prices are assumed to remain at Reference Case levels, although, in this case, as discussed below, there could be additional upward pressures.

The results for oil demand and supply in this higher growth scenario appear in Tables 4.3 and 4.4. By the end of the projection, in 2035, oil demand is now 9.1 mb/d higher than in the Reference Case. Again, assuming this rise to be reflected in higher OPEC supply only, the scenario sees OPEC crude production rising considerably swifter than in the Reference Case: by 2035, it has risen to over 43 mb/d. There is a slight asymmetry in the results for the LEG and HEG scenarios because of the additional emphasis in the former of the on-going Euro-zone crisis.

The Liquids Supply Surge scenario

The LSS scenario focuses specifically on supply uncertainties. There are a number of reasons for focusing on supply issues:

- It is feasible that the oil price assumption may lead to higher non-OPEC supply than portrayed in the Reference Case. This scenario therefore assumes greater responsiveness to these prices;
- This scenario also entails more supply coming from shale oil and NGLs in the US;
- In Chapter 3, it was noted that USGS estimates of the URR have increased. The Reference Case has used these new figures to consolidate the estimated feasibility of the supply potential from non-OPEC crude oil and NGLs. However, it is also possible that the higher resource estimates should be associated with stronger non-OPEC oil supply, and this is assumed in the scenario;

Table 4.5
Liquids supply in the LSS scenario *mb/d*

	2015	2020	2025	2030	2035
Non-OPEC	**58.1**	**64.6**	**67.8**	**68.5**	**69.9**
Crude	42.1	44.8	44.2	41.3	38.4
NGLs	7.3	8.0	8.5	8.9	9.4
Unconventional (incl. biofuels)	6.3	9.3	12.4	15.3	19.1
OPEC	**33.9**	**32.3**	**33.0**	**35.7**	**37.4**
NGLs	6.4	7.7	8.9	10.0	10.9
Crude	27.2	24.2	23.7	25.1	25.9
Difference from Reference Case					
Non-OPEC	**2.2**	**6.0**	**7.7**	**7.4**	**7.2**
Crude	1.2	3.5	4.3	3.2	1.9
NGLs	0.2	0.5	0.8	1.2	1.5
Unconventional (incl. biofuels)	0.8	2.0	2.5	3.0	3.9
OPEC	**–2.3**	**–6.2**	**–8.0**	**–7.6**	**–7.5**
NGLs	0.2	0.5	0.8	1.2	1.5
Crude	–2.5	–6.7	–8.8	–8.8	–9.0

- In the case of biofuels, it is assumed that over the medium-term, first generation biofuels production expands more rapidly than in the Reference Case: China and India emerge as significant biofuels producers; future targets, as yet unannounced, accelerate biofuels development; costs for advanced technologies are reduced considerably, especially in the long-term; and already in the current decade second generation technology becomes commercially viable. Taking all this into consideration, the major changes occur in the longer term and by 2035, total biofuels supply is assumed to reach 9.2 mb/d.

With these factors in mind, the LSS scenario has been developed. It portrays an outlook that could be regarded as feasible. Table 4.5 documents the supply levels for each of the elements of liquids supply in the scenario.

In this scenario, however, the surge of non-OPEC crude oil cannot be indefinitely maintained. In fact, over the long-term, an accelerated exploitation of the finite resources available, even with the larger URR assumption, points to resource constraints for some regions emerging over the projection period. Additionally, the assumption for additional shale oil foresees a similarly accelerated supply over the next 10–15 years, but this rapid expansion does not continue indefinitely in the scenario. Thus, since demand is assumed to be unaffected in this scenario, OPEC crude supply by 2035 has risen back to 26 mb/d after falling to below in 2025. But this is still well below current output levels.

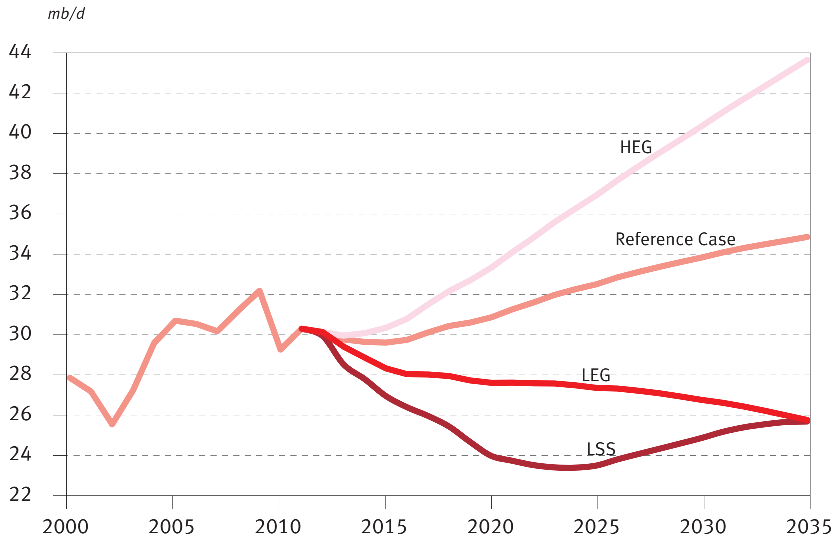
Possible implications for OPEC crude

The change in expectations relative to the Reference Case is startling in all three cases. On the one hand, they demonstrate genuine concern over security of demand; on the other, it has also been seen that circumstances could arise where considerably more OPEC crude oil will be needed than the Reference Case suggests.

It is clear that the separate drivers, economy and supply surges are substantial elements in their own way. Figure 4.1 brings together the implications for OPEC crude supply in all three scenarios. The two downside risk cases involve either a stagnant call on OPEC crude or a falling one, while the HEG scenario sees substantially higher production levels. By 2035, the expectations for OPEC crude are very similar across the downside risk scenarios, at 25–26 mb/d, while the HEG scenario sees the need for OPEC crude to rise to over 43 mb/d.

Naturally, the feasibility of these OPEC supply paths needs to be questioned. The dramatic fall in supply in the downside scenarios, as well as the rapid increase in the HEG scenario may not be sustainable, in which case, the behaviour of the drivers

Figure 4.1
OPEC crude oil supply in the three scenarios



in these scenarios would point to alternative price paths to that of the Reference Case. Hence, uncertainties over these key drivers are intrinsically linked to large uncertainties (both upside and downside) regarding future oil price developments. Close attention needs to be continually paid to all of these elements, as well as OPEC capacity expansion plans, to understand what pressures might be expected upon oil prices in the coming years.

Human resources

With the oil industry continuing to expand, and the need to increasingly tap resources in more frontier and challenging areas, the industry needs more skilled people. For a number of years, however, it has increasingly been observed that there is a shortage of human resources entering the industry. This has also been highlighted in previous WOOs.

The issue can be traced back to the 1980s and 1990s when large scale downsizing led to a lack of recruitment into the energy sector. At that time, many universities also cut back drastically on the number of people taking energy disciplines. In recent years, there has also been a dramatic expansion in the service and emerging knowledge economies, which has led to fierce competition for talent. And additionally, there is now a sizeable section of the industry's workforce, particularly the large numbers that entered the industry in the 1970s, that are now approaching retirement.

Earlier this year, Schlumberger, in its 2011 Oil & Gas Human Resources Benchmark Survey,[31] said that pressures on the industry's technical workforce threaten the timely completion of projects. In the survey, up to 70% of national oil companies and 60% of major international oil companies acknowledged project delays due to staffing difficulties.

It is apparent that there are no real short-term solutions. Meeting the human resource challenge will not happen overnight. The industry must look long-term. The industry is one characterized by long lead-times, and often long payback periods.

The key is making the industry more appealing; to make it accepted as an inclusive and forward looking workplace. The industry needs to be sure it is well presented as a prime employment choice; a high-tech and diverse sector with great prospects.

In fact, this needs to begin before actual employment – with education and training. It is important for the industry to be significantly involved in fostering and supporting new graduates and its potential workforce at an early stage. The focus is on further developing a better relationship between prospective employees, universities and the industry. This includes making sure that energy-related courses are open to all students from across the world, as well as furthering cooperation between universities around the globe, in terms of helping to facilitate the transfer of technologies and know-how.

Moreover, it is also essential to underscore the issue of local content and the utilization of domestic companies. This is of particular importance to many oil and gas producing developing countries; in helping provide a strong platform for the country's economic and social development.

Technology and R&D

Across the entire petroleum industry, technology has played a central role in its transformation over the decades. For instance, in terms of the way reserves are identified, developed, produced and delivered, leading to a massive growth in recoverable resources and supply, in converting crude into desirable fuels and products, in helping improve efficiencies and in continually improving the environmental credentials of both production processes and consumption.

The improved acquisition, treatment and interpretation of geological, geophysical and reservoir data and information in terms of quantity, quality and timeliness have increased the petroleum exploration success rate, extended the reach of the industry into new plays, frontier areas and harsher environments, led to better oil recovery from fields, diminished costs and reduced the environmental footprint.

Petroleum science has evolved from basic geology to elaborate supercomputer-based calculations, reservoir simulators and 3D views of deep and complex horizons in the subsurface. Enhanced 3D, for example, lets us see through thick salt layers.

In terms of drilling, the industry has moved from drilling tens of metres to many kilometres below the surface. Drilling offshore – originally technologically and economically a non-starter – is now a mainstay of the industry. As well as drilling vertically, technology now allows the industry to drill horizontally, including great distances from the drilling rig, through extended reach drilling. In addition, technological innovation has seen drilling wastes and the footprint of well pads decrease significantly over the years.

From the perspective of refining, improvements in conversion processes such as hydrocracking, fluid catalytic cracking and coking have allowed the industry to produce lighter products and, in particular, much needed volumes of transportation fuels, as well as to exploit the vast resources of heavy and extra heavy crude oil by upgrading it to streams that are suitable for international markets. And desulphurization technologies have enabled the industry to significantly reduce the environmental impact of sulphur emissions.

The industry has a long history of technologies helping to successfully reduce its environmental footprint. For example, in drilling, gas flaring reduction and cutting plant emissions. OPEC's Member Countries have invested billions of dollars over the past decades in flared gas recovery projects. This represents a significant contribution to the reduction – by more than half since the early 1970s – of the amount of gas that has been flared per barrel of oil produced.

And the automotive industry, as well as the refining industry, has a good track record in continuously reducing the pollutant emissions of vehicles.

And looking to the future, particularly given the continuing large reliance on fossil fuels, it will be important to look at technological options that allow the continued use of fossil fuels in a carbon-constrained world. In this regard, carbon capture & storage (CCS) is a proven technology that can be cost effective, and has the potential to contribute significantly to emissions reductions.

Technology will remain at the heart of the industry, in helping it overcome both existing and new challenges. Thus, it will be essential to ensure that the required technology is available, and at the right cost, meaning that significant investment in research and development is paramount. To this end, OPEC Member Countries are collaborating among themselves, as well as with companies and international research and technology development institutions to identify gaps and opportunities in technologies in the petroleum industry.

Addressing energy poverty

Poverty alleviation has been an important theme in multilateral negotiations on sustainable development. At the conclusion of the Millennium Summit in 2000, world leaders demonstrated an unprecedented commitment to tackling poverty by adopting eight Millennium Development Goals – although none of these included "energy poverty". Since then, however, despite significant progress in poverty alleviation, there has been an emerging consensus that without simultaneously alleviating energy poverty, the Millennium Development Goals cannot be fully achieved. OPEC has long been aware of this fact. It has thus made energy poverty alleviation a principal objective of its aid programme through its multilateral development agency, the OPEC Fund for International Development.

UN General Assembly Resolution 65/151, which declared 2012 as the "International Year of Sustainable Energy for All", highlighted the important role that energy plays in the development of nations. In this same vein, during the 2012 Rio+20 Conference in Rio de Janeiro, Brazil, the OPEC Fund for International Development announced its commitment to provide $1 billion toward the alleviation of energy poverty.

The large extent of energy poverty across the developing world is a challenge that requires international cooperation. It requires a clear understanding of the size, scope and severity of the problem – which, in turn, depends on how the parameters of energy poverty are defined and whether a temporary or a permanent solution to the problem is sought.

The core issue is making energy services available to those who are identified as energy-poor. Energy poverty arises either because people do not have physical access to energy services or because they cannot afford energy services. This points to the need to identify the thresholds at which one would be considered energy-poor, since this would determine the characteristics of subsequent international efforts, including the magnitude of investment needs, the types of fuel required, and the strategies to deliver energy and energy services to the energy-poor.

While access to electricity for lighting has been identified as a priority, sustaining access to this and providing other similar services in the long-term are matters that underscore the need to empower the poor to be able to earn an adequate and sustainable level of income so that they may pay for such services in the long-term. Thus, successful eradication of energy poverty in the long-term must rely on creating employment and income generating opportunities for the poor. In this context, an important area for international cooperation is assisting the poor in the transformation of their subsistence agriculture into income-generating agriculture. This requires that attention be given to two areas: shifting toward more productive mechanized agriculture and facilitating access to international markets for agricultural products by removing agricultural subsidies in developed countries.

It is important to note that modern mechanized agriculture uses far more energy than traditional agriculture but produces a much higher yield. In the US, for example, modern rice production uses 64,885 megajoule (MJ) of energy but yields 5,800 kilograms of rice per hectare, whereas traditional rice farming in the Philippines uses only 170 MJ of energy per hectare but yields only 1,250 kilograms of rice per hectare. This is more than a 381-fold difference in energy use and a 4.64-fold difference in yield. Such transformation leads to higher income for the poor and provides them with the opportunity to escape the poverty trap.

However, while access to international agriculture markets is essential to sustain the livelihood of poor farmers in developing countries, the significant agricultural subsidies in developed countries hinder such market access. In 2010, for example, OECD countries provided over $227 billion in subsidies to their agricultural sector. In this context, the eventual conclusion of the Doha Round of trade negotiations, which may include the removal of such agricultural subsidies in developed countries, could be one important step in supporting multilateral efforts to provide income generating opportunities for the poor and enable them to benefit from expanded energy services – not only to fulfill their basic needs but also for use in value added production processes and job creation.

Dialogue & cooperation

In an increasingly globalized and interdependent world that is bringing us all closer together, the importance of dialogue and cooperation grows. It is crucial for all the industry's various stakeholders.

Closer stakeholder engagement at various levels is critical for better understanding each other's viewpoints, developing common understandings, building confidence and finding the right balance in handling the uncertainties and challenges before the industry in a manner that allows for future economic growth and social progress.

Throughout 2012, OPEC has been actively involved in a number of dialogues, including the global producer-consumer dialogue, under the auspices of the International Energy Forum (IEF), the EU-OPEC Energy dialogue, the OPEC-Russia Energy dialogue, as well as working with other international organizations, such as the International Energy Agency (IEA), the International Monetary Fund, the World Bank, the Gas Exporting Countries Forum and the G-20, in terms of energy-related issues.

In Kuwait, in March 2012, the 13th IEF Ministerial Meeting took place. OPEC, which has been active in this dialogue since its inception, collaborates closely with the IEF on a number of issues, and in this instance, one of its Member Countries played host to its biennial ministerial gathering .

In 2012, OPEC has continued to cooperate with the IEF on the IEA-IEF-OPEC dialogue, G-20 energy-related issues and the Joint Organisations Data Initiative (JODI). The latter has proved to be an effective vehicle for improving energy data transparency at the global level.

One of the main features of the IEA-IEF-OPEC dialogue is the annual series of Symposia on Energy Outlooks, the second of which took place in Riyadh, Saudi Arabia, in January 2012. It provided a means of sharing and exchanging views about oil market trends and uncertainties, as well as short-, medium- and long-term energy outlooks. Moreover, in November 2011, the IEA, the IEF and OPEC held their second joint workshop on financial markets, and in October 2012, the three organizations held their First Joint Symposium on Gas and Coal Market Outlooks.

In February 2012, the IEA and OPEC also held a joint workshop in Kuwait on CO_2-enhanced oil recovery with CCS. The event brought together OPEC Member Country experts and international CO_2-EOR experts to discuss commercial, economic, technical, and regulatory aspects associated with the technology.

The EU-OPEC Energy dialogue, which was inaugurated in 2005, held its 9th Ministerial-level meeting in June 2012 in Brussels. The dialogue, which continues to go from strength-to-strength, also incorporates various joint studies, roundtables and workshops. Upcoming events include the organization of an international roundtable on offshore safety in oil and gas exploration and production activities, which will be held in November 2012, and a study and roundtable to assess the potential manpower bottlenecks in the petroleum industry, which is set for the first half of 2013.

In September 2012, OPEC and Russia saw a continuation of their Energy Dialogue, with an exchange of views on the current oil market situation and an underscoring of the importance of stable and predictable markets for the long-term health of the industry and investments, and above all, the well-being of the global economy.

OPEC has long recognized the importance of a cooperative and coordinated approach to dialogue aimed at fostering market stability in both the short- and long-term. It is essential that the industry continues to evolve, and look to expand cooperation, as and when appropriate, in the years ahead.

Section Two

Oil downstream outlook to 2035

Chapter 5

Demand outlook to 2035

Refined product demand to 2035

In this Chapter, and the whole of Section Two, it should be noted that the regional definition used differs from that in Section One because of the necessity to include inter-regional trade flows in downstream estimates. Therefore, it is based on a geographic, rather than an institutional basis. The World Oil Refining Logistics and Demand (WORLD[1]) model provides a working framework for all estimates related to the downstream sector. The model breaks the world into 22 regions, which for reporting purposes are aggregated into the eight major regions defined in Annex C.

To a significant extent, developments in specific oil demand sectors determine the current and future demand structure in terms of the product slate. Observed key trends in sectoral demand, described in detail in Chapter 2, are reflected in projections for global product demand, as presented in Table 5.1 and Figures 5.1 and 5.2.

The importance of the transportation sector is reflected in the fact that out of 19.5 mb/d of additional demand by 2035, compared to 2011, around 60% is for middle distillates – gasoil/diesel and jet/kerosene – and another 38% is for gasoline and naphtha. The main reason for this is the growth in the road transportation sector, which is driving demand for gasoline and diesel. However, demand for diesel also receives support from marine bunkers, jet/kerosene from the expanding aviation sector, and the growing petrochemical industry provides momentum for naphtha.

For the remaining products, a decline in residual fuel oil is broadly offset by an increase in ethane/liquefied petroleum gas (LPG) and the group of 'other products'.

A clear consequence of these demand trends is a progressive change in the make-up of the future product demand slate. Middle distillates not only record the largest volume increase, but they are also expected to increase their share in the overall slate from 37% in 2011, to 41% by 2035. The share of light products – ethane, LPG, naphtha and gasoline – will also increase, but more moderately. Their total share rises only 1%, from 42% in 2011 to 43% in 2035. In contrast, the share of (mostly) heavy products decreases by around 5%, from 21% in 2011 to 16% by 2035.

Table 5.1
Global product demand, shares and growth, 2011–2035

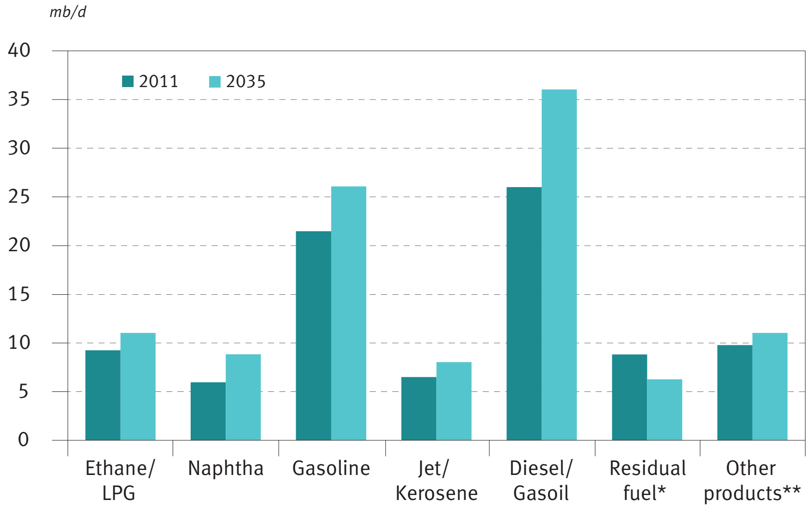
	Global demand *mb/d*						Growth rates *% p.a.*		Shares *%*	
	2011	**2016**	**2020**	**2025**	**2030**	**2035**	**2011–2016**	**2016–2035**	**2011**	**2035**
Light products										
Ethane/LPG	9.2	9.8	10.2	10.5	10.8	11.0	1.1	0.6	10.5	10.3
Naphtha	6.0	6.5	7.1	7.7	8.3	8.8	1.8	1.6	6.8	8.2
Gasoline	21.5	22.5	23.4	24.5	25.3	26.1	0.9	0.8	24.5	24.3
Middle distillates										
Jet/Kerosene	6.5	6.8	7.1	7.5	7.7	8.0	1.0	0.9	7.4	7.5
Diesel/Gasoil	26.0	28.9	31.3	33.2	34.7	36.0	2.1	1.2	29.6	33.6
Heavy products										
Residual fuel*	8.8	8.2	7.5	7.0	6.7	6.3	–1.4	–1.4	10.1	5.8
Other**	9.8	10.2	10.2	10.4	10.7	11.0	0.8	0.4	11.1	10.3
Total	**87.8**	**92.9**	**96.9**	**100.9**	**104.2**	**107.3**	**1.1**	**0.8**	**100.0**	**100.0**

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

Despite the fact that part of the additional demand will be covered by non-refinery products, it is clear that these structural changes cannot be achieved by simply increasing refinery crude runs. They require investments to change the configuration of the global refining system (Chapters 6 and 7).

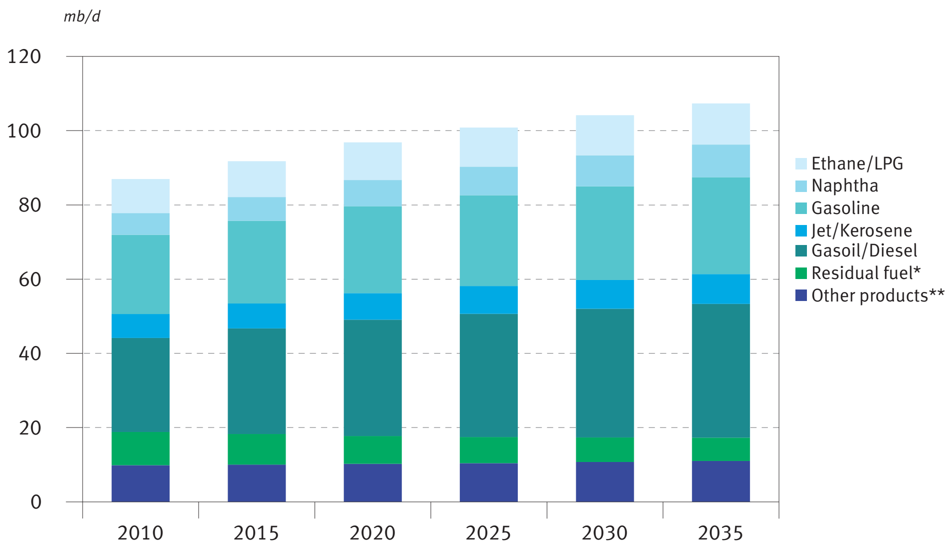
Gasoil/diesel is expected to witness the largest volume gain, increasing by more than 10 mb/d between 2011 and 2035, mainly due to the growing transport sector including marine bunkers. However, on a percentage basis, naphtha is anticipated to be the fastest growing product in the long-term, especially in developing Asian countries. Following a temporary decline in 2009, demand growth for naphtha resumed in 2010 and is expected to continue over both the medium- and long-term. The average growth rate for naphtha in the medium-term is 1.8% per annum (p.a.), and in the long-term it is 1.6% p.a. The largest volume increase for naphtha is projected for the Asia-Pacific, around 3 mb/d between 2011 and 2035, while China itself accounts for roughly half of this increase as its petrochemical industry expands significantly.

Figure 5.1
Global product demand, 2011 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.*

Some new major petrochemical projects are also foreseen in the Middle East and the US. However, these are mostly based on using ethane – mostly from natural gas – as feedstock; thus naphtha growth in the Middle East is limited and is projected to marginally decline in North America. Stagnant or declining naphtha demand is also foreseen in other OECD regions, which partly compensates for increases in other developing countries and the Former Soviet Union (FSU).

Another product witnessing demand expansion is gasoline, with demand increasing almost 5 mb/d between 2011 and 2035. This, however, is less than half of the diesel/gasoil increase for the same period.

What is interesting to note is that gasoline represents the product with the widest regional growth rate differences. This ranges from a substantial decline in North America, of almost 1 mb/d by 2035, through stagnant demand in Europe, to substantial growth in Asia-Pacific, especially China and India. Significant gasoline demand growth is also projected for the Middle East, Africa and Latin America. The current significance of North America and Europe to total gasoline demand is the main reason behind gasoline's relatively low global growth rate. The two regions comprised 53% of the global gasoline demand in 2011. Therefore, developments in these regions have a significant impact on the global picture, offsetting increases in other regions.

For kerosene, which typically consists of two similar products, jet kerosene for the aviation sector and domestic kerosene used mostly for lighting, heating and cooking, there is a continuing shift away from kerosene use in aviation to jet fuel. While demand for jet fuel is projected to grow steadily, especially in non-OECD regions, kerosene will continue to be displaced by alternative fuels in most regions, with the upshot being a steady demand decline. This means that this product group's overall growth is lower than it would have been if jet kerosene was considered alone. Consequently, combined jet/kerosene demand is projected on average to grow by 0.9% p.a. for the entire forecast period, which is a moderately above-average growth rate for all products.

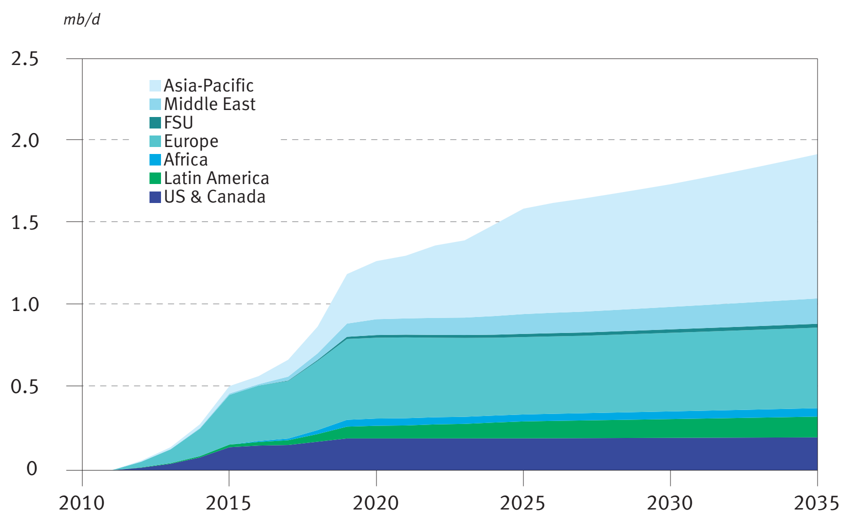
Residual fuel oil is the only product group that is set to decline globally in the coming years. Its use in industry, mainly for electricity generation and refineries, has faced competition from natural gas in most regions for decades, with the result being a drop in demand. This trend is expected to continue in the future, especially in regions where a high ratio of oil to gas price persists. Moreover, this demand decline will be accelerated by the shift from fuel oil to diesel in marine bunkers stemming from International Maritime Organisation (IMO) regulations. In total, fuel oil demand is set to decline by close to 3 mb/d between 2010 and 2035, out of which almost 2 mb/d is associated with marine sector developments.

Figure 5.3 presents the details of this shift in terms of the projected intermediate fuel oil (IFO) that would be switched to marine distillate under the IMO MARPOL Annex VI regulations. The figures also assume that several countries/regions will apply for Emission Control Area (ECA) status that requires yet tighter standards.

The two key compliance dates are 2015 and 2020; the former a switch from a maximum sulphur level of 1 wt% to 0.1 wt% for fuel consumed within ECAs, and the latter the current official date for the transition to a global (non-ECA) standard of 0.5 wt% sulphur, to replace the current 3.5 wt%. Recognizing this, fuel switching was graduated in the projected figures under the assumption that suppliers 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 first step increase in IFO switching is expected around 2015, which essentially sees Northern Europe, the US and Canada moving to the 0.1 wt% ECA standard. The second major increase switching to diesel is projected around 2020.

There is, however, a high degree of uncertainty over the extent to which emissions compliance will be achieved by fuel switching versus on-board scrubbing. A current 'working assumption' is that larger ships, comprising around 20% of the marine fleet, but consuming around 80% of the fuel, will be the ones that are either retrofitted or built new to use scrubbers. Moreover, pessimism as to whether the industry

Figure 5.3
Projected IFO switch to diesel oil, 2010–2035



will fully comply with the regulations and the expectation that the use of scrubbers will increase gradually, leads to a flattening in the required switching from IFO in the period after 2020.

It must be recognized that uncertainties exist over the implications of IMO regulations for marine fuels and energy efficiency improvements in the sector. Increasingly there are some noises being made that the implementation year for tightening global fuel standards could be shifted to 2025, rather than 2020, as originally proposed. Moreover, another option for compliance – especially longer term and for larger new vessels – is increasingly being discussed, namely liquefied natural gas (LNG) (Box 5.1). Nevertheless, from the current perspective, projections indicate that some 0.5 mb/d of IFO will be switched to distillate by 2015, 1.3 mb/d by 2020 and 1.9 mb/d by 2035.

The last product group – '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, China and Japan. In the long-term, however, it is assumed that the direct use of crude oil will be eliminated and replaced with more cost effective solutions. At the global level, demand for these products is projected to increase by 1.1 mb/d by the end of the forecast period, compared to 2011. This represents an average growth rate of 0.5% p.a.

It should also be noted that these 'other products' taken individually demonstrate a range of longer term growth rates, from declines in the direct use of crude oil, an essentially flat outlook for lubricants and waxes derived from crude, moderate growth for asphalt and stronger growth for petroleum coke grades, as well as for still gas and sulphur, as refineries become more complex and move increasingly to low and ultra-low sulphur (ULS) products.

Box 5.1
Will LNG become an important new bunker fuel?

With new and more severe emission standards on the horizon, ship operators are being pushed into either switching to cleaner, alternative fuels, or fitting exhaust gas cleaning systems. For 2020, the IMO has set a global limit of <0.5% sulphur oxide (SOx) for marine fuels, although there is the possibility that this could be delayed until 2025 if there are severe supply shortages. It begs the question: what will this mean for refiners in the coming years?

To meet the new regulations and standards, only a few technologies are available, and each of them comprises a list of pros and cons.

At first glance, retrofitting scrubbers is an obvious and quick solution to eliminate SOx emissions. The systems can also help remove nitrogen oxide (NOx) and particulates (soot), although for this the technology becomes more complex and expensive. The bulkiness of scrubbers, the confined space available on existing ships, increased maintenance, corrosion issues when dealing with SOx, as well as discharge challenges, remain areas of concern and need to be properly addressed. Nonetheless, especially for large vessels, scrubbing technology is viewed as part of the solution to comply with future regulations.

Switching to low sulphur gasoil is also an alternative, especially for smaller ships operating mainly in ECAs. While this will advance the life of the ship's engine, it will, however, also increase fuel costs. Moreover, technical upgrades, such as different injector nozzles and fuel system reconfigurations to cope with lower viscosities and pour points will have to be fitted.

Biodiesel would also be able to accommodate the IMO requirements. In addition, it could offer some potential 'environmental-related' benefits, such as carbon credits, and better biodegradability in case of oil spills. However, given the length of time fuel is often on-board ships and at temperatures suited to microorganisms, there are concerns that the high levels of humidity could promote bacterial growth and deterioration. This raises serious concerns in terms of corrosion, filter plugging and, in the worst case, gel formation inside the entire fuel system. In addition, the price and availability of marine biofuels may be out of reach for many ship owners. The current common presumption is that there will be no substantial volumes of biodiesel in this sector for the foreseeable future.

All this has led to a number of companies and organizations, such as Det Norske Veritas, MAN, Mitsubishi, Rolls Royce, Wärtsilä and Austal, exploring the LNG option. LNG is being seen as a new 'green bunker fuel' and a convenient way to address the challenges outlined by the IMO regulations. Supporters of LNG see it as an option that solves most of the concerns related to the other possibilities being explored.

LNG combustion is virtually soot- and SOx-free, NOx emissions are controllable, and due to the higher hydrogen content in methane, natural gas-powered ships can emit up to 25% less CO_2,[2] on a tank-to-wheel basis, compared to traditionally powered ships. Other potential benefits include reduced lubricant oil consumption and avoiding the need for heavy fuel oil pre-treatment installations. Dedicated LNG ship engines are designed as four stroke spark ignition versions, or large dual-fuel two stroke piston engines, which do not represent a major deviation from current designs and operations. This is an important factor for shipping lines, especially in the light of staff hiring and/or retraining.

From the economic point of view, LNG technology is also fairly appealing, especially when it comes to new vessel orders. Capital investment is generally around 10–20% more, when compared to conventional oil burning ships, but given the current lower natural gas prices there is the promise a quick return of the extra money invested, though the sustainability of the existing price advantage is questionable. And, with higher market penetration, the price premium for LNG technology is expected to come down further.

Having reviewed the benefits of LNG, it is important to ask the question as to why there are still only limited numbers of LNG powered ships. It is clear there are a couple of important reasons why the current adoption rate of LNG as a bunker fuel is slow and mainly confined to smaller vessels operating in the Baltic or North Sea.

Despite LNG-powered ships substantially reducing emissions from combustion of the fuel, methane, which has a climate-warming potential 25 times higher than CO_2 over a period of 100 years, could be released into the atmosphere during travel and LNG bunkering procedures. This could reverse the gains made by CO_2 reductions from LNG ships. Solutions to this problem are available, but they still need to be converted into commercial applications, marine standards, as well as an international monitoring system. Similarly, safety regulations and new standards must be developed for LNG ships, and applied globally.

In addition, and perhaps the main reason currently holding back large orders for LNG-powered vessels, there is the absence of a global LNG retail network. A classic chicken-and-egg situation has emerged. Insufficient numbers of LNG-powered ships make it risky to invest and develop a capital intensive global LNG bunkering network, but without guaranteed LNG bunkering facilities at major world seaports, shipping lines will remain hesitant to purchase new LNG ships or retrofit old ones.

The situation, however, could change, particularly in the Baltic and North Sea region. Here, IMO regulations for ECAs have already been implemented and a number of Northern European governments have encouraged the adoption of LNG as a bunker fuel.

However, with an average life for ships of 25–30 years, substituting the existing global fleet with LNG vessels will take a long period of time. For example, looking to the past and similar innovations, when solid fuel steam power was replaced by oil-based technology, a full technology adoption cycle for the marine transport sector took around 50 years. The industry as a whole is also often viewed as one that is slow to adopt to change.

Moreover, as already underscored, prior to any sustained LNG adoption for ships, a robust LNG retail sector has to be established at major world sea ports.

It should also be noted that there continues to be an oversupply of cargo vessels and this will continue to depress new ship order books for some time. Market adoption is expected to mostly take place through new ship orders, as retrofitting old vessels is much less appealing, due to higher safety concerns, the enormous costs involved and the ship's long off-duty time during conversion.

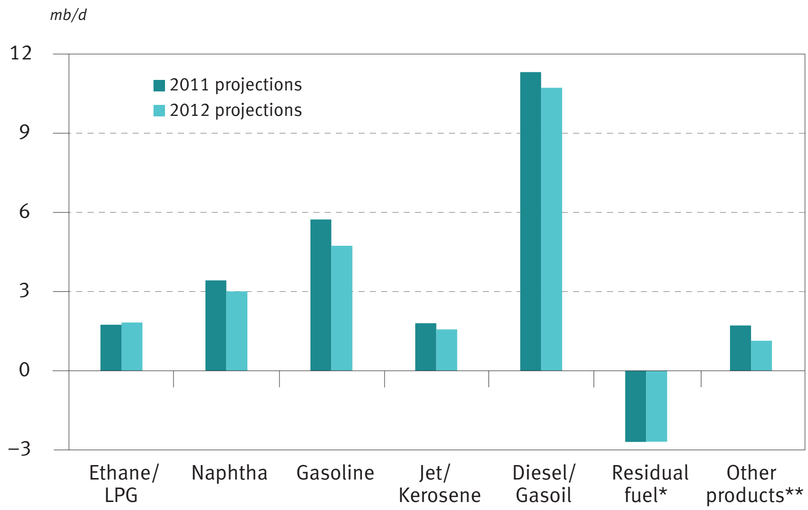
In addition, slow steaming, alongside the use of kites and sails, will bring long-voyage fuel oil consumption down further, thus reducing the incentives and pushing forward the date when early adopters could start ordering new LNG-powered vessels in greater numbers.

Many ship operators can also be expected to wait and observe the performance of any newly delivered LNG vessels for a few years. Only if these vessels produce attractive profits, prove safe and reliable, will others follow the early adopters and lead to LNG establishing itself as an additional bunker fuel.

Figure 5.4 demonstrates changes introduced to this year's update, compared to the WOO 2011. In this year's WOO, projected global gasoline demand in 2035 is expected to be around 1 mb/d lower, compared to the WOO 2011.

The revision for diesel/gasoil oil is much smaller. It is around 0.5 mb/d lower by 2035 compared to WOO 2011. For this product group, several factors interplay. In contrast to gasoline, diesel demand is spread across several sectors and is more sensitive to a region's overall economic performance. For example, downward revisions for China's economic growth versus WOO 2011 and an upward revision for India, play a role. In addition, it is also essential to look at efficiency improvements. In the road transportation sector, a relatively large portion of the diesel demand is consumed by medium and heavy duty vehicles and buses where efficiency improvements are likely to be less swift. And another factor that comes into the equation is the likely switch from heavy fuel oil demand to diesel fuel in the marine bunkers sector. In this year's update, a slightly delayed compliance with the IMO regulations is assumed, which yields some delays in the volume of the projected switch over time, whereas the assumption about the use of onboard scrubbing was kept unchanged. This reflects the widely accepted industry view that scrubbers will likely be fitted to around 20% of the marine fleet, but that these will be the larger vessels consuming about 80% of bunker fuels.

Figure 5.4
Global product demand changes between 2010 and 2035



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

Upward revisions to ethane[3] and LPG demand, compared to last year's WOO, have also been made. These reflect recent developments in the gas sector, primarily a projection of US higher shale gas production, as well as some other regions, given its higher production of associated liquids.

Another major revision was made in the category of 'other products', primarily related to the progressive elimination of direct crude burning in line with recently announced policies, for example, in Saudi Arabia. However, there are significant regional variations in projected demand changes for this grouping, as well as differences in demand trends for specific products within the group.

These variants span declines in demand in Europe and North America – within the range of 1% to 2% p.a. – to strong increases in Africa, the Middle East and Asia, with average regional growth rates between 2% and 3% p.a. At the product level, demand for such products as bitumen, lubricants, waxes and solvents is strongly linked to economic growth, whereas the production of still gas, coke and sulphur are very much a function of the growth or decline in refining activity, both throughput and secondary processing.

Regional product demand to 2035

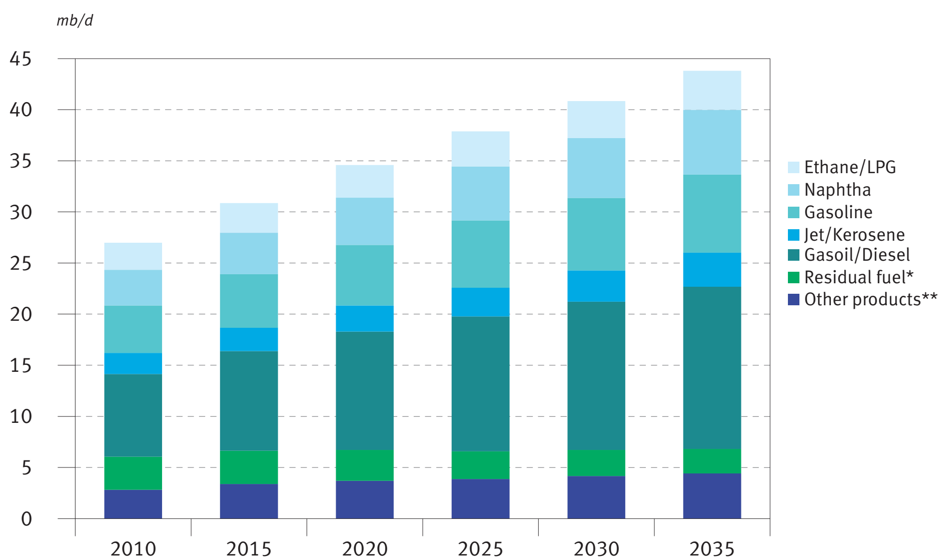
Turning to the regional distribution of product demand, Table 5.2 provides an overview of the breakdown of product demand in the major regions.

Asia-Pacific

Product demand growth in the Asia-Pacific region dominates future trends with the region accounting for more than 80% of the global growth in petroleum product demand. Moreover, the region's product demand is largely determined by what happens in China and India. Strong growth in these two countries pulls up the region's demand growth to an annual average of 2% between 2010 and 2035, despite the fact that demand in the region's industrialized countries – Japan, Australia and New Zealand – is projected to decline by more than 1 mb/d over the same period. This represents a net average annual demand increase of 0.7 mb/d. It means that petroleum product demand for the Asia-Pacific by 2035 is expected to be around 44 mb/d (Figure 5.5).

Diesel, naphtha and gasoline will be the main products contributing to the Asia-Pacific increased demand. Diesel expansion will see the largest growth, contributing

Figure 5.5
Outlook for oil demand by product, Asia-Pacific, 2010–2035



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

Table 5.2
Refined product demand by region

mb/d

	World	US & Canada	Latin America	Africa	Europe	FSU	Middle East	China	Asia-Pacific
2010									
Ethane/LPG	9.2	2.4	1.0	0.4	1.2	0.4	1.2	0.7	2.0
Naphtha	5.8	0.4	0.3	0.0	1.2	0.3	0.2	1.0	2.5
Gasoline	21.3	9.3	1.9	0.8	2.3	1.1	1.2	1.6	3.0
Jet/Kerosene	6.5	1.9	0.3	0.3	1.2	0.3	0.4	0.3	1.8
Diesel/Gasoil	25.3	4.4	2.4	1.4	6.2	1.0	1.8	3.5	4.6
Residual fuel*	8.9	0.7	1.0	0.7	1.5	0.4	1.3	0.6	2.6
Other products**	9.9	2.5	1.4	0.2	1.9	0.4	0.6	1.2	1.6
Total	87.0	21.6	8.3	3.9	15.5	3.9	6.7	9.0	18.0
2020									
	World	**US & Canada**	**Latin America**	**Africa**	**Europe**	**FSU**	**Middle East**	**China**	**Asia-Pacific**
Ethane/LPG	10.2	2.4	1.2	0.5	1.0	0.5	1.4	0.9	2.3
Naphtha	7.1	0.3	0.4	0.0	1.1	0.3	0.2	1.6	3.0
Gasoline	23.4	9.0	2.4	1.1	2.1	1.2	1.5	2.5	3.4
Jet/Kerosene	7.1	1.9	0.4	0.4	1.1	0.3	0.5	0.5	2.1
Diesel/Gasoil	31.3	4.7	3.0	1.8	6.8	1.2	2.3	5.5	6.1
Residual fuel*	7.5	0.4	0.9	0.8	0.7	0.4	1.3	0.6	2.4
Other products**	10.2	2.1	1.4	0.3	1.5	0.5	0.9	1.5	2.2
Total	96.9	20.9	9.6	4.9	14.3	4.4	8.1	13.2	21.3
2035									
	World	**US & Canada**	**Latin America**	**Africa**	**Europe**	**FSU**	**Middle East**	**China**	**Asia-Pacific**
Ethane/LPG	11.0	2.3	1.3	0.6	0.8	0.5	1.7	1.1	2.7
Naphtha	8.8	0.3	0.5	0.0	0.9	0.4	0.4	2.4	3.9
Gasoline	26.1	8.4	2.9	1.4	2.2	1.4	2.1	3.7	4.0
Jet/Kerosene	8.0	1.7	0.5	0.5	1.0	0.4	0.7	0.7	2.6
Diesel/Gasoil	36.0	4.2	3.4	2.1	6.3	1.3	2.9	7.3	8.6
Residual fuel*	6.3	0.2	0.7	0.9	0.4	0.4	1.3	0.3	2.1
Other products**	11.0	1.8	1.5	0.3	1.3	0.5	1.3	2.0	2.4
Total	107.3	19.0	10.8	5.7	13.0	4.7	10.4	17.6	26.2

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

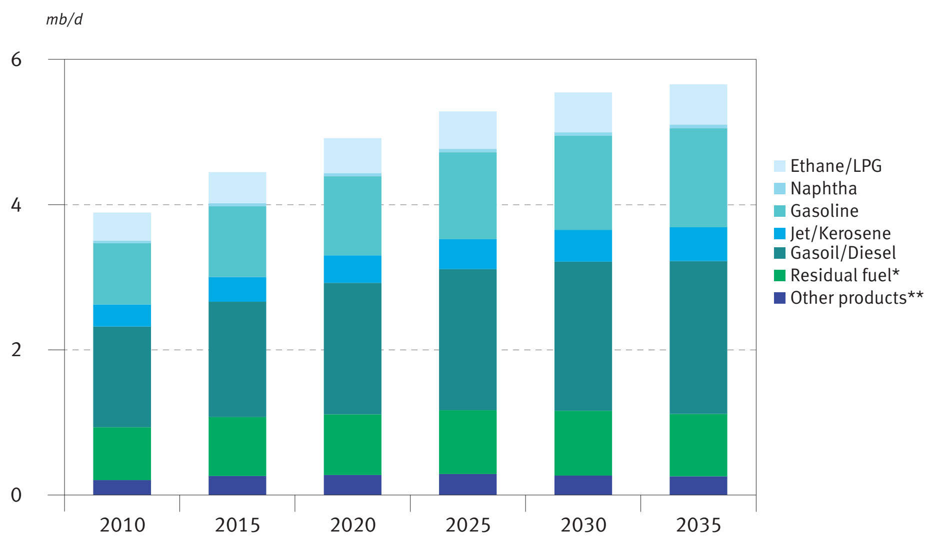
8 mb/d of additional volume between 2010 and 2035. These additional barrels will be needed primarily for transport supported by developments in the commerce, industry and household sectors. Naphtha demand growth in the region is driven by the expected rapid expansion of the petrochemical sector, adding close to 3 mb/d of incremental demand over the forecast period. A comparable increase is also foreseen for gasoline, as increases in car ownership outweigh the effect of improved new car efficiencies.

The remaining part of the region's demand increase is spread across other product groups, except fuel oil. While fuel oil demand in the Asia-Pacific is set to grow marginally through the medium-term, after 2015, the implementation of new ECAs and the expected implementation of tighter global IMO regulations for marine bunkers will eliminate the product's demand growth. In 2020, fuel oil demand in the region will be 0.2 mb/d lower than in 2015. A gradual demand decline is expected to continue during the remainder of the forecast period.

Africa

Demand in Africa is projected to remain relatively strong over the entire forecast period, although increases in volume terms are less than 2 mb/d. Demand is expected to grow

Figure 5.6
Outlook for oil demand by product, Africa, 2010–2035



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

by 2.7% p.a. through to 2015, then slow in the period thereafter. It means the average growth rate will fall to 1.2% p.a. between 2015 and 2035. Over the entire forecast period, growth will average 1.5% p.a. Africa, however, currently represents less than 5% of the global demand for refined petroleum products and, therefore, even at an above average growth rate, the annual average volume increases are below 0.1 mb/d. Total product demand will likely remain below 6 mb/d by 2035 (Figure 5.6).

Gasoline and road diesel will continue to be the major demand drivers in Africa, followed by the use of LPG, mainly for cooking, and a still expanding demand for residual fuel oil. Indeed, Africa is the only region where residual fuel oil demand will not decline throughout the entire period, despite the effect of IMO regulations on marine bunkers. The effect of expanding inland consumption of fuel oil is expected to offset the decline in bunker fuels. Compared to other regions, Africa consumes very little naphtha, so most of this region's production of this product is exported. In terms of volume increases, diesel is set to add around 0.7 mb/d between 2010 and 2035, gasoline 0.5 mb/d, while increases in LPG and residual fuel oil are projected to be below 0.2 mb/d.

Europe

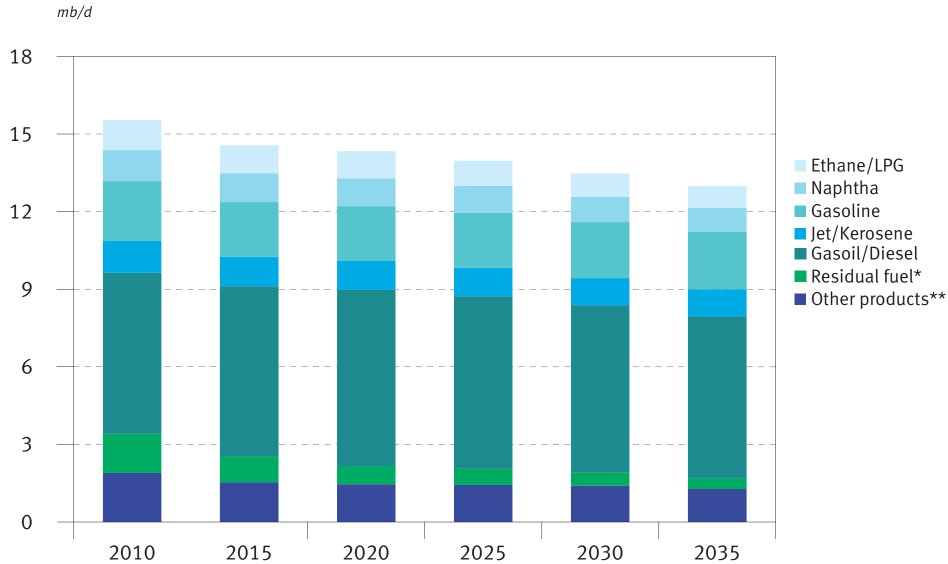
In addition to continuing fuel efficiency improvements and the expected increased use of gas and renewable energy, Europe's medium- and long-term demand trend for refined products will also be affected by the implementation of marine fuels regulations.

It is expected that the pace of conversion from gasoline to diesel will slow in the medium-term. A diminishing price advantage for diesel in the long-term, combined with faster fuel efficiency improvements in the segment of gasoline-based engines, constitute the basis for the gasoline demand recovery, albeit marginal, so that by the end of the forecast period, Europe's gasoline demand will stabilize in the range of 2.2 mb/d.

However, diesel demand in Europe will get support from the conversion of marine bunkers, especially close to and after 2015 when the IMO regulations setting the maximum sulphur content in ECAs at 0.1% come into effect. In the case of Europe, this regulation could result in additional diesel demand in the range of 0.3 mb/d by 2016, which will expand to around 0.5 mb/d by 2035. Therefore, it is clear that diesel will remain the dominant factor in European product markets through to 2035.

Demand for jet/kerosene in Europe is also projected to decline, although this is relatively minor. This is the result of structural changes within this product group, with modest increases in demand for jet kerosene, being offset by losses in the domestic and industrial use of kerosene. A decline in naphtha demand reflects the tendency

Figure 5.7
Outlook for oil demand by product, Europe, 2010–2035



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

to 'relocate' part of the petrochemical industry to developing countries, especially from the western part of Europe. In Central and Eastern Europe, however, naphtha demand is expected to grow.

Major demand losses are projected for fuel oil and 'other products'. Towards the end of the forecast period, fuel oil will be almost eliminated from European markets, declining by more than 1 mb/d between 2010 and 2035 to the level of 0.4 mb/d. 'Other products' are projected to decline by 0.6 mb/d by 2035, from a level around 1.9 mb/d in 2010.

In total, Europe's liquids product demand will decline on average by 0.7% p.a. for the period until 2035, or by 2.5 mb/d in terms of volume loss (Figure 5.7).

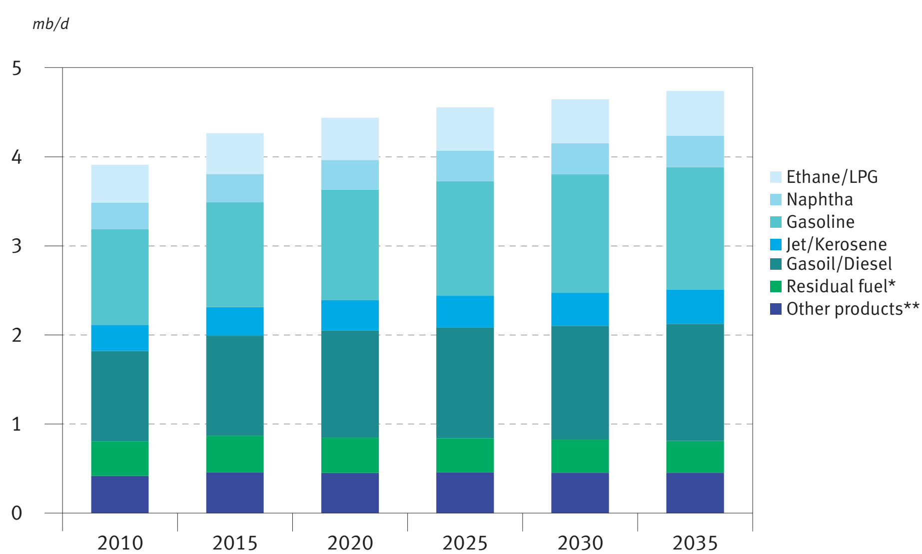
Former Soviet Union (FSU)

Refined product demand in the FSU is dominated by Russia, which currently accounts for around 70% of the region's total demand. Overall product demand is expected to increase by almost 1 mb/d between 2010 and 2035, which represents an average growth rate of just below 1% p.a. (Figure 5.8). The drivers of this growth are mainly transportation fuels. Traditionally this has been gasoline, but increasingly there will be future growth in diesel and jet kerosene, notably in Russia.

For gasoline, the region sees moderately higher than average demand growth, projected to be around 1% p.a. over the forecast period. In the medium-term, however, growth rates are higher than the long-term average, reflecting the recent increases in new car registrations, the majority of which are gasoline vehicles. Similar increases are foreseen for diesel/gasoil. This product group will also see a shift in its sectoral consumption, away from the industrial sector to the transportation sector. This shift is partly supported by the on-going elimination of gasoline-oriented trucks and buses, but also by the implications of IMO regulations in the Baltic ECA. Substitution by natural gas will moderate growth in fuel oil and diesel/gasoil demand for off-road uses.

Lower than average increases are projected for naphtha, despite an expanding petrochemical industry in the region. This can be attributed to the expectation that a portion of the additional feedstock for this industry will be based on natural gas, including the use of currently flared gas, which should be almost eliminated within the next few years.

Figure 5.8
Outlook for oil demand by product, FSU, 2010–2035



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

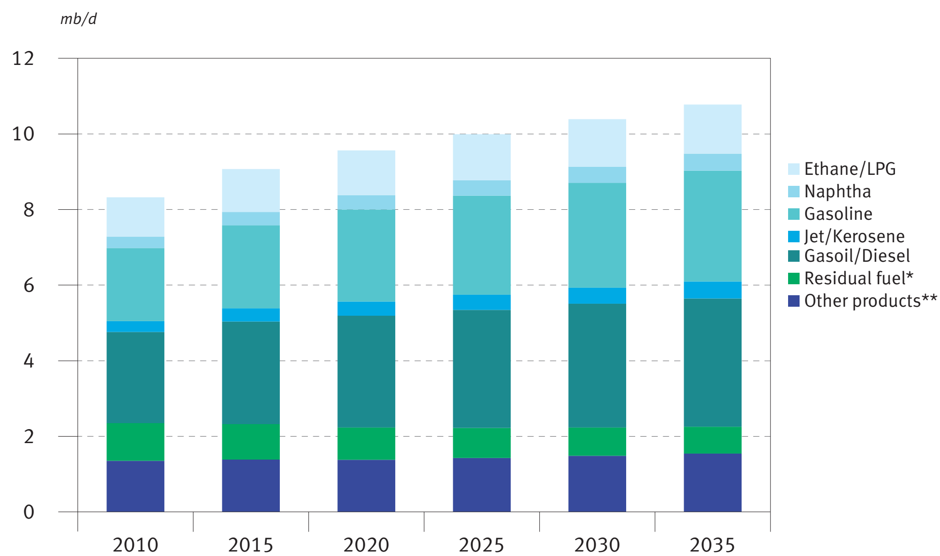
The increases already highlighted are partially offset by declining fuel oil demand. This is a result of the rationalization and efficiency improvements in the industrial sector, as well as substitution by natural gas in the heat and power sectors.

Latin America

Refined product demand in Latin America is projected to grow by close to 2% p.a. in the medium-term, with rates gradually declining to below 1% p.a. over the longer term. Similar to other developing regions, growth will occur mainly in middle distillates and gasoline (Figure 5.9).

Out of 2.5 mb/d of incremental demand by 2035, 1 mb/d is attributed to gasoil/diesel expansion and another 1 mb/d to gasoline. Increasing air traffic, mostly in the region's largest countries such as Brazil, Argentina and Venezuela, will support demand for jet fuel. Therefore, jet/kerosene and naphtha – largely determined by petrochemical expansion in Brazil – also show above average growth rates. However, this is from a relatively low base, which means their overall contribution to demand change is less than 0.2 mb/d between 2010 and 2035.

Figure 5.9
Outlook for oil demand by product, Latin America, 2010–2035



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

Chapter 5

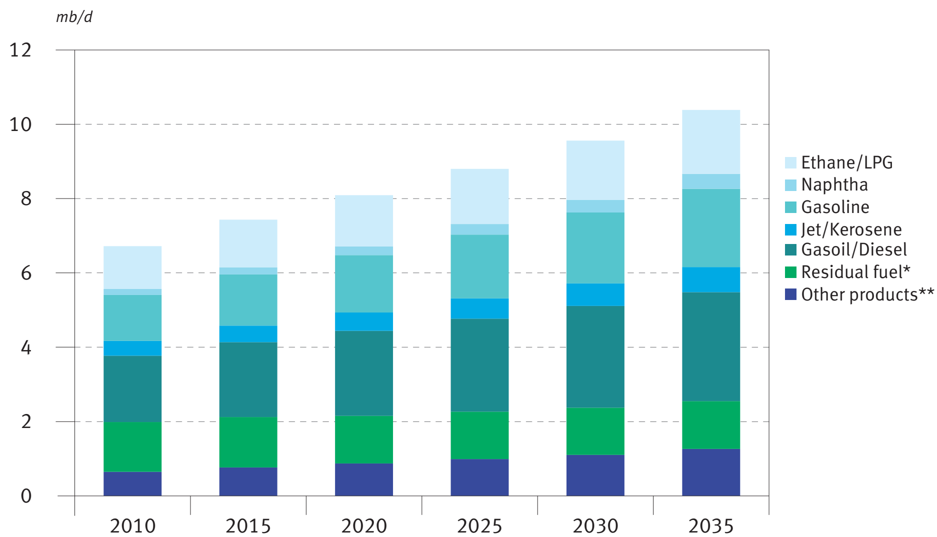
Specific to Latin America is the large share of LPG in the demand structure. It is the highest among all regions, with the level currently around 14%. LPG demand will maintain its share over the forecast period as growth is projected at roughly the same rates as the region's total demand. The only product that is set to decline is fuel oil, which drops by 0.3 mb/d.

Middle East

Refined product demand in the Middle East is expected on average to grow by 1.8% p.a. over the forecast period, from 6.7 mb/d in 2010 to 10.4 mb/d in 2035 (Figure 5.10).

In contrast to other regions, the typical product slate in the Middle East consists of a relatively high share of fuel oil, in volumes that are comparable with both distillates and gasoline. However, in the coming years, economic growth, extensive construction activity and a shift in the composition of marine bunkers will lead to diesel gaining share at the expense of residual fuel oil. For middle distillates in general, it is expected there will be stronger than average product demand growth, at 2% p.a.

Figure 5.10
Outlook for oil demand by product, Middle East, 2010–2035



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

Demand for fuel oil will remain relatively stable, as various factors affect its demand. These factors include growing overall marine bunkers demand, although part of this will be shifted to diesel; and expanding refining activity, thus, higher refinery fuel use, to some extent, however, this will be offset by substitution through natural gas.

A similar interplay of factors leads to a fairly stable demand outlook for 'other products'. Within this category, the region's major refinery expansions will increase the production and consumption of refinery gas and coke, and expansion in the region's infrastructure will require more bitumen and lubricants, although this growth will be largely offset by the declining direct use of crude oil.

Demand for naphtha is relatively small, despite the region's large petrochemical production operations as these use mainly ethane and LPG feedstock for ethylene cracking operations, as opposed to naphtha. However, as a consequence of recently integrated refinery-petrochemical projects, naphtha demand is projected to grow by almost 4% p.a. through to 2035, faster than ethane and LPG, which are seen to grow at 1.6% p.a.

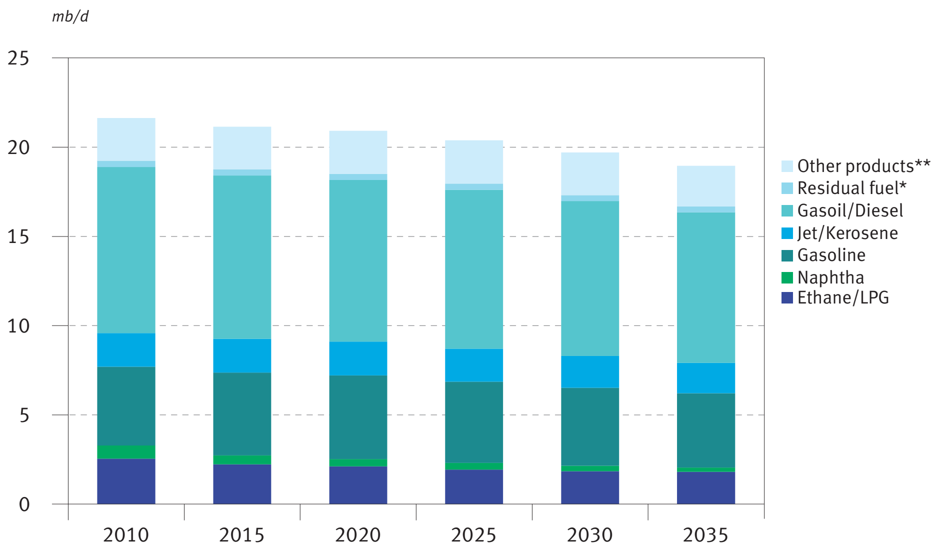
US & Canada

The US & Canada currently account for approximately 25% of global oil demand. However, total demand for liquid products in the region is believed to have already peaked, and is projected to contract throughout the forecast period, dropping by almost 3 mb/d between 2010 and 2035 (Figure 5.11). On average, this demand contraction represents an average yearly change of –0.5%.

The most affected product is gasoline, which is expected to decline by close to 1 mb/d over the forecast period, mainly due to improved engine efficiencies. It should be noted that these projections discount any widespread adoption of diesel-fuelled vehicles that would lead to a substantial increase in diesel demand at the expense of gasoline. Diesel/gasoil is the only product group where demand in the region is seen to rise in the next ten years, driven mainly by the implications of IMO regulations,[4] and by expansion in truck freight, buses and other economic areas, such as industry and households.

However, even for diesel, the projection is for the demand increase to be limited to 0.2–0.3 mb/d in the medium-term, before declining at some point after 2020 as efficiency improvements kick in. The same argument – except that IMO regulations are not applicable – holds for jet/kerosene demand, which is likely to stay basically unchanged, or decline marginally, throughout the forecast period. Nevertheless, there

Figure 5.11
Outlook for oil demand by product, US & Canada, 2010–2035



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

are significant uncertainties in this outlook for diesel demand in the US & Canada. This is related to shale gas developments in the region (Box 3.1).

Naphtha represents only a small portion of product demand in the US & Canada, since much of the ethylene/propylene capacity in the region is based on ethane/LPG feedstock and other olefin sources – from refinery catalytic cracking – and less than 20% of ethylene cracker capacity uses naphtha as a feedstock. Therefore, the recent comeback in petrochemical activity in the region is not expected to affect naphtha demand, which is projected to move in a relatively narrow range over the forecast period. It is worth mentioning, however, that this stable outlook for naphtha demand represents an upward revision from last year's report, which saw this product declining.

What is changing in the US is the outlook for petrochemical expansions fed primarily by ethane from the growing supplies of Natural Gas Liquids (NGLs) associated with shale gas. Ten years on from a severe downturn for petrochemicals in 2002–2003, several companies are expanding. Chevron Chemical, Dow Chemical, Shell Chemicals and Formosa Plastics have all committed to build new ethane-fed ethylene crackers and associated units, and in June 2012, ExxonMobil stated it would build a new ethane cracker in Texas. Four other companies are reported to be planning restarts and/or expansions at existing facilities, and others are believed to be evaluating options. Reportedly, the new plants plus the expansions should increase US ethylene cracking capacity by around 30% by 2017.[5] Other developments are also taking place which use propane as feedstock.

In terms of fuel oil, a significant contraction in demand is expected. Fuel oil will almost disappear from the region's demand; only 0.2 mb/d of fuel oil demand is projected for the US & Canada by 2035.

Product quality specifications

In the past 30 years or so, significant investment has been made 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 process is still ongoing globally – the focus turned to sulphur content in the mid-1990s, especially in the EU, Japan, Canada and the US. This shift combined with the growing importance of diesel oil and gasoil, especially in road transportation, resulted in the tightening of quality requirements for these products too.

Over the past decade, many developed regions and countries, including the EU, the US, Canada and Japan, have successfully completed a transition to Ultra Low Sulphur (ULS) fuels. The follow-up steps to improving gasoline quality are focused on the reduction of benzene and aromatics content, together with increasing the octane number. And for diesel, cetane improvement and a reduction in polyaromatics are now starting to be addressed. In addition to limits on exhaust emissions of SOx, NOx and particulates, the US and Europe are moving towards reducing greenhouse gases, specifically CO_2.

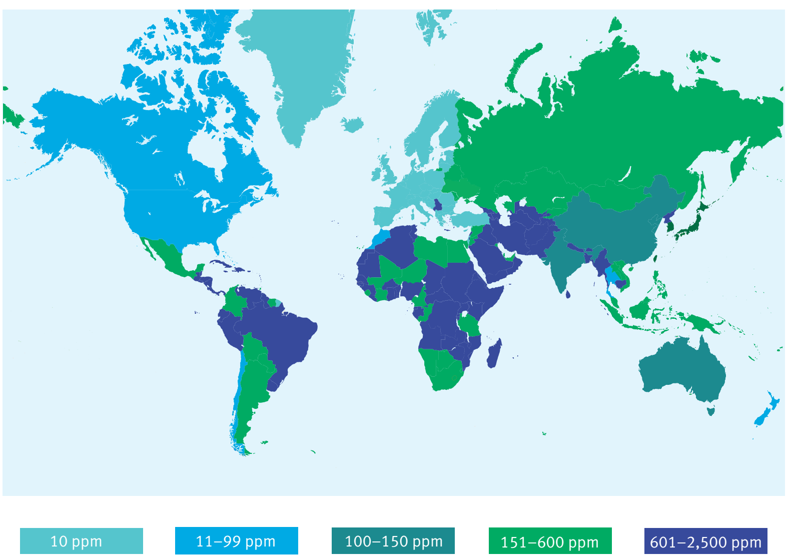
Figures 5.12 and 5.13 show the maximum legislatively permitted sulphur content worldwide in gasoline and on-road diesel fuel respectively as of September 2012. However, it is important to emphasize that actual sulphur content levels for products available in specific countries can (and often do) differ from those permitted by regulators.

Since 2010, the US has limited sulphur content in gasoline to a 30 parts per million (ppm) maximum standard for all refiners, although California has its own stricter specifications set at a 15 ppm maximum. Canada implemented a 30 ppm sulphur limit in 2005. Since January 2009, the EU has required gasoline containing 10 ppm maximum sulphur content. Before that, as of 2005, EU Member States were required to ensure certain volumes of 10 ppm fuels in their markets – alongside 50 ppm fuels – to facilitate deployment of more efficient and environmentally friendly vehicles, resulting in many EU countries reaching full penetration of 10 ppm gasoline before 2009. Japan has required 10 ppm gasoline since January 2008, but this level had already been reached in 2005. South Korea and Hong Kong also reduced gasoline sulphur to 10 ppm maximum in January 2009 and July 2010, respectively. In recent years, other European countries, including Turkey, Macedonia, Albania and Croatia have switched to 10 ppm gasoline.

The growing demand for gasoline in a number of developing countries means that any improvement in its quality has a considerable impact on required hydro-treating capacity and associated investments. Despite significant improvements in many developing countries, however, in general, these countries still lag somewhat behind.

China's nationwide gasoline sulphur limit was reduced to 150 ppm in December 2009. Stricter fuel quality requirements of 50 ppm are imposed in Shanghai, Guangzhou, Shenzhen, Dongguan and Nanjing. Beijing has the strictest fuel quality

Figure 5.12
Maximum gasoline sulphur limits, September 2012



Source: *Hart Energy's International Fuel Quality Centre (IFQC), September 2012.*

requirement of 10 ppm. China is expected to lower its nationwide limits to 50 ppm by December 2013, and possibly to 10 ppm by 2016.

India requires 150 ppm sulphur gasoline nationwide, while 50 ppm has been required for 13 selected cities since September 2010 – and for seven additional cities since March 2012. India's Ministry of Petroleum and Natural Gas has identified 50 other cities with large vehicle populations and high pollution levels to be included in the implementation of 50 ppm sulphur gasoline. This is expected to be conducted in phases and completed by 2015.

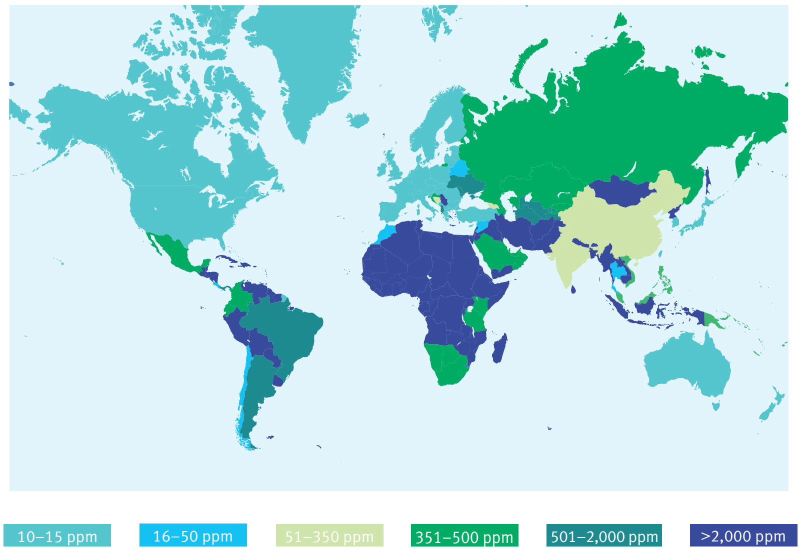
Other major consuming countries around the globe are also progressing with tightening gasoline quality specifications, albeit from much softer current requirements. This trend is especially evident in the Middle East, Russia, South Africa and some countries in Latin America. Saudi Arabia plans to switch to 10 ppm gasoline by 2013, followed soon after by other countries in the Middle East region, while Russia expects a nationwide penetration of 10 ppm gasoline by 2016. South Africa has agreed to enforce 10 ppm gasoline by 2017.

Turning to diesel fuel specifications, these not only differ between countries and regions, but also between various sectors. In the EU, the European Fuel Quality Directive has required on-road diesel fuel sulphur content to be set at 10 ppm since 2009, with off-road diesel sulphur reaching the same level in January 2011 (there is derogation in some countries and sectors).

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 Canada, a switch to 15 ppm for on-road diesel happened in June 2006 and off-road diesel was fully aligned in October 2010. The same level of maximum 15 ppm sulphur for on-road diesel has also existed in the US since 2010, though California introduced a 15 ppm limit for both on-road and off-road in June 2006. At the US federal level, the off-road diesel limit of 15 ppm maximum came in to effect in 2012, with the exception of small refineries, which are required to do so by 2014.

China planned to reduce its on-road diesel sulphur to 350 ppm in January 2010, but the deadline was later postponed to July 2012. This limit, however, is still not widely enforced. Nevertheless, at the more regional level, Beijing has a diesel sulphur limit of 10 ppm, while cities of Shanghai, Guangzhou, Shenzen, Dongguan and Nanjing have required a 50 ppm maximum since May 2012. It is worth stating that the legislation behind this switch includes China's first official differentiation between on-road and off-road diesel requirements. India has also set two different diesel fuel specifications, one for nationwide supply and the other for 20 selected cities. The

Figure 5.13
Maximum on-road diesel sulphur limits, September 2012



Source: Hart Energy's IFQC, September 2012.

sulphur content specification for 20 urban centres is established at a 50 ppm maximum, and the national specification is 350 ppm. Other countries in Asia where improvements in on-road diesel quality have been observed include Indonesia, Malaysia, Philippines and Thailand.

In Latin America, the maximum sulphur limit for premium diesel in Argentina was lowered from 50 ppm to 10 ppm in June 2011. Chile has been at 50 ppm diesel since 2006. Elsewhere, although premium diesel with tighter quality specification is available, the majority of countries still have sulphur limits for diesel oil above 500 ppm, although progress has been reported from countries such as Brazil, Ecuador and Mexico.

The region with the largest sulphur content is Africa, as in most countries it is in the range of 2,000 to 3,000 ppm for on-road diesel, and much higher for off-road. The exceptions are South Africa, which plans a switch to 10 ppm fuels by 2017, and some of the countries in the North African sub-region.

Looking at the long-term prospects, the timeline for sulphur reduction does not differ significantly from last year's WOO, although there has been progress observed in several countries since then, as well as postponements at the legislative level elsewhere. It should be highlighted that the resulting differences in the consumption weighted average sulphur content – compared to last year's projections – might not necessarily be caused by legislative change, as the update of product demand among countries within a given region also have a strong effect on the final average value as well.

In respect to gasoline, while future quality initiatives will continue to concentrate primarily on sulphur, there is now an growing focus on increasing the octane number and the reduction of benzene and aromatics. Projected gasoline qualities in respect to sulphur content for 2012–2035 are shown in Table 5.3.

The removal of sulphur from middle distillates, specifically diesel, presents a greater challenge to the refining industry than its removal from gasoline. This is mainly due to the fact that it has a greater need for processing unit additions, and subsequently, higher investment costs. Table 5.4 summarizes regional diesel fuel qualities between 2012 and 2035 for on-road diesel, with a projected step-wise progress in quality improvements for all developing regions.

For Europe and North America, on-road and off-road ultra-low sulphur programmes already require diesel sulphur to be below 15 ppm for most of the diesel market (10 ppm in Europe). By 2015, the most significant reduction in sulphur content for on-road diesel compared to 2012 is projected to be in Latin America and the

Table 5.3
Expected regional gasoline sulphur content*

ppm

Region	2012	2015	2020	2025	2030	2035
US & Canada	30	30	10	10	10	10
Latin America	520	255	130	45	30	20
Europe	13	10	10	10	10	10
Middle East	605	235	75	25	16	10
FSU	315	115	35	20	12	10
Africa	795	493	245	165	95	65
Asia-Pacific	205	130	65	35	20	15

* *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.

Table 5.4
Expected regional on-road diesel sulphur content* *ppm*

Region	2012	2015	2020	2025	2030	2035
US & Canada	15	15	15	10	10	10
Latin America	1,085	440	185	40	35	20
Europe	13	10	10	10	10	10
Middle East	1,725	415	155	70	20	10
FSU	440	175	60	15	10	10
Africa	3,810	2,035	930	420	175	95
Asia-Pacific	400	200	100	45	25	15

* *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.

Middle East, while further improvements will be also observed in the Asia-Pacific and the FSU regions due to refinery modernization and construction. With the exception of Africa, all regions are projected to reach an average on-road sulphur content of below 70 ppm by 2025. In most of the developing regions, off-road diesel requirements will continue to lag significantly behind ones for on-road diesel.

The reduction of sulphur content will continue to necessitate substantial investments in hydro-treating capacity. A significant portion of this capacity is already on the way, led by investments in Russia, the Middle East and the Asia-Pacific, in many cases as part of grassroots refinery projects. However, more will be needed across all regions if the proposed targets are to be met. There will also be moves to improve the octane number, which will be met by installing reforming, alkylation and isomerization units in regions where meeting octane via oxygenates, for example, is not seen as an immediately viable option. The details of these capacity requirements are further elaborated on in Chapters 6 and 7.

In terms of other products, such as heating oil, jet kerosene and fuel oil, these are increasingly becoming targets for tighter requirements, especially in developed countries.

Sulphur content in Europe's distillate-based heating oil was reduced from 2,000 ppm to 1,000 ppm in January 2008, and some countries, for example, Germany, provide tax incentives for 50 ppm heating oil to enable the use of cleaner and more efficient fuel burners. Parts of North America plan to reduce sulphur levels in heating oil to 15 ppm before 2020. Elsewhere, some progress is expected to be made in reducing the levels of sulphur in heating oil, but not to very low levels, and only after the transition in transportation fuels is completed.

In Europe, reductions in the sulphur content of jet fuel have been discussed with initiatives aimed at global harmonization. However, no major progress has been achieved until now and, as reported in last year's WOO, current jet fuel specifications still allow for sulphur content as high as 3,000 ppm, although market products run well below this limit, at approximately 1,000 ppm. Longer term, it is expected that jet fuel standards for sulphur content will be tightened to 350 ppm in industrialized regions by 2020, followed by other regions in 2025. Industrialized regions are also assumed to see a further reduction to 50 ppm by 2025.

Marine bunker fuels are also subject to regulation. In 2005, Annex VI of MARPOL regulations for the IMO entered into force, which provides the initial control strategy for marine emission control. The IMO approach also created grounds for establishing ECAs for NOx, SOx and particulate matters. To date, there are three ECAs in operation, two in Europe (the Baltic Sea ECA and the North Sea ECA) and one including the North American coastline (East and West Coast). In April 2008, the IMO's Marine Environment Protection Committee (MEPC) moved to revise Annex VI, establishing a much tighter global cap on bunker fuel sulphur, in particular. In October 2008, the MEPC decided that as of July 2010, the sulphur level in marine fuels used in ECAs should be reduced from 1.5 wt% to 1 wt% and, as of January 2015, the level will be further lowered to 0.1 wt% (1,000 ppm). The North American 1 wt% sulphur limit was enforced in August 2012.

Moreover, as of January 2012, the global sulphur cap was lowered from 4.5 wt% to 3.5 wt%, and will be further lowered to 0.5 wt% (5,000 ppm) as of January 2020, although it will be subject to a review that will be carried out in 2018 to establish whether there is sufficient 0.5 wt% sulphur fuel oil available. If not, the further reduction of sulphur content in marine fuels will be deferred until 2025. However, in September 2012, the European Parliament approved final legislation requiring all ships in the EU waters to switch to 0.5 wt% sulphur fuel (or use corresponding technology allowing ships to reach the required emissions reduction) in 2020, independently of the IMO's decision on global cap requirements.

Chapter 6

Medium-term refining outlook

Assessment of refining capacity expansion – review of existing projects

Since its first edition in 2007, the annual WOO has increasingly emphasized the ongoing shift in future refining capacity from developed OECD regions to developing countries, especially those in Asia and the Middle East. The continuation of this trend has been even more evident over the past year, an additional and second dimension to the shift is progressively emerging. Until mid-2011, the story was mainly about capacity additions in Asia and the relatively stagnant levels of refining capacity in the US, Europe and Japan. Limited capacity additions in industrialized countries were being offset by occasional refinery closures, some of them temporary – while the refinery was put up for sale – others permanent.

However, developments have accelerated in the second half of 2011 and in 2012, both in terms of additions and closures. In the OECD regions, substantial refining capacity rationalization has materialized. By the end of 2011, capacity closures for the year passed the 1 mb/d mark, bringing cumulative shutdowns since 2008 to more than 2 mb/d. Although information about closures, sales and restarts can often change on an almost weekly basis, a current assessment indicates that another 1.5 mb/d of distillation capacity will be permanently closed in 2012. On the other side, there are more new refinery projects now on the list than before, and overwhelmingly in developing countries. In recent years, these projects were concentrated mainly in Asia. While the region still dominates future capacity additions, shifting the medium-term forecast horizon ahead by one year (from 2015 to 2016) brings in new projects to be built in the Middle East, Latin America and Africa. These are in line with demand increases in those regions, combined with an emerging trend among crude producers to refine domestically especially heavier crudes.

The summary of assessed capacity additions from existing projects is presented in Table 6.1 and Figure 6.1. It is estimated that around 7.2 mb/d of new crude distillation capacity will be added to the global refining system in the period to 2016. The greatest portion of this new capacity is expected to materialize in Asia, mainly in China and India, which together account for more than 40%, or 3.2 mb/d, of additional capacity. Indeed, over the next five years, China alone will expand its refining sector by more than 2 mb/d, in line with the objectives specified in its 12th Five-Year Plan (FYP). Significant capacity additions will also be achieved in India, which dominates (from the perspective of refining expansion) the 'Other Asia' region. The high proportion of total capacity additions in these two countries is a continuation of a trend already observed over the past few years, through the completion of large projects like the Reliance Jamnagar refinery in India and the Tianjin and Qinzhou plants in China.

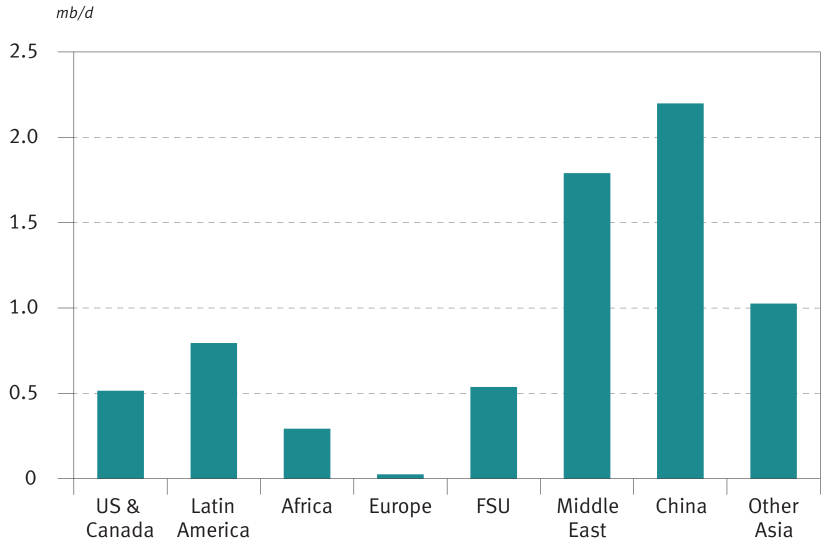
The speed of expansion in India, however, seems to be slowing in the medium-term. The reason for this lies with the country's currently changing tax policy. In contrast to China, where investments in refining capacity are predominantly driven by growing domestic demand, a combination of export-oriented business opportunities resulting from favourable tax conditions and local demand had originally led to sizeable capacity expansion in India. Indeed, export-oriented refineries in India which came onstream before April 2012 enjoy tax holidays of up to 15 years. Such benefits provide a competitive advantage to Indian refiners on international markets. For future projects, however, these tax holidays are being reduced: starting with fiscal year 2012, the Indian government removed some benefits that had previously been in place. This step will likely impact new projects as product exports from India become more expensive and, consequently, future capacity expansion moves more in line with local demand.

In the other three regions with the highest capacity additions to 2016 – the Middle East, Latin America and the FSU – the drivers are a combination of local demand and policies aimed at capturing the value added through refining 'at home', thereby increasing supplies of domestic (and mainly) heavy crude streams. This is especially true for the Middle East where demand increases by some 0.6 mb/d in the medium-term, whereas crude distillation capacity rises by 1.8 mb/d. A similar comparison for Latin America – where there is a 0.8 mb/d demand increase versus 0.8 mb/d of additional distillation capacity – indicates that most of the additional refined products will remain in the region (though not in the same country). Taking a longer term perspective – beyond 2016 – brings in additional refinery projects in

Table 6.1
Distillation capacity additions from existing projects, by region *mb/d*

	US & Canada	Latin America	Africa	Europe	FSU	Middle East	China	Asia-Pacific	World
2012	0.07	0.01	0.01	0.00	0.22	0.06	0.62	0.33	1.31
2013	0.33	0.14	0.01	0.03	0.11	0.59	0.22	0.33	1.76
2014	0.09	0.41	0.05	0.00	0.06	0.34	0.51	0.15	1.60
2015	0.02	0.08	0.03	0.00	0.12	0.51	0.48	0.14	1.37
2016	0.01	0.17	0.20	0.00	0.03	0.30	0.38	0.07	1.15
2012–2016	0.51	0.79	0.29	0.03	0.54	1.79	2.20	1.03	7.18

Figure 6.1
Distillation capacity additions from existing projects, 2012–2016



Brazil that are planned to process heavy domestic crude and create finished products for export. For the countries of the FSU, there are again prospects that demand growth will exceed refinery expansions by 2016 – 0.2 mb/d versus 0.5 mb/d – which are driven mainly by policies designed to encourage the exports of products rather than crude oil. Based on the above 'balances', it is clear that new refineries in the Middle East could have the biggest impact on inter-regional product movements, at least in the medium-term.

In the case of the US & Canada, the prospect is for demand to decline by around 0.2 mb/d in the medium-term, while crude distillation will rise by 0.5 mb/d. Moreover, the current utilization rates in the US are relatively low, which, when combined with growing local crude supplies, creates the potential for higher product exports from the region.

Asia-Pacific

Turning to the specifics of key refining projects in China, the implementation of projects there is subject to approval by the National Development and Reform Commission (NDRC). Moreover, the NDRC also regulates final retail prices for key refined products,[6] which thus determines refining margins and profitability. Final approvals and endorsements given for new projects indicate that around 2.2 mb/d of new distillation capacity will be built in the period 2012–2016. Among the key projects executed solely by Chinese oil companies are expansions to existing plants in Maoming in Guangdong (240,000 b/d), Yinchuan in Ningxia (100,000 b/d), Anqing in Anhui (60,000 b/d) and Huizhou in Guangdong (200,000 b/d). Other important projects are planned in Kunming in Yunnan and Chongqing in Sichuan. These two refineries will be linked to a new pipeline running from Kyaukryu Port in Myanmar to China, bypassing the congested Malacca Strait. The pipeline's capacity is projected to be 0.45 mb/d and the crude distillation units at these refineries are each expected to be able to absorb 200,000 b/d of imported crude.

In addition to these projects, a new trend in the Chinese downstream sector is emerging wherein oil companies look for cross-border cooperation with crude producers. This is the case with both expansion projects and grassroots refineries in several locations that are planned as joint ventures with Kuwait Petroleum, Saudi Aramco, Venezuela's PDVSA, Qatar Petroleum and Russia's Rosneft. Kuwait Petroleum is expected to partner with Sinopec and France's Total in a refinery project located in the port city of Zhanjiang. Sinopec is also planning a new 300,000 b/d refinery in Fujian, together with Saudi Aramco and Exxon Mobil Corp. Construction has already started on a Guangdong-based world scale 400,000 b/d refinery, financed by the China National Petroleum Corporation (CNPC) and PDVSA, which is designed to process Merey-16 heavy crude oil imported from Venezuela. Similarly, Petrochina and Rosneft are constructing a refinery in Tianjin. Finally, CNPC and Qatar Petroleum agreed this year to become partners in a Taizhou refining and petrochemical project which will, to a great extent, utilize condensate crudes from Qatar to produce ethylene and other petrochemicals.

Refining capacity additions will also be achieved through the expansion of small independent refineries, which currently account for more than 2 mb/d of capacity and include so-called 'teapot' refineries. These typically use imported fuel oil as feedstock since they do not obtain crude import allocations from the NDRC. In April 2011, the NDRC released the Guidance Catalogue for Adjustment of Industrial Structure, effective as of 1 June 2011, which states that China will shut all crude distillation units with an annual capacity of less than 2 million metric tonnes (40,000 b/d) by the end of 2013. This regulation could affect around 80% of the independent refineries in China, including all 'teapot' refineries. However, as pointed out in last year's WOO, in their efforts to survive, these small refineries "could also choose to be merged or acquired by state-owned companies or could switch to bitumen or chemical production". Recent reports from China indicate that most of them will opt to expand in order to surpass the 40,000 b/d mark. Some are expected to get help from China National Offshore Oil Corp. (CNOOC) and Sinochem, which see this as a chance to enter the downstream sector and expand their presence. The full extent of this expansion, however, remains to be seen, since investments in these refineries are scattered across the country and are difficult to monitor. Some sources indicate the cumulative expansion could be in the range of 0.5 mb/d.[7]

Another country projected to see substantial capacity expansion in the medium-term is India. After recently completing several complex large-scale refineries, India has become an important player in the global market for refined products. As discussed earlier, although the rate of expansion in India seems to be slowing, likely projects will still add significant capacity. In March 2012, for example, Hindustan Petroleum fully started up a 180,000 b/d refinery in Bhatinda, Punjab province and this year Essar Oil has also completed the expansion of its Vadinar refinery, increasing capacity to 375,000 b/d. The latter will reportedly optimize processes – including conversion of a visbreaker into a crude distillation unit able to process extra-heavy feedstock – to reach up to 400,000 b/d capacity. Other projects include the expansion of the Bina refinery, currently at 120,000 b/d, in Madhya Pradesh, planned by Bharat Oman Refineries, and completion of a delayed 125,000 b/d refinery at Cuddalore by Nagarjuna Oil Corporation. These projects, combined with additions expected from the Korangi project in Pakistan, the Petrovietnam project in Nghi Son in Vietnam and the expansion of the Chittagong refinery in Bangladesh, will result in around 1 mb/d of additional crude distillation capacity in the region by 2016.

Middle East

Additional refining capacity in the Middle East between 2012 and 2016 is projected to be 1.8 mb/d. The biggest portion of this capacity is expected to come from grassroots projects in the region. The most likely developments within the time horizon to 2016 are the Jubail and Yanbu refineries in Saudi Arabia, and the Ruwais refinery in the UAE, each adding 400,000 b/d. In addition, there are expansions of existing plants in Karbala in Iraq, Isfahan in Iran and Rabigh in Saudi Arabia.

Saudi Aramco is partnering with Sinopec for the new Yanbu refinery and with Total for the Jubail project. In addition to these projects, Saudi Arabia is planning another refinery at Jizan Industrial City and has revived an older project for the expansion of the Ras Tanura refinery, which would add another 400,000 b/d of new capacity to the already existing 550,000 b/d facility. However, these projects are expected to be completed after 2016. Similarly, a question mark remains over the implementation date of the huge (625,000 b/d) Al-Zour project in Kuwait, which was initially cancelled, and is now being re-considered.

Elsewhere, Iraq is in negotiations with several investors on building four new refineries with a total capacity of 0.75 mb/d. The UAE has announced plans to build a new refinery in Fujairah; Oman is considering building a 230,000 b/d refinery in Duqm; and Qatar has announced projects in Ras Laffan and Mesaieed. The latter would be designed to process expected additional barrels from the Al-Shaheen field. The development of all these projects will be closely monitored and their status re-evaluated as more details become available. In addition to the grassroots refineries, several expansion projects are also underway in the region that will add some minor capacity.

Latin America

In the period to 2016, Latin America is expected to see around 0.8 mb/d of new crude distillation unit capacity come onstream. However, part of this new capacity will be offset by the announced permanent closure of the Hovensa refinery in St. Croix, US Virgin Islands. The 350,000 b/d facility was shut down in February 2012 and is reportedly in the process of being converted to a storage facility. Similarly, the 235,000 b/d Valero Aruba refinery has had a history of being idle over the past three years and, in March 2012, Valero announced it was closing the plant. Sinopec is reportedly in discussions to buy and operate the refinery but, like the Hovensa refinery, its fate could be converted to a storage terminal.

New capacity will be realized in several countries. The largest contribution will come from Brazil and is related to Petrobras' stated policy of expanding the local refining industry in line with increasing crude production. However, this new capacity will likely be available only towards the end of – and beyond – the medium-term horizon. In 2012, additional capacity will only come from a small expansion project in the Paulinia, Araucaria, refinery. Larger additions are scheduled for 2014 and include a 230,000 b/d joint project of Petrobras and PDVSA in Abreu e Lima, Pernambuco, and phase one of the new refinery at the Rio de Janeiro Petrochemical Complex (COMPERJ), designed to process heavy oil from the Marlim field in the offshore Campos Basin. Further, the first phase of the Premium I refinery in Maranhao is tentatively scheduled for 2016. Other Petrobras projects, such as the second phase of the COMPERJ refinery and phase two of the Maranhao project, are assessed to be completed only after 2016.

Elsewhere, in Mexico, after the inauguration of the Pemex refinery expansion in Minatitlan in July 2011, no additional distillation capacity is projected to be added through to 2016. However, additional capacity will result from several expansion projects in other countries, such as Colombia, where Ecopetrol is enlarging its refineries in Barrancabermeja, Santander, and in Cartagena, which will add 160,000 b/d of combined distillation capacity. Some additional capacity will also be realized through expansion projects in existing refineries in El Palito and Puerto la Cruz in Venezuela, Shushufindi in Ecuador, Talara in Peru and Cienfuegos in Cuba.

Russia and other FSU countries

Refining capacity additions in Russia and other countries of the FSU are determined by several factors. The medium-term demand increase is relatively low (around 0.2 mb/d between 2011 and 2016) and thus does not provide a strong enough impulse for new projects, especially since utilization rates in existing refineries are relatively low. Despite this, new investments are expected in relation to domestic demand for gasoline and diesel, particularly for conversion capacity to increase yields of light products, and for the desulphurization of middle distillates for both domestic product and exports.

A new incentive for elevated exports of high-valued products, especially diesel, comes from the changed structure of export duties that was introduced in Russia in October 2011. Under the new scheme, export duties for refined products in Russia are based on export duties levied on crude oil, which are set by the Finance Ministry at \$29.20/t (\$4/b), plus 60% of the difference between the average Urals price over the set monitoring period and \$25. Until 31 December 2014, duties for refined products (except gasoline) are to be derived from this crude export duty as 66% of the crude oil export tax.[8] From 2015, all heavy products will be taxed at 100%, while light products (excluding 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.

The fact that light products will be taxed at lower levels than crude oil and fuel oil creates an incentive for Russian oil companies to invest in the export of clean products rather than crude or fuel oil. Higher export duties on heavy products make simple refineries less profitable, thus potentially supporting investments to increase refinery complexity.

The effect of the new regulation, combined with the state-mandated upgrades, is starting to be seen in the list of projects, particularly in additional upgrading projects, although more time is probably needed to see the full response from refiners. Based on the current list of projects, the region is projected to add 0.5 mb/d of new crude distillation capacity by 2016. These projects are scattered across several existing refineries in Russia and Belarus. Potentially the largest project is emerging on Russia's Pacific Coast, which will be fed by the newly operational Eastern Siberia–Pacific Ocean (ESPO) pipeline. In this respect, the options under discussion range from new refineries in Nakhodka, Kozmino and Vladivostok ports, to an expansion of the existing Khabarovsk or Komsomolsk refineries. While at this stage a final decision is unclear, it is believed that additional capacity in the range of 200,000–300,000 b/d will be constructed by 2016.

In addition, Kazakhstan and Turkmenistan are both considering investments in their refining industries to modernize (or possibly replace) aging refineries in the Caspian region. However, insufficient progress on proposed projects has been observed to consider them for a 2016 start-up. It is also worth mentioning that some incremental capacity in the region will likely be offset by permanent shut downs at existing plants, especially in the Ukraine where the Odessa refinery (following the reversal of the Odessa-Brody pipeline), the Kherson refinery and the Lisichansk refinery are currently shut. It is unlikely that all of them will be restarted at full capacity.

US & Canada

The refining sector in the US & Canada is experiencing a period characterized by a delicate balance between capacity rationalization, primarily in the East and West Coasts, and capacity growth and re-positioning for future feedstocks in the Midwest and US Gulf. The refinery shutdowns experienced so far, whether temporary or permanent, are already in the range of 1 mb/d. (A detailed discussion of this issue is included later in this Chapter.) In contrast to the closures, medium-term capacity additions from existing projects are seen to reach 0.5 mb/d and are dominated by developments in the US refining sector. These additions will be achieved almost exclusively through the expansion of existing facilities, despite the fact that several proposals exist for new refineries in both the US and Canada.

More than half of the incremental capacity will come from the Motiva project in Port Arthur, Texas. This will add 325,000 b/d of distillation capacity. The expanded refinery was inaugurated on 31 May 2012 as the largest facility in the US with a total capacity of 600,000 b/d. However, only days afterward, during a temporary shutdown for maintenance, a leakage of caustic into the distillation unit caused damage, which will take months to repair. Therefore, it is assumed the expanded refinery will be effectively operational only in 2013.

The rest of the capacity additions will be achieved from smaller projects including expansion of the Billings, Montana, refinery by ConocoPhillips; BP's project in Whiting, Indiana; Marathon's refinery in Detroit, Michigan; Harvest Energy Trust's refinery in Come By Chance, Newfoundland; and the Consumers Co-operative Refinery Limited's expansion of the Regina refinery in Saskatchewan, among others. Moreover, many of the US projects, especially in the Midwest, are geared to configuring refineries to receive increasing amounts of Canadian oil sands, thus switching feedstock from light sweet or sour crude toward heavier grades.

Europe

For the next few years, refining in Europe will not be about expansion, but rationalization. Europe's refining industry suffers from the problem of overcapacity and, therefore, investment in crude distillation capacity is limited to the single on-going expansion of Galp Energia's refinery in Porto, Portugal. Besides this, there are several upgrading projects – mainly in Southern and Eastern Europe – that are primarily geared to increase diesel production by adding hydro-cracking units, as well as hydrotreating projects, linked to meeting tight product quality specifications on sulphur content. In contrast to these minor project additions (compared to other regions), there are a number of refineries, mainly in Western Europe, that are either for sale, being converted to storage terminals or face closure. (Box 6.1).

Africa

Africa is the region where prospects for the refining industry are most difficult to assess. Certainly there is a need for more refining capacity, especially in highly populated countries such as Nigeria, Egypt, Kenya, Uganda and Ethiopia, all of which depend heavily on product imports. In addition, the region's oil demand is growing and domestic crude oil is available in most of these countries, none of which is short of refining plans. If all announced projects on the continent were counted, they would yield more than 7 mb/d of additional distillation capacity. Nonetheless, there are not many projects that have a real chance for implementation within the next five-year horizon.

Currently, the largest project under construction in Africa is the Lobito refinery in Angola, which was originally designed for a capacity of 200,000 b/d. The construction of a new refinery has also started in Biskra, Algeria, after the country launched an extensive programme to increase its refining capacity. As part of the programme, bottlenecking projects are underway in two Algerian refineries, in Skikda and Algiers.

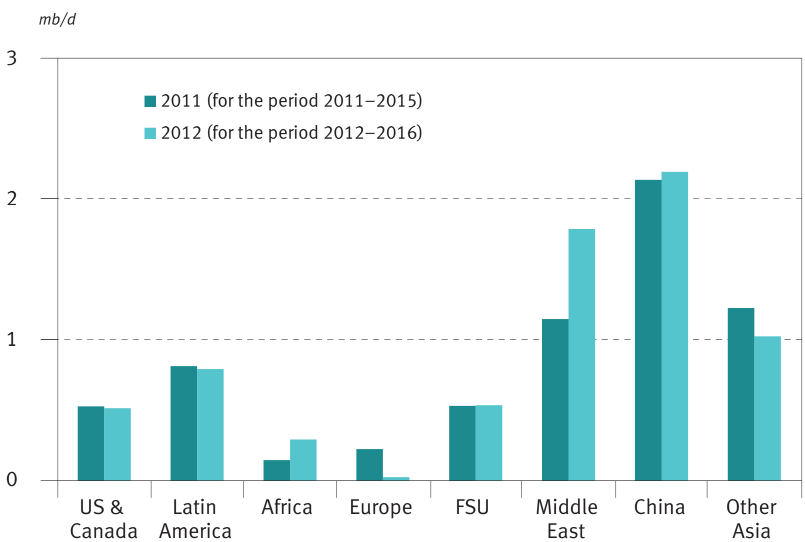
Nigeria is seeking partnership with Chinese investors to rehabilitate its refineries and to construct new grassroots plants. The initial plan called for three new refineries with a combined capacity of 750,000 b/d. However, as of the completion date of this WOO, no final decision has yet been made regarding either capacity or timing.

Some progress has been achieved regarding the 80,000 b/d refinery to be built by the Egypt Refining Company (ERC) on the outskirts of Cairo, Egypt. In June of this year, the ERC announced it had reached an agreement with investors led by Citadel Capital and Qatar Petroleum to secure financing for the project, set to be operational in 2016. Similarly, PetroSA and Sinopec have agreed to build a world scale refinery in South Africa, the details of which will be determined by a feasibility study. However, the timing of the project is cited between 2018 and 2020. Refinery capacity in some form is also likely to be realized in Uganda, although it is not yet clear which of the three proposed projects will actually go ahead, and when.

Growing demand for refined products in Africa, as well as the availability of local crude, would certainly justify more investments in Africa's refining industry, but due to local circumstances, only around 0.3 mb/d of new distillation capacity is estimated to be available by 2016, compared to the 2011 base. In addition, the Sub-Saharan African countries particularly are the subject of competition from exporters in Europe, the Middle East and Asia to supply products.

Figure 6.2 shows the latest 2012 assessment of existing refining projects, compared to 2011. In total, incremental distillation capacity is 0.4 mb/d higher this year than it was for the period of 2011–2015 – it is currently 7.2 mb/d compared to 6.8 mb/d last year. Last year's review pointed to the Asia-Pacific and Latin America as the regions with the highest year-on-year increments. This year, the major change (in part because of the inclusion of 2016) is the large increase in Middle East capacity additions, up from 1.2 mb/d to 1.8 mb/d, which is much closer to China, for which additions are projected at 2.2 mb/d. In contrast, Europe shows a sharp decline in additions; this is because of the elimination from the list of projects that

Figure 6.2
Distillation capacity additions up to 2015 from existing projects, 2011 and 2012 assessment



came onstream during 2011, combined with a lack of new projects. The net effect of these changes is a further shift of new refining capacity to developing countries in the medium-term.

Distillation capacity requirements

Prospects for future utilization rates are often seen as a good indicator of margins – and, thus, profitability – for the refining business. Utilization rates depend on the set of factors that comprise developments in demand for refined products, including their mix, the structure of available feedstock, existing refining capacity and changes therein. Prospects for supply and demand shifts in the medium-term were described in Section One. In the first section of Chapter 6, incremental distillation capacity resulting from existing projects globally was assessed at 7.2 mb/d during the 2012–2016 period, with regional details provided in Table 6.1. In addition to the announced projects, however, there are two other elements related to future distillation capacity that need to be taken into consideration: additions achieved through minor 'de-bottlenecking' within existing facilities (often during maintenance turnarounds and usually referred to as 'capacity creep') and refinery closures.

Capacity creep most often focuses on small expansions in crude distillation and major upgrading units. The extent of these additions typically varies between regions. For the purpose of this WOO, it is assumed that additions achieved annually through capacity creep are around 0.2% of established capacity – or about 0.8 mb/d globally in respect to crude distillation capacity from 2011–2016. Some sources refer to much higher levels of capacity creep (at times reaching more than double this level), but these stem from a rather variable definition of 'creep', which sometimes includes not only larger projects, but every expansion that is not a new refinery. The conservative estimate of capacity creep applied here is tightly linked to the very detailed list of projects that was used for the capacity assessment. In other words, what other sources typically include within the category of 'creep' (expansions in the range of 5,000 to 10,000 b/d, or larger) are often explicitly identified as individual projects on the list used for the projects assessment. Consequently, only a small level of creep was allowed in order to cover minor expansions that are 'under the radar' and not on the detailed projects lists. By adding in the effect of capacity creep, crude distillation capacity is seen as increasing by 8 mb/d by 2016, from the 2011 base level.

The issue of capacity closures is more complex. The past three years have seen a very turbulent period for the downstream sector. Almost on a weekly basis, media have reported on low utilization rates, negative margins, refineries up for sale (or idled and restarted again) shut downs for maintenance, then extended maintenance, band permanent closures. The effect over this period has been such that almost 5 mb/d of distillation capacity has been (most likely permanently) shut down or is scheduled for closure, the details of which are described in Box 6.1.

Box 6.1
Refinery closures: down, down, down...

In the 2010 WOO, the state of play of refinery closures was discussed under the title "Outlook for refinery closures – a drama in three acts?" It was assumed that in mid-2010 the industry was at a point where the need for substantial post-recession refinery closures was clear, but refiners were trying to sell rather than close. There was arguably an element of 'who blinks first' loses market share. This was depicted as Act One.

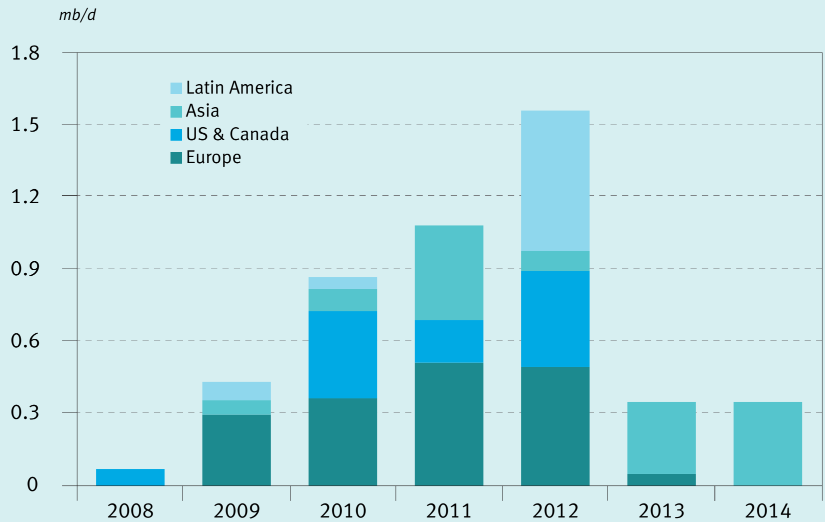
It was suggested that what might follow this act would be a sustained period of closures, followed by a final unknown act. At this point, the only certainty being that the refining industry would look very different.

One year later, the 2011 WOO concluded that in mid-2011 the industry was still mainly "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". At that time, some capacity had already been closed, but, reportedly, mostly on a temporary or an extended maintenance basis until negotiations on sales progressed, or refining margins improved. There were only a few cases where permanent closure had been announced.

In the second half of 2011, however, events started to accelerate, reaching 'full speed' in 2012. The cascade of closures that was indicated as inevitable arrived. Since the start of this year, an increasing number of announcements have been about permanent closures and the conversion of idled or previously underutilized refineries to storage terminals. This is evident from Figure 1, which presents the level of closed capacity based on the specific year in which the capacity was either first idled or permanently closed. (The closures would show much more concentration in 2011 and 2012 if capacity were assigned solely based on the year when the permanent closure was announced.)

The largest segment of the closures – around 1.7 mb/d – have so far occurred in Europe, of which 0.45 mb/d are in Germany (Ingolstadt, Wilhelmshaven and Harburg refineries), slightly above 0.4 mb/d in the UK (Coryton, Teesside and the partial closure of Fawley refinery), close to 0.4 mb/d in France (Reichstett, Berre,

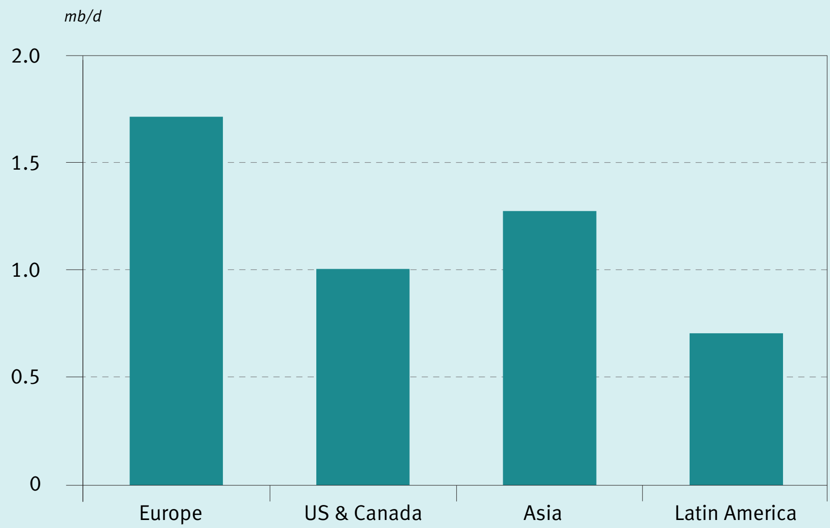
Figure 1
Estimated distillation capacity closures as of mid-2012, 2008–2014



Dunkirk and the partial closure of the Gonfreville refinery), and 0.3 mb/d in Italy (Cremona, Rome, Porto Marghera/Venice and the partially closed Gela refinery). In addition to these countries, Arpechin SA closed its Pitesti refinery in Romania, Repsol announced the partial closure of its Cartagena refinery in Spain and there are three idled refineries in Ukraine. Moreover, there are several refineries in Europe that are for sale.

Developments in the Asia-Pacific are driven by Japan where more than 0.8 mb/d of distillation capacity has already been closed or is scheduled to be closed. These closures are very much the result of an ordinance by Japan's Ministry of Economy, Trade and Industry (METI) that requires refiners to meet a cracking-to-crude distillation ratio of 13% by March 2014. Under this ordinance, cracking is defined as resid fluid catalytic cracking (FCC) plus coking plus resid hydro-cracking (it excludes vacuum gasoil FCC and hydro-cracking). To meet this requirement, refiners must either close distillation capacity and/or increase resid upgrading. With the prospect of declining demand for refined products in the country, the clear preference is for closures. As of June 2012, Nippon Oil had shut down a total of 0.26 mb/d capacity and announced the closure of another 0.25 mb/d facility by 2014. Showa Shell has added its 0.12 mb/d refinery in Keihin Ogimachi to the closure list, as has Cosmo Oil with a 0.09 mb/d refinery. Before 2014, Indemitsu Kosan is expected to close at least 0.1 mb/d of distillation capacity.

Figure 2
Estimated distillation capacity closures by region as of mid-2012, 2008–2014



China is another case where legislation is likely to have an impact, though it seems, the effect could be double-sided. In an effort to eliminate small independent refineries, known as 'social' or 'teapot' refineries, China's central government in 2011 raised the minimum capacity limit to around 40,000 b/d, effective as of 2014; anything below this requires refineries to close. Since then, these small, but numerous refineries have been seeking partnerships with investors to expand above the required limit and many of them have reportedly been successful. Some will inevitably close, but it looks as though a principal, albeit unintended, consequence of the regulation is that it has increased – rather than cut – the aggregate capacity of small refineries. Separately, the Fushun refinery in China was closed in 2011 after an explosion. Elsewhere in the region, Shell and Caltex announced closures of their Australian refineries in Clyde and Sydney, respectively.

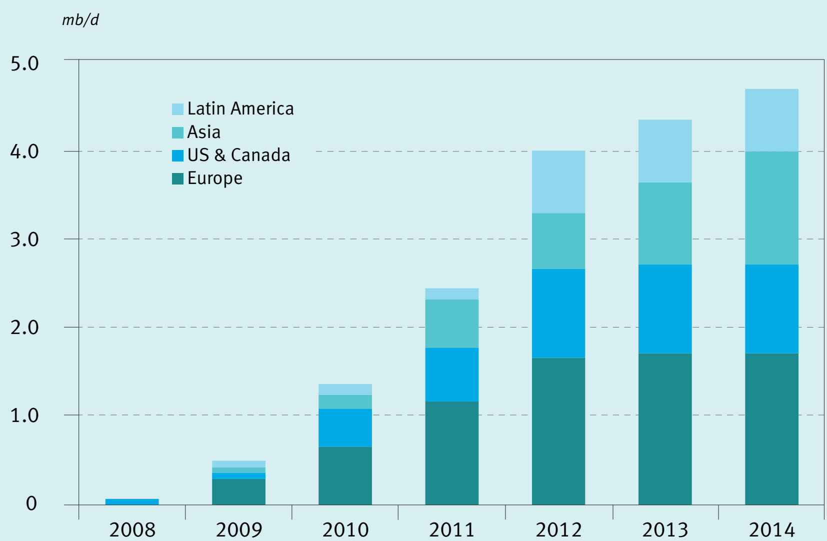
The wave of closures has also hit the US and Canada, including refineries in the US territories in the Caribbean (reported under Latin America in Figure 2). Between 2010 and 2011, five refineries were closed on the East Coast, namely Sunoco's Eagle Point and Marcus Hook plants, Chevron's Perth Amboy, Western Refining's facility at Yorktown and the Montreal refinery owned by Shell. In addition, two other refineries, that of Sunoco in Philadelphia and Phillips66 at Trainer, have seen 'narrow escapes' from closures. However, these do not necessarily mean that these refineries will remain in business in the long-term.

The situation on the US East Coast is complicated by closures in the broader region, which include the export oriented Hovensa refinery in St. Croix, US Virgin Islands, Valero's refinery in Aruba, as well as two plants in Puerto Rico.

The situation is less dramatic elsewhere in the US and Canada. On the US West Coast, only two smaller refineries have been shut down to date – one in Bakersfield, California, and the other a unit of Western Refining in New Mexico. However, BP has put its refineries at Carson, California, and Texas City, Texas, up for sale. Both are highly complex facilities for which BP expects to find buyers during 2012/2013.

Figure 3 presents the cumulative capacity closures since 2008, including known closures announced for 2013 and 2014. Globally they have already reached 4 mb/d and are heading for the 5 mb/d mark and potentially higher, as currently there are at least 15 refineries known to be on sale globally. What is also important to note is the size and complexity of the closed refineries. The story is no longer solely about small and simple plants: To name just a few, the Hovensa refinery on the US Virgin Islands had a capacity of 0.5 mb/d; Wilhelmshaven, Germany, was 0.26 mb/d; Valero's Aruba refinery was 0.23 mb/d; Petroplus' Coryton, UK, was 0.22 mb/d, with a Nelson complexity index of 12.

Figure 3
Cumulative distillation capacity closures as of mid-2012, 2008–2014

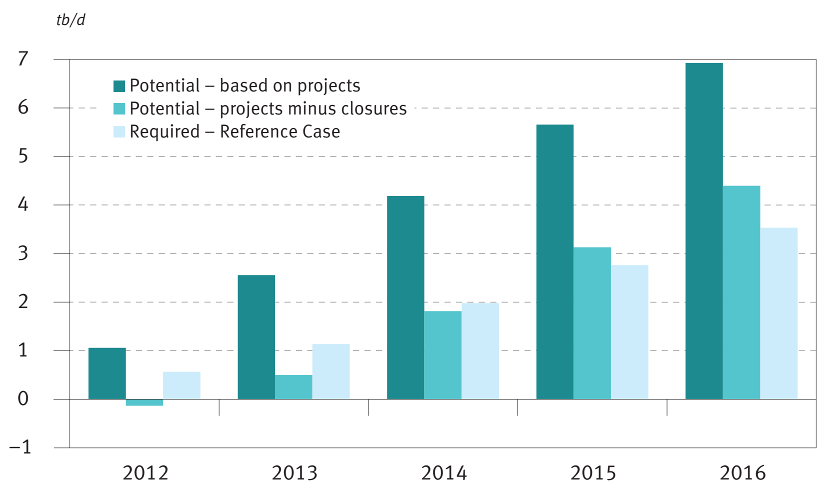


Returning to the 'drama in three acts', the industry has arguably moved well into Act Two, with activity that is leading to both significant closures and changing downstream ownership. To date, close to 5 mb/d of distillation capacity can be considered permanently closed. However, the regional balances suggest that more is to be expected – or, as Peter Voser, the CEO of Shell, said: another "shake-out is still to happen".

Required additional incremental refinery runs in Figure 6.3 are based on projected incremental global demand from 2012 through 2016, net of incremental supply from non-crudes that bypass the refining system. Against this, potential incremental refinery crude runs (resulting from new projects) are based on assessed nameplate capacity additions minus a factor representing expected maximum sustainable utilizations.[9] The column of 'potential projects minus closures' takes into account the assessed capacity closures that reduce the ability of refiners to process incremental barrels of crude oil. In addition, the analysis incorporates the phasing of capacity additions and closures, to arrive at the net additional capacity for each year, and allows for typical capacity utilization rates to deliver the assessed effective potential for incremental crude runs.

If potential incremental crude runs based on projects (assuming no closures) are compared with required crude runs based on demand, it is evident that new projects

Figure 6.3
Additional cumulative refinery crude runs, required and potential*



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

exceed the incremental 'call on' refining every year from 2012 through to 2016. The surplus potential is in the range of 0.5–0.9 mb/d every year, making for a cumulative overhang of more than 3 mb/d by 2016. These numbers change, however, if capacity closures are included. In this case, 2012 will likely end with a marginal decline in potential crude runs (compared to 2011) as closed refineries during the year exceed newly built capacity. Set against required incremental crude runs of 0.6 mb/d for the year, this leads to a gap (deficit) of 0.7 mb/d, which will help to increase the average utilization rate for 2012, albeit by less than 1%.

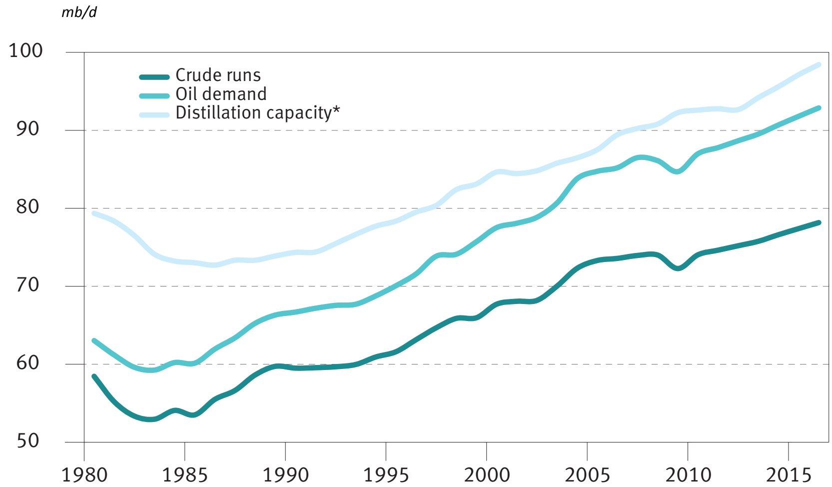
In 2013, unless more refineries close than are currently on the list, the cumulative gap will be broadly maintained, narrowing somewhat in 2014, and emerging as a surplus only in 2015. In total, by the end of the medium-term horizon, the potential for incremental crude runs arising from new projects and estimated closures will exceed the additional runs required by the projected rise in oil demand by less than 1 mb/d.

In other words, the situation for the refining sector, in terms of the average utilization rate, will not change significantly over the medium-term. It is critical, however, to recognize that this relatively balanced increase in refining capacity and demand for refined products is happening in the context of the industry experiencing a capacity surplus that has been gradually building since 2009. In that year, as presented in Figure 6.4, refining capacity increased by more than 1 mb/d from projects that came onstream, while required runs dropped by 1.6 mb/d. In the years that immediately followed, oil demand gradually recovered and, with that, crude runs, although the pace of the crude run growth was slower because of increasing non-crude supplies (ethanol and NGLs in particular). Figure 6.4 also reinforces this long-term phenomenon of a gradually widening gap between demand and crude runs. In 1980, crude-based products from refineries covered almost 93% of demand. In the 1990s, this ratio declined to below 90%, before reaching 85% in 2012. Projections indicate that crude runs will lose another half of one per cent share by 2016.

While this medium-term assessment considers additions versus requirements on an aggregate global basis, strong regional differences apply. As seen in Figure 6.5, the two regions with the largest capacity surpluses between 2011 and 2016 are the Middle East and the US & Canada. In the case of the US, the surplus results partly from demand decline and partly from capacity additions. In the Middle East, while both components grow, capacity additions from large grassroots refineries far exceed required increases in crude runs. This is also the case for the FSU, albeit to a much lesser extent.

In Europe and Africa, potential incremental runs and requirements are roughly in balance although, again, for differing reasons. In Africa, a modest rise in run

Figure 6.4
Global oil demand, refining capacity and crude runs, 1980–2016



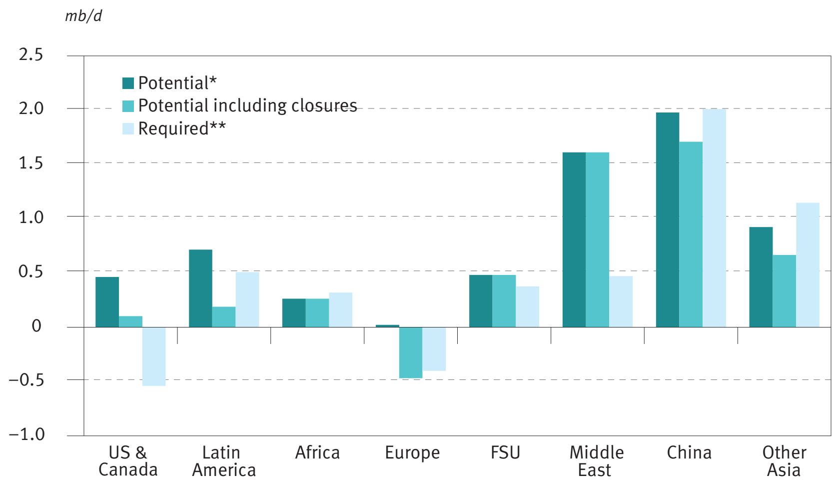
* *Accounted for capacity additions and closures.*

potential roughly matches a required increase driven by demand growth, whereas in Europe, demand decline is projected to roughly match closures. However, this is a different situation from the US & Canada region, where domestic demand decline does not currently look as though it will be matched by closures in the medium-term, largely because expansions authorized before the recession are now coming onstream – and due to support from growth in domestic crude supplies.

In contrast (and assuming the closures assessed in this WOO), Latin America, China and Other Asia stand out as regions where potential incremental runs are below the required runs. Changes in regional refinery utilizations, whether up or down, could help reduce these regional imbalances. Beyond that, however, the implication is that the Middle East and, secondarily, the US & Canada and the FSU, are the regions with the greatest potential to increase medium-term product exports, and these are most likely to flow to Latin America and China/Other Asia. Given the respective geographic locations, another implication is that US product exports to Latin America could continue to increase and that Middle East product exports to China/Other Asia may also grow. The FSU's export infrastructure is geared mainly to moving products to Europe, which has potential implications for product import/export balances there.

It is also important to remember that spare capacity still exists in Europe and that part of the newly built capacity in India is export-oriented. Therefore, the years

Figure 6.5
Additional refinery crude runs by 2016 compared to 2011



* *Potential: based on expected distillation capacity expansion (excluding closures) by 2016 compared to 2011.*

** *Required: based on projected regional demand increases by 2016 compared to 2011, assuming no change in trade.*

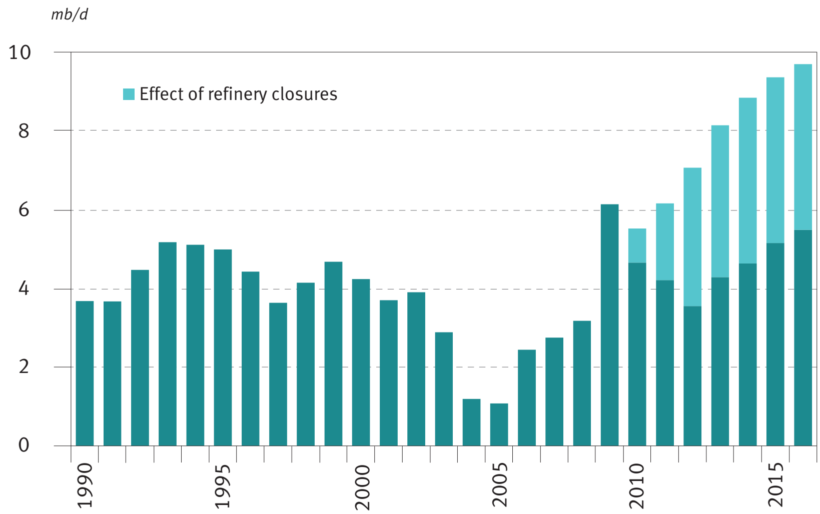
ahead will witness strong competition between refiners, especially for markets of light transport fuels, as new refining projects are typically relatively complex and efficient.

The implications of these developments for refining 'spare' capacity (the difference between 85% of crude distillation capacity and crude runs) are presented in Figure 6.6. Post-recession developments shifted the global refining system to a new level of spare capacity in 2009 of more than 6 mb/d, far greater than what the industry had observed during the 'good days' for refining in 2004 and 2005.

In 2010, the situation was somewhat reversed as a resurgence in refining runs outpaced refining capacity additions, which moderately reduced the level of spare capacity. In 2011 and 2012, refinery closures (primarily in OECD regions) reduced the level of spare capacity further, to below 4 mb/d; but unless more refineries are closed, new refining projects in developing countries should bring it back to above 5 mb/d towards the end of the medium-term horizon.

This indicates that there is scope (and need) for more capacity rationalization. Under the Reference Case, refinery shutdowns improve global utilization rates during

Figure 6.6
Global spare distillation capacity,* 1990–2016

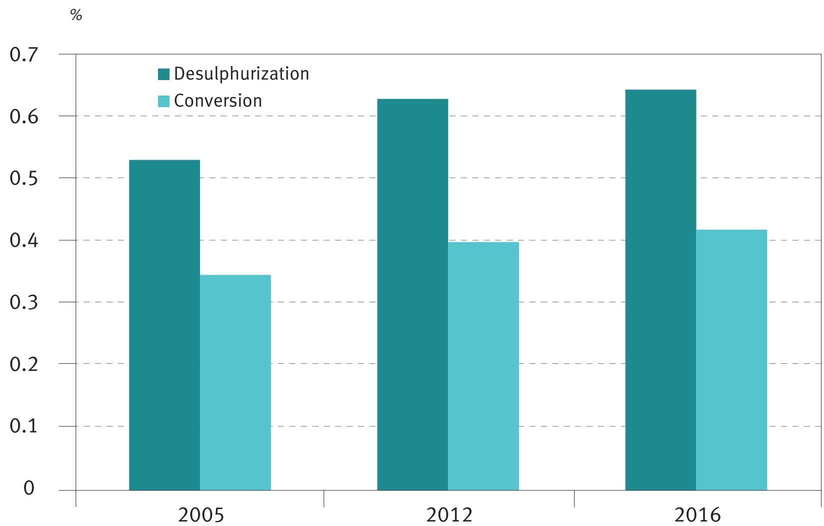


* *Equal to 85% of distillation capacity less crude runs.*

2011 and 2012, but the effect is short-lived as these fall back during the 2013–2016 period to 2010 levels of around 80%. The implication of these projections is again for a sustained period of low refinery utilizations (though slightly better than those projected last year) and, hence, poor economics with continued weak margins and sustained potential for refinery closures. Clearly, with the seasonal pattern of product demand and a number of refineries going off- and onstream, markets will see some fluctuations in refining margins. However, unless more refinery closures take place, a significant sustained improvement is highly unlikely.

In fact, the closure of around 5 mb/d of capacity across Europe, the US, Japan and other places so far has primarily removed surplus capacity (often idled) and has had little impact on margins.[10] Shutting down a further 2 mb/d for a combined total of 7 mb/d should lead to improved margins since global utilization rates, in this case, would then increase to 82%, which is comparable to levels seen in pre-recession years. However, it is potentially misleading to infer refining margins purely as a function of distillation capacity utilization. Figure 6.7 shows how the global refining system has become progressively more complex since 2005. Because of this, it would not be appropriate to assume that if refinery utilizations returned to levels of around 82%, margins would also return to high levels, as was the case in around 2005.

Figure 6.7
Global secondary units as percentage of crude distillation capacity



* *Percentages for 2012 and 2016 estimated based on review of existing refining projects.*

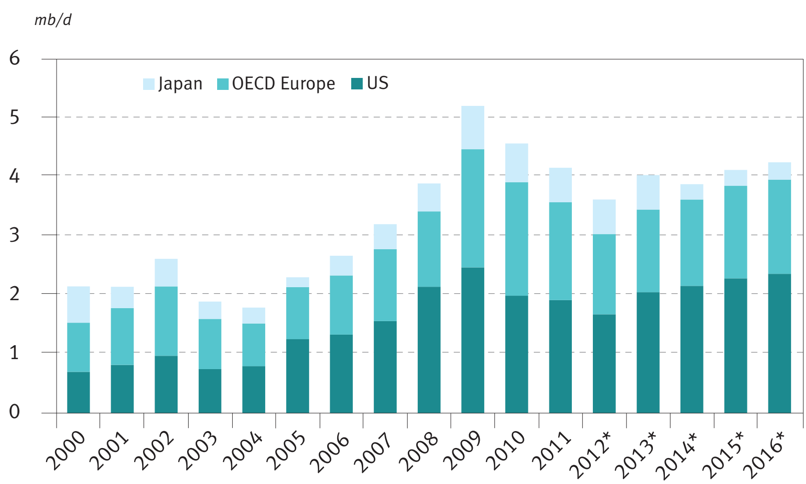
On the contrary, the increases in conversion, desulphurization and other secondary capacity per barrel of distillation capacity seen since 2005, and which are projected to continue to 2016 (and potentially beyond), signify that a high level of distillation utilization would not lead to a level of tightness on secondary units, such as was the case in 2005. In addition, there was appreciable 'nameplate' capacity in the FSU and Africa around 2005 that was, in effect, unavailable. Since then, there have been notable improvements in those two regions (utilizations and effective availability have risen). These improvements in effective availability mean higher actual utilizations are needed today and, in the future, to achieve the same level of actual tightness reached several years ago.

The data indicates that to restore margins to long-term viable levels, it is necessary to eliminate much more than the 7 mb/d that would restore utilizations to 82%. Closures in the order of 10 mb/d would be required, implying an associated global utilization rate of at least 85% (and possibly higher). To fully eliminate 10 mb/d of spare capacity and achieve an 85+% utilization rate, means capacity closures would have to occur across both industrialized and developing regions, although the latter to a lesser degree. This would restore refinery margins to the healthy levels that make the industry sustainable in the long-run. It should be noted, however, that global utilization rates have not reached 85% anytime since the 1980s and, as witnessed by recent events across a range of countries, there has often been a reluctance to accept refinery closures.

In summary, current estimates imply that closures in the order of 7–10 mb/d are needed (including the 5 mb/d observed or committed so far) to restore long-term refining viability, but the prospects of reaching those levels and related higher utilization rates are not bright. Thus, unless firmer policies are widely applied to achieve capacity rationalization and closure across even more refineries, the outlook is for continuing surplus, low utilizations and soft margins.

In terms of these required additional closures (beyond 5 mb/d) the following question is where could they take place. Figure 6.8 maps the situation in Japan, OECD Europe and the US. Refineries in Japan – with declining demand, no domestic crude production, relatively high operating costs and, thus, little chance to compete on international markets – have no alternative, but to adjust capacity in line with local requirements. This process has already started and, if it progresses according to commitments, will reduce spare capacity to a level of around 0.3 mb/d. Therefore, there is little room for further closures in this country – beyond already assessed levels – as they would need to be compensated by the increased imports of refined products. Currently Japan imports close to 1 mb/d of refined products, with net imports of around 0.7 mb/d. In summary, additional closures in Japan cannot be excluded, but it is unlikely that these will take place on a large scale.

Figure 6.8
Distillation capacity at risk in selected regions**



* *As of 2012, estimated based on domestic demand changes assuming no changes in exports/imports.*
** *Equal to 95% of crude distillation capacity less crude runs.*

The situation in Europe is different. Significant spare refining capacity in the region has built gradually for several reasons. The first one is demand decline in OECD Europe from a peak level of 16 mb/d in 2006 to an estimated 14 mb/d in 2012. From a refiner's perspective, this demand decline has been exacerbated by incentives supporting the expansion of biofuels, which have further reduced crude runs in the region. However, the most important factor relates to the structural change in European demand – namely, the on-going shift from gasoline to diesel in the key transportation sector. To balance refinery operations in Europe (where many older refineries were configured for gasoline production), the evolving diesel/gasoil deficit has been increasingly met by imports, primarily from the FSU, while surplus gasoline has been exported to various markets, most significantly the US.

However, this rebalancing of European demand away from gasoline toward gasoil/diesel is getting more and more difficult. Options for Europe's gasoline exports to the US are being impacted by declining demand, the fast expansion of ethanol, which further reduces demand for crude-based gasoline, and more favourable conditions for US refineries due to increased domestic crude production, price discounts and access to cheap natural gas. While recent refinery closures along the US East Coast and in the Caribbean (US Virgin Islands and Aruba) could provide new export opportunities for Europe's gasoline for some time, how long this opportunity lasts is an open question. This is due to the fact that the trend in product imports into the US has been on a steep decline for the past few years, and mandates for engine efficiency improvements and for ethanol production will continue to act as drivers in the years ahead.

Increasing competition is also certainly the case for European exports to the Middle East where new refining projects will not only exceed the regional demand increase, but also create export potential, especially for neighbouring regions in Africa and Asia. Similar competition is foreseeable in Latin America, especially given existing refining centres in the US Gulf. On top of this, the situation in Europe is becoming more complicated and uncertain, in light of the emerging carbon regime that will add to refining costs and, thus, reduce margins and competitiveness on international markets. For all these reasons, Europe is one of the regions where additional closures are likely to take place.

Box 6.2
US and Canada: avoiding major refinery closures?

The situation in the US in respect to closures appears different from that in Europe. There appears to be a number of reasons why.

Firstly, in marked contrast to Europe where domestic crude oil production is declining, in the US it is now rising after years of steady decline. One result of this

– because the US crude oil logistics system has been 'caught off guard' and has not had the capacity to get these rising volumes to markets beyond the US Petroleum Administration for Defense District 2 (PADD2) – has been a deep and widely publicized price discount (against Brent) for West Texas Intermediate (WTI), as well as essentially all inland crudes in the US plus Canada, since all are priced off WTI. These discounts have given support to refineries that process the discounted crudes, leading to a period of exceptional margins for almost all refineries that are inland. In the US Midwest, refineries are 'awash' with growing light crude production from the Bakken and older producing basins in places such as Texas, Oklahoma, and Kansas, as well as increasing supplies from heavy Canadian grades. As a result, capacity and throughputs in the Midwest are rising even though demand is falling and ethanol supplies are rising. Product movements from the US Gulf Coast into the Midwest have therefore been dropping, releasing additional supplies that Gulf Coast refiners are able to export and/or move up to the Northeast via pipeline.

Despite delays and disputes over two major pipeline projects (Keystone XL and Northern Gateway), the US and Canadian logistics system is reacting by adding pipeline and, increasingly, rail and barge capacity to bring Western Canadian and especially Lower 48 crudes to the Gulf Coast markets, the West and East Coasts, and Eastern Canada. Given the pressure from continually rising production and the pace of the adaptation taking place in terms of logistics, some degree of inland crude price discounting could continue for several years, thereby supporting the economics of both inland and, to some degree, US and Canadian coastal refineries.

Another factor that is boosting the competitiveness of US refineries, especially in the Gulf Coast, but potentially across other regions, is the availability of inexpensive natural gas at prices below $3/million British thermal unit (Btu) as a result of the shale gas boom. Thus, US shale (oil and gas) developments may act to give the US – and possibly Eastern, as well as Western Canadian – refineries a competitive edge in the medium- and possibly long-term, one that mitigates against closures.

However, there are other factors that weigh in the opposite direction. Firstly, the shale gas boom is itself a two-edged sword. While cutting costs, it is also accelerating the displacement of heating oil and potentially transport fuels via CNG and, possibly, in the longer term, LNG and/or GTL liquids. Secondly, US and Canadian product demand continues to trend downward and new transport efficiency mandates, notably the US Corporate Average Fuel Economy (CAFE) standards, will help maintain this direction over the long-term. Similarly, renewable fuels mandates call for the continued displacement of crude oil-based fuels, primarily gasoline by ethanol, thereby further reducing ex-refinery product demand. In addition, refiners in both the US and Canada are concerned about the impacts of a potential further tightening in standards for both products and stationary source emissions.

The impact of this array of factors has seen a recent steady climb in US product exports, and by 2011 the country had become a net product exporter for the first time in many years. The competitive factors outlined should act to continue this trend, at least for the large Gulf Coast refining complexes, leading to few if any closures there, and likely at inland US refineries. This scenario should apply in the short- to medium-term, but, in the long-term, growing competition from newer refineries worldwide, as well as from existing plants in Europe, could curb the region's ability to increase product exports, while declining national demand plus growing renewables could curb supply going into domestic markets. The implication is that there is scope for closures in the region in the long-term, but not in the short- to medium-term.

The outlook for refineries on the East and West Coasts of the US and Canada is, however, more clouded. As discussed in Box 6.1, on the US East Coast, several refineries have recently closed. In addition, two refineries have narrowly averted closure. It remains to be seen whether the changes in ownership and processing/commercial strategies will mean that these refineries stay open.

The US West Coast represents a special case. Traditionally, the region has been relatively isolated, with limited competition for product markets from outside, partly because of the severe California Air Resources Board (CARB) product specifications that apply in the state. Similar to elsewhere in the US, demand for refinery-produced products is flat to declining, but this trend could be exacerbated by Law AB32 in California that calls for a Low Carbon Fuel Standard (LCFS) to reduce the energy intensity of transport fuels consumed in the state. AB32 is being challenged in the courts, but if it is upheld and implemented, it could lead to closures of refineries in California, a state that has 2 mb/d of capacity.

Western Canadian refineries have the benefit of access to both local crude and growing regional demand, buoyed by oil sands developments. Conversely, most Eastern Canadian refineries do not appear to have the advantages of the US Gulf Coast refineries in terms of their ability to export products economically, or have access to low cost gas (although this could change). Therefore, inevitable demand declines in Canada for ex-refinery products indicate that some measure of additional closures is inevitable.

As detailed in Box 6.2, viewed from a global perspective, selected refineries in the US and Canada could be additional candidates for closure over the medium-term, albeit on a limited scale.

Another region where some capacity closure might happen is the FSU. Refineries in the Ukraine and Caspian regions, especially, are either run at very low utilization rates or are currently idled. As mentioned previously, three refineries in Ukraine (Odessa, Kherson and Lisichansk) remain shut and it is unlikely that all of them will be restarted at full capacity. Moreover, some capacity is at risk in Russia as well. Several simple refineries in Russia survived the past few years because of favourable export duties that allowed healthy margins on fuel oil exports. Those duties were introduced to enable upgrading projects, but the net effect was surging exports of fuel oil and little investment for upgrades. To reverse this trend, the government modified the export duties in October 2011 to reduce the profitability of fuel oil exports. And, with further reforms planned to go into effect as of 2015, the instruction to hydro-skimming refineries in Russia seems to be: invest or close. In other words, refineries that fail to upgrade their processes in order to produce higher value products might be forced to shut.

Finally, closures might occasionally take place in other regions as well (for example, the shutdown of the Clyde refinery in Australia, but it is unlikely that this will happen on a large scale in any of these regions. On a cumulative basis, however, they could potentially shave off part of the surplus capacity.

All in all, this medium-term outlook is not good news for refining utilizations and economics. It reinforces the expectation of a challenging and likely turbulent period continuing, with low refinery utilizations and weak margins.

Conversion and desulphurization capacity additions

In addition to crude distillation capacity, it is equally important to assess the expansion of secondary process units before any conclusions can be drawn on the adequacy/inadequacy of new projects. Sufficient distillation capacity is a necessary precondition for the adequate functioning of the refining sector; but it is supporting conversion and product quality related capacity that plays the more vital role in processing raw crude fractions into increasingly advanced finished products – and in delivering the majority of a refinery's 'value added'. The importance of these secondary processes has been increasing with a general trend toward lighter products and more stringent quality specifications.

A significant proportion of additions to secondary refining processes materializes through smaller upgrading projects in existing facilities. These projects are less costly and have shorter lead times. In respect to conversion capacity, the historical trend toward a growing share of lighter products in total demand, especially diesel, has led to higher proportions of conversion capacity additions compared to distillation units. Typically, this proportion is in the range of 40–50%. However, for projects coming onstream in the period to 2016, it will be around 65%, indicating a trend toward higher refining complexity with more upgrading capacity per barrel of crude distillation. In respect to sulphur removal processes, tighter specifications on sulphur content in OECD countries, and several major developing countries, have forced an expansion of hydro-treating capacity. This momentum continues to be visible in the number of projects under construction for the period to 2016, so that total hydro-treating capacity additions reach around 85% of those for distillation units.

Table 6.2 presents the results of the review of existing projects in respect to secondary process units. Additions to global conversion units are estimated at 4.7 mb/d for the period 2012–2016. Most of this capacity will come in the form of hydro-cracking units (2 mb/d), followed by coking (1.5 mb/d) and FCC units (1.2 mb/d).

Table 6.2
Estimation of secondary process additions from existing projects, 2012–2016 *mb/d*

	By process		
	Conversion	Desulphurization	Octane units
2012	1.1	1.4	0.3
2013	1.2	1.5	0.5
2014	1.0	1.3	0.3
2015	0.8	1.1	0.3
2016	0.6	1.0	0.2
	By region		
	Conversion	Desulphurization	Octane units
US & Canada	0.5	0.3	0.2
Latin America	0.6	0.8	0.2
Africa	0.2	0.3	0.1
Europe	0.3	0.1	0.0
FSU	0.5	0.5	0.1
Middle East	0.9	1.4	0.4
China	1.0	1.7	0.4
Other Asia	0.6	1.1	0.3
Total World	4.7	6.2	1.7

As a primary means to increase the production of much needed middle distillates, new hydro-crackers will be scattered throughout almost all regions, including additions of around 0.2–0.3 mb/d in each of North America, Europe (Southern and Eastern) and the FSU. Additions in the latter will be driven by prospects of higher diesel/gasoil exports to Europe, which is, and will remain short of this product. The Middle East should see 0.35 mb/d of additions, as elements of the major new refinery projects in the region, notably Jubail and Yanbu, plus projects in Iran and, potentially, the UAE are added. The most new hydro-cracking units will be constructed in Asia, 0.55 mb/d of capacity, where diesel demand growth is highest. Out of 1.5 mb/d of global additional coking capacity, around 0.45 mb/d is projected for Asia, more than 0.3 mb/d will be built in Latin America and 0.2 mb/d in North America. FCC units, accounting for around 1.2 mb/d of conversion capacity, will be constructed mainly in Asia, the Middle East, the FSU and Latin America, for the reasons set out earlier.

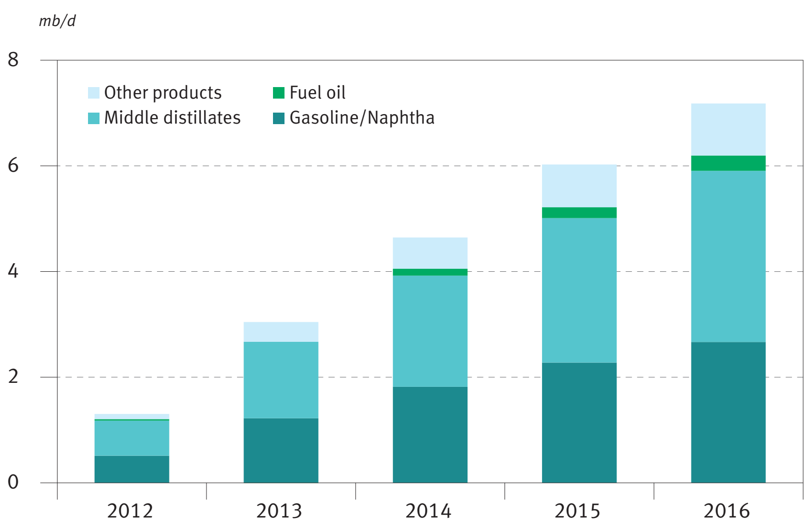
Coking additions are geared to the upgrading of heavy crudes and so are present mainly in Latin America and the US & Canada for processing oil sands 'DilBit'. Additions are projected in all regions, though, partly as a result of a growth in supplies of high Total Acid Number (TAN) and other heavy crudes in most regions, combined with declines in residual fuel demand. As mentioned previously, FCC additions are mainly in developing regions where there is growth in gasoline demand. Broadly speaking, in regions where there is relatively balanced growth in demand across products, including gasoline, there is a fairly even distribution of additions across the three conversion processes.

Desulphurization capacity will increase by 6.2 mb/d in the period to 2016. Most of the new capacity will be realized in Asia (2.8 mb/d) with another 1.4 mb/d and 0.8 mb/d in the Middle East and Latin America, respectively. This partly reflects recent trends towards cleaner products within these regions, but also an effort by export-oriented refineries to provide low or ULS products for their potential customers in developed countries. This rationale is also driving desulphurization capacity additions in Russia. Remaining capacity additions are shared by North America (0.3 mb/d), Africa (0.3 mb/d) and Europe (0.1 mb/d). Additions in North America and Europe are mainly related to achieving compliance with ULS gasoline and off-, as well as on-road diesel standards, including – in the case of the US – for export.

There is a last category of capacity additions, commonly referred to as octane units, which refers to the quality of finished gasoline. It is generally comprised of catalytic reforming, isomerization and alkylation processes. Projections suggest that about 1.7 mb/d of these processes will be added to the global refining system during the period 2012–2016. Catalytic reforming will account for the majority of this, with 1.3 mb/d globally. This capacity will primarily be constructed in regions where gasoline demand increases are expected: Asia (0.6 mb/d), the Middle East (0.3 mb/d), Latin America (0.16 mb/d) and the gasoline-dominated North American market (0.1 mb/d). In addition, lesser amounts of isomerization (0.2 mb/d) and alkylation (0.2 mb/d) units are planned. Since all these processes are gasoline-related, the regional distribution of their additions is similar to reforming capacity additions. Significant additions are also evident in hydrogen, sulphur recovery and other units, in order to support the various cracking, desulphurization and octane units.

The combination of additional distillation capacity and secondary process units projected to 2016 leads to an increased potential for the global refining system to produce incremental barrels of specific refined products. To some extent, refiners have some flexibility in optimizing their final product slate by either altering the composition of their feedstock or by adjusting the operating modes of process units. This flexibility, however, is limited for any one unit and for any given refinery. With all this in mind, Figure 6.9 presents an estimation of the potential cumulative incremental output of refined products, grouped into major product categories, resulting from existing projects. The assessed implementation of current projects would allow for a total of around 7.2 mb/d of additional products to be available by 2016, compared to 2011 levels. The majority of this increase is for middle distillates (3.2 mb/d) and light products, naphtha and gasoline (2.7 mb/d). In addition, fuel oil production is set to

Figure 6.9
Cumulative potential for incremental product output



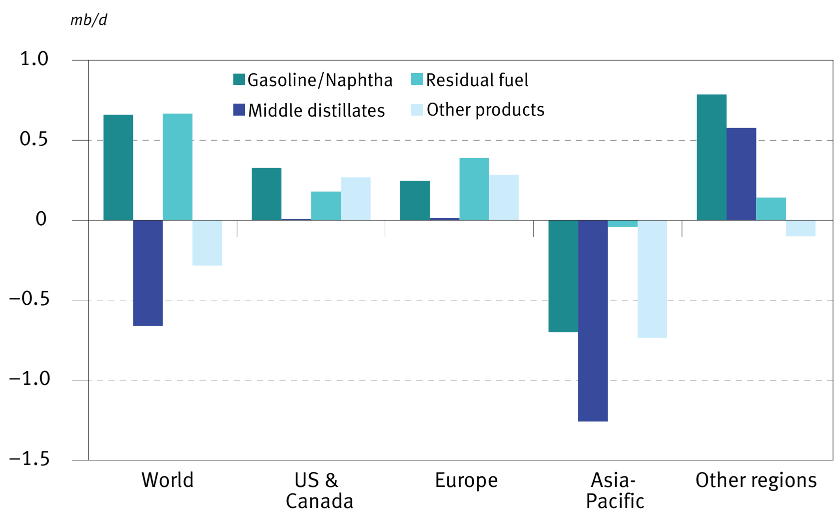
increase by (0.3 mb/d), while other products will account for the remaining balance of 1 mb/d.

To shed further light on the impacts of continuing capacity additions on the supply balances of refined products, the assessment of refinery projects was extended. Figure 6.10 shows the results of comparing the potential additional regional output of major product groups from firm projects against projected incremental regional demand for the years 2011 and 2016. The results are presented as net surplus/deficit of product groups by region and worldwide.

When looking at the level for 'all products', incremental output and incremental demand essentially match. This contrasts from what was assessed in the previous two years – namely, refining projects that significantly exceeded total incremental demand growth. However, although there is, of course, some uncertainty and flexibility in the product yields that result from any one project, the balances show a continuation of projects that produce too much naphtha/gasoline and residual fuel, too little distillate and, to a lesser degree, too few 'other products'.

The data indicate, for example, an unchanged situation for middle distillates in Europe and the US & Canada, as new projects broadly balance demand change. Conversely, in these regions all three other product groups are projected to be in surplus.

Figure 6.10
Expected surplus/deficit of incremental product output from existing refining projects, 2011–2016



One implication of this is that regional projects will not help alleviate the gasoline/distillate imbalance in the Atlantic Basin. A striking conclusion from the data is that the Asia-Pacific is projected to have substantial deficits in both gasoline/naphtha and distillates – of around 0.7 mb/d for the former and 1.3 mb/d for the latter – as well as a deficit in other products. Equally significant is that the group of other regions, which comprise Latin America, the FSU, Middle East & Africa, show substantial surpluses of both gasoline/naphtha and distillate. These could partially offset the deficits in the Asia-Pacific, with corresponding implications for product trade. One particular implication of this is increased product exports to the Asia-Pacific from the Middle East, where a number of important large projects are planned by 2016.

On a global scale, the net effect of this is for continued imbalances with excess gasoline/naphtha and residual fuel, and a distillate deficit. The implication is that distillate margins relative to crude are likely to remain strong, while those for naphtha/gasoline are weak. Moreover, these figures point to the need for more conversion capacity to be added, especially in the Asia-Pacific region. Another implication is that advances in refinery process technology are needed to make existing units more capable of yielding distillate fractions over gasoline/naphtha and to convert naphtha into distillate. These requirements have been pointed out in previous reports and are further discussed in Chapter 8.

Chapter 7

Long-term refining outlook

Last year saw another period of post-recession recovery, with global demand increasing by some 0.8 mb/d over 2010. Under the Reference Case, a similar increase is expected to be maintained through 2012 and 2013, which will then rise to 1.2 mb/d by 2014, before gradually slowing to 0.6–0.7 mb/d after 2025. Such numbers could imply a relatively static situation in the global downstream. The reality is, however, that fundamental shifts are underway which are reshaping the industry as measured across all its key parameters: utilizations, expansions, closures, investments, crude versus non-crude supply, logistics, trade and economics.

The global numbers do not convey the underlying differences that exist today between the world's major regions. Demand in the industrialized regions has peaked and is projected to continue to decline. Conversely, the non-OECD regions (led by non-OECD Asia) are projected to be the focus of sustained growth. Thus, while demand in the industrialized regions is expected to drop by around 0.1 mb/d annually between 2012 and 2020, and then accelerate to a drop of around 0.3 mb/d annually from 2025 onward, for other world regions it is projected to grow by an average of 1.2 mb/d through 2020 and 1 mb/d from 2025. Around 70% of the demand growth in these non-industrialized regions will be in Asia. In short, the projection is for modest growth overall, but with a substantial relocation of demand. It is these fundamental shifts that will be the primary drivers in reshaping the future global downstream industry.

Another key factor impacting the long-term outlook for refining investments, as well as for trade, is the make-up of crude supply, the resulting quality of the global crude slate and the growth in non-crudes. Driven by certain policy measures and the increasing production of natural gas, the expansion of non-crudes is projected to rise at a faster rate than that of oil demand. Consequently, the proportion of non-crudes in the total supply increases, while the crude required to be processed per barrel of additional product demand declines. The surge of US ethanol supplies has already impacted refining economics, as well as capacity requirements, both there and worldwide. Biofuels supplies are projected to continue to grow over the period to 2035, as are the supplies of NGLs, Gas-to-liquids (GTL)/Coal-to-liquids (CTL) and petrochemical return streams.

Adding to this are developments in the refining sector within the medium-term. What is evident is that the 7.2 mb/d of incremental refining capacity expected to be onstream within five years (by 2016) is well in excess of the incremental demand needed from refineries, even allowing for the 4 mb/d of refinery closures that have occurred to date. It is also apparent that continued closures in industrialized countries will be needed; but whether they will be enacted in a timely manner – or resisted, which continues to drag margins down – is open to question. The implication is for difficult times to continue for the refining sector, with severe international competition for product markets between refineries in the US (that are successfully raising product exports), Europe (where refineries are desperate to find markets for gasoline so that they can produce more co-product diesel) and new export refineries in the Middle East, India and, potentially, Brazil. All these factors are underlined in this Chapter, along with a consideration of the implications for future additions to both distillation capacity and secondary units.

Distillation capacity requirements

Table 7.1 presents estimated refinery distillation capacity additions in the Reference Case for the period 2011–2035. Known projects are assessed under the Reference Case as those that will be constructed. New units represent the further additions (major new units and de-bottlenecking) that are projected as needed in order to balance the system. The review of known projects arrived at an assessment of 6 mb/d of new capacity additions to come onstream by 2015 and 7.2 mb/d by 2016. In terms of the 6 mb/d of firm new capacity by 2015, the model added 0.7 mb/d of additional refinery capacity (essentially de-bottlenecking) for an overall total of 6.7 mb/d. With regards to the 7.2 mb/d of additional capacity assessed to be available by 2016, the model indicated a further 0.7 mb/d as required by 2020 and an additional 2 mb/d by 2025. Moving forward to 2030 and 2035, additional distillation capacity requirements were assessed at 2.2 mb/d and 2.1 mb/d, respectively.

Cumulative total additions (firm projects plus total further model additions) are thus projected to reach 14.9 mb/d by 2035. Significantly, 40% of these additions, 6 mb/d of firm projects, are projected to be onstream by 2015, and nearly 50%, the 7.2 mb/d of firm projects, by 2016. The annual rate of capacity addition to 2015 is 1.7 mb/d. In the subsequent five-year periods – 2015–2020, 2020–2025 and so on – the required level of capacity addition averages a far lower 0.4 mb/d p.a. In short, the industry is witnessing a surge of capacity additions in the short- to medium-term, which results in a much slower rate of additions being needed thereafter, right through to 2035. The medium-term surge is a combination of projects that were authorized before the recession, notably in the US, along with others that have more recently been given the go-ahead to either meet domestic demand growth, notably in non-OECD regions led by China, to boost product export capacity in the Middle East and, secondarily, the FSU, or to process growing regional supply, specifically of heavy crudes, with a focus on the US & Canada, and Latin America. All told, some 70%

Table 7.1
Global demand growth and refinery distillation capacity additions by period *mb/d*

	Global demand growth	Distillation capacity additions			
		Known projects*	New units	Total	Annualized
2011–2015	4.0	6.0	0.7	6.7	1.7
2015–2020	5.1	1.2	0.7	1.9	0.4
2020–2025	4.0	0.0	2.0	2.0	0.4
2025–2030	3.3	0.0	2.2	2.2	0.4
2030–2035	3.2	0.0	2.1	2.1	0.4
	Global demand growth	**Cumulative distillation capacity additions**			
		Known projects*	**New units**	**Total**	**Annualized**
2011–2015	4.0	6.0	0.7	6.7	1.7
2011–2020	9.1	7.2	1.4	8.6	1.0
2011–2025	13.1	7.2	3.4	10.5	0.8
2011–2030	16.4	7.2	5.6	12.8	0.7
2011–2035	19.5	7.2	7.7	14.9	0.6

* *Firm projects exclude additions resulting from capacity creep.*

of firm capacity additions are in the Middle East and Asia-Pacific, with the balance spread across other regions (with the exception of Europe).

Looked at another way, total additions of 6.7 mb/d through 2015 are well in excess of the projected demand increase of 4 mb/d for that period. By 2020, this situation starts to invert and, in the long-term, cumulative refining capacity additions settle at around 75% of cumulative demand growth. This is to be expected since, in the Reference Case, non-crude supplies – NGLs, biofuels, CTLs/GTLs, petrochemical returns – satisfy around 25% of the total 'liquids' demand, leaving only 75% to be met by crude-based refining. Thus, today's projects potentially represent a substantial proportion of the total additions that will be needed over the next 10-to-15 years. It is important to remember, however, that these projections entail a combination of new capacity additions in non-OECD regions, especially in Asia, at rates that are much closer to increases in regional demand levels.

Table 7.2 presents the global and regional outlook in terms of refinery crude throughputs and utilizations. Obviously, future capacity additions and refinery throughputs are affected by the same set of factors. Therefore, moderate future demand growth and rising non-crude supplies also curb growth in refinery crude throughputs. The annual growth rate in refinery crude throughputs is projected to slow from over 0.7 mb/d in the period 2010–2015 to some 0.5 mb/d in 2015–2020, before declining further to 0.4 mb/d in 2020–2025 and then to around 0.2 mb/d in 2025–2035. This phenomenon of slowing growth will create challenges for maintaining the viability of the refining sector, especially given the medium-term capacity surge. As stated elsewhere, it also indicates that discipline is required in assessing any new project, especially a major expansion.

In terms of utilization rates, which are subject to any additional closures above the 5 mb/d already accounted for (Box 6.1), the overall outlook is for flat global annual refining utilizations, while throughputs gradually rise from 74 mb/d in 2010 to around 84 mb/d in 2035. The impacts, however, are not regionally uniform. Table 7.2 highlights the contrast between the US & Canada and Europe – or, more broadly, the (northern) Atlantic Basin – and other regions. Taken together, the US & Canada and

Table 7.2
Crude unit throughputs and utilizations

	Total crude unit throughputs *mb/d*								
	World	**US & Canada**	**Latin America**	**Africa**	**Europe**	**FSU**	**Middle East**	**China**	**Asia-Pacific**
2010	74.0	16.3	5.9	2.8	13.1	6.5	6.0	8.9	14.5
2015	77.4	16.8	5.8	3.0	11.7	6.6	7.6	11.1	14.8
2020	79.9	16.7	6.2	3.1	11.3	6.7	8.0	12.2	15.6
2025	81.9	16.5	6.4	3.4	10.9	6.9	8.3	12.9	16.5
2030	82.9	15.8	6.8	3.7	9.6	7.2	8.8	13.4	17.6
2035	84.1	14.6	6.9	3.9	9.4	7.5	8.9	13.8	19.2
	Crude unit utilizations *% of calendar day capacity*								
	World	**US & Canada**	**Latin America**	**Africa**	**Europe**	**FSU**	**Middle East**	**China**	**Asia-Pacific**
2010	82	83	73	78	76	80	82	86	83
2015	80	85	75	75	74	76	83	83	81
2020	81	84	78	74	72	76	84	86	82
2025	81	83	79	77	70	78	86	89	83
2030	80	79	81	79	61	80	88	89	85
2035	80	73	81	81	60	82	87	90	88

Europe lose 5.5 mb/d of throughput between 2010 and 2035 (3.7 mb/d of which is in Europe), while all other regions combined gain almost 16 mb/d. Of this, almost 10 mb/d, or over 60%, is in Asia. The 10 mb/d increase in Asia is itself a combination of a decline in Japan and Australia – potentially close to 1 mb/d – and an increase for the rest of Asia in the range of 11 mb/d.

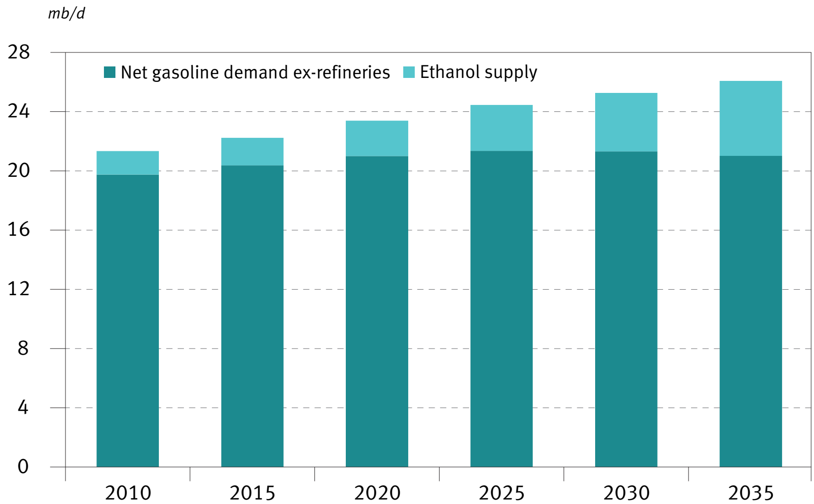
A key implication of these projected declines in Atlantic Basin throughput is that they again presage the need for additional closures beyond those included in the Reference Case. Specifically, the projections indicate that by 2035, around 3 mb/d of capacity would have to be closed in the US & Canada region to restore utilizations there to 85%, and well over an additional 4 mb/d in Europe to improve utilizations to the same level. Given the generally lower utilizations projected for Europe, the pressure for additional closures appears strongest and earliest there. Globally, around 6.5 mb/d of closures would be required in order to increase the utilization rates to the level of 85%.

Growth in non-crude supplies is a key factor that limits the need for refinery growth and curbs crude throughputs. Figure 7.1 illustrates the important role that ethanol is projected to play in impacting gasoline globally. Driven by the US and Brazil as the main sources, global ethanol supply is projected to rise from 1.6 mb/d in 2010 to 2.4 mb/d by 2020, and then accelerate to 5.1 mb/d by 2035. Over the same period, worldwide gasoline consumption is projected to rise from 21.3 mb/d to 26.1 mb/d. Thus, ethanol as a share of total gasoline grows from 7.5% in 2010 to over 19% globally by 2035.

An implication of the expanding ethanol supply is limited capacity additions – beyond firm projects – related to gasoline; and even these are only to fill regional needs. While the emphasis in refinery projects has shifted to distillates, every refinery expansion inevitably increases gasoline and naphtha producibility. There is currently no such thing as a 'zero naphtha/gasoline' refinery. Even with combined naphtha and gasoline demand growth at 7.7 mb/d from 2010–2035, the combination of NGL/condensate and ethanol supply increases, along with refinery producibility increments, act to sustain a 'soft' market for gasoline and naphtha in the future Reference Case, with adverse consequences for naphtha/gasoline crack margins.

In this respect, the situation in the US & Canada is even more pronounced, as shown on Figure 7.2. Gross gasoline demand in the region is projected to decline gradually from 9.3 mb/d in 2010 to 8.4 mb/d by 2035, while ethanol supplies are expected to grow rapidly. This growth continues recent ethanol supply trends, which went from 0.3 mb/d in 2005 to 0.6 mb/d in 2008. It reaches 1 mb/d in 2015 and 2.3 mb/d by 2035.[11] Correspondingly, ex-refinery gasoline requirements in the region

Figure 7.1
Global gasoline demand and ethanol supply, 2010–2035

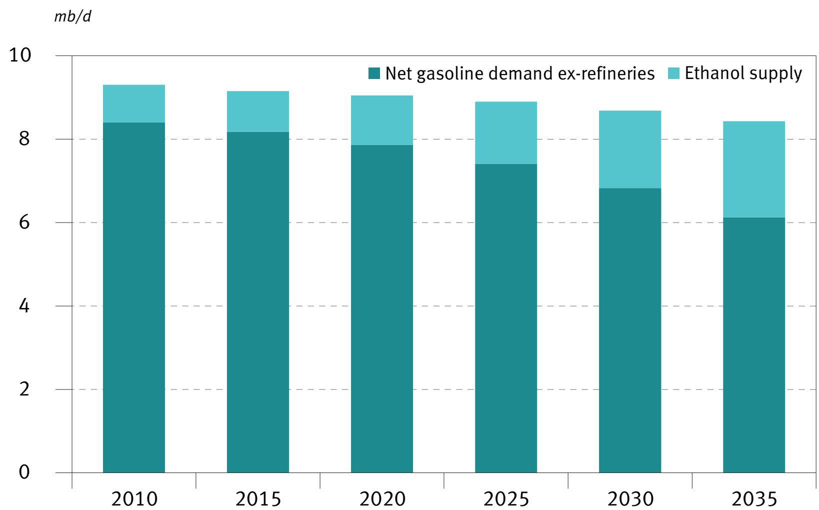


continue to decline through to 2035 as ethanol supplies rise, while improved vehicle efficiencies cut consumption. The projected decline is to below 8 mb/d ex-refinery by 2020, and to around 6 mb/d by 2035.

In short, renewable fuels and transport efficiency legislation are projected to remove 0.5 mb/d of demand for gasoline production from US & Canadian refineries by 2020, and well over 2 mb/d by 2035. The Reference Case is for total US & Canadian liquids demand to decline by 2.7 mb/d between 2010 and 2035. It is worth noting that a 2010 study by the US Environmental Protection Agency (EPA) projected that total demand across all US transport fuels could be reduced by 4 mb/d by 2030 – and possibly more than 6 mb/d – if more aggressive measures were adopted than those in place.[12]

As a result of declining regional demand, it is inevitable that US refinery throughputs will progressively need to make adjustments, although part of the decline is being offset by increasing product exports. This trend is already taking place since the US became a net product exporter in 2011 after many years of being a net product importer. Moreover, higher product exports are leading to an increasing degree of competition on international markets, notably for gasoline, as surplus capacity for the product exists, or will be added, in the US Gulf Coast, northern and southern Europe, Russia, the Middle East, India and other locations.

Figure 7.2
Total gasoline demand and ethanol supply in the US & Canada, 2010–2035



Europe's refining sector will also likely experience a decline in refinery throughputs. Efficiency/carbon emissions reductions and carbon intensity mandates are expected to drive down demand, while increasing biofuel supply. In the period 2010–2035, demand declines by around 2.5 mb/d and biofuels supply rises by nearly 1.2 mb/d. In other words, there is a steady reduction in the need for crude-based refinery products that exceeds 3 mb/d by 2035. As a consequence, no refinery capacity expansion beyond current projects is needed through the period to 2035. As in the US, regional refinery throughputs are projected to drop from 13.1 mb/d in 2010 to 11.3 mb/d by 2020 and to 9.4 mb/d by 2035. This is a total reduction of 3.7 mb/d, broadly matching the reduction in refinery product demand. Even allowing for the significant refinery closures to date, utilizations are expected to steadily decline to 60% by 2035, again signifying the potential for a substantial rationalization of capacity in the region – in the range of an additional 4 mb/d.

As is the case with Europe, no new refinery capacity will be needed in the Pacific OECD countries. The outlook allows for a series of closures in the region, primarily in Japan, where it is driven by a combination of declining demand and a new government order which mandates increases to refinery upgrading ratios. The latter is leading refiners to fully or partially close refineries – or at least cut their distillation capacity – rather than add new upgrading units. As a result, 2035 utilization for the region is projected at nearly 78% (compared to 60% last year, a projection that did not include any closures).

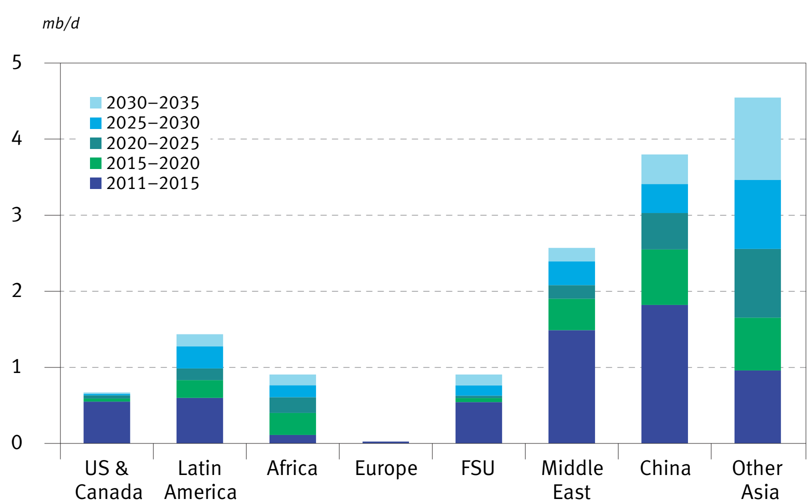
This long-term utilization level is still low enough to suggest that additional closures may occur. A further 0.4 mb/d would be needed to raise the utilization rate to 85%.

Figure 7.3 presents required crude distillation capacity additions in major regions by 2035, compared to the base level of 2011. This figure clearly demonstrates that the outlook in the three major industrialized regions stands in stark contrast to that for developing regions. Indeed, the vast majority of the refining capacity expansions to 2035 are projected as needed in the Asia-Pacific and the Middle East, with 8.3 and 2.6 mb/d, respectively, out of a global total of 15 mb/d.

Expansions in Asia are driven by projected demand paths within the region and are dominated by China and India. In the period to 2015, capacity additions in China are almost double those in Other Asia for the reasons explained in detail in Chapter 6. Beyond the medium-term, however, capacity additions in China will gradually slow, while those in Other Asia, mainly India, will maintain momentum and expand by around 1 mb/d in every five-year period.

Sustained Middle East demand growth, at 1.7% p.a., will result in a total demand increase of nearly 3.5 mb/d from 2011–2035. Against this, distillation capacity additions through 2035 are projected at 2.6 mb/d. Of these, 1.5 mb/d are projects assessed to be onstream by 2015. Thus, project additions are 'front-loaded' within the region, with further additions totalling 1.1 mb/d spread across the period 2016–

Figure 7.3
Crude distillation capacity additions in the Reference Case, 2011–2035



2035. As a result, crude throughputs are projected to expand from 6 mb/d in 2010 to 8 mb/d in 2020, and then to 9 mb/d in 2035. Product exports are projected to rise to 2.8 mb/d by 2020 and 3.8 mb/d by 2035, and comprise roughly half finished refined products and half NGL streams.

In the region with the next highest required capacity additions, Latin America, projections are for 1.4 mb/d by 2035, which is well below demand growth that is seen as rising by 2.5 mb/d for the same period. This gap is primarily accounted for by the projected substantial growth of 0.9 mb/d for biofuels in the region, dominated by Brazil. Moreover, utilizations are expected to gradually rise from 75% in 2015 to 81% by 2035.

These figures, though, mask a key product trade relationship – namely the evolution of product exports from the US to Latin America. In 2011, total product exports from the US comprised 2.5 mb/d of finished refined products, supplemented by nearly 0.2 mb/d each of NGLs/LPG and other liquids, comprising methyl tetra-butyl ether (MTBE), ethanol and other gasoline blend components. The total of 2.9 mb/d is more than double the gross product exports since 2007, when the level was 1.4 mb/d. Of the 2.9 mb/d of products exported in 2011, 1.5 mb/d went to Latin America.[13] Of these, 0.6 mb/d went to Mexico and 0.9 mb/d to a wide range of other countries across the Caribbean and Latin America. Exports were significant and growing to Brazil (0.2 mb/d), Chile (0.1 mb/d), Panama (0.1 mb/d) and lay in the range of 25,000–75,000 b/d (and generally growing) to another eight countries in the region.

It is projected these exports will continue to grow to almost 1.9 mb/d by 2015 (from the US and Canada combined), then ease to 1.6 mb/d by 2020, and fall slightly again to 1.5 mb/d by 2035. In the medium-term, the current trend of growing Latin American imports from the US continues, but then, between 2015 and 2020, regional capacity expansions take effect, led by major new refinery projects in Brazil, as well as ethanol growth there, so that total product imports – including those from the US – subsequently decline.

Distillation capacity additions in the FSU region are projected to rise by 0.9 mb/d by 2035. Chronologically, this can be divided into an initial surge of over 0.5 mb/d by 2015, in part a response to new Russian taxation rules and mandates for modernization, followed by a long period from 2016–2035 when required additions are projected to be 20,000 b/d or so each year. This second slow period of capacity additions reflects modest demand growth in the region, a gradual increase in utilizations, as well as constrained demand in Europe, a primary market for Russian product exports. However, this relatively stagnant outlook for overall capacity requirements may not necessarily mean low investment requirements in the region, since part of the outdated facilities will require replacements or substantial investments to modernize, which could also lead to more capacity being added than indicated.

Despite projected demand increases for refined products in Africa of 1.8 mb/d between 2011 and 2035, current firm construction in the region is modest – 0.3 mb/d by 2016 – and total expansion by 2035 is projected to be 0.9 mb/d, roughly only half of the anticipated demand increase. Rising utilizations also contribute to meeting demand growth, but product imports are projected to remain a major factor in the region's total product supply. Africa has the benefit of growing domestic/regional crude oil production, which is mainly of good quality, for refinery feedstock. Against this, many of the refineries in the region face challenges of being small scale, relatively old, low in complexity, low in energy efficiency and historically poor in terms of utilizations. In addition, there is intense and growing competition to supply product imports into Africa from Europe, the Middle East, India and the US. These factors lead to an outlook wherein regional refinery expansions struggle to compete with product imports.

Conversion and desulphurization capacity additions

Sufficient distillation capacity is a necessary pre-condition for the adequate functioning of the refining sector. Supporting conversion and product quality related capacity play vital roles in processing raw crude fractions into increasingly advanced finished products – and they deliver most of a refinery's 'value added'. The importance of these secondary processes has been increasing with a general trend toward lighter products and more stringent quality specifications. Essentially all major new refinery projects comprise complex facilities with high levels of upgrading, desulphurization and related secondary processing. It means they have the ability to produce high yields of light clean products which, almost invariably, can be produced to the most advanced specifications (such as Euro V standard).

In addition, many new refineries are being designed with the ability to process heavy, low quality, and often high acid number (high TAN) crudes, as well as better quality grades and/or to produce petrochemical feedstocks such as propylene and aromatics. Smaller projects in existing refineries are generally directed toward the same aims. Together, these factors are leading to high levels of secondary processing capacity additions and associated progressive increases in the proportions of secondary capacity per barrel of distillation.

Results and projections for secondary processing to 2035 are presented in Table 7.3 and Figures 7.4–7.7. In respect to conversion capacity, these projections emphasize a sustained need for incremental hydro-cracking, which constitutes almost

Table 7.3
Global capacity requirements by process, 2011–2035
mb/d

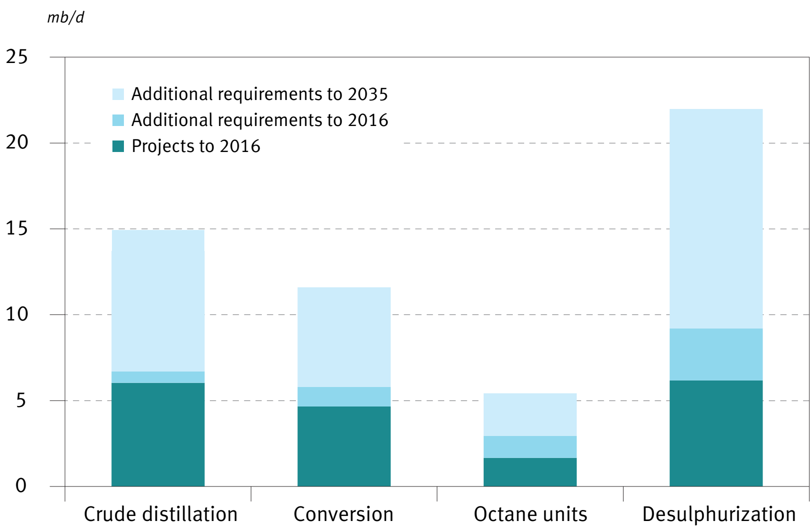
	Existing projects	Additional requirements		Total additions
	to 2015*	to 2015	2015–2030	to 2035
Crude distillation	**6.0**	**0.7**	**8.2**	**14.9**
Conversion	**4.7**	**1.1**	**5.8**	**11.6**
Coking/Visbreaking	1.5	0.0	0.6	2.1
Catalytic cracking	1.2	0.1	0.5	1.8
Hydro-cracking	2.0	1.0	4.7	7.7
Desulphurization	**6.2**	**3.0**	**12.8**	**22.0**
Vacuum gasoil/Resid	0.2	0.3	1.5	2.1
Distillate	4.5	2.2	8.8	15.5
Gasoline	1.4	0.6	2.4	4.4
Octane units	**1.7**	**1.3**	**2.5**	**5.4**
Catalytic reforming	1.3	1.3	1.4	4.0
Alkylation	0.2	0.0	0.1	0.3
Isomerization	0.2	0.0	1.0	1.1

* *Existing projects exclude additions resulting from capacity creep.*

8 mb/d out of just under 12 mb/d of total conversion capacity requirements by 2035. These levels of hydro-cracking additions were indicated despite the fact that all model cases were run in FCC high distillate modes, reflecting what is reported to be happening as refiners adjust FCC yields to maximize distillate. However, FCC yield variation is a somewhat limited means today for raising refinery distillate yields, leaving hydro-cracking as the primary option for incremental distillate production. 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 other light products well into the future (barring any major process technology breakthroughs).

Conversely, recent and current substantial coking capacity additions, together with the limited export supply of heavy sour crudes in the medium-term, are leading to a coking surplus. Global coking capacity has risen from 3.9 mb/d in 2000 to 4.9 mb/d in 2005 and 6.8 mb/d in 2011. A further 1.5 mb/d of coking additions are projected to be in place by 2015, leading to an installed capacity that is more than double that of 2000. As a result, coking utilizations are projected to weaken by 2015 to around 60%,

Figure 7.4
Global capacity requirements by process type, 2011–2035



before steadily recovering thereafter in line with continuing declines in residual fuel demand (inland and marine bunkers) and a global crude slate that becomes gradually heavier. Required additions from 2016 to 2035 are projected to be 0.6 mb/d for a total of 2.1 mb/d in new capacity needed by 2035. However, this is small relative to the 7.7 mb/d of projected total hydro-cracking additions for the same period.

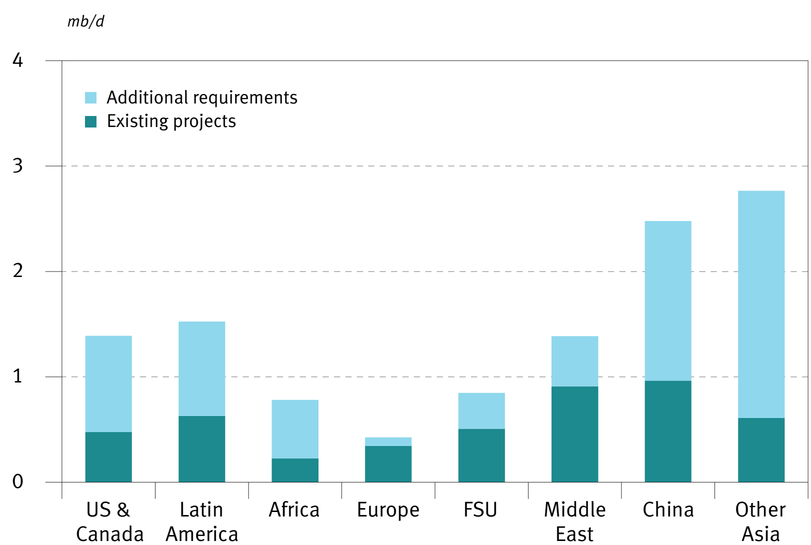
The outlook for catalytic cracking is similar. Demand for FCC gasoline is adversely impacted by both declining gasoline demand growth and rising ethanol supply in the Atlantic Basin. The projections allow for an increased role for the FCC unit in producing propylene, which is a high growth product, and also for a shift to operating modes that yield more distillates. Even so, estimated increases beyond current projects are seen as minor until after 2015 and then are spread across non-OECD regions where there is gasoline demand growth – Latin America, Middle East and Asia. Total additions to 2035 are seen at 1.8 mb/d, two-thirds of which comprise firm projects that are expected to be onstream by 2015.

Unlike hydro-cracking units whose utilizations will likely be consistently high – 90% in 2015, then in the high 90% range thereafter – and coking units whose utilizations are projected to suffer and then recover, those for FCC units are forecast to gradually decline from around 70% globally in 2015 to around 60% by 2030/2035. This projection ties in with the corresponding modelling results that indicate continuing weak margins for gasoline; therefore it is the refineries that emphasize gasoline production (rather than distillates) that are most vulnerable to closure. A further implication of the projections is that hydro-cracking will partially displace catalytic cracking over time as the primary means to upgrade vacuum gasoil feedstocks.

Moreover, it is worth mentioning that total conversion additions to 2015 are 4.7 mb/d, a level approaching 80% of total crude unit additions. In the entire forecast period to 2035, total conversion additions of 11.6 mb/d represent 85% of distillation capacity additions. This sustained high ratio reflects the need to increase the production of light products for every barrel of crude processed, as well as a continuing need to build hydro-cracking, at times effectively displacing FCC units, in order to produce incremental distillate.

On a regional basis, Asia-Pacific will dominate conversion capacity requirements, attracting more than 45% (over 5 mb/d) of total future additions in the period to 2035 (Figure 7.5). Nearly half of this will be needed in China alone. In Latin America, a significant increase of 1.5 mb/d should also take place in the period to 2035 as demand for light products in the region expands. The same is expected for the supply of heavy crudes. Similar levels of conversion additions are projected for the

Figure 7.5
Conversion capacity requirements by region, 2011–2035

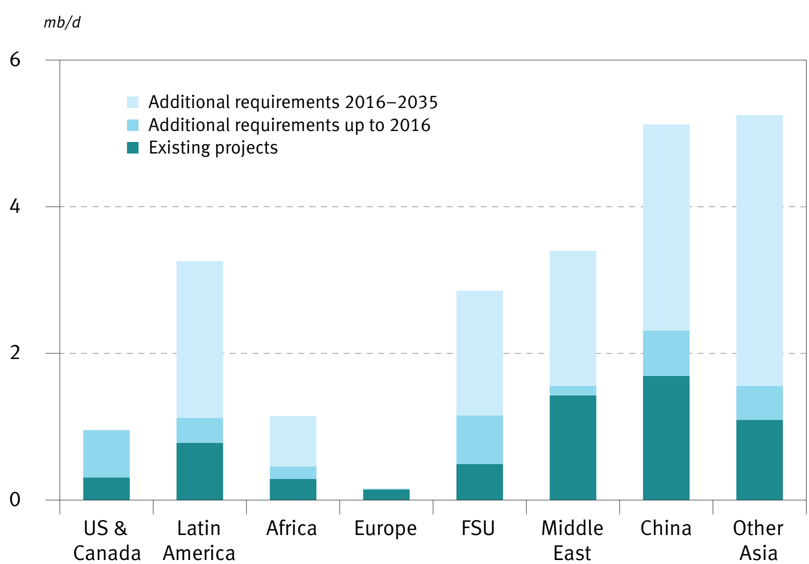


US & Canada region, driven in part by growth in the supply of heavy streams such as oil sands, and a progressive shift in the product demand mix away from gasoline and toward diesel. Across nearly all regions, long-term conversion capacity additions are seen as being mainly biased toward hydro-cracking.

Developments in product quality specifications outlined in Chapter 5 result in significant additions to desulphurization capacity that will be necessary to reduce the sulphur content in finished products. With OECD regions already largely at ULS standards for gasoline and diesel, the main focus in the future will shift to non-OECD regions as they move progressively to low and ULS standards for domestic fuels (often following the Euro III/IV/V standards), and build export capacity to meet advanced ULS standards. It is estimated that 22 mb/d of additional desulphurization capacity will be required globally by 2035, which compares with less than 15 mb/d of total distillation capacity additions to 2035. In short, the drive to continued tighter fuels sulphur standards leads to desulphurization comprising the largest volume of capacity additions in the period to 2035, nearly 1.5 times those for distillation.

Not surprisingly, the bulk of these additions is projected in Asia (10.4 mb/d), the Middle East (3.4 mb/d) and Latin America (3.3 mb/d), driven by an expansion

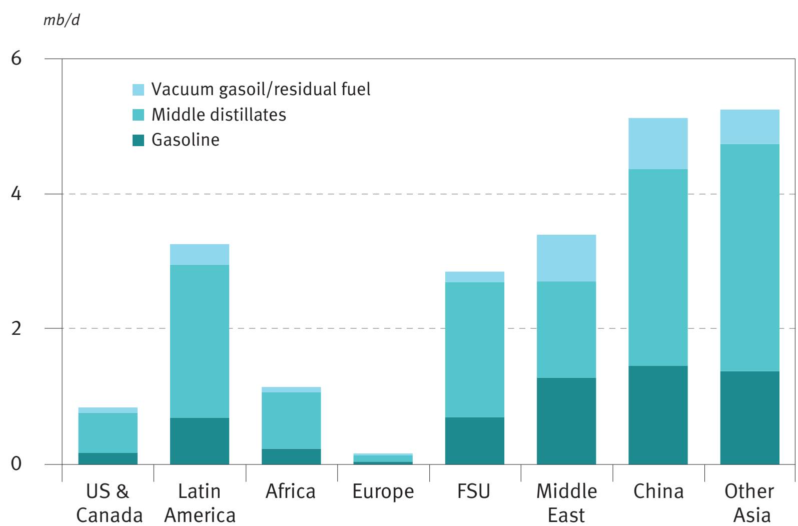
Figure 7.6
Desulphurization capacity requirements by region, 2011–2035



of the refining base and demand, as well as stricter quality specifications for both domestic and exported products. Significant additions are also projected for the FSU (2.9 mb/d), in line with the tightening of domestic quality standards in that region, and the need to produce diesel to ULS standards for export to Europe. The lowest desulphurization capacity additions are projected for the US & Canada and Europe where almost all transport fuels are already at ULS standards.

Figure 7.7 relates desulphurization capacity additions to the key groups of refined products. It indicates that between 2011 and 2035, more than 60% of global desulphurization capacity additions – or almost 14 mb/d – are for the desulphurization of middle distillates, while the bulk of the remainder is for gasoline sulphur reduction (6 mb/d).

Figure 7.7
Desulphurization capacity requirements by product and region, 2011–2035



Finally, 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.

Chapter 7

Chapter 8

Downstream investment requirements

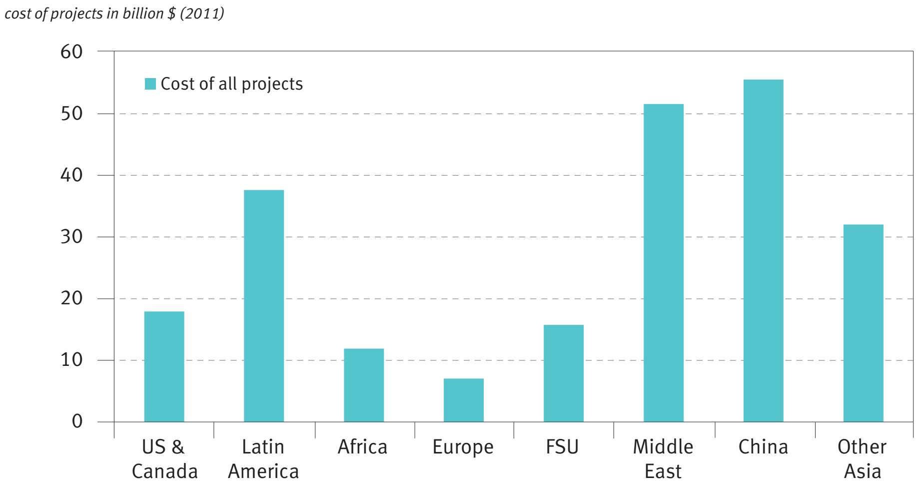
The projected investment requirements for the refining sector in this year's WOO consist of three major components. The first category relates to identified projects that are judged to go ahead. The second category comprises capacity additions – over and above known projects – that are estimated to be required to provide adequate future refining capacity. And the third category covers maintenance of the global refining system and capacity replacement.

As set out in Chapter 6, in terms of additional distillation capacity, the global refining system is projected to expand by 7.2 mb/d, the result of existing projects coming onstream by 2016, compared to the 2011 base. In addition to distillation capacity, these projects will add more than 6 mb/d of desulphurization capacity, 4.7 mb/d of conversion capacity and around 1.7 mb/d of combined reforming, alkylation and isomerization capacity.

The cost of constructing this capacity is assessed to be $230 billion for the period 2012–2016 (Figure 8.1). Of this, the Asia-Pacific region is projected to require the highest level of investment, close to $90 billion for known projects, with China alone attracting some $55 billion. Closely following the Asia-Pacific, in terms of investments, is the Middle East. Investors in the region will spend around $50 billion, mainly on new grassroots refineries. Latin America has total projected investment requirements of close to $40 billion. Investments in other regions are significantly lower, in the range of $10–20 billion, except for Europe where new unit investments are limited. The main focus here is on desulphurization for diesel plus some limited conversion and distillation expansion, mainly in Southern and Eastern Europe.

Continued interest in downstream capacity expansion in developing countries is contributing to the upward movement in construction costs. This is also evident in the behaviour of the downstream capital costs index (DCCI) developed by IHS CERA. It rose during 2010 to its pre-economic crisis level of around 180, compared to the base year 2000, and increased further during 2011 to end the year at 196. Increased downstream capital costs during 2011 not only reflect the rising price of raw materials, but also higher labour costs and the premium price contractors needed to pay for construction equipment due to increased competition between various industry sectors. A similar rising trend is also evident in the behaviour of the US-oriented Nelson-Farrar construction index published by the Oil and Gas Journal, albeit at more moderate rates. The DCCI indicates an increase in global construction costs in

Figure 8.1
Cost of refinery projects by region, 2012–2016



the range of 10% for 2011, while the increase in the Nelson-Farrar index is slightly below 5% for the same year.

The trend of rising costs is expected to continue, though not at the rates witnessed in the pre-crisis years and during the recovery period of 2010 and 2011. The assumption employed in the projections is that investment costs will increase during the forecast period, although at moderate levels.

The second category of downstream investments comprises capacity additions – over and above known projects – that are projected to be required to provide adequate future refining capacity. These are presented in Figure 8.2. At the global level, these investments are estimated to total around $300 billion in the period to 2035. This amount is very similar to the WOO 2011 estimate, although current global distillation capacity additions are some 2 mb/d lower than last year's projection. Higher construction costs and a somewhat higher proportion of secondary process units, broadly compensate for lesser distillation additions in the make-up of total investments.

Extending the time horizon to 2035 amplifies the significance of the Asia-Pacific. The region should attract the highest portion of future downstream investments, driven by the region's strong demand growth. From the $300 billion of required investments above existing projects, almost 45%, or $130 billion, is projected to be in the Asia-Pacific. While in the medium-term China attracts more investments than

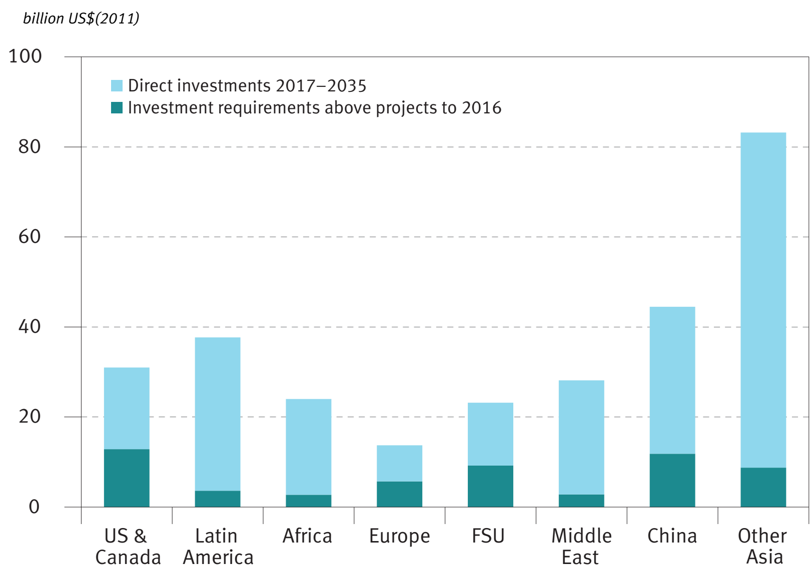
Other Asia, in the long-term, the pattern changes as the latter region is expected to require more capacity additions.

After large medium-term investments in the Middle East, longer term requirements are significantly lower. As a result, Latin America appears as the region with the next highest long-term investment requirements after the Asian regions. In Latin America, these investments will be mainly used to expand the distillation base and desulphurization capacity.

Somewhat lower investments are expected in the FSU and Africa, in the range of $20 billion each. These are fairly equally distributed across expansions for all major process units. In the US & Canada, expected investments are just over $30 billion. Here, an important factor is the expanding production of heavy crudes that necessitates further investments in conversion capacity, as well as units related to future fuel quality improvements.

Beyond existing projects, little investment to expand the capacity base will be required in Europe, as well as in the OECD part of Asia, which is not shown

Figure 8.2
Projected refinery direct investments* above assessed projects



* *Investments related to required capacity expansion, excluding maintenance and capacity replacement costs.*

Chapter 8

separately in Figure 8.2. The reasons for this are related to the lack of demand growth in these two regions, with investments relating mainly to quality compliance in regards to growing distillates volumes.

The last category is on-going annual investments required to maintain and gradually replace the installed stock of process units. Following industry norms, the maintenance capital replacement level was set at 2% of the installed base p.a. Thus, replacement investment is highest in regions that have the largest installed base of primary and secondary processing units. Moreover, since both costs and the installed refinery capacity base increases each year, so does the related replacement investment.

Therefore, progressively in all regions, a higher portion of investment requirements will be needed to cover maintenance and replacement costs. This is especially true in OECD regions, where projected investments are mainly for maintaining existing capacity. It is important to note, however, that as the base capacity steadily expands in non-OECD regions, so will the associated investment required for on-going capital replacement. Globally, it is estimated that around $750 billion will be needed for capacity maintenance and replacement in the period to 2035. The regional distribution of these requirements is presented in Figure 8.3.

Figure 8.3
Refinery investments in the Reference Case, 2011–2035

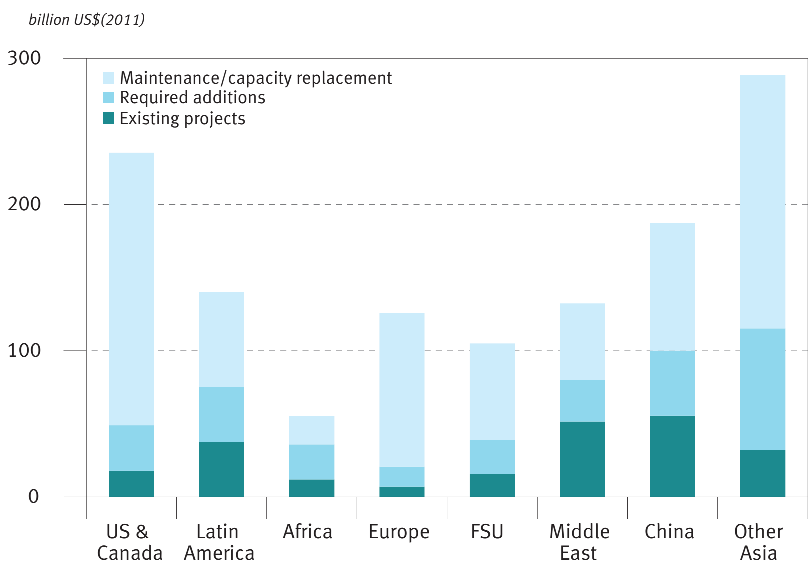


Figure 8.3 also summarizes total investment requirements, combining all three major categories into one graph. In short, in the period to 2035, global refining investments are estimated at around \$1.3 trillion, out of which \$230 billion are needed for investment in existing projects, \$300 billion for required additions and around \$750 billion for maintenance and replacement. This excludes related infrastructure investments beyond the refinery gate, such as port facilities, tankers, storage and pipelines.

The key components of the additional investments needed beyond the refinery gate – typically referred to as the midstream sector – relate to the necessary expansions in regional pipeline systems and tanker capacity that are required to move volumes of crude oil and liquid products. In addition to this, some investments will be necessary for loading and receiving ports, related storage capacity, as well as to expand the retail distribution network. Combined, midstream investment costs for the period up to 2035 are estimated to be close to \$1 trillion.

Adding in upstream investment needs, estimated in Section One at more than \$4 trillion, as well as those for refining and the midstream, results in an estimated oil related investment requirement of somewhere in the range of \$6 to \$7 trillion, between 2011 and 2035.

Chapter 9

Oil movements

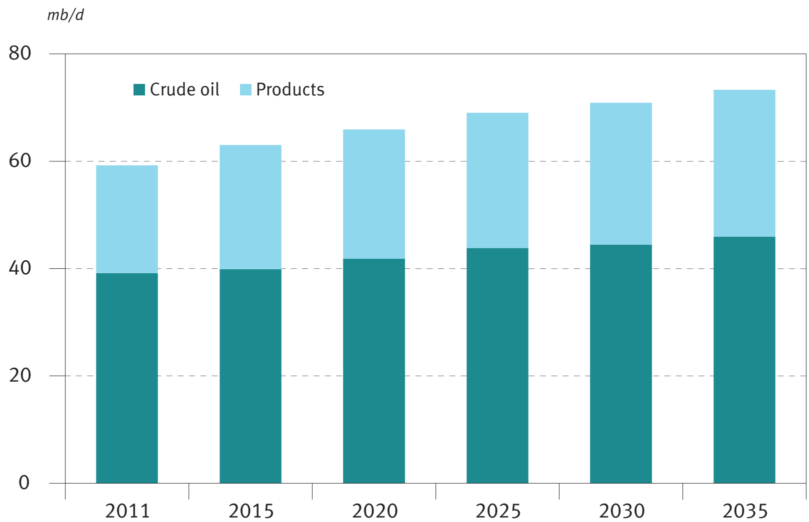
Generally, the economics of oil movements and refining means there is a preference for locating refining capacity in consuming regions. This is mainly due to lower transport costs for crude oil, as opposed to oil products, unless construction costs for building the required capacity outweigh the advantage of transport costs. For consuming countries, there is the added significance of securing a supply of required refined products, by emphasizing local refining over products imports, regardless of economic factors. Conversely, many oil producing countries may look to increase their domestic refining capacity to benefit from the 'value-added' of oil refining via the exporting of products. Moreover, in efforts to secure future outlets for their crude production, some producing countries opt for joint participation in refining projects in consuming countries that are often associated with long-term contracts for feed-stock supply.

Given these potentially conflicting interests, and because oil is to a large extent a fungible commodity traded on global markets, there is a great deal of uncertainty associated with projections about future oil movements, especially if the guiding principle for future trade flows is global cost minimization as is the case for the WORLD model that was adopted to examine the likely changes in key inter-regional flows, as well as refining developments.

In addition, the trade volumes of crude oil and products that are generated and reported depend on regional groupings within the model. A more detailed regional breakdown will tend to show higher imports and exports than 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.

Compared to last year, changes in the regional supply and demand levels, combined with this year's more detailed breakdown of the US & Canada into sub-regions, results in higher reported volumes of global oil movements. If oil trade between all 22 model regions is considered,[14] as presented in Figure 9.1, projections indicate steady growth in the trade flows of both crude oil and liquid products. In terms of volume, increases are in the range of 7 mb/d each between 2011 and 2035. However, from a growth rate perspective product trade will grow faster, on average around 1.3% p.a., compared to crude oil trade at 0.7% p.a. This difference is especially noticeable in the period up to 2015. Within this period, product trade is set to increase by around

Figure 9.1
Inter-regional crude oil and products exports, 2011–2035



3 mb/d, or 3.6% p.a., while crude oil trade will grow along the lines of its long-term trend, increasing by less than 1 mb/d.

There are however, great variations and divergent trends behind these global numbers. These are discussed in detail in the following two sub-sections, in terms of the specific trade flows of crude oil and refined products.

In the medium-term, the key factor relates to refining capacity expansion, primarily in the Middle East and Latin America, which will make more products available for exports. This is supported by developments in the US & Canada region, where there is declining demand and growing supply. The net result is a higher volume of product exports, with relatively stagnant crude oil trade.

In the period after 2015, total oil movements are projected to increase by more than 10 mb/d, of which 6 mb/d is for crude oil and 4 mb/d is for products. Growth in product exports will slow during this period, as regional refining capacity in the long-term is projected to grow more proportionally with regional demand. The majority of the export increase will be directed towards expanding Asian markets. Similarly, crude oil export growth will be primarily driven by demand increases in the Asia-Pacific, which is associated with substantial refining capacity expansion.

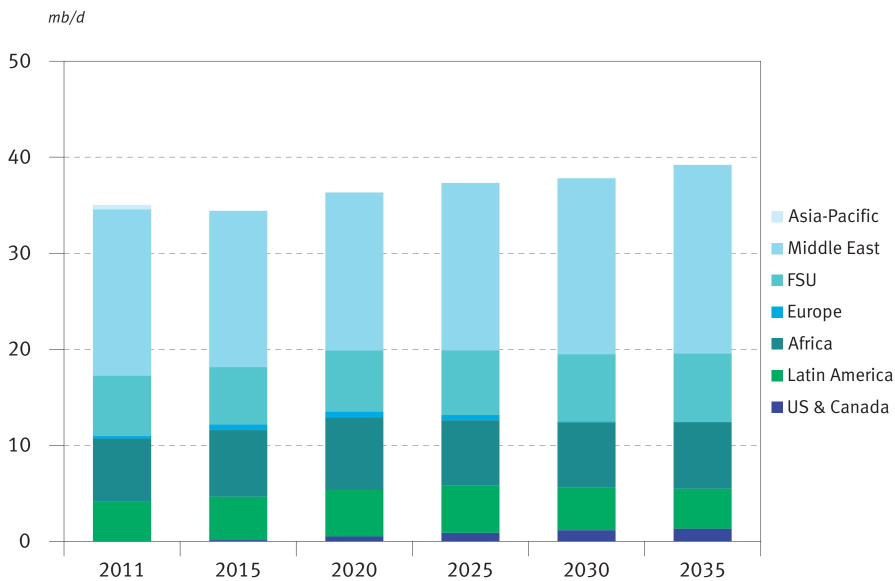
In summary, the combined crude and liquid products inter-regional trade between 2011 and 2035 increases by around 14 mb/d to a level of 73 mb/d, from 59 mb/d in 2011.[15] Breaking this down further, oil trade movements by 2020 will be around 66 mb/d, rising to 69 mb/d by 2025 and then 71 mb/d by 2030.

Crude oil movements

Figure 9.2 presents crude oil movements between the seven major regions[16] in the period 2011–2035. In the medium-term, these are projected to decline marginally, but then grow in the long-term. The decline to 2015 is around 0.6 mb/d, from a level of 35 mb/d in 2011. However, total crude exports are expected to be above 36 mb/d by 2020 and exceed 39 mb/d by 2035. This will lead to a total increase in crude oil exports of around 4 mb/d by 2035, compared to 2011.

There are a number of factors behind the medium-term marginal decline projected for crude oil exports between major regions. Demand and refining capacity increases in Latin America will absorb some additional barrels produced in the region and will even lead to a decline in crude exports from the Middle East and the FSU.

Figure 9.2
Global crude oil exports by origin*, 2011–2035



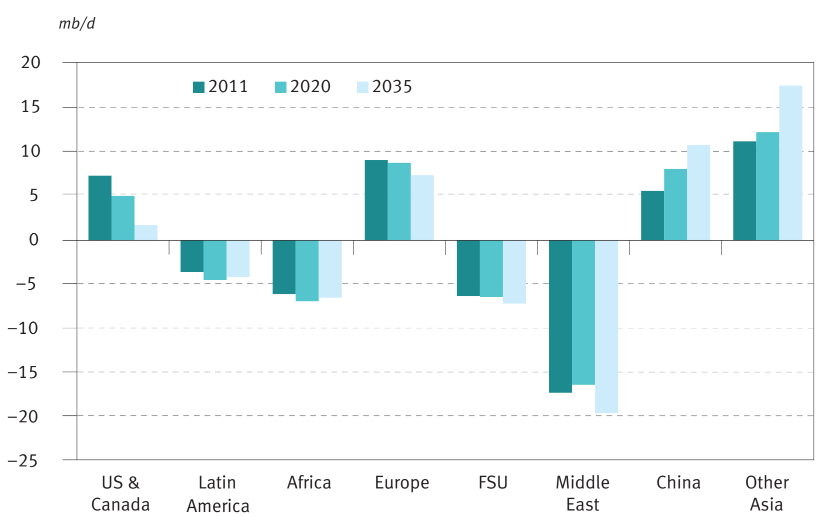
* *Only trade between major regions is considered.*

Growing product exports from the US & Canada only partially compensate for the demand decline and supply increases in this region, so that crude imports to the US are also expected to fall. Elsewhere, a lack of new refining projects in Africa, alongside a demand decline in Europe, will allow for higher crude oil exports from these regions in the medium-term. The net effect of these developments is a relatively stagnant (or declining) level of total crude exports traded between 2011 and 2015, although there are some changes in trade direction.

In the long-term, however, changes become much more visible. These concern both volumes and trade patterns. The most obvious is the growing importance of the Middle East as the key crude exporting region in the decades ahead. Indeed, after a decline between 2011 and 2015, and then a minor increase between 2015 and 2020, crude oil exports from this region are set to grow by around 1 mb/d every five years, reaching almost 20 mb/d by 2035, compared to 17 mb/d in 2011.

One of the key regions where this year's upward revision of crude production affects the global crude trade pattern is the US & Canada. Figure 9.3 shows how these revisions amplify the future trend towards reduced crude oil imports into this region. For the reasons described in detail in Section One (relating to supply and demand), net crude oil imports to the US & Canada as one region are set to decline to below 2 mb/d by 2035, from more than 7 mb/d in 2011 and 5 mb/d in 2020. The signifi-

Figure 9.3
Regional net crude oil imports, 2011–2035



cant decline in US crude imports – since Canada is a net crude exporter – leads to a shift in the global crude trade, which, to a great extent, will be determined by the type of additional barrels that are expected to be produced in this region.

A considerable proportion of these additional barrels will reach the US market as heavy crude from Canada's oil sands for which sufficient conversion capacity is assumed to be available, mainly in the US Midwest and Gulf Coast, provided adequate transportation exists. A further part of the increased crude production in the region will come in the form of light crude oil grades – supplemented by a rise in ethanol supply – that will gradually displace some of the current imports from Africa and the North Sea.

Box 9.1
Pipeline, rail, barge...any way out!

Three-to-four years ago, the US and Canadian logistics system for delivering crude oil to the market was stable and relatively 'quiet'. Then matters started to change as pricing for WTI at the Cushing Oklahoma hub, which had always run in close parity with Brent, started to disconnect. Discounts deepened, affecting essentially all inland Lower 48 crude grades, as well as Western Canadian crude oils (since these are also priced off WTI). Since January 2011, these discounts have been steep and have been considered 'structural'. It begs the question: what happened?

Broadly speaking, the US and Canadian crude oil pipeline system, which was originally designed for taking crude oils into the US heartland, was caught off-guard by expanding production in Western Canada, as well as the Bakken and other shale plays, which required a system to get crude out to coastal markets. This lack of capacity led to the 'congestion' seen most clearly at Cushing, which continues to persist today. It has become a race between expanding supply and attempts to put adequate capacity in place in order to move crude oils to markets beyond the US interior and inland Western Canada.

In addition, three years ago no one would have anticipated that a pair of pipeline projects would become the focus of 'political heat' at the highest levels. The TransCanada Keystone XL project, originally intended as a 700,000–900,000 b/d line to mainly carry oil sands streams from Hardisty, Alberta, to the Gulf Coast via Cushing, has become a focal point of the political and environmental pro- and anti-oil sands debate in the US. Likewise, the Enbridge Northern Gateway project that would initially take 525,000 b/d of heavy oil sands streams west to the British Columbia port of Kitimat – and then to markets mainly in Asia – has become the centre of impassioned support and vehement resistance in Canada. As of the date of this report, the Keystone XL project has been split into two: a southern leg project from Cushing to the Gulf that has received all the permissions necessary to proceed, and which is expected to start operations by late 2013; and a northern segment from Hardisty to Steele City, Nebraska (where there is an existing line on to Cushing), with no final decision on this made yet. Start-up would likely be no earlier than 2015. For the Northern Gateway project, Enbridge has filed an application with the Canadian National Energy Board, but a review will take at least until the end of 2013. The expected start-up for this is around 2017, but some delays are likely.

The response to the delays on these two headline projects, from the midstream industry has been an almost ever-changing array of new developments and proposals. There are already several project proposals related to modifying existing pipelines and/or taking advantage of existing rights-of-way to construct new parallel pipelines. A leading example is the 300,000 b/d Trans Mountain pipeline from Edmonton-to-Vancouver, which has recently been heavily over-subscribed. Currently a spur pipeline carries the bulk of the crude moved to US refineries in Washington State and another 50,000 b/d has consistently gone to a refinery at Burnaby near Vancouver. As a result, historically, less than 50,000 b/d of crude has been exported over the one and only export dock that currently exists for Western Canadian crudes. Operator Kinder Morgan has obtained sufficient shipper commitments to support expanding the Trans Mountain capacity by 450,000 b/d. Much of the increased throughput would be moved over the Vancouver (Westridge) dock, with destinations mainly in Asia. The expansion has a start-up date of 2016, although this could slip because of concerns over the resulting increase in tanker movements in the already busy Port Metro Vancouver harbour.

The Northern Gateway and the Trans Mountain expansion represent the only pipeline projects that would take Western Canadian crude west to the Pacific. All other pipeline capacity moves Western Canadian crudes south into the US Rocky Mountain and Midwest regions, from which there is an onward pipeline to Sarnia in Ontario. After recent expansions, which include the base Keystone system, there is more than 3.5 mb/d of cross-border capacity from Alberta into the US interior. There are, however, bottlenecks in moving Canadian crudes through and out of the Midwest. At the same time, the Cushing hub has also become a major bottleneck. Increasing supplies from Western Canada, the Bakken, the Permian Basin region (West Texas), as well as from Oklahoma and Kansas, are all creating pressure to move crudes mainly from the North into Cushing and out in multiple directions, but especially south to the large refining centres on the Gulf Coast.

Until recently, there was no pipeline that flowed south from Cushing to the Gulf Coast; only the 93,000 b/d Pegasus line flowed from the Chicago area to the Gulf.

The Seaway line used to flow north to Cushing, but this has recently been reversed. It will be expanded to a capacity of 400,000 b/d from Cushing to the Gulf Coast by early 2013 and to 850,000 b/d by mid-2014. Associated with these expansions is a planned new Flanagan South line that will use the right-of-way of the existing Spearhead line to add nearly 800,000 b/d of capacity from Chicago to Cushing. This will help relieve the bottleneck in the Chicago area and will enable Canadian – and Bakken – crudes to flow via Seaway to the Gulf Coast. A Seaway reversal and expansion, with the Keystone XL southern leg, will add over 1.65 mb/d of capacity out of Cushing to the Gulf by 2014. This will substantially alleviate the 'Cushing congestion' and should, consequently, narrow the WTI-Brent spread, as well as Western Canadian-WTI differentials.

Growing Western Canadian and Bakken supplies have also led Enbridge to propose modifying its existing pipeline through Eastern Canada. The system already carries Western crudes east as far as the refining complex at Sarnia. Another line (Line 9) used to run east from Sarnia to Montreal, but was reversed; it is now bringing imported crudes west via Montreal and a connecting Portland (Maine) to Montreal Pipeline (PMPL) into Sarnia. Enbridge has now proposed to re-reverse Line 9 so that it runs east to Montreal, where there is access to two refineries in Montreal and Quebec City. This could also tie-in with a possible reversal of the PMPL to take Western Canadian and Bakken crudes out to the Atlantic, from where they could reach refineries in the Canadian Maritimes, the US East Coast and potentially beyond. Enbridge has already reversed a first short section of the line and has applied for permits that would allow full reversal. This project, like Northern Gateway and Keystone XL, is meeting some resistance, however, since it would move oil sands east, and so its timing is uncertain. A joint undertaking by MarkWest and Sunoco is also underway to convert Mariner East pipeline to transport natural gas liquids from the Marcellus and Utica shale plays to Sunoco facilities at Marcus Hook, Pennsylvania. Propane and ethane exports to Europe are also planned as part of the project, thus further unlocking the region's shale oil and gas production potential.

TransCanada is also considering switching one or more existing gas pipelines that run from Alberta to Quebec into crude service. The concept is apparently attracting interest and a possible capacity range of 400,000–900,000 b/d is being discussed. The main objective would be to carry Western Canadian crudes, including oil sands, synthetic crude and/or DilBit, through to the Sarnia refineries, on to Quebec and then to the 300,000 b/d Irving refinery in New Brunswick. At the moment, this is only an idea and has not been taken to the formal 'open season' stage to test the level of commercial commitment. Part of the impetus behind this possible gas line conversion and the Enbridge Line 9 project is uncertainty over the major projects that would move Western Canadian crudes to the west, and south to the Gulf

Coast. To the extent that either the TransCanada or Line 9 projects go ahead, they will enable light sweet and medium sour crude oils out of Eastern Canadian and possibly also to refineries on the US East Coast.

Uncertainties over key pipeline projects, and steep discounts in US Lower 48 and Western Canadian crude prices, have spurred the above proposals (and additional ones) to modify and expand existing pipeline infrastructure, but they have also led to a growing role for rail. There has been marked growth in Bakken 'takeaway' capacity via rail. Faced with a dearth of existing infrastructure in North Dakota, mainly smaller producers and transport companies in 2009 began a rapid expansion of rail terminals. These use 'unit train' technology (load dedicated 60,000–75,000 barrel trains, often one or more per day) that then move to corresponding receiving terminals with no stops along the route. Bakken rail takeaway capacity went from 30,000 b/d in 2008 to 335,000 b/d by 2011 and should reach nearly 800,000 b/d by the end of 2012.

Pipeline takeaway capacity is also expanding rapidly, but what is new here is that rail is becoming established as an important mode for moving crude oil, at scale, to multiple destinations. Most delivery terminals for Bakken crude are in the Gulf Coast, but movements are expanding to both the West Coast and, especially, East Coast. These movements are taking Bakken production – which recently passed the 640,000 b/d mark and is expected to go much higher – into mainly coastal US markets. The new trend for Bakken prices to exceed those for WTI is evidence of the new-found 'freedom' that rail to the coast is providing to the former.

This year (2012) may also be the point when crude movement via rail starts to catch on as a means to move Western Canadian crudes. Small volumes of Western Canadian crudes have recently moved to the Western US, the Gulf Coast and the East Coast, as well as Ontario via rail. What is new is that longer term commitments and unit train developments are starting to surface – for instance, for the movement of Western Canadian crudes at scale to the Irving refinery in New Brunswick.

Rail movement via 'manifest' train can be three times the cost of pipeline. However, unit trains narrow the gap and shorten the delivery time. Moving oil sands bitumen by rail can come even closer to pipeline costs as less diluent is needed; even bitumen with no diluent can be carried if the rail cars are heated. Given the severe price discounts on heavy Canadian crudes, rail looks to be an attractive option. Both pipeline and rail are also tying in with barge movements, notably from the Midwest to the Gulf Coast, using rail or pipeline for part of the way and then barges down the Mississippi river for the last leg. Within the Gulf Coast, midstream companies are also expanding their options to move crudes along the coast (for example, Eagle

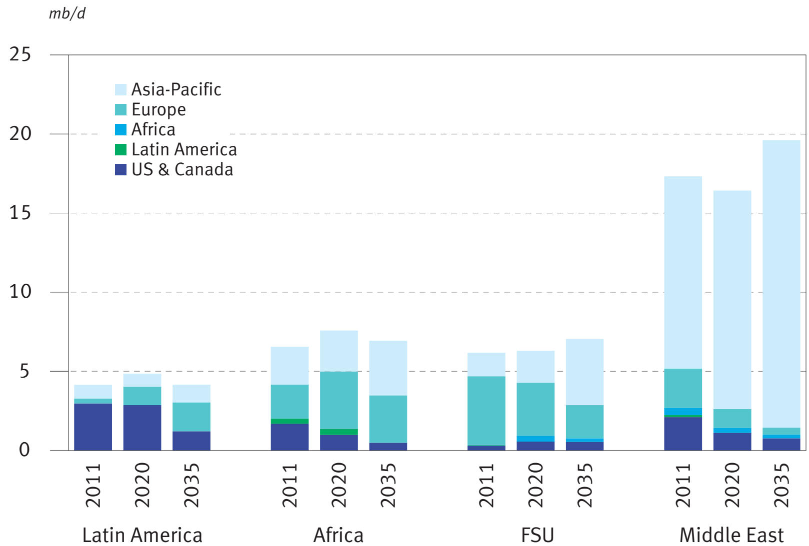
Ford crude east along the Gulf and also via tanker up to the East Coast) and to move crude west to rail terminals in St. James, Louisiana.

The net effect of all these developments is that the US and Canadian crude oil logistics system is changing rapidly as it seeks to adapt to a new reality of steadily growing oil production, both north and south of the border. There is appreciable uncertainty, however, over how the system will evolve in the longer term. It will depend in part on whether (and when) a few major pipeline projects are brought online, as well as on how much Western Canadian crude ends up moving west and to Asia versus south into the US and east into Eastern Canada. By 2014, WTI discounts could be partially alleviated, but we are witnessing a race between production growth and infrastructure restructuring. By several counts, crude oil discounts could persist to 2020 – and even beyond – if US shale production rises at optimistic rates. The emergence of rail is an important new factor. Although rail car availability is a constraint in the short-term, terminals are low cost compared to pipelines, can be put online within 12–18 months and offer shorter payback times.

The bottom line is that the combination of pipeline expansion, and rail and barge transportation options, will enable US Lower 48 and Western Canadian crudes to flow in an increasingly less restricted way to coastal markets. Data shows that as of the third quarter of 2012, US and Canadian oil movements by rail have already increased by 650,000 b/d, compared to their historical level. This is consistent with the surge in rail loading and offloading capacity that, by the end of 2012, will see over 700,000 b/d of receiving capacity in operation, with over 200,000 b/d on the Eastern Seaboard (US and Canada), 450,000 b/d on the Gulf Coast and 50,000 b/d on the West Coast. By the end of 2013 and into 2014, this rail capacity will have essentially doubled to over 1.4 million b/d, with nearly 600,000 b/d of receiving terminals on the Eastern Seaboard, close to 750,000 b/d on the Gulf Coast and around 110,000 b/d on the West Coast. By 2015/2016, this new capacity may well have grown further and will have been joined by 1.65 million b/d of new pipeline capacity to the Gulf Coast from Cushing. Hence, a total of over 3 million b/d of capability will exist to take US Lower 48 and Western Canadian crudes to coastal markets in the US and Canada. This capacity growth is well under way; it is developing rapidly and is substantial.

As presented in Figure 9.4, FSU exports to the Asia-Pacific increase by almost 3 mb/d between 2011 and 2035, while an additional 1 mb/d of crude oil will be exported to this region from Africa. The decline in European imports from both the FSU and the Middle East is projected to be in the range of 2 mb/d for the same period. The largest change in traded volumes of crude oil over the period relates to crude oil exports from the Middle East to Asia-Pacific, which increases by 6 mb/d.

Figure 9.4
Major crude exports by destination, 2011–2035



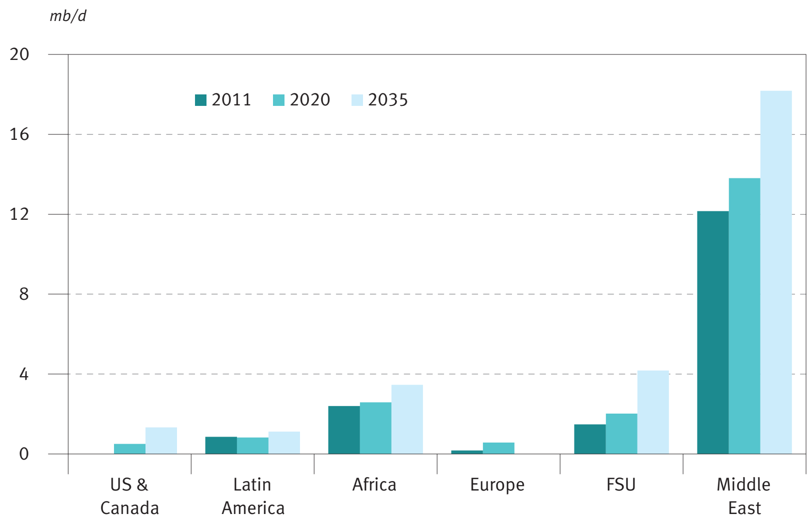
In addition to increased African exports to the Asia-Pacific, this region will also increase its crude exports to Europe by more than 1 mb/d by 2020, compared to 2011 levels. However, Europe's declining demand and Africa's growing demand in later years will cut back these African exports to Europe to around 3 mb/d by 2035, although it is still almost 1 mb/d higher than in 2011. All this is mainly due to reduced African deliveries to the US & Canada.

Crude oil exports from Latin America show a similar pattern to those from Africa. Expanding crude oil production will enable gradual export increases over the next 10-to-15 years, despite growing local demand and higher refinery throughputs. Towards the end of the forecast period, however, domestic demand will gradually shave the volumes available for exports. Volume changes are not large, as total crude exports from the region are projected to stay within the range of 4–5 mb/d over the entire forecast period.

Turning to the major crude oil exporting region, the Middle East, crude exports from the region will shift over the forecast period. The key projected trend over time is a re-direction of exports from Europe and the US & Canada to the growing markets of the Asia-Pacific. Throughout the entire forecast period, the destination that receives the most crude oil exports from the Middle East is the Asia-Pacific.

For the Asia-Pacific, however, the Middle East will not be an exclusive partner in covering its crude demand. As clearly demonstrated in Figure 9.5, the Asia-Pacific will increase crude exports from practically all producing regions, including Canada, under an assumption that export routes to the Pacific coast will be available.[17] By 2035, product demand in the Asia-Pacific will increase by some 16 mb/d, compared to 2011 levels. However, the region's 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, to a limited extent, crudes from the Americas. Imports from Canada and Latin America are at levels of around 1 mb/d by 2035.

Figure 9.5
Asia-Pacific crude oil imports, 2011–2035

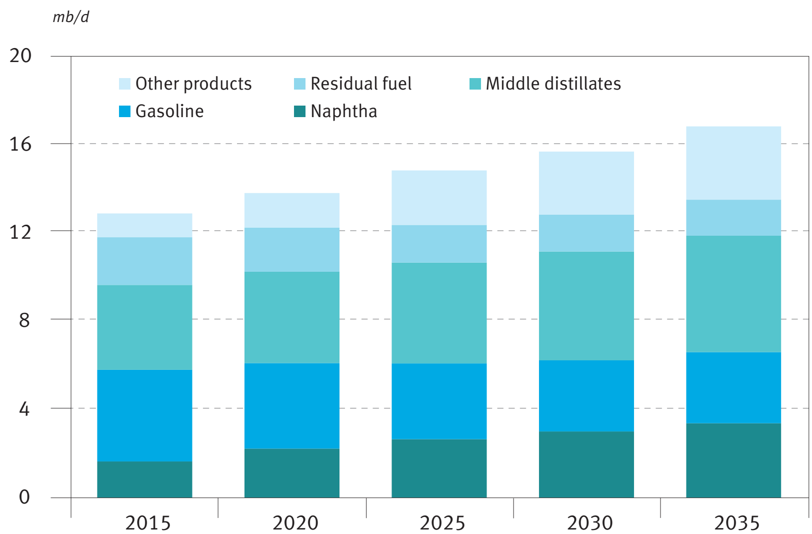


Product movements

The overall rising trend in inter-regional product movements between the major seven regions, broken down into key product groups, is presented in Figure 9.6. In total, product movements are set to increase by close to 5 mb/d between 2011 and 2035, from around 12 mb/d in 2011 to almost 17 mb/d by 2035.

In terms of specific products, some will impact future trade flows more than others. The two products that drive the major changes are middle distillates and

Figure 9.6
Global product imports by product type, 2015–2035



naphtha. Global exports of middle distillates are projected to reach a level of almost 4 mb/d by 2015, and then close to 6 mb/d by 2035. A similar increase, in terms of volume, is foreseen for naphtha, although it starts from a lower base. However, while middle distillate imports are spread among the Asia-Pacific, Europe, Africa and Latin America regions, increased volumes of 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. Moreover, increased trade volumes are also envisaged for the group of 'other products', driven by exports of LPG (mainly NGL-based), bitumen and lubricants, among others. There is an overall increase in the inter-regional exports of other products of around 1 mb/d between 2015 and 2035.

The export increases of the products mentioned will be partially offset by decreasing trade in gasoline and residual fuel oil. Combined, these fall by around 1 mb/d between 2015 and 2035. Declining gasoline exports are mainly the result of falling demand for this product in the Atlantic Basin and increasing ethanol supplies, especially in the US. It is projected that the overall gasoline trade decline is in the range of 0.6 mb/d between 2015 and 2035. However, there is an additional element of uncertainty in these projections related to the degree to which refiners in Europe and the US will be able to resolve the problem of the projected future gasoline surplus in these two regions. The remaining decline of 0.4 mb/d in product exports is associated with residual fuel oil. This decline reflects this product's expected demand reduction, due to falling inland use and marine bunker developments.

Figures 9.7 and 9.8 illustrate the trends in regional patterns for product imports in terms of total imports and net product imports, respectively. The most obvious change in future product trade concerns the rising product imports of the Asia-Pacific, which reach a level of almost 9 mb/d by 2035. These products will come from a variety of regions, led by the Middle East, and followed by Russia, Latin America and the US & Canada. Future product imports to the US & Canada are likely to oscillate around the levels reached in 2011, particularly as the eastern part of the region is expected to continue importing products from the Atlantic Basin. However, overall net product exports from the US & Canada are set to expand by around 1 mb/d by 2035, compared to 2011 levels, when the US became a net product exporter after decades of net imports.

With the new refining capacity in place after 2015, Latin America is also expected to turn from a net product importer to a net exporter. The level of net exports could reach 0.5 mb/d by 2020 and expand over time to 2 mb/d by the end of the forecast period.

Figure 9.7
Global product imports by region, 2011–2035

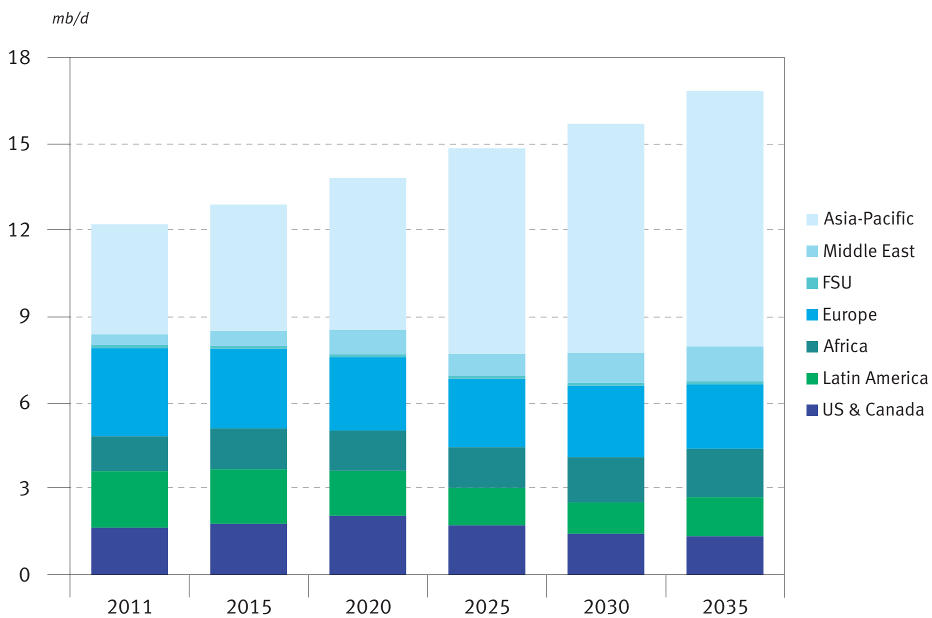
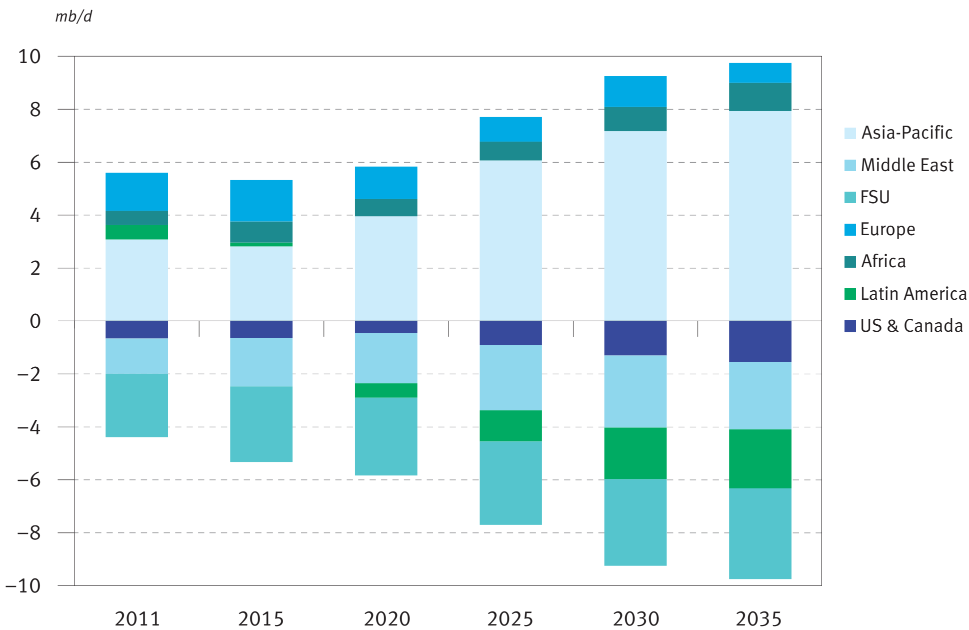


Figure 9.8
Net imports of products by region, 2015–2035



A pattern of declining product imports is expected in Europe. Currently, Europe is a net importer of around 1.5 mb/d of products. In the medium-term, similar levels are expected to be maintained, but in the longer term net imports are projected to decline by around 1 mb/d. This is a result of declining demand in the region.

For the remaining regions, the FSU and the Middle East will keep their status as net product exporters. Net product exports from the FSU and the Middle East are set to grow, not only because of expansion in domestic refining capabilities, but also due to additional non-crude based products. In the case of the FSU, net product exports will grow from close to 2.5 mb/d in 2011 to around 3 mb/d by 2015. This growth will moderate in the following years, however, so that overall growth is expected to reach 1 mb/d by 2035, compared to 2011 levels. A similar increase is expected in 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 add more refining capacity than projected in this year's WOO, which will, in turn, increase their capacity for product exports.

Chapter 10

Downstream challenges

This Chapter reflects on the analysis and findings of Section Two to highlight some of the key challenges facing the downstream sector. Since long-term trends are important drivers, some themes carry forward from year to year; but the situation is one that constantly evolves – and every year there is something new.

Growth shift to non-OECD regions

With each recent Outlook, it is ever more evident that there is a shift in impetus, growth and investment away from the OECD to non-OECD regions, as well as an associated sharp contrast between the Atlantic and Pacific Basins. It is also increasingly clear that OECD oil demand has peaked. The long-term oil demand trend in the US & Canada, Europe and Japan is down. In contrast, oil demand growth continues across all non-OECD regions with the main concentration in non-OECD Asia, led by China and India. These developments have led to a contrasting picture between the Atlantic and Pacific Basins, with the former (dominated by the US and Europe) having significant refining capacity surplus with associated product export potential, and the latter in need of continued refining capacity increases and/or additional product imports.

Refining capacity surplus, competition and closure

These shifts are reshaping the global downstream industry and will continue to do so in the years ahead: on-going closures in OECD regions contrasted by expansions in non-OECD regions. However, in a world of crude oil prices in the range of $100/b, the costs for transporting both crudes and products make up a smaller proportion of delivery costs compared to the past. This, combined with a near-term surge in refinery projects (7.2 mb/d by 2016) makes for a period of intense international competition – across both long and short distances – for product markets.

Many US refineries, notably in the Gulf Coast, are already well depreciated, highly complex and flexible, meaning they can produce products that meet advanced specifications. Gulf Coast refiners, in particular, have progressively raised distillate yields and lowered those of gasoline. Led by the Gulf Coast region, US refiners are already demonstrating a marked ability to export increasing product volumes, as domestic ex-refinery product demand declines, and are benefitting from the added competitive advantage and current low price of natural gas. Sustained discounts on inland US Lower 48 and Western Canadian crude oils have been delivering processing advantages and high margins to inland US refineries. There is also a race between necessary infrastructural improvements and growing production from these regions. As a result, some level of discounting could last several years, while pipeline and rail developments increasingly bring these crude oils to the US Gulf, West and East Coasts. This will sustain the ability of US refineries to make available products for export while, at the same time, impacting global crude oil trade patterns by reducing crude oil imports into the US, and also Canada.

In Europe, pending EU efficiency and renewable energy targets, as well as carbon regime initiatives, are likely to maintain the reduction in regional product demand and also raise refiners' costs in the region. That said, European refiners have an incentive to export gasoline at relatively low prices since added gasoline output enables the production of additional distillates as a co-product. 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 Brazil, India and the Middle East to compete for markets in Africa, Asia and Latin America. Managing this competition– while remaining profitable – will be a challenge in the years ahead.

A weeding out of the weaker refineries in OECD regions has advanced appreciably over the past year. However, substantial additional closures – potentially a further 3–6 mb/d (and possibly more) beyond today's level – are seen as necessary to reduce excess capacity, and restore utilizations and margins to long-term sustainable levels. Just as this degree of rationalization is needed, it is also entirely possible that it will be slow to occur. Recent narrowly averted closures in Europe and on the US East Coast have indicated that new entities are prepared to step in and run unprofitable refineries that seasoned large oil companies have abandoned. And, in other cases, there has been concerted support by stakeholders at the state and local levels to keep refineries open – at least for now.

Declining crude oil and refining share of the incremental demand barrel

While the proportion of crude oil needing to be refined per barrel of incremental product continues to decline, the total percentage of biofuels, GTLs, CTLs, NGLs and other non-crudes continues to rise. The impact is significant. In the Reference Case, supply increases by almost 20 mb/d between 2011 and 2035, from 87.8 to 107.5 mb/d. Of this increase, however, over 12 mb/d is projected to be met by growth in non-crudes and process gains. This equates to some 60% of total supply growth and leaves less than 8 mb/d of growth for crude oil, an average increase of some 0.3 mb/d per year. This translates essentially into a similar growth rate for refining and accounts for the low projected rate of annual capacity additions required beyond 2015.

Shale gas developments could change this picture even further. Supply side impacts centre on the potentially increased production of NGLs, thus further reducing the need for refining. Moreover, the current price premium favouring oil could lead to higher production of liquids from shale gas. Furthermore, natural gas at cheaper prices could mean more substitution of crude oil based liquids on the demand side. The net effect could be that conventional refineries in the US are further squeezed by both additions to non-crude supply and reductions in demand.

Distillate deficit – gasoline surplus

This year's projections for distillates and gasoline confirm the trend outlined in recent editions of the WOO. The market is facing an imbalance, at least in the medium-term, characterized by a gasoline/naphtha surplus and a continuing distillate deficit. New policies in Europe, however, may act to slow the rate of dieselization there. The mix of a refinery's products, particularly in regard to the proportions of distillate versus gasoline/naphtha, will thus be a key factor 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 being favoured.

Technology responses

As discussed in Box 10.1, the current pricing of crude oil relative to coal and natural gas (in North America, at least) has created strong incentives to produce more liquids from these two commodities. Accordingly, commercial capacity is starting to appear. Rising natural gas production also means more non-crude supply of NGL liquids, which in the future might compete directly with conventional transport fuels. Substantial biofuels supply growth is also included in the Reference Case, but that, too, could be positively impacted by technological advances (and vice versa, if new technologies are slow to evolve). In addition, refinery process technologies nearing the commercial stage could markedly change refinery yields, especially with the aid of hydrogen, which itself is often produced from natural gas. In short, process advances that could materially alter the shape of the global liquids supply system over time cannot be ruled out; rather, they need to be closely monitored.

Box 10.1
Process technology developments – traditionally slow-paced, but too risky to ignore

A dilemma implicitly present in longer term assessments of the refining sector is how to treat possible advances in refining and related processing technology. A great deal of effort goes into understanding how technological developments could impact future demand for transport fuels, in terms of efficiency and the fuel mix. Conversely, developments in refinery process technologies are generally constrained to those that are currently commercially proven, with some allowance for gradually improving efficiencies.

This is the case in the downstream modeling using WORLD. It looks ahead almost 25 years, but does not allow for any radical shifts in process technology. Again, this is a common and 'safe' practice, partly because the overwhelming preponderance of refining capacity comprises units that already exist and which are modified only very slowly (if at all), and because the industry has a 40-year history or so of process technologies that have seen only gradual evolution. For instance, radical new process technologies involving biotechnology and ultrasound as a means to desulphurize and crack streams have been touted for a number of years but, to date, have not proven to be commercially viable.

What drive technological advances in the marketplace are economic and regulatory developments. It is, therefore, necessary to have a sense of what important new developments might be available commercially over the next several years and, if warranted, have the means to be able to test their potential impacts by incorporating them into the modeling system. Recent reports consider 'likely' developments that could drive technological advancements, such as alternatives to hydro-cracking (which is costly, as well as energy and hydrogen intensive) that would produce incremental distillate from crude oil, and processes that would convert the ever-growing volumes of NGL/condensate/naphtha fractions into distillates.

US shale developments are reinforcing supplies of NGLs and natural gas such that, among other implications, two leaders in GTL technology, Shell and SASOL, are considering building GTL plants in the country – something that would have been unthinkable even two-to-three years ago. In addition, there are other GTL projects that are active. Shell claims that despite the high final costs, they are pleased with their Qatar Pearl GTL plant from which they have learned valuable lessons that can be applied to improve the next generation of projects. In short, with the growing availability of natural gas supplies, GTL (and related technological developments, such as CTL) could play a larger future role . All these processes that convert natural gas, coal and/or NGLs into liquids reduce the need for crude oil supply and processing. Abundant and cheaper natural gas also increases the incentive to adopt upgrading processes that add hydrogen (hydro-cracking) instead of removing carbon (FCC, coking). A review of key processes provides insights into the potential for technological change.

Upgrading

At around 18 mb/d installed capacity, FCC/Resid FCC units represent a key means to upgrade vacuum gasoils and residua. Catalyst and additive advances continue to enable these 'workhorse' gasoline units to adapt to different feed and yield imperatives, notably raising the proportions of residuum in feed (as vacuum gasoil is increasingly pulled away to hydro-crackers) and shifting yields to maximize propylene or distillate production. Technological advancements range from catalyst improvements, which continue to incrementally raise total conversion and/or distillate yields, to at least one set of processes that would convert FCC LPG and light gasoline range olefins to distillates. (Note that a 5% yield swing from gasoline to distillate on all installed FCCs would reduce gasoline supply by nearly 1 mb/d and raise distillate supply by a corresponding amount, substantially impacting the gasoline/distillate balance.) An 8,000 b/d COD unit is already in operation at the PetroSA Mossel Bay facility in South Africa. The FCC olefins are oligomerized to raw distillate which is then hydrogenated to create a high-quality finished product. Such technology could enable FCC refineries to switch their yields much more significantly to distillates, thus helping refineries in Europe and elsewhere to continue to function economically, and thereby altering refining investments, product trade balances and price differentials.

Declining demand for inland and marine residual fuels continues to lead to more upgrading of the 'bottom of the barrel' vacuum residua fractions. Little new visbreaking capacity has been built in recent years, as the primary product is still fuel oil. New 'hydrogen-injected' variants could lead to a new lease on life for visbreakers by improving their yields. Several advances in resid hydro-cracking technology and catalysts are occurring, and are likely to lead to a greater role for this process in the future, at least in upgrading better and medium quality residua, and/or to deal with streams such as coker gasoil and FCC clarified oil. A radical resid hydro-cracking variant is the long evolving ENI Slurry Technology (EST) process that claims total conversion of residua to transport fuels (that means no production of coke or other heavy oil by-products). After extensive testing across multiple feedstocks with a 1,200 b/d plant, ENI is now constructing a full commercial scale 23,000 b/d unit at its Sannazzarro refinery, with expected start-up in late 2012. The significance of this process is that it could represent an improved way to fully upgrade low-grade/extra-heavy oil residua, bitumen and other streams to clean products or synthetic crude oils.

At sustained relatively high crude prices – and especially in regions where natural gas prices are also high – gasification as a form of upgrading could also play a role. Gasifiers can process a wide range of feedstocks, including petroleum coke and other low-value refinery bottoms streams, as well as coal and biomass. The syngas they yield (a mixture of carbon oxides and hydrogen) provides a source of the latter. It can be used to generate steam and/or power and constitutes a feedstock for the production of ammonia, methanol and other derivatives. Capital costs for gasification units are high, however, and have historically limited their use. Nevertheless, according to data from the US Department of Energy, worldwide gasification capacity will surge by 72% in the period 2010–2016. Additionally, 60% of world gasification capacity will use coal as a feedstock and around 25% will use refinery streams, obtained mainly from the bottom of the barrel. The remaining capacity will be running primarily on natural gas. In short, this is another technology that looks likely to begin materially impacting refinery configurations and operations going forward.

NGLs/naphtha to distillates

Significant price differentials evident in the modeling outlook between NGL/naphtha/gasoline streams and distillates point to a potential need to process the former streams – projected to be in relative surplus – into the latter, which comprise the leading growth products. One of the effects of US shale developments is a reported weakening in prices for NGL/LPG streams and for naphtha (relative to crude). Various reports, however, have indicated that there are currently no commercial projects that would directly convert NGL/naphtha to distillate. Propylene dehydrogenation projects are going ahead, although the current goal is to produce propylene for chemicals feedstock. Despite the strong growth rate that propylene currently enjoys, there is expected to come a time when the high-value propylene market becomes saturated. Thus, with NGLs production continuing to expand worldwide, the choice for incremental NGL streams may end up being conversion to distillate or combustion at fuel value. Therefore, the potential for NGL/naphtha to distillate conversion remains something to watch out for. In the meantime, the necessary process 'pieces' are in place, as is evident from the PetroSA COD technology.

Gas/Coal-to-Liquids

While GTL plants installed to date have a history of high capital costs, operating experience keeps on accumulating. At the same time, next generation R&D is active, including into processes that claim to be able to economically recover lower volume gas streams, such as those that are currently flared. As already indicated, growing supplies of low-cost natural gas in North America could provide an impetus for further development and investment.

There are no less than nine energy and technology companies currently involved in developing GTL technology, including one using gas generated from biomass conversion. Advances have been made in catalyst performance and Fischer-Tropsch (FT) reactor design. The diesel fuel blend components produced by the GTL FT process are of exceptionally high-quality (cetane numbers in excess of 70, near-zero sulphur content and low aromatics content) and, thus, command a premium. As a result, GTL refinery netbacks are now claimed to compare favourably with LNG disposition alternatives. The next few years could be a critical period; GTL capacity could start to play a much increased role, provided the current high plant fuel consumption is lowered significantly and the price premium over oil remains large in the medium- to long-term.

Moreover, progress is being reported on new and more efficient technologies that convert coal or petroleum coke into ethanol. While currently overshadowed by ethanol, methanol has also been used as a transport fuel for years. In China, methanol from coal comprises a significant percentage of the country's transport fuel pool. Some of the advantages claimed are that methanol can be produced from many feedstocks, ranging from coal and natural gas to pulp mill and other by-products.

This overview of technological developments – from resid upgrading, to GTL, to methanol – is by no means exhaustive. Some technologies may make little or no progress, but others could have impacts at a scale that reshapes global process capacity, as well as crude oil consumption, trade patterns and market economics. Thus, awareness and monitoring of the developments in these technologies is essential.

A Reference Case outlook, but many uncertainties

The factors discussed in this Chapter add up to a wide range of potential developments which, if taken individually, or especially if taken together, could substantially alter the evolution of the downstream and its key elements (refining/processing activity, investment, trade and economics). Put another way, while the Reference Case provides a valuable and plausible outlook, the chances of the global downstream straying far from this outlook appear to be increasing as different factors – from capacity surplus to competition, economic drivers to technology, as well as supply and demand developments – all interplay.

Footnotes

Section One

1. The OPEC Reference Basket price is a production–weighted average of an OPEC basket of crudes consisting of: Saharan Blend (Algeria); Girassol (Angola); Oriente (Ecuador); Iran Heavy (IR Iran); Basrah Light (Iraq); Kuwait Export (Kuwait); Ess Sider (Libya); Bonny Light (Nigeria); Qatar Marine (Qatar); Arab Light (Saudi Arabia); Murban (United Arab Emirates); and Merey (Venezuela).
2. OTC derivatives statistics at end-December 2011, Bank of International Settlements, May 2012.
3. G-20 Leaders Declaration, Pittsburgh, Pennsylvania, US, September 2009.
4. http://esa.un.org/unpd/wpp/Excel-Data/population.htm. The 2012 revisions are due to be released in early 2013.
5. Standards for international bunker fuels are administered by the IMO under the International Convention for the Prevention of Pollution from Ships known as MARPOL.
6. Excluding non-commercial use of biomass.
7. Supply is higher than demand to account for stock growth.
8. US Geological Survey World Petroleum Assessment 2000 – Description and Results.
9. World Research Institute's online database: http://earthtrends.wri.org/searchable_db/index.php?theme=3.
10. In this assessment, the term commercial vehicles is used to mean lorries and buses, as documented and published by the International Road Federation. Passenger cars are designed to seat no more than nine persons (including the driver). Sport utility vehicles are included in this analysis.
11. For example, http://www.fhwa.dot.gov/ohim/onh00/bar8.htm.
12. For instance, the introduction of the more stringent Corporate Average Fuel Economy standards as part of the US Energy Independence and Security Act legislation in December 2007. And the December 2010 proposal by the US Environment Protection Agency to raise new vehicle economy standards to 54.5 miles per gallon by 2025. This policy represents a 60% rise over the 2016 targets that are already in place, and implies a dramatic change in average fuel use per vehicle. It is important to stress, however, that a key variable in this is an assessment of how likely it is that any given target will be met.
13. American Transportation Research Institute, survey 2008.
14. US Natural Gas Act 2011.
15. Forbes.com, June 2012.
16. International Civil Aviation Organization, http://icaodata.com.
17. Centre for Aviation, http://www.centreforaviation.com/analysis/eu-ets-and-the-aviation-industry-between-a-rock-and-a-hard-place-52146.
18. Monthly Oil Market Report (MOMR), March 2012, OPEC Secretariat.
19. World Petroleum Assessment 2000, US Geological Survey.
20. 'An estimate of undiscovered conventional oil and gas resources of the world, 2012', US Geological Survey, April 2012.

21. OPEC Annual Statistical Bulletin, 2012 edition, OPEC Secretariat.
22. Hart Energy, Global Shale Oil Study, February 2011.
23. Wood Mackenzie.
24. Hart Energy/Rystad Energy, 2Q2012 North American Shale Quarterly Report.
25. In August 2012, the Director-General of the UN Food and Agricultural Organization, Jose Graziano da Silva, pleaded for the suspension of biofuel mandates, see Financial Times, 10 August 2012. It is also worth mentioning the recent decision of the EU to not increase biofuels targets and to include sustainability criteria for biofuels that are considered for reaching this target.
26. See 'Global Biofuels Outlook 2011–2012', Hart Energy, 2011.
27. Although there is still debate over the direction of causality between savings and economic growth.
28. For example, 'IMF World Economic Outlook', October 2012 and 'India's Challenge: Harnessing Demographics for Long-Term Growth', Roubini Global Economics, 16 April 2012.
29. The IMF sees the Euro-zone's budget deficit falling to 3.2% in 2012 from 6.3% in 2012. MOMR, May 2012, OPEC Secretariat.
30. Lower demand leads to a slight fall in processing gains, so the fall in OPEC crude supply relative to the Reference Case is 9.1 mb/d, compared to the 9.3 mb/d drop in demand.
31. http://www.slb.com/news/press_releases/2012/2012_0308_sbchrbenchmark_pr.aspx.

Section Two

1. The World Oil Refining Logistic and Demand model is a trademark of EnSys Energy & Systems, Inc. OPEC's version of the model was developed jointly with EnSys Energy & Systems.
2. For example, Technology Outlook 2020, DNV, 2012.
3. Ethane demand in this Section relates to petroleum-derived ethane, excluding ethane from natural gas.
4. Both the US and Canada have ECAs that came into effect as of 1 August 2012.
5. http://www.icis.com/Articles/2012/04/02/9546235/afpm-shale-gas-leads-to-mega-projects.html, http://www.frackcheckwv.net/2012/04/03/the-future-of-ethane-cracker-chemical-plants-in-the-u-s/, http://www.plasticstoday.com/articles/ExxonMobil-plans-to-build-new-ethane-cracker-and-two-PE-units-in-Texas-0601201201.
6. Fuel oil, naphtha and liquefied petroleum gas prices are not regulated but those for gasoline, diesel, etc., are.
7. International Oil Daily, Tuesday, 7 February 2012.
8. ESPO crude enjoys tax reductions which should be on a temporary basis.
9. 90% is considered the maximum sustainable utilization rate over the longer period for a region.
10. The 'narrow escapes' encountered by the Sunoco Philadelphia and Phillips66 Trainer refineries, combined with sales and planned restarts at some of the idled Petroplus refineries in Europe, have arguably (according to a range of industry commentators) served only to continue to depress margins in the Atlantic Basin, which otherwise were beginning to show signs of recovery. As such, these 'escapes' sustain the need for further closures.
11. An underlying assumption for the projected continuing growth in US ethanol supply is that cellulosic ethanol technology will be available in the longer term. The first commercial scale cellulosic ethanol plant are currently under construction in the US.
12. 'EPA Analysis of the Transportation Sector: Greenhouse Gas and Oil Reduction Scenarios', 10 February 2010.
13. Europe was the next most important destination at 0.6 mb/d, followed by Asia/Middle East/Africa at 0.5 mb/d and Canada at 0.25 mb/d.
14. Oil here includes crude oil, refined products, intermediates and non-crude streams (including biofuels and GTLs).
15. Compared to last year's report, trade data for the base year 2011 were adjusted to account for changes in regional definitions.
16. Because of aggregated regions, some movements are eliminated. For example, between regions in the US and Canada, and trade within Latin America, Africa and Asia. Therefore, total trade volumes are lower than reported earlier in this Chapter.
17. It is assumed that the current policy of no crude exports from the US will be in place over the entire forecast period.

Annex A

Abbreviations

API	American Petroleum Institute
ASB	Annual Statistical Bulletin
bcf	Billion cubic feet
b/d	Barrels per day
boe	Barrels of oil equivalent
CAFE	Corporate Average Fuel Economy
CARB	California Air Resources Board
CCS	Carbon capture and storage
CDU	Crude distillation unit
CFTC	Commodity Futures Trading Commission
CNG	Compressed natural gas
CNOOC	China National Offshore Oil Corporation
CNPC	China National Petroleum Corporation
CO_2	Carbon dioxide
COMPERJ	Rio de Janeiro Petrochemical Complex
CTLs	Coal-to-liquids
DCCI	Downstream capital costs index
DCs	Developing countries
ECAs	Emission control areas
ECB	European Central Bank
EFSF	European Financial Stability Facility
EIA	Energy Information Administration
EISA	(US) Energy Independence and Security Act
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency
ERC	Egypt Refining Company
ESM	European Stability Mechanism
ESPO	Eastern Siberia–Pacific Ocean
EST	ENI Slurry Technology
EU	European Union
EU ETS	EU Emissions Trading Scheme
FCC	Fluid catalytic cracking
FSU	Former Soviet Union
FT	Fischer-Tropsch
FYP	Five Year Plan

G-20	Group of Twenty
GDP	Gross domestic product
GHG	Greenhouse gas
GTLs	Gas-to-liquids
GW	Gigawatt
ICE	Intercontinental Exchange
ICE	Internal combustion engine
IEA	International Energy Agency
IEF	International Energy Forum
IFO	Intermediate fuel oil
IFQC	International Fuel Quality Centre
IHS CERA	IHS Cambridge Energy Research Associates
IMO	International Maritime Organization
JODI	Joint Oil Data Initiative
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
MEPC	Marine Environmental Protection Committee
METI	Ministry of Economy, Trade & Industry
MJ	Megajoule
MOMR	(OPEC's) Monthly Oil Market Report
mpg	Miles per gallon
MTBE	Methyl tetra-butyl ether
NDRC	National Development and Reform Commission
NGLs	Natural gas liquids
NGV	Natural gas vehicle
NOx	Nitrogen oxide
Nymex	New York Merchantile Exchange
OECD	Organisation for Economic Co-operation and 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
PADD	Petroleum Administration for Defense District
PMPL	Portland (Maine) to Montreal Pipeline
ppm	Parts per million
R&D	Research and development
RFCC	Residue fluid catalytic cracking
R/P	Reserves-to-production
SEC	Securities and Exchange Commission
Sinopec	China Petrochemical Corporation
SOx	Sulphur oxide
TAN	Total acid number
Tcf	Trillion cubic feet
TFP	Total Factor Productivity
ULS	Ultra-low sulphur
UN	United Nations
URR	Ultimately recoverable resources
USGS	United States Geological Survey
WOO	World Oil Outlook
WORLD	World Oil Refining Logistics Demand Model
WRFS	World Refining & Fuels Services
WTI	West Texas Intermediate
WTO	World Trade Organization
wt%	Per cent of weight

Annex B

OPEC World Energy Model (OWEM): definitions of regions

OECD

OECD America

Canada
Chile
Guam
Mexico
Puerto Rico
United States of America
United States Virgin Islands

OECD Europe

Austria
Belgium
Czech Republic
Denmark
Estonia
Finland
France
Germany
Greece
Hungary
Iceland
Ireland
Italy
Luxembourg
Netherlands
Norway
Poland
Portugal
Slovakia
Slovenia
Spain
Sweden
Switzerland
Turkey
United Kingdom

OECD Asia Oceania

Australia
Japan
New Zealand
OECD Asia Oceania, Other
Republic of Korea

Developing countries

Latin America

Anguilla
Guadeloupe

Antigua and Barbuda
Argentina
Aruba
Bahamas
Barbados
Belize
Bermuda
Bolivia (Plurinational State of)
Brazil
British Virgin Islands
Cayman Islands
Colombia
Costa Rica
Cuba
Dominica
Dominican Republic
El Salvador
Falkland Islands (Malvinas)
French Guiana
Grenada
Guatemala
Guyana
Haiti
Honduras
Jamaica
Martinique
Montserrat
Netherlands Antilles
Nicaragua
Panama
Paraguay
Peru
St. Kitts and Nevis
St. Lucia
St. Pierre et Miquelon
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
Malawi
Mali
Mauritania
Mauritius
Mayotte
Morocco
Mozambique
Namibia
Niger
Oman
Réunion

Côte d'Ivoire
Democratic Republic of Congo
Djibouti
Egypt
Equatorial Guinea
Eritrea
Ethiopia
Gabon
Gambia
Ghana
Guinea
Guinea-Bissau
Jordan
Kenya
Lebanon
Lesotho
Liberia
Madagascar
Rwanda
Sao Tome and Principe
Senegal
Seychelles
Sierra Leone
Somalia
South Africa
Sudan
Swaziland
Syrian Arab Republic
Togo
Tunisia
Uganda
United Republic of Tanzania
Western Sahara
Yemen
Zambia
Zimbabwe

India

Other Asia

Afghanistan
American Samoa
Bangladesh
Bhutan
Brunei Darussalam
Cambodia
China, Hong Kong SAR
China, Macao SAR
Cook Islands
Democratic People's Republic of Korea
Fiji
Mongolia
Myanmar
Nauru
Nepal
New Caledonia
Niue
Pakistan
Papua New Guinea
Philippines
Samoa
Singapore

French Polynesia
Indonesia
Kiribati
Lao People's Democratic Republic
Malaysia
Maldives
Micronesia (Federated State of)
Solomon Islands
Sri Lanka
Thailand
Timor-Leste
Tonga
Vanuatu
Viet Nam

China

OPEC

Algeria
Angola
Ecuador
I.R. Iran
Iraq
Kuwait
Libya
Nigeria
Qatar
Saudi Arabia
United Arab Emirates
Venezuela, Bolivarian Republic of

Eurasia

Russia

Other Eurasia

Albania
Armenia
Azerbaijan
Belarus
Bosnia and Herzegovina
Bulgaria
Croatia
Cyprus
Georgia
Latvia
Lithuania
Malta
Montenegro
Republic of Moldova
Romania
Serbia
Tajikistan
The Former Yugoslav Republic of Macedonia

Gibraltar
Kazakhstan
Kyrgyzstan
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

Anguilla
Antigua and Barbuda
Aruba
Bahamas
Barbados
Belize
Bermuda
British Virgin Islands
Cayman Islands
Colombia
Costa Rica
Cuba
Dominica
Dominican Republic
Ecuador
El Salvador
Falkland Islands (Malvinas)
French Guiana
Grenada
Guadeloupe
Guatemala
Guyana
Haiti
Honduras
Jamaica
Martinique
Mexico
Montserrat
Netherlands Antilles
Nicaragua
Panama
Puerto Rico
St. Kitts & Nevis
St. Lucia
St. Pierre et Miquelon
St. Vincent and the Grenadines
Suriname
Trinidad and Tobago
Turks and Caicos Islands
United States Virgin Islands
Venezuela, Bolivarian Republic of

Rest of South America

Argentina

Paraguay

Bolivia (Plurinational State of)
Brazil
Chile
Peru
Uruguay

Africa

North Africa/Eastern Mediterranean

Algeria
Egypt
Lebanon
Libya
Mediterranean, Other
Morocco
Syrian Arab Republic
Tunisia

West Africa

Angola
Benin
Cameroon
Congo
Côte d'Ivoire
Democratic Republic of Congo
Equatorial Guinea
Gabon
Ghana
Guinea
Guinea-Bissau
Liberia
Mali
Mauritania
Niger
Nigeria
Senegal
Sierra Leone
Togo

East/South Africa

Botswana
Burkina Faso
Burundi
Cape Verde
Central African Republic
Mayotte
Mozambique
Namibia
Réunion
Rwanda

Chad
Comoros
Djibouti
Ethiopia
Eritrea
Gambia
Kenya
Lesotho
Madagascar
Malawi
Mauritius
Sao Tome and Principe
Seychelles
Somalia
South Africa
Sudan
Swaziland
Uganda
United Republic of Tanzania
Western Sahara
Zambia
Zimbabwe

Europe

North Europe

Austria
Belgium
Denmark
Finland
Germany
Iceland
Ireland
Luxembourg
Netherlands
Norway
Sweden
Switzerland
United Kingdom

South Europe

Cyprus
France
Gibraltar
Greece
Italy
Malta
Portugal
Spain
Turkey

Eastern Europe

Albania
Bosnia and Herzegovina
Bulgaria
Croatia
Czech Republic
Hungary
Montenegro
Poland
Romania
Serbia
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
Republic of 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
Japan
New Zealand
Republic of Korea

Pacific High Growth – non-OECD Industrializing

Brunei Darussalam
China, Hong Kong SAR
China, Macao SAR
Indonesia
Malaysia
Philippines
Singapore
Thailand

China

Rest of Asia

Afghanistan
American Samoa
Bangladesh
Bhutan
Cambodia
Cook Islands
Fiji
French Polynesia
Guam
India
Democratic People's Republic of Korea
Kiribati
Lao People's Democratic Republic
Maldives
Micronesia, Federated States of
Mongolia
Myanmar
Nauru
Nepal
New Caledonia
Niue
Pakistan
Papua New Guinea
Samoa
Solomon Islands
Sri Lanka
Timor-Leste
Tonga
Vanuatu
Viet Nam

Annex D

Major data sources

Africa Oil & Gas Monitor

American Petroleum Institute

APICORP

Arab Oil & Gas

Baker Hughes

Bank of International Settlements

BP Statistical Review of World Energy

Canadian Association of Petroleum Producers

C1 Energy Limited

Canadian Energy Research Institute

Cedigaz

Centre for Global Energy Studies, Monthly Oil Report

Consensus forecasts

Direct Communications to the OPEC Secretariat

Det Norske Veritas, Technology Outlook 2020

The Economist

Economist Intelligence Unit online database

Energy Intelligence Group

Energy Policy Research Foundation, Inc

Energy Security Analysis, Inc

ENI, World Oil and Gas Review

EnSys Energy & Systems, Inc

European Commission

Eurostat

Financial Times

F. O. Licht

Goldman Sachs

Hart Energy

Hart Energy's International Fuel Quality Centre

Haver Analytics

IEA World Energy Outlook

IHS Cambridge Energy Research Associates

IHS Global Insight

IHS Herold

IHS Petroleum Economics and Policy Solutions

IMF, Direction of Trade Statistics

IMF, International Financial Statistics

IMF, World Economic Outlook

International Air Transport Association, Vision 2050 and Technology Roadmap

International Civil Aviation Organization

The Institute of Energy Economics, Japan

International Oil Daily

International Road Federation, World Road Statistics

Joint Organisations Data Initiative

Latin America Oil & Gas Monitor

Lloyd's Register EMEA

Middle East Economic Survey

National Oceanic & Atmospheric Administration, Monthly Climatic Data for the World

OECD Trade by Commodities

OECD/IEA, Energy Balances of non-OECD countries

OECD/IEA, Energy Balances of OECD countries

OECD/IEA, Energy Statistics of non-OECD countries

OECD/IEA, Energy Statistics of OECD countries

OECD/IEA, Quarterly Energy Prices & Taxes

OECD, International Trade by Commodities Statistics

OECD, National Accounts of OECD Countries

OECD Economic Outlook

Oil & Gas Journal

OPEC Annual Statistical Bulletin

OPEC Fund for International Development

OPEC Monthly Oil Market Report

Petroleum Economist

PFC Energy

Pike Research

Platts

Plunkett Research

PricewaterhouseCoopers

Purvin & Gertz, Global Petroleum Market Outlook

Ricardo Strategic Consulting

Society of Petroleum Engineers

Strategic Energy & Economic Research, Inc

Turner, Mason & Company

UN, Department of Economic and Social Affairs

UN, Energy Statistics

UN, International Trade Statistics Yearbook

UN, National Account Statistics

UN Statistical Yearbook

UN online database, http://unstats.un.org

US Commodity Futures Trading Commission

United States Geological Survey

US Energy Information Administration

World Bank, World Development Indicators

World Health Organization

Wood Mackenzie

World Nuclear Association

World Oil

World Resources Institute

World Trade Organization, International Trade Statistics

Organization of the Petroleum Exporting Countries
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A-1010 Vienna, Austria
www.opec.org
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