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MEDIUM-TERM Oil Market Report

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FOREWORD

To understand the dynamics and trends in the oil market, accurate, timely and comprehensive information is invaluable. The International Energy Agency (IEA) strives to improve, expand and provide the best data and analysis available. With this objective in mind, we are delighted to introduce the *Medium-Term Oil Market Report*, a new annual publication with interim updates that will look further into the future, beyond the *Oil Market Report*. We believe this additional focus will help to fill the gap that exists between our shorter-term analysis and the longer-term projections that appear in the *World Energy Outlook* and other IEA work.

The *Medium-Term Oil Market Report* provides a global overview of demand and supply trends through to 2011 based on the pressures that would develop under existing market forces and plans. We consider it a guide to the future assuming current trends persist. Any unforeseen shifts in the global economy, geopolitics, or other factors could of course produce different results.

One notable finding which emerges from our analysis shows that, based on investment committed to viable upstream projects during this period, effective surplus capacity should increase from recent razor-thin levels to a more comfortable level of 4-6 mb/d in 2011. Much of this increase comes from recently announced OPEC investments to expand crude and natural gas liquids. Preliminary analysis also suggests that product supplies should increase, reflecting increased refinery capacity and growth in biofuels. We welcome this result as good news since low spare capacity both upstream and downstream has contributed to tightness in the market.

We believe this projected build in spare capacity to be a positive development that should bring greater stability to the oil market. However, even by the tail-end of this forecast it is apparent that non-OPEC supply growth is well below the level of demand growth. With oil consumption projected to continue to increase to 2015 and beyond, continued investment will be critically needed to ensure reliable oil supplies. Furthermore, consumer governments should maintain efforts to improve energy efficiency since demand, left unchecked, will continue to grow at a rapid pace. The impact of such policies on global oil markets is assessed in the *Alternative Scenario* of the forthcoming *World Energy Outlook* 2006.

One important element that is not addressed in this medium-term report is crude quality, an issue that we have highlighted elsewhere as having significant implications for the availability and affordability of oil products. To give the topic the attention it requires, we will prepare further analysis that will be released as a supplement to the September *Oil Market Report*.

Claude Mandil
Executive Director

ACKNOWLEDGEMENTS

This *Medium-Term Oil Market Report* is the result of continuing work by the Oil Industry and Markets Division (OIMD) of the International Energy Agency (IEA) geared towards building models, databases and structures to analyse the medium-term oil market. The models have been designed to enable this work to be produced on a regular basis, both in a primary medium-term publication each summer and also to extend the regular impact analysis in the *Oil Market Report (OMR*) supplementary updates.

The work has been conducted under the direction of Kenji Kobayashi, Director of the Office of Oil Markets and Emergency Preparedness, with full and equal credit shared by every member of the analytical team, Toril Bosoni, Jeff Brown, Lawrence Eagles, David Fyfe, David Martin, James Ryder and Harry Tchilinguirian, ably assisted by Anne Mayne.

Rebecca Gaghen, Jim Murphy, Olivier Parada, Francois Iglesias, Angela Gazar, Corinne Hayworth, Loretta Ravera, Bertrand Sadin, Olivier Lavagne D'Ortigue and Sylvie Stephan provided essential support in the report's production and launch, with technical support from Danny La Belle, Einar Einarsson and David Bjorndahl.

Significant contributions and feedback were provided by IEA experts: Fatih Birol, Pierpaolo Cazzola, Ralph Sims, Nicola Pochettino, Laura Cozzi, Tom O'Gallagher, Ian Cronshaw, Helmer Horlings, Dan Simmons and the earlier work of Lew Fulton on biofuels.

The report benefited greatly from discussions with many external experts including: Dermot Gately (New York University) and Craig Parsons (Yokohama National University), Dr. Christoph Berg (F.O. Licht), Peter Reimers (Archer Daniel Midland), Ken Miller and Alfred Luaces (Purvin & Gertz Inc.).

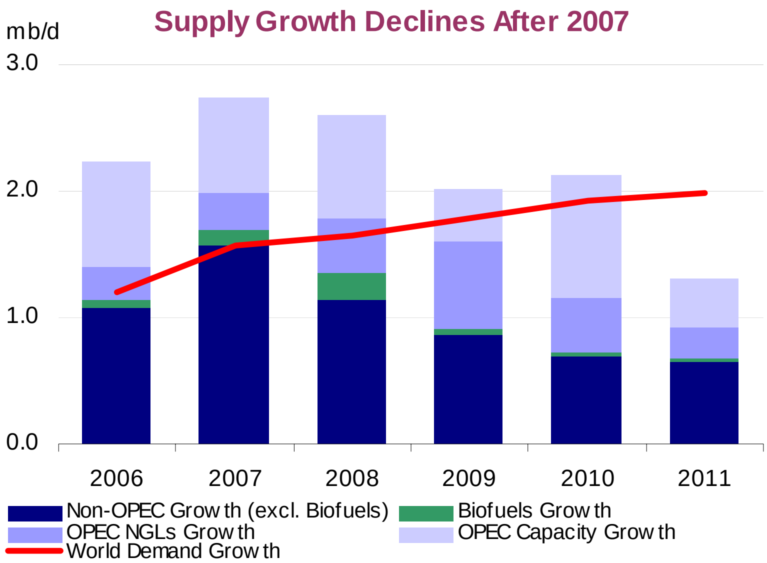
However, the responsibility for the content, data, graphs and tables contained within this report lie with the IEA.

EXECUTIVE SUMMARY

Overview

Seven years of rising prices are clearly having an effect on the oil market: upstream supplies are improving and substantive investment is helping to stem some oilfield decline while expanding the project base. Non-OPEC supplies will grow by an average 1.1 mb/d (2.0%) per year to lift supply to 56.7 mb/d in 2011 from 51.3 mb/d in 2006, including biofuels, with further gains coming from OPEC gas liquids and condensates. OPEC crude capacity is expected to rise by 3.3 mb/d over the same period to 36.3 mb/d.

There is little doubt that high prices are tempering global demand, which is forecast to come in below global supply capacity growth through to 2010. But beyond 2007, supply and demand growth trends are moving in opposite directions. By 2011 current price and income effects will have faded; non-OECD growth will be accelerating and global growth will marginally exceed supply-side expansions. World demand is projected to grow by 2.0% pa (1.8 mb/d) to reach 93.7 mb/d by 2011, fractionally above the 1.8% annual average seen over the past 10 years.



Taking these supply and demand shifts into account, OPEC's effective spare capacity is projected to rise from current levels of 2.0 mb/d to between 4.2 and 6.1 mb/d. While this is a more comfortable level than in the past two years, at 7% of global demand it represents a return to the ratio of spare capacity to demand seen earlier this decade, but still well below levels seen in the 1990s. Further, as the last five years have shown, OPEC spare capacity levels can change rapidly if demand surges. Without seeking to anticipate the geopolitical context, this level of spare capacity may not have a significant impact on prices – currently most OPEC spare capacity is quality constrained, and spare crude capacity has little effect on the spot market without the appropriate refinery capacity to process it.

On the refinery side, we expect to see refinery capacity increasing by 11.7 mb/d between 2006 and 2011, concentrated at the tail-end of the forecast period. With the addition of upgrading capacity, preliminary assessments show that gasoline and distillate supply capability should improve over the next few years. However, whether this results in lower transportation fuel differentials relative to crude is debatable: while surplus European gasoline is likely to continue to be of sufficient quality to meet US requirements, it is less clear if the increase in diesel production outside the Atlantic Basin will be of a suitable quality to meet tight sulphur requirements.

This refinery assessment also assumes that shifts in refinery capacity will be matched by appropriate crude quality - an assumption that is not readily verifiable but very important to the outcome. The issue of crude quality will be analysed in detail in further *Oil Market Report* analyses later this year.

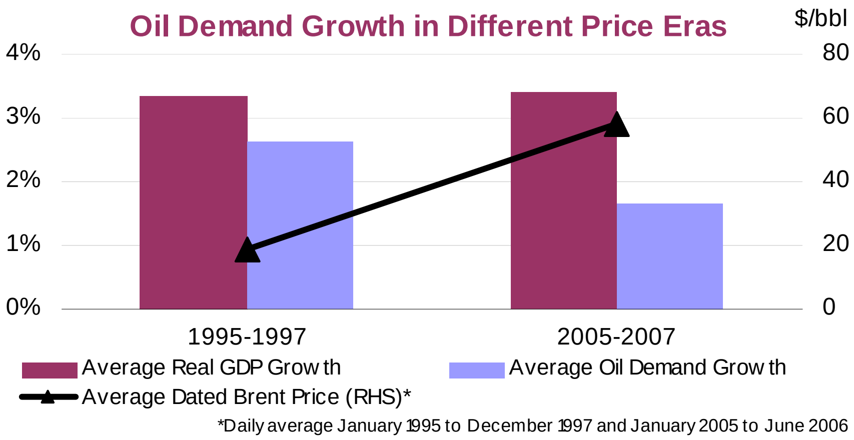
As with any forecast however there are areas of uncertainties. Tight commodity, labour and service sector markets increase the risk of upstream project slippage. Contracts and access terms are being tightened and there are no signs of an end to geopolitical issues. While we have taken a conservative view on new projects (and removed them completely where there are doubts about their viability), the risk of further slippage remains, particularly over the next two years. Economic forecasts (from the IMF, the OECD and other institutions) necessarily project less volatile outcomes than are the case in reality, and the timing of any general economic growth surge or decline will be important in determining the impact for the oil market five years forward. Problems or large price moves in other forms of energy supply (coal, gas, nuclear) can also bring unexpected demand-side fluctuations for oil.

The 2011 horizon should be seen therefore as a guide, rather than a pinpoint projection in the current market environment. It does not try to achieve a balance but, taking a price path determined by current spot prices, the forward futures curve and oil company investment thresholds, it seeks to identify the pressures that might evolve under this scenario.

The outcome of this exercise suggests that the forward prices are too high and that the clear trend towards an improved supply picture for crude and gasoline over the next five years should help moderate crude forward prices. But there are limiting factors - lower prices would spur more rapid demand growth and perhaps, eventually lower investment. Furthermore, by 2011 capacity growth is already seen slowing and demand will have strengthened, suggesting that any lull in price pressures would be temporary without continued investment and continued momentum to conserve energy.

Demand

Oil demand growth is expected to remain strong, expanding on average by 2.0% or 1.8 mb/d annually and rising to 93.7 mb/d in 2011 from 84.8 mb/d in 2006. The accelerated-consumption phase of populous countries such as China and India, together with the oil price-fuelled expansion in Middle East oil producing countries have pushed the medium-term oil demand growth above the average of 1.8% for the past 10 years. However, despite this structural strength, current and assumed higher prices have essentially lowered average growth by over 200 kb/d from those projected in the autumn of 2005.



OECD demand is expected to expand by 0.8% on average annually between 2006 and 2011. North America will account for about 85% of incremental oil demand growth, while OECD Europe and Asian oil demand will remain relatively stagnant. First quarter 2007 North American demand growth is inflated to 3.2% due to the extraordinarily mild weather in the first quarter of 2006. Non-OECD oil product demand will account for over three-quarters of global demand growth over the 2006-2011 period. By 2011, Asia's total oil demand (28.2 mb/d) is expected to surpass North America's (27.4 mb/d).

Transport fuel demand will continue to expand rapidly, with global demand for gasoline and diesel/gasoil growing by approximately 2.5% annually over 2006-2011.

In contrast, with the exception of specific areas such as marine bunkers, the global demand for residual fuel oil should remain stagnant. Overall, residual fuel oil demand is projected to grow by 1.4% in the non-OECD, but decline by 0.7% in the OECD.

Supply

The identified projects in both OPEC and non-OPEC countries due to come on-stream by 2011 appear sufficient to outpace demand-side growth. Non-OPEC oil supplies are seen growing by an average of 1.1 mb/d (2.0%) from 51.3 mb/d in 2006 to 56.7 mb/d in 2011, while OPEC NGLs are increasing by 2.1 mb/d over the period. However, it should be noted that much of the non-OPEC expansion takes place in 2006 and 2007, with 2011 output expanding by just 700 kb/d.

In volume terms, the largest increases in non-OPEC output between 2006 and 2011 will come from the FSU (2.4 mb/d), Latin America (1.3 mb/d), and Africa (1.4 mb/d), with decline seen in Europe. Investment from OPEC is expected to continue over the period, with crude capacity rising from 32.1 mb/d in 2005 to 36.3 mb/d in 2011.

Tight commodity, labour and service sector availability could impede timely development. There are also contractual risks as producing countries look to renegotiate access and revenue terms on new and existing contracts, and risks stemming from geopolitical tensions in key producing areas such as Iran, Iraq, Nigeria and Venezuela. Although high prices and modular development could bring some projects slightly forward, the downside risks to the supply side are considerably higher.

The global projections for non-OPEC supplies and OPEC capacity represent the supply *potential* under ideal conditions. This report has therefore reflected the implied level of spare capacity in three ranges, which show OPEC spare capacity rising from June 2006's effective level of 2 mb/d to a more comfortable level between 4.2 mb/d and 6.1 mb/d in 2011.

Global Balance Summary

	2006	2007	2008	2009	2010	2011
Global Demand	84.80	86.37	88.01	89.80	91.72	93.70
Non-OPEC Supply	51.31	53.01	54.36	55.28	56.00	56.68
OPEC NGLs, etc.	4.72	5.00	5.43	6.12	6.54	6.79
OPEC Capacity	32.97	33.73	34.55	34.95	35.93	36.31
Call on OPEC Crude + Stock Ch.	**28.77**	**28.35**	**28.22**	**28.40**	**29.17**	**30.24**
Adjusted Call on OPEC Crude + Stock Ch.[1]	**29.65**	**29.24**	**29.11**	**29.29**	**30.06**	**31.13**
Implied OPEC Spare Capacity[2]	4.20	5.37	6.33	6.55	6.76	6.07
Adjusted OPEC Spare Capacity[3]	3.32	4.48	5.44	5.66	5.87	5.18
Effective OPEC Spare Capacity[4]	2.32	3.48	4.44	4.66	4.87	4.18

1 Arithmetic 'Call on OPEC + Stock Ch.' adjusted to include 350 kb/d for non-OPEC underperformance and including the most recent 8-quarter average of Miscellaneous to balance (538 kb/d) from OMR.
2 OPEC Capacity minus 'Call on Opec + Stock Ch.'
3 OPEC Capacity minus 'Adjusted Call on OPEC Crude + Stock Ch.'
4 'Adjusted OPEC Spare Capacity' minus 1 mb/d allowance for non-usable capacity

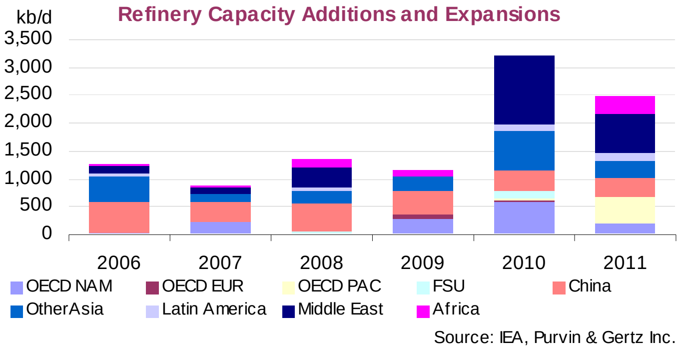
The first measure is the arithmetic implied level of spare capacity: the simple difference between OPEC capacity and the call on OPEC + stock change. A more realistic reflection is achieved by performing the same calculation but using the adjusted call which allows for the *miscellaneous to balance* (the difference between reported supply, demand and stock changes) and the standard average 300-400 kb/d allowance for non-OPEC slippage.

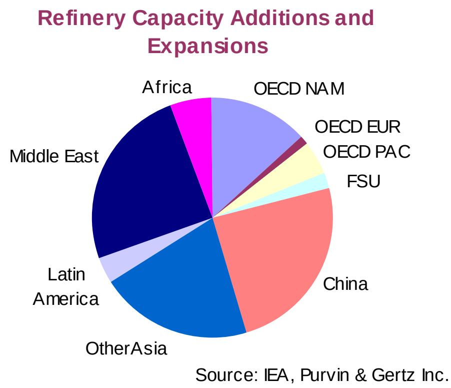
A further lower level is shown, reflecting an adjustment of 1 mb/d to reflect the difference between nominal OPEC spare capacity and effective spare capacity over the past year. While it is far from certain that there will continue to be a nominally unusable portion of OPEC capacity, carrying it forward provides a subjective buffer for other potential losses over the next five years.

However, in making these allowances, it also has to be recognised that while there are downside risks to the supply side, there are potentially counterbalancing risks. While the current domestic situations in Iraq and Venezuela have encouraged us to leave supply flat, both countries have the potential to rapidly add capacity. The IMF warns that GDP risks are to the downside, potentially lowering oil demand growth, We have restrained biofuels supply growth beyond 2008 due uncertain economics and the *miscellaneous to balance* adjustment assumes demand remains understated, when it could also represent unreported stock building. All these factors offer a potential counterbalance to any downside supply risks.

Refining

The mismatch between available crude quality, refinery configurations and product demand growth has been an important driving force behind recent high prices. The difficulty faced by the refinery sector to meet tightening product specifications and strong demand for transportation fuels have raised prices and dampened the impact of the remaining OPEC spare capacity. A bottom-up assessment of refinery projects shows refinery capacity growth keeping pace with global demand through to 2009 and rising sharply in the last two years of the survey. Overall, global crude distillation capacity is expected to increase by 11.7 mb/d during the 2006 to 2011 period, including capacity creep.





Gasoline supply potential is expected to outstrip demand in volume terms. However, tighter quality specifications may continue to keep gasoline prices at historically high levels relative to crude inputs. Diesel and jet/kerosene output potential, while seeing a lower increment than gasoline also appear (on balance) to improve, helped by the rise in biodiesel production. Fuel oil output looks likely to tighten, removing some of the current downside price pressures, with the additional mix of upgrading capacity suggesting a further shift towards heavier, sour crude demand.

Without looking at the crude quality issue, firm conclusions on product supply are difficult, but it would appear that the supply of gasoline and gasoil should improve.

Biofuels

A study of the projects that are either planned or underway show that ethanol and biodiesel have the potential to add close to 1 mb/d to global product supply. This should further loosen the gasoline balance. Biodiesel could also make a significant contribution to the pool of ultra-low-sulphur diesel (ULSD) in Europe. However, in our balances we have restrained biofuels growth beyond 2008 due to the uncertainties surrounding the complex interrelationships between petroleum, biofuels and agricultural economics, all of which make it difficult to assess their impact five years forward. However this still shows biofuels growing from 650 kb/d in 2005 to 1.2 mb/d in 2011.

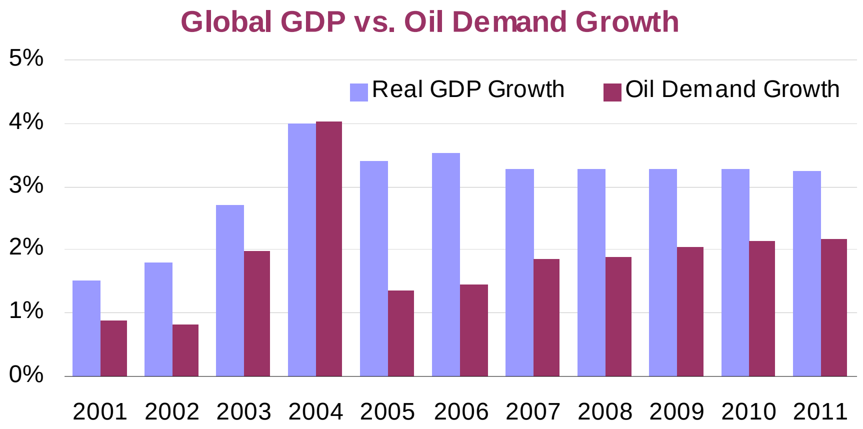
The speed with which biofuel projects are coming online contrasts with upstream economics, where current high prices are more likely to have an impact beyond 2011. Given the lower associated costs and lead times, and the competition for feedstocks from the (far more important) food sector, it would therefore be reasonable to assume that biofuels could also become a more price-sensitive source of supply. This would have implications for their development. Upstream construction with funding in place tends to be delivered in five years' time, refinery projects underway will be delivered in three to five years, whereas the low lead times on biofuels projects mean they could fall by the wayside as early as 2008 if the market ceases to be attractive.

In our balances we have therefore taken a conservative approach. In Brazil, where there are clear competitive advantages in terms of cost, efficiency, land and the impact on the food chain, we have assumed strong growth in ethanol production. In all other regions, we have assumed that the current capacity growth will have a significant impact through to 2008, but due to the economic uncertainties we have held output flat beyond that point.

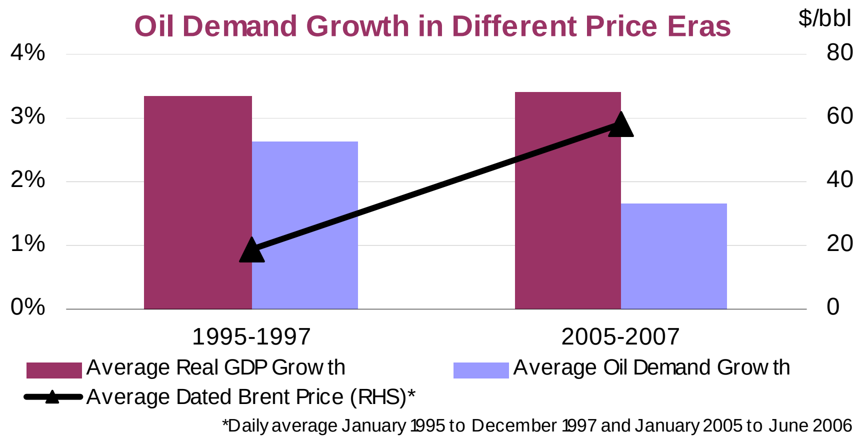
DEMAND

Summary

- **Global oil product demand growth** is projected to average 2.0% (1.8 mb/d) annually over the period 2006-2011. Demand will expand by some 8.9 mb/d, from 84.8 mb/d in 2006 to 93.7 mb/d in 2011. By 2011, Asia's total oil demand (28.2 mb/d) is expected to surpass that of North America (27.4 mb/d). This forecast is dependent upon a continued robust global economic expansion, coupled with some easing of crude oil prices. Risks are biased to the downside, as economists have warned that increasing global economic imbalances could begin to weigh on the world economy.

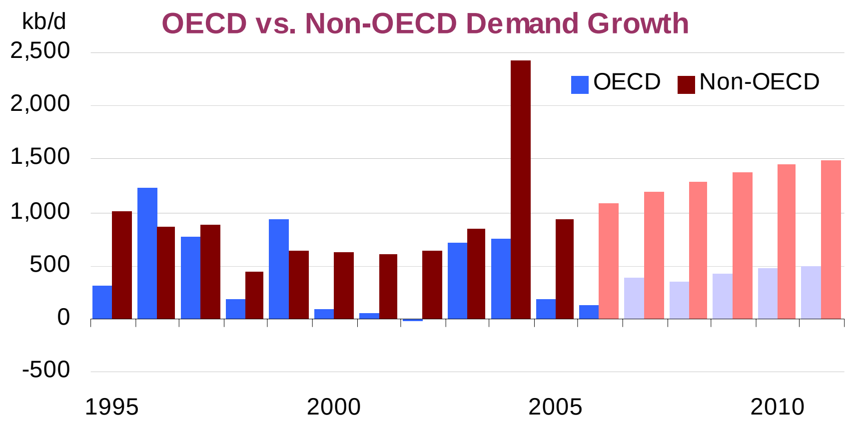


- **High oil prices** are certainly having an impact on oil product demand growth at the margin. This impact will be felt throughout the forecast period, as it takes time for users to adjust consumption patterns. Over 2005-2007 oil demand is expected to grow by 1.7% annually while the global economy expands by an inflation-adjusted 3.4% (at market exchange rates). By way of comparison, a decade ago the global economy also expanded by 3.4% (in 1995-1997), but global oil demand grew by a much stronger 2.6%. During the 1995-1997 period Brent crude averaged $19/bbl, almost $40/bbl below the January 2005-June 2006 average.

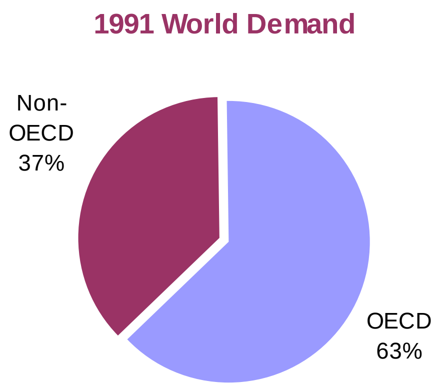


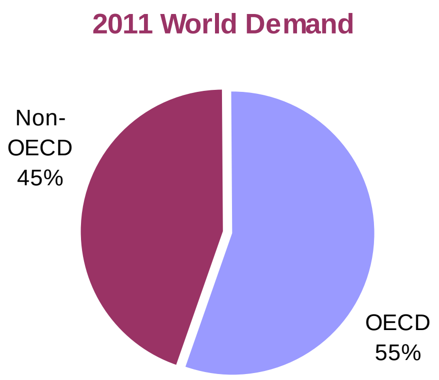
- **OECD demand** will expand by 0.8% on average annually between 2006-2011, with about 85% of incremental oil product growth coming from North America. Economic and demographic trends, as well as patterns of interfuel substitution, suggest that OECD Europe and Asian oil demand will remain relatively stagnant during the forecast period, increasing by only 0.3% and 0.2% respectively. In contrast, North American demand should increase by an average of 1.4%, led by Mexican growth of some 2.1% and US50 growth of 1.3%. North American 2007 demand growth will be boosted by the fact that temperatures were extraordinarily mild in the first quarter of 2006. Viewed against this low baseline, North American oil product demand is expected to grow by 3.2% year-on-year in the first quarter of 2007.

- **Non-OECD oil product demand** will expand by 3.6% on average between 2006 and 2011. Non-OECD demand comprises 41% of the global total in 2006, but it will account for over three-quarters of global demand growth during 2006-2011. Recent increases to administered retail prices in key consuming countries such as Thailand and Indonesia will slow Asian growth in the near term, but more robust growth should return as the region's economies continue their rapid expansion.



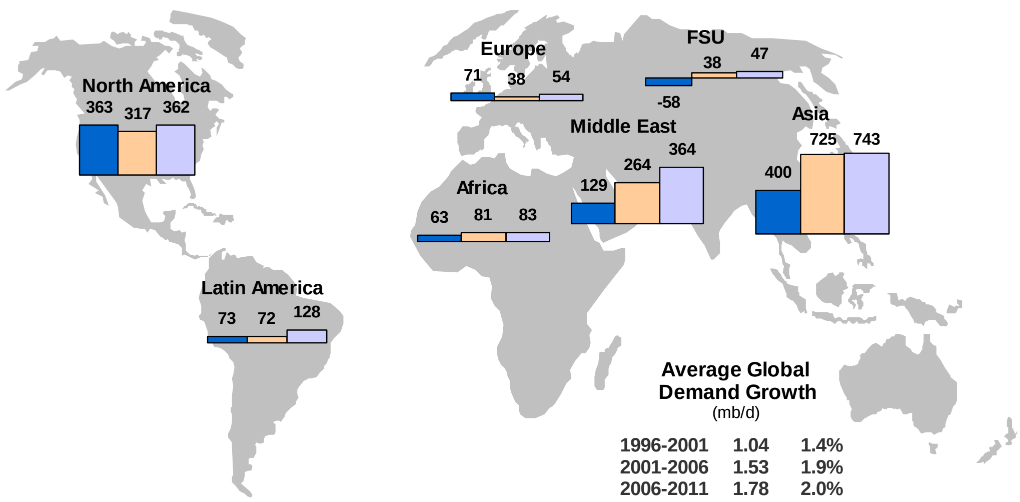
Transport fuel demand will continue to expand rapidly, with global demand for gasoline and diesel/gasoil growing by approximately 2.5% over 2006-2011. In contrast, with the exception of specific areas such as marine bunkers, the global demand for residual fuel oil should remain stagnant. Overall, residual fuel oil demand is projected to grow by 1.4% in the non-OECD countries, but decline by 0.7% in the OECD.





- **The Middle East and China** will account for close to 45% of global oil product demand growth during 2006-2011. Demand for transport fuels is projected to grow by approximately 6% in these areas as their rapid economic expansion continues. Low administered retail prices for oil products and demographics (an extraordinarily young population) help underpin Middle Eastern demand growth. China's fuel oil demand is expected to stabilise by 2008 as the power sector comes back into balance in 2007. Oil demand in power generation spiked in 2004 due to power shortages, and has generally been in decline since then.

Average Global Demand Growth 1996-2001/2001-2006/2006-2011
thousand barrels per day



Methodology

Note that a detailed analysis of the recent trends in income, price and interfuel cross-price elasticities of oil demand will be included in a special chapter in the 2006 edition of the *World Energy Outlook*, to be published this autumn.

The methodology underlying the medium-term oil demand projections is broadly similar to the short-term analysis that serves as the basis for the *OMR*. In both cases an underlying demand trend is derived based on expectations of economic growth and oil prices. Numerous factors can lead to short-term deviations from the underlying trend, especially weather-related disruptions such as unusually warm/cold weather, abnormal rainfall, natural disasters, etc.

For the medium-term analysis weather patterns are assumed to be normal so the impact is minimal, but other deviations from the underlying trend can extend further into the future. Examples include interfuel substitution due to changes in the relative price of fuels and sharp changes to administered prices in countries where prices are government controlled. Note that oil is typically a relatively costly fuel for use in areas such as power generation, but it is often turned to as a stopgap option if power demand surges unexpectedly or if other fuels are temporarily unavailable—as was the case in Japan in 2002-2003, China in 2004 and Italy this year. Once infrastructure adjusts and other less-costly fuels are put to use, demand for oil may recede.

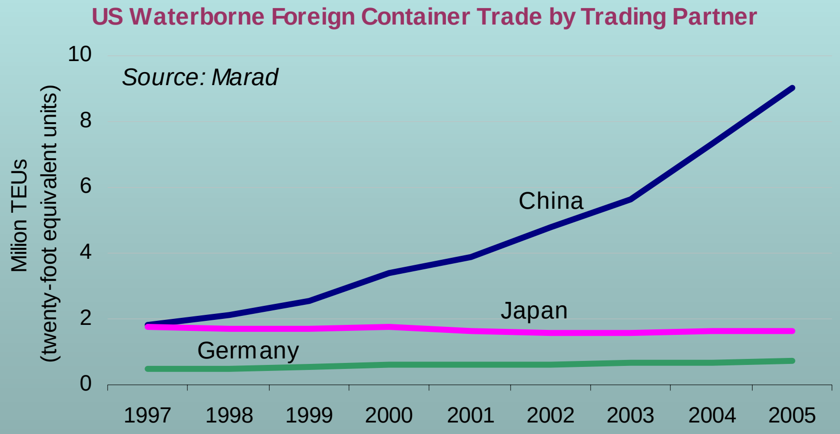
It is should be emphasised that while the forecasting framework incorporates both economic growth and changes to the price of crude oil, research consistently shows that economic growth is the leading determinant of oil demand growth. Most economists are projecting relatively strong economic growth for the foreseeable future, especially in non-OECD areas. However, it is notoriously difficult to project economic cycles and, given past history, it is unlikely that global economic growth will follow a smooth path. Both the IMF and the OECD have warned that there is an increasing risk of a substantial downside to their current economic outlooks. High oil prices, an overheated housing market and growing imbalances, including budget and trade deficits in key consuming economies, are all cause for concern. Giving due consideration to these caveats, the likely bias for the oil demand forecast lies to the downside.

In contrast to economic growth, the evidence linking the impact of crude oil prices to oil product demand is more uncertain, partly because the link between changes in the crude price and the retail price of products is sometimes tenuous. For many OECD countries, including most of Europe, Japan and Korea, unit taxes comprise a very large portion of the final retail price, especially for road transport fuels. In the eyes of the consumer this lessens the impact of a change in the price of crude and thus the price response is possibly muted. Taken together, these relatively high-tax OECD countries account for over one-quarter of world oil demand.

Globalisation and Oil Demand

Manufacturers have long been shifting labour-intensive production overseas to take advantage of comparatively low labour costs. In recent years there is evidence that this movement may have accelerated with the emergence of China as a low-cost manufacturing base that is friendly to foreign direct investment. Manufacturers have signalled a growing willingness to tolerate higher use of energy to transport raw materials and finished products longer distances to take advantage of China's relatively low-cost labour pool.

Although it is difficult to isolate the impact of growing trade on oil consumption, certain indicators suggest that it has been substantial. Global merchandise trade grew by 9% year-on-year in 2004, close to double 2003 growth. At the same time, global oil demand growth surged by 4.0%. Chinese demand for marine bunkers increased by over 50% in 2004, which corresponded with a very rapid rise in container traffic from key ports in China. Similarly, traffic in US West Coast ports, which are an important entry point for Chinese exports, has boomed. The US Trucking Tonnage Index also took off, increasing by 5.7% in 2004—thereby contributing to a rapid rise in diesel demand. Oil used in the transport of energy is also increasing as the world's oil and gas resources are found further from the point of consumption.



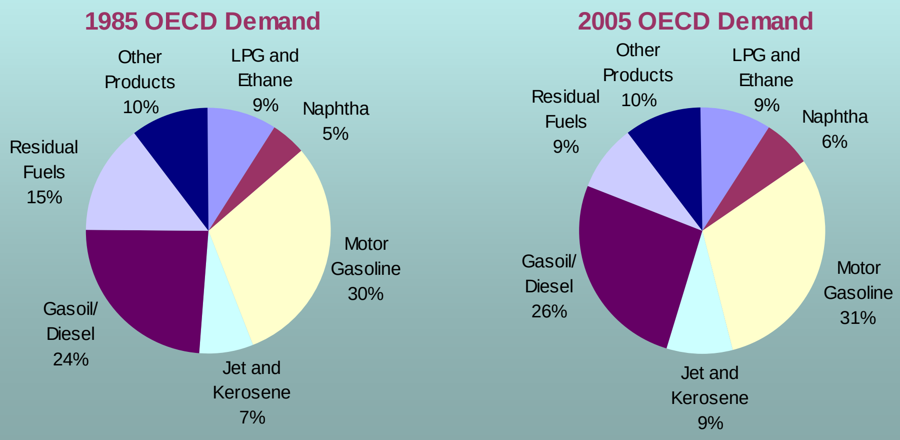
Most economic analysts expect that the growth in Chinese merchandise exports, which was approximately 35% in 2004, will inevitably slow as the boom in foreign direct investment tapers off. This will lead to a corresponding slowdown in trade-related oil demand growth. Note that this does not mean that China's trade-related oil demand will not post robust increases in absolute terms − it will. It is just that the rate of growth in trade-related oil demand will possibly slow to a more sustainable rate.

Moreover, in many non-OECD countries retail prices are subsidised and administered by the government at fixed levels, so consumers are largely insulated from changes in the price of crude. The Middle East is an obvious example, with administered retail prices that are among the lowest in the world, but China and India have also sought to minimise increases to administered product prices as international market prices have risen. These economies account for just under 20% of global oil demand, and there are certainly other smaller non-OECD consumers that would fit into this category. In sum, well over half of global demand is from countries where domestic retail price movements are to some extent detached from crude price movements in the international market.

Complicating matters further, the affect of crude price changes is not symmetric, i.e., the negative impact of a crude price increase on demand has been shown to be larger than the positive impact of a price decrease of similar magnitude. In addition, extraordinarily high crude and product prices may reduce demand by a disproportionably large amount, as evidenced in the immediate aftermath of hurricanes Katrina and Rita. Ideally, the price of individual products would be tracked directly, but unfortunately such price series are often incomplete or non-existent for many countries, so crude price is used as an imperfect proxy variable.

The Changing Price Sensitivity of Global Oil Product Demand

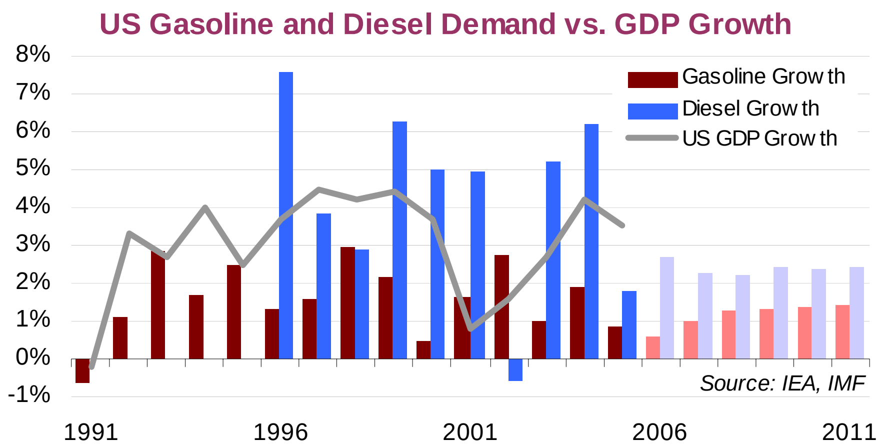
While it is challenging to dissect the exact impact of oil price changes on demand, it is certain that the price elasticity of global oil demand is changing slowly over time due to the shifting composition of oil product consumption. There is a clear movement towards growth in transport fuels (especially diesel and jet fuel), for which there are limited substitutes, and away from oil use in industry and power (fuel oil and gasoil). Thus the scope for interfuel substitution with movement in oil prices is reduced and, on the whole, global oil product demand is less price sensitive.



OECD

North America

North American demand growth should average 1.4% annually over 2006-2011, accounting for some 85% of OECD oil product demand growth during the forecast period. US50 and Mexican demand will lead the way, growing by 1.3% and 2.1% respectively, while Canada is projected to lag at 1.1%. It must be emphasised that this fairly robust demand outlook is dependent upon relatively strong economic growth of over 3% in both the US50 and Mexico, which will continue to encourage consumption in the face of high prices. While most economists are projecting that the region's economies will remain strong, there are concerns related to higher interest rates and an accompanying slowdown in the US housing market which could have a knock-on effect on other sectors.

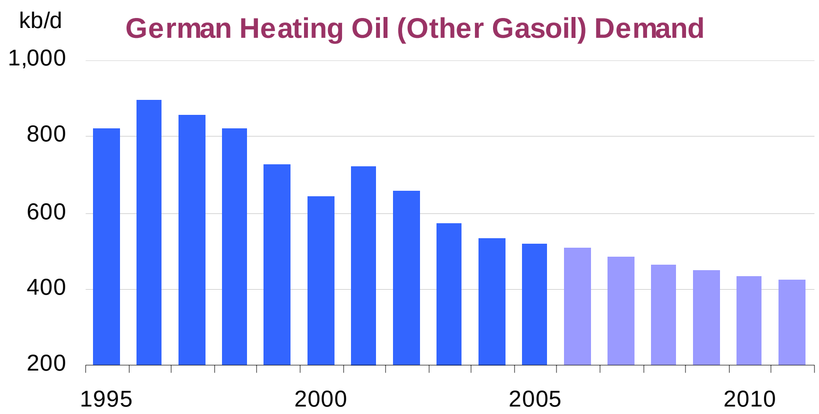


Among individual products, US50 gasoline demand should grow by 1.0% year-on-year in 2007, accelerating slightly to 1.4% by 2011 as prices ease. Mexican gasoline demand growth will average about 3% over 2006-2011, in part because consumers are largely insulated from increases in international market prices. While there is evidence that high fuel prices are shifting the transport of manufactured goods to more efficient rail rather than trucking at the margin, US50 diesel demand should expand by some 2.3-2.4% annually during the forecast period. This is well below the growth typically witnessed over 1996-2004 and more in-line with the easing of diesel demand growth seen in 2006, partly as a result of high prices.

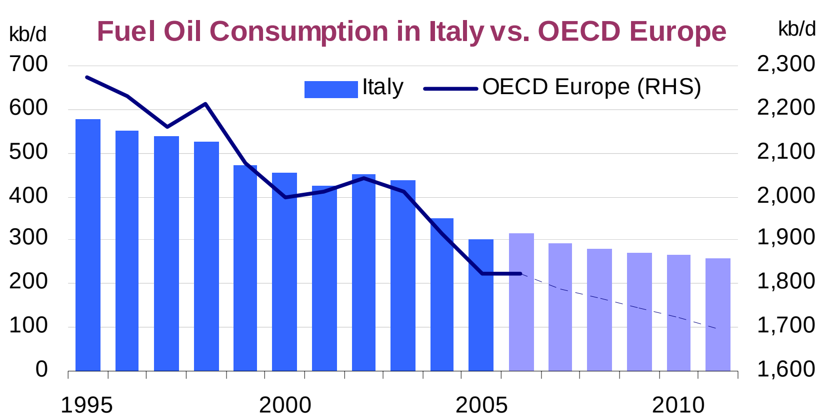
In the first quarter of 2007 North American demand is expected to grow by 3.2% year-on-year. This is in large part due to a weak 2006 baseline, as temperatures were exceedingly mild in the first quarter of this year. Heating oil and fuel oil demand should increase by 3.5% and 7.7% respectively year-on-year in the first quarter. LPG/ethane demand is also expected to increase by 6.6% over the same period. Not all of the increase in LPG/ethane demand is temperature related; the first quarter of 2006 saw some decline due to hurricane-related outages of both natural gas liquids and petrochemical production. It should be noted that the strong first quarter of 2007 somewhat distorts the medium-term demand picture, in that North American demand growth increases to 1.5% year-on-year in 2007 and then falls back to 1.3% in 2008. Without the temperature-related rebound from a low 2006 baseline, 2007 demand growth would be more in line with 2008.

Europe

Despite the fact that Europe's major economies are expected to strengthen relative to recent years, OECD Europe's oil product demand is projected to grow by only 0.3% (40 kb/d) on average annually over 2006-2011. Demand will decline in key consuming countries, such as Germany and Italy, in part due to interfuel substitution of other fuels for oil products. This will be balanced to a certain extent by more rapid oil product demand growth among the region's less mature economies, such as the Czech Republic.

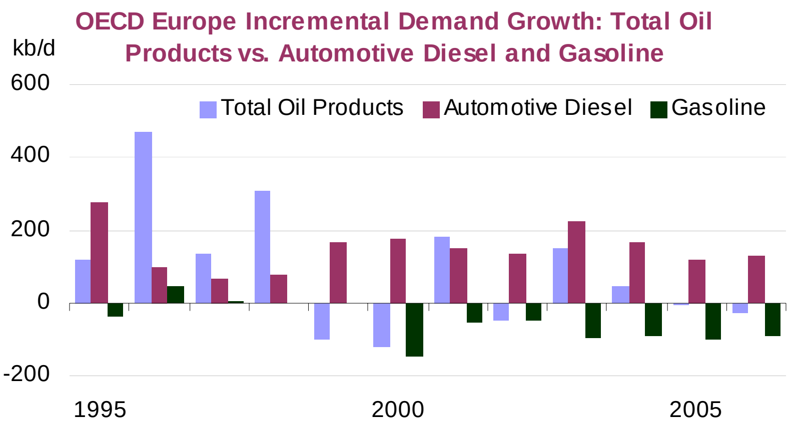


Natural gas will continue to make inroads in some countries, in many cases replacing petroleum products—although disruptions to Russian natural gas supplies in the winter of 2005/2006 have certainly given some European countries cause for concern. For example, Italy had long been a major consumer of fuel oil (approximately 30% of total oil consumption in 1995), but since the mid-1990s it has steadily reduced its consumption of fuel oil and has moved in the direction of relatively clean natural

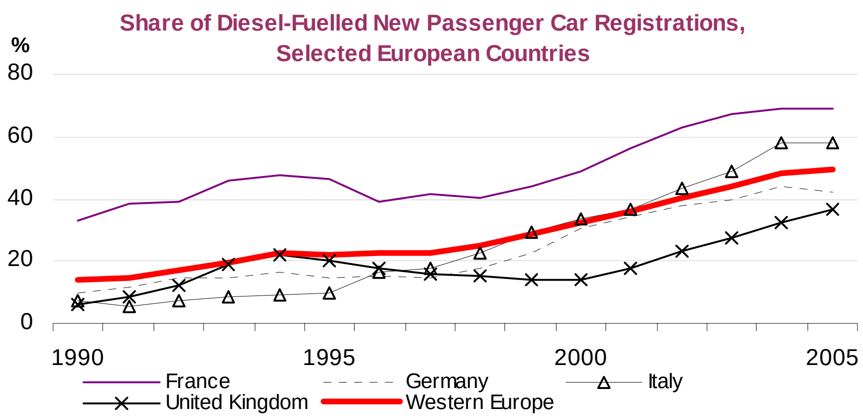


gas. This changed in the first quarter of 2006, largely due extraordinarily cold temperatures and a disruption to Russian natural gas supplies. Italy's electric utilities were forced to rely on natural gas inventories and fuel oil to fill the gap. Although Italy's fuel oil consumption could spike once again if gas supplies tighten, this event lies outside the clear downward trend. Turkey also stands out as a country where natural gas has made substantial inroads. Substitution of oil by natural gas should continue as Turkey has made commitments to take additional natural gas supply.

Although the overall growth in demand for oil products in OECD Europe has been relatively stagnant, the composition of demand has experienced a marked shift. A key change that is well documented is the rapid rise in diesel demand and the corresponding decline in gasoline consumption. A number of factors have driven the move towards diesel, including lower taxes and superior fuel efficiency versus gasoline. The performance of diesel engines has also improved, helping to encourage the purchase of diesel-fuelled passenger vehicles. Although government pricing policy played an important role in the early move to diesel fuel, the transition gained momentum as the use of diesel became more commonplace.



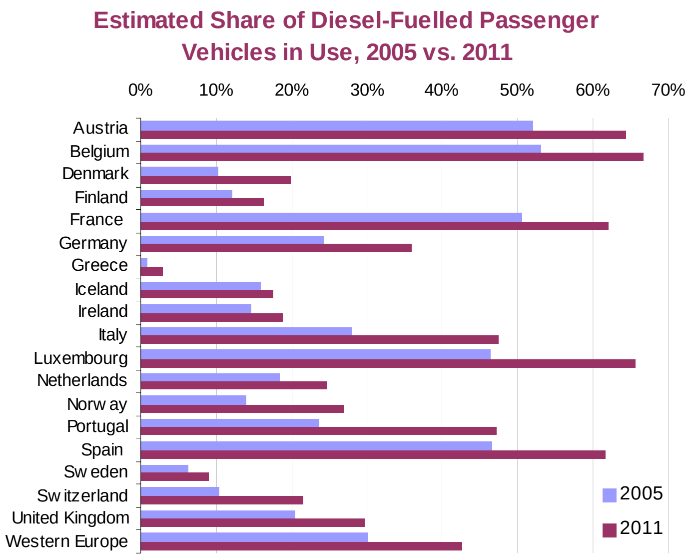
The rapid increase in diesel-fuelled new passenger car registrations is striking, with a combination of new car sales and vehicle retirements accelerating the rise in diesel consumption. Assuming a vehicle life of approximately 15 years, Western Europe is retiring a group of vehicles that is approximately 85% gasoline fuelled and replacing it with new cars, approximately 50% of which are diesel powered. This trend is extraordinarily pronounced in some countries, such as Italy. In 1990 only 7% of Italy's new vehicle sales were diesel powered. By 2005 this share had risen to almost 60%. In Austria, Belgium, France and Spain the share of new diesel-fuelled passenger vehicles has risen to about 70%.



Even if the share of diesel car sales begins to plateau—as it did in 2005, rising by only 1% compared to about 4% annually over 1998-2004, the replacement of older gasoline vehicles will mean a growing share of diesel in transport fuels. This is true under a relatively wide range of assumptions regarding new car sales. In 2011 the share of diesel powered vehicles in Western Europe's passenger vehicle fleet is projected to rise to approximately 43%, versus only 30% in 2005.

It is possible that a tightening of the regional diesel market and corresponding gasoline surplus will contribute to a rise in the average wholesale price of diesel relative to gasoline. This could in turn reduce the retail price advantage that diesel has in most European markets. However, there is evidence that once diesel makes inroads into a market it can continue to supplant gasoline even if the price differential is minimised. For example, in the UK regular gasoline and diesel retail prices are roughly equal, but the efficiency advantages of diesel in a relatively high-priced oil product market have spurred sales of diesel-fuelled passenger vehicles.

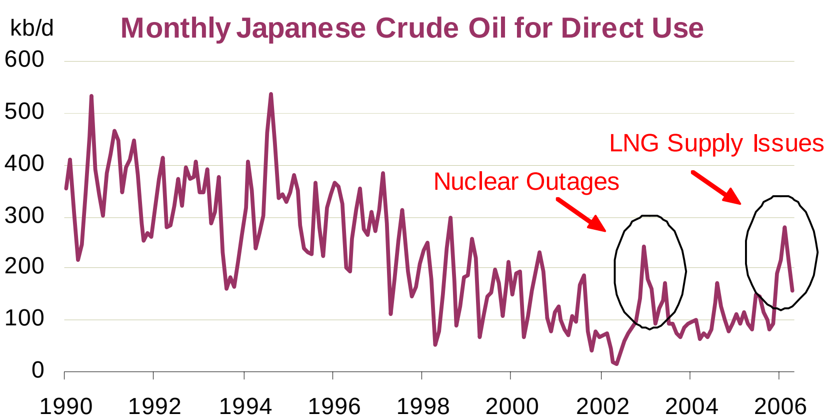
In short, Europe's move towards diesel has gained substantial momentum. Looking to 2006-2011, diesel demand is projected to increase by some 600-700 kb/d while gasoline demand is expected to decline by 300-400 kb/d. There is no escaping the fact that this transition will have a major impact on Atlantic Basin product trade, as well as on decision-making related to refinery upgrades and the crude import slate.



Pacific

OECD Asian demand growth should average only 0.2% (20 kb/d) annually over 2006-2011. Korea, Australia and New Zealand will post growth in the range of 1-2%. However, Japanese demand (which accounts for over 62% of the region's consumption in 2006) will decline by some 0.4% annually. This, despite the fact that the Japanese economy appears to be emerging from its long malaise and is expected to grow by 1.5-2.0% through to 2011.

Japan is seeing a continued shift toward smaller, more efficient vehicles, which is limiting growth in the demand for transport fuels. Mini-vehicle sales (under 660cc), which account for about one-third of the market, grew by 1.7% in 2005, while sales of larger vehicles shrank by 0.9%. This trend is expected to continue as mini-vehicles are especially popular among female drivers, which comprise an expanding share of the market. Gasoline demand should grow by less than 0.5% annually over the forecast period.



Japan's use of oil in power generation has been subject to wide variation in recent years, playing a role as a substitute fuel when generation by other means, including nuclear and liquefied natural gas (LNG), fell below expectations. Overall, the demand for residual fuel oil spiked upwards 16.1% year-on-year in 2003 coinciding with nuclear outages. In the first quarter of 2006 demand for 'other' products, which includes crude oil used for direct burning in power generation, grew by 28.7% as deliveries of LNG proved to be lower than expected.

Although there is always the possibility that demand could spike again, Japanese demand for oil in the power sector will likely resume its pattern of decline. Including all sectors, demand for residual fuel oil is projected to decrease by 1-2% annually through 2011. Demand for 'other' products, including direct crude use, should decline by 3-5% in 2007-2009 following an increase of 9.6% in 2006. While Indonesia's LNG supply problems are expected to persist, shifts to other fuels and alternative LNG suppliers may reduce utilities' demand for direct crude burning in the medium term.

The Korean economy has bounced back from a period of comparatively slow growth in 2004 and appears poised to expand by some 4-5% annually over 2006-2011. However, Korea's oil demand growth will not keep pace, growing by 1.3% during the forecast period. Korean oil consumption is heavily weighted towards industry, which is feeling the effect of high prices and is also relatively open to interfuel substitution. At the same time, Korea's transport sector is fairly mature, rendering the prospects for rapid growth unlikely.

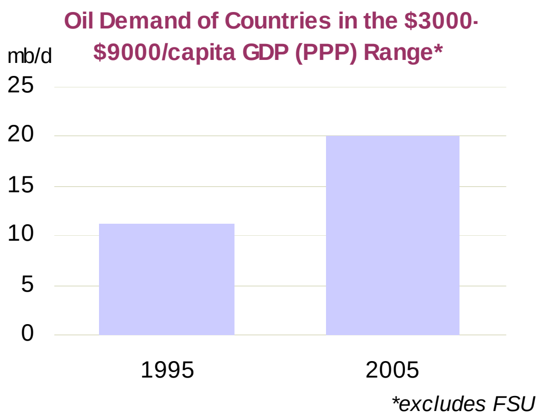
Non-OECD

The Role of Non-OECD Demand

Perhaps the most important consideration in evaluating the medium-term demand projections is the rising importance of non-OECD areas. Due to a combination of rapid economic growth and swiftly expanding manufacturing and transport sectors, non-OECD countries are quickly assuming a large share of oil consumption and are thus expected to dominate future changes in global oil demand. It is critical to understand why this growth is taking place and the key risk factors that could lead to deviations from the baseline demand projection.

As previously highlighted, economic growth is by far the most important driver of oil demand. Because the link between oil consumption and economic output is close, it is not surprising that booming economies in areas such as developing Asia have posted strong oil demand growth. If, as projected by most economists, underlying economic trends remain strong in these areas, incremental oil demand growth should remain robust.

Structural changes to key developing economies may also point to a period of relatively strong oil demand growth. A variety of research suggests that the income elasticity of oil demand changes at different levels of prosperity. When developing economies reach a stage of growth where a manufacturing sector emerges and purchases of automobiles take off, the income elasticity tends to increase. As the economy matures and growth in the service sector predominates, growth in oil demand begins to taper off—the income elasticity is lower. Of course, there is not a clearly defined line where this change in elasticity takes place. Some believe that the take-off stage could be around $3,000/capita using a purchasing power parity (PPP) measure of GDP. Further, growth is sometimes thought to taper off in the region of $9,000/capita.



In this context, it is important to note that in recent years, several major non-OECD consuming nations, including China, have passed the $3,000/capita threshold. In 1994, countries in the $3,000-$9,000/capita income bracket consumed only 11.3 mb/d, accounting for about 16% of global demand. By 2004 countries in this income group consumed 20.1 mb/d, accounting for 24% of global demand. Having a larger proportion of oil demand fall in this potentially high growth category may help spur global oil demand growth.

Quite simply, the rapidly expanding volume of non-OECD consumption implies an increasingly important role in incremental global oil demand growth. For example, in 2004 non-OECD demand grew by a robust 7.9%, or 2.43 mb/d, to 33.14 mb/d. By contrast, if non-OECD demand had grown by 7.9% in 1994 (from a 1993 level of 24.4 mb/d) oil demand would have increased by only 1.93 mb/d, 500 kb/d less than in 2004. Clearly, the growing absolute size and importance of non-OECD demand is affecting how we view global demand growth over the next five years.

While the prospects for non-OECD growth affecting future oil demand are large, there exist some important caveats, notably oil price and the growing use of natural gas. A continuing shift towards transport fuels, where demand is typically less price-sensitive than in other uses, has lent support to demand in the face of high prices. Although prices are expected to recede somewhat in the medium term, a further rise in oil prices—or even maintaining prices at current levels—may continue to erode medium-term demand growth in developing areas.

Here, retail prices are important. The rise in oil prices since 2003 has pushed some countries towards the liberalisation of retail prices. Initial attempts to limit the economic impact of increased costs for transportation and heating fuels led to burdensome increases in subsidies in many (particularly Asian) countries. Not only was the cost of the subsidies high, but consumers had no incentive to change usage patterns, leading to an unsustainable situation. The abandonment or reduction of subsidies was eventually forced upon several countries (including Indonesia and Thailand) by a growing fiscal burden, leading to clear evidence of a drop-off in demand growth.

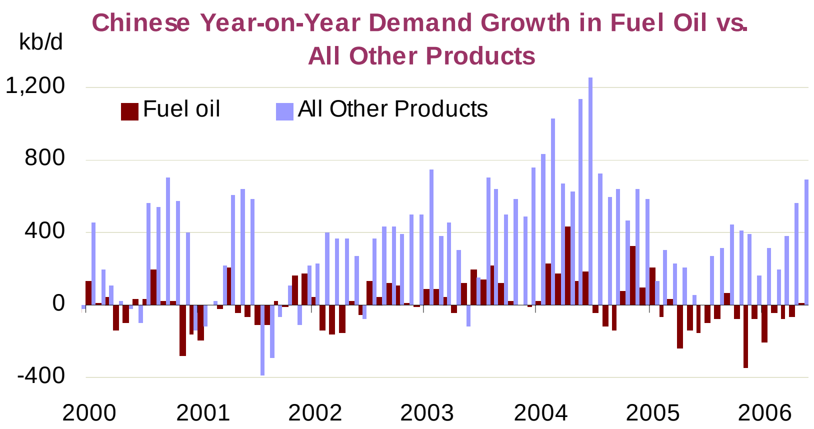
The growing importance of natural gas (both pipeline and liquefied) in non-OECD economies could also help temper the increase in oil demand in these countries. This has been witnessed in India in recent years, and China certainly has ambitious plans to increase natural gas use. However, a rise in international gas prices appears to have somewhat slowed plans for gas imports in these price-sensitive countries.

It is clear that both short- and medium-term forecasts of non-OECD oil demand growth will be affected by the degree to which price movements are passed on to consumers. Structural changes in the economy and the opportunity for interfuel substitution are further important variables to consider. But a combination of robust economic prospects, a shift from an agrarian to a manufacturing and consumer-led economy, and a higher absolute level of oil consumption point towards strong medium-term demand growth for countries outside the OECD.

China

China's energy needs have increased tremendously since its economy took-off following the SARS crisis in the first half of 2003, but the growth in demand for oil products has presented a mixed picture. To assess how Chinese oil demand will evolve over the medium-term forecast period, it is critical to examine recent patterns of growth on a product-by-product basis, as this yields important insights about future growth prospects.

In 2004, Chinese apparent oil demand grew by an astounding 15.8% (880 kb/d), accounting for well over one-quarter of global demand growth (3.18 mb/d). The key drivers of China's oil demand growth were: (1) a booming economy, which increased the demand for all products, and (2) power shortages that induced a dramatic rise in the use of gasoil and residual fuel oil in power generation. Overall, the



demand for residual fuel oil increased by some 14.9% (110 kb/d) in 2004 as the consumption of fuel oil by electrical utilities peaked, especially in the South. Likewise, the demand for gasoil grew by about 17.0% (290 kb/d) as there was surge in the purchase of small gasoil-powered generators used to protect businesses and others against blackouts/brownouts.

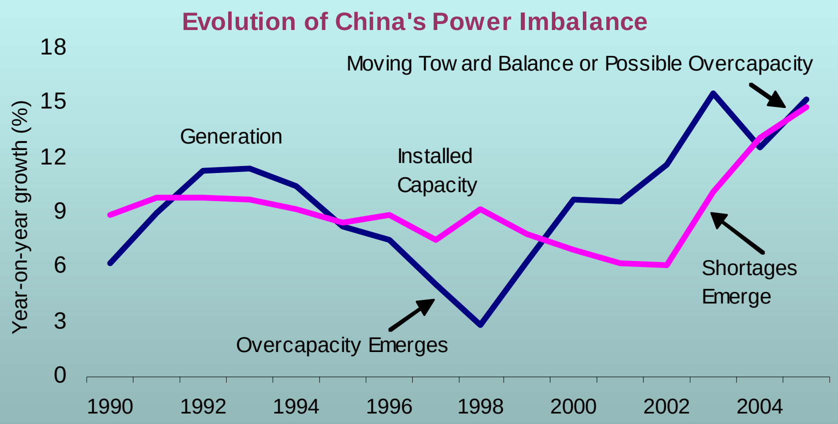
Although China's economic growth remained robust in 2005, oil product demand grew by only 2.6%. Gasoil demand growth was scaled back to 5.3% and fuel oil demand actually declined by 8.9%. The slowdown may in part be a reaction to a rise in the international market price of crude and products. However, the government maintained relatively low administered retail prices for key products, including gasoil, so consumers typically did not feel the full impact of the rise in international prices.

Certainly a key factor in the 2005 slowdown was the beginning of a return to balance of the power sector and a reduction in power shortages. Because drawing electricity from the power grid is much cheaper than using a small diesel generator, a reduction in power shortages induced less use of gasoil-powered generators and contributed to a corresponding decline in gasoil demand in power generation. Utilities also sharply reduced their use of fuel oil, turning to both coal and hydropower, especially in the South. Looking forward, the demand for fuel oil is expected to remain relatively stagnant throughout the forecast period.

In contrast to the demand for oil in power generation, the outlook for transport fuels and naphtha use in petrochemicals is much more robust. Economists project that the Chinese economy will expand by 8-9% and that vehicle sales, air travel, road transport, etc. will post correspondingly strong growth. As such, the demand for transport fuels should increase by 5-7% over 2006-2011. This is in spite of government efforts to encourage the sale of smaller vehicles by taxing larger ones at higher levels.

China's Demand for Oil in Power Generation Stabilises as Power Sector Returns to Balance

In 2006, power consumption is expected to grow by 11-12%. At the same time, State-approved power projects are set to boost capacity by some 70-75 GW, or approximately 14-15%. Peak demand needs remain an issue, but there is a clear trend towards mitigating the power shortages associated with rapid increases in power consumption. By 2007 the market is expected to return to balance, and in fact, the government's new concern is the looming prospect of a power surplus.



Given trends in the power sector, it is likely that the decline in the consumption of oil for power generation will continue through 2007, until the market is fully in balance. After that, the demand for oil in power should begin to stabilise. Of course, there will be some areas where fuel oil demand will continue to decline due to interfuel substitution, notably in South-eastern China as imports of liquefied natural gas accelerate. On the whole, fuel oil demand is projected to grow by about 1% year-on-year after 2007 with growth in some areas, such as marine bunkers, offsetting declines in others, such as power generation.

The prospect of future changes to the administered retail price of petroleum products is a continued source of uncertainty looking to the medium term. There is speculation that the government may move towards a more market-oriented pricing scheme. This would imply a price rise, as recent changes to administered prices have lagged relative to international price increases. This, in turn, could act to slow demand growth. Note, however, that if international prices were to decline in the near future, the impact on Chinese demand could be minimal, as the government might choose to maintain current retail price levels until they are more closely aligned with the international market (see *Other Non-OECD* for related discussion).

Other Non-OECD

Most major non-OECD consumers have some form of administered retail prices for oil products, and in many cases the retail price of key products is subsidised. While there is obviously not a strict rule, the retail price of fuels associated with the poor, such as kerosene, has typically been kept low thereby encouraging consumption. The administered retail price of other fuels, such as gasoline, is often higher. Recently, upward adjustments to administered product prices have typically lagged increases in international crude and product prices. Consequently, the burden of price subsidies reached intolerable levels for many countries, especially in Asia. Thailand reacted by moving to a market-based pricing system and Indonesia roughly tripled prices for key products. India, Malaysia and Vietnam, among others, have all reluctantly raised administered prices in the face of public opposition. Although the increases to administered prices have often not matched the surge in international prices, it has served to slow demand growth in the near term, especially in Thailand and Indonesia.

The fact that administered retail prices remain comparatively low (and the cost of subsidies high) in many countries has implications for the medium-term outlook. If, as expected, the international market price of crude and products does decline somewhat going forward, non-OECD countries may not adjust prices downwards in lock-step, taking the opportunity to help reduce product subsidies. In this case, a reduction in international prices would provide a less significant boost to demand in the non-OECD than might typically be expected, since consumers would often not see the price decline at the retail level.

Among other trends, due in large part to high oil prices, the use of petroleum alternatives including compressed natural gas (CNG) and biofuels has taken off in many non-OECD countries. CNG is growing primarily in areas where it enjoys government support, such as Argentina, India and Pakistan. Thailand's government hopes to convert half a million cars to CNG by the end of the decade and is aggressively pursuing biofuels. A 10% ethanol blend was recently introduced in Thailand with widespread distribution.

On the whole, **non-OECD Asia's** (excluding China) demand growth is expected to bounce back from unusually low growth of only 1.2% in 2006 as the impact of administered retail price increased subsides. Higher administered retail prices in key consuming countries will serve to temper demand growth at the margin, but in general they will be overwhelmed by robust economic growth. The expanding trade of goods both within and outside the region will also help support oil product demand. Over 2006-2011, non-OECD Asia is expected to account for about 17% of global demand growth. **Indonesia's** demand should rebound from a one-off year-on-year decline of some 8.5% in 2006, which was induced by a dramatic rise in administered retail prices in the fourth quarter of 2005. Booming trade will support demand for marine bunkers, boosting **Singapore's** demand prospects.

After a period of relatively robust increases from 2002 to early 2004, **India's** oil product demand growth has slowed since the second half of 2004. However, growth is projected to accelerate over the coming years as the substitution of alternative feedstocks for naphtha and fuel oil slows. Naphtha consumption will continue to fall in 2007 (-3.8%), but this pattern of decline is expected to taper off in 2008 as the substitution of natural gas for naphtha in fertiliser production slows and petrochemical use expands.

India's oil demand is expected to grow by 2.8% year-on-year in 2007, the same as 2006. In 2011, demand is forecast to grow by 4.0% if the economy maintains annual growth of 6-7%. The demand for road transport fuels, including gasoline and diesel, should expand by some 5.3% over 2006-2011, but the demand for fuel oil will remain stagnant.

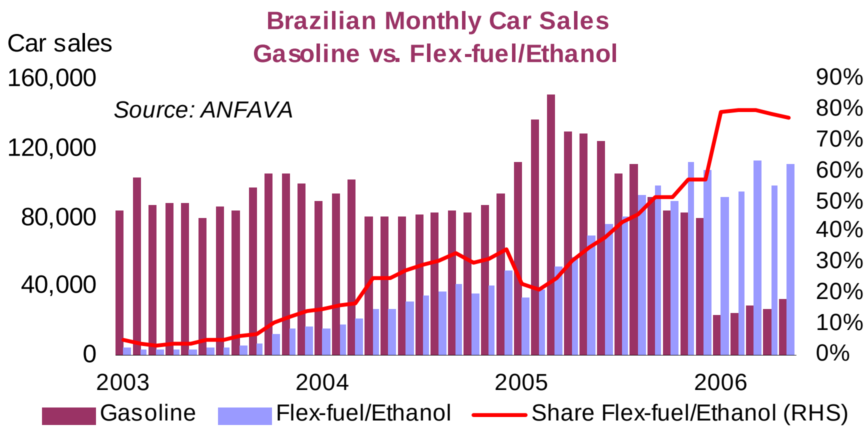
Although India and China are often lumped together in discussions of key consumers, it must be remembered that India's demand is much smaller at 2.7 mb/d versus China's 7.0 mb/d. India's economy is also less oriented towards energy-intensive manufacturing than is the case for China. India's impact on global oil demand growth will therefore be more limited over the forecast period. Moreover, there are still areas of inefficiency related to past industrial policy that could slow oil product demand growth in the near term as policies are rationalised.

For example, while LNG is currently a cheaper fertiliser feedstock than naphtha, some participants in the international market have questioned the long-term viability of importing LNG for fertiliser production at all. If the access to the domestic fertiliser market were not restricted, it would almost certainly be less costly to import fertiliser directly from other areas, including the Middle East. Why incur the expense of liquefying natural gas and transporting it when fertiliser can be produced closer to the feedstock source and transported inexpensively to the end user? The inauguration of the Oman India Fertiliser Company in January 2006 may signal that marginal production is likely to move overseas in the longer term, which would have an impact on natural gas and naphtha demand at the margin.

Given the region's surging economy and extraordinarily low oil product retail prices, it should not be surprising that the **Middle East** is projected to be among the global growth leaders over the forecast period. Demographic factors also lend underlying support to demand; the population is extraordinarily young, and thus the driving age population is expanding rapidly (see *OMR* dated 12 April 2006 for further discussion). A construction boom is helping to fuel growth in the near term, and while some analysts are predicting a slowdown in this sector, a prolonged period of high oil prices has swelled government coffers, which should help sustain oil demand growth. A number of countries in the region (e.g., Saudi Arabia) are also actively seeking to expand their energy-intensive industrial sectors. While this may not add to global growth as it largely shifts production from one region to another, it is likely to add to Middle East growth prospects.

Middle East demand is projected to grow by 5.3% in 2007, and should average over 5% throughout the forecast period. The region's major oil exporters will contribute the most to oil demand growth. **Qatar**, with its rapid expansion of natural gas projects and the associated economic boom, is expected to post oil demand growth of 6.8% over 2006-2011—the highest in the world.

Gasoline demand is forecast to expand by approximately 6% annually for the Middle East as a whole. **Iran** and **Saudi Arabia**, which are the region's major consumers, should see gasoline demand grow by 7-8% over 2006-2011. Iran is taking measures to restrain consumption growth, as rapidly expanding gasoline imports requirements are straining the government budget. In contrast, Saudi Arabia recently moved to reduce administered retail prices for petroleum prices, which should help sustain rapid growth.



Brazilian demand growth is forecast to average 2.8% annually over 2006-2011. In 2007 (2.4%), year-on-year growth should exceed 2006 (1.7%), and may accelerate slowly with solid economic performance and a gradual decline in oil prices. Given relatively high oil price projections, the popularity of flex-fuelled cars and favourable government policies, ethanol will likely continue to supplant gasoline at the margin over the forecast period. For some producers, the cost of production of ethanol is reported to have declined by 50% in the last 10 years. 'Other products,' which includes ethanol, is expected to grow by over 6% during the forecast period.

FSU apparent demand (crude production less net crude and product exports) is projected to grow by 1.2% yearly on average over the forecast period, which is lower than might be expected given the economic prospects of major consumers in the region. Some economists expect **Russia's economy** to grow by a robust 5-6% over 2006-2011. A primary driver behind the low growth in oil product demand is a gradual rationalisation of the hugely inefficient use that developed in the Soviet era. Energy prices, including oil product prices were typically kept very low, thereby encouraging inefficient use. Oil demand fell substantially following the disintegration of the Soviet Union and although the demand for transport fuels has recovered since, the move towards international price levels has tempered growth.

SUPPLY

Summary

- **Rising upstream activity** levels hold the potential to boost non-OPEC oil supplies markedly in the next five years, augmented by strong growth in OPEC gas liquids and biofuels capacity. Installed OPEC crude capacity also sees renewed growth after stagnating during 2001-2006, which saw declining availability from key producers. OPEC spare capacity should increase after over three years at sub-3 mb/d levels.

- Company upstream investment budgets look likely to have grown by in excess of 20% in both 2005 and 2006, and onshore and offshore drilling levels are attaining new peaks. At mid-2006 there is evidence of recovery from Russian and North American production facilities severely affected by political, economic and meteorological factors since mid-2004.

- Despite cost inflation, **prevailing crude prices remain well above marginal supply costs**, encouraging operators to accelerate new project completion where possible, and to revisit earlier by-passed high cost prospects. An influx of capital from importing country NOCs holds the potential to sustain supply growth in higher risk areas, despite potentially diluting incentives for host governments to improve the longer-term upstream investment environment. In the immediate short term, 2006-2008 sees the start-up of new non-OPEC facilities capable of producing over 9.0 mb/d in gross terms.

- Less promisingly, **higher prices are encouraging host governments to tighten access conditions and fiscal and regulatory terms for foreign operators**. A growing tide of resource nationalism is evident in parts of Latin America and the FSU, with signs that existing barriers to access may be rising. Geopolitical risks hang over a number of OPEC expansion projects. And spiralling, double-digit cost increases for raw materials, drilling, labour and service capacity reflect genuinely tight availability which may take two to three years to unravel. Project overruns are therefore a particular threat to forecast supply for 2006-2008, but the temptation to reduce projections arbitrarily is resisted in this report.

- Bottom-up projections of **non-OPEC supply** (including biofuels) for 2006-2011 show a potential increment (net of field decline) of 5.4 mb/d, with growth of 2.0% per year (versus 1.9% per year for 2001-2006). Rising supply is heavily skewed into the 2006-2008 period, with an average 1.4 mb/d of net additions annually. Increments slow to 700-900 kb/d annually thereafter. The shift in production towards non-OECD countries, away from maturing OECD provinces, continues. However, Canada remains a source of longer-term OECD growth. Non-OECD countries represent 60% of non-OPEC supply in 2011 versus 50% in 2001.

- Although less dependent on Russian supply growth, which drove early-decade increases, non-OPEC supply increments remain concentrated among a number of key producers. Together, Russia (+1.31 mb/d), Brazil (+1.22 mb/d), the Caspian Republics (+1.15 mb/d), Angola (+1.06 mb/d) and Canada (+0.74 mb/d) account for all of the expected growth. This clearly raises the potential for aggregate non-OPEC supply to be thrown off course if political, economic or technical issues impinge on supply growth in these few countries.

- **OPEC NGL, condensate and non-conventional oil supply**, unhindered by OPEC quota restrictions, is seen growing by 2.1 mb/d, with 7.5% annual growth for 2006-2011 being close to the rate evident in 2001-2006. Ongoing policies to boost natural gas utilisation and exports are being driven by domestic energy diversification and environmental imperatives. Qatar, Iran, Saudi Arabia and Nigeria each sees a 300-500 kb/d gain in gas liquids supply during 2006-2011.

- **Sustainable OPEC crude production capacity** could rise to 36.3 mb/d by 2011 from an average 2006 level of 33 mb/d. Resumed capacity growth overall follows a decline earlier this decade brought about by deteriorating conditions in Iraq and Venezuela. Underlying growth of 1.9% per year however stands close to the adjusted historical average if these two politically disrupted cases are excluded. Saudi Arabia leads the way with net capacity additions of 1.6 mb/d during 2006-2011. Algeria, Kuwait, Nigeria, Qatar and UAE also see net increases of 200-600 kb/d each based on firm investment projects. The forecast assumes no net growth from Iraq and Venezuela due to the exceptional political uncertainties inherent for the oil sector in both countries. OPEC capacity could be some 1-1.5 mb/d higher by 2011 if identified investment projects in these countries were to proceed.

Methodology

The approach used in generating these medium-term oil supply projections comprises:

- Estimates of possible future 'baseload' production from fields already producing, whether they are in build-up to plateau, at plateau or at decline stage;
- Additions to baseload production for such new production from firmly planned investment projects (new field developments, expansion and satellite field developments plus enhanced oil recovery) as is deemed likely to materialise for the forecast period;
- Potential extra production for the tail end of the forecast period (2009-2011), taking into account historical average exploration performance, trends in the reserve to production (R/P) ratio and the constraints of the ultimate resource base.

This final component is only added for those countries which would otherwise show an exaggerated rise in forecast R/P ratio compared to historical absolute and trend levels, and which therefore could support a higher production profile, despite an apparent lack of specific short-term development projects. Conversely, for some producers, an overly sharp resultant decline in R/P ratio is used to adjust down the expected production profile. A second criterion used to gauge whether additional production volumes are likely in the 2009-2011 period is the prevailing, and most likely future, investment environment. For example, extra volumes might not be included for a country, despite a sharp rise in R/P ratio during 2006-2011, if there are signs of access barriers which would impede future exploration and appraisal work.

Itemising known investment projects is one thing. Ascertaining which projects should be included for the five-year forecast is another. In general, engineering and construction tenders need to have been awarded and finance obtained before a project is deemed 'firm'. Clearly, projects already under construction or at the detailed engineering stage are included. Operating company guidance is used in the first instance to gauge possible project start-up and the pace of build to plateau production levels. However, judgement is applied to amend such details if uncertainties arise due to equipment delays, a lack of associated export infrastructure or other technical, economic or political factors. The projections tend towards a conservative view as to production start- and ramp-up for projects or regions deemed to be subject to particular risk.

Perhaps the most uncertain part of any supply forecast is the assumptions used for decline rates at mature fields. A top-down supply forecast would generate vastly different results depending upon whether a 5% or 10% level is employed. While the projections presented here are more disaggregated in nature, and thus tend to avoid a generic decline rate, discussions with oil companies suggest a representative global decline rate lying closer to 5% than to 10%. In reality, decline rates vary depending upon reservoir geology, type of production system employed, reservoir management practices and the application of enhanced recovery techniques. Oilfields will tend to enter a decline phase, other things being equal, when over 50% of reserves have been produced. However, there are many instances of fields showing multiple peaks or plateau with the application of supplementary recovery techniques, or in cases where improvements in exploration and appraisal technology supplement initial, overly conservative reserve estimates.

This report relies again upon company guidance, and on observations as to prevailing decline rates typical for a field, country or region from monthly historical production. Discussions with producers and service companies reinforce the known tendency for onshore decline rates to be shallower (0-10%, and frequently sub-5%) relative to offshore production (frequently 10%-plus). However, this in part reflects international oil companies' (IOCs) employment of a rapid recovery/rapid decline production programme to recoup capital outlays for capital-intensive deepwater projects. In contrast, onshore production in certain OPEC countries can show a flatter production profile, aimed at sustaining production longer and maximising recovery rates.

The Upstream Investment Environment Looking Ahead

Any supply forecast has to be based on a fairly static view of the future operating environment. By definition, the forecast assumes a continuation of the prevailing upstream investment environment and operating terms. Already announced changes and trends in access terms, regulatory regime and fiscal operating environment are accounted for. But this leaves the projections prone to adjustment for future years if unforeseen deregulation and enhanced access on the one hand, or nationalisation and punitive fiscal measures on the other, significantly shift the goal posts.

Future oil prices, cost structures and technological developments will also have an effect on production levels. However, technological and economic factors tend to have a more lagged impact on production than political and regulatory ones. Typical upstream project lead times lie between three to seven years from project conception to first oil. The portfolio of new project completions possible by 2011 is therefore well established. Upstream supply is relatively price inelastic, at least for periods of up to three years ahead. The one exception may prove to be project delays brought about by shortages of raw materials, drilling and services capacity and qualified labour which are themselves reflected in a higher cost base. Industry sources have for some time cited this as a key short- to medium-term impediment to supply growth. This is discussed in more detail below, but we conclude that it is not helpful to apply an additional, arbitrary adjustment factor, over and above known or possible project delays, in the forecast.

This aspect aside, economic considerations may have less of an impact on ultimate 2011 supply than corporate, political and regulatory factors do. However, they will set in train changes in industry activity during 2006-2011 that will clearly influence longer-term production levels.

Price Assumptions Rising

While the demand projections in this report are based on the prevailing futures curve (average real IEA import price for 2006-2011 of around $55/bbl), the supply forecast rests on international oil company hurdle rates which appear in mid-2006 to be shifting up into a $30/bbl to $35/bbl range. A number of IOCs are still testing projects down to price levels close to $25/bbl, but there has been an apparent upward shift amongst most others to $30-$35/bbl. Budget price assumptions used by producer governments and national oil companies (NOCs) also appear to have settled around $35/bbl.

Independent E&P companies appear to be working on higher estimates, at least for the purposes of budgeting. Price assumptions up to $55/bbl have been quoted. In recent months OPEC too has been testing the water as regards a new price floor to replace its erstwhile, but long redundant, $22-$28/bbl level. A price floor of $50/bbl appears to be the most often cited. However, bearing in mind most OPEC producers' markedly lower production costs, this price aspiration would appear to be more for domestic political and social imperatives.

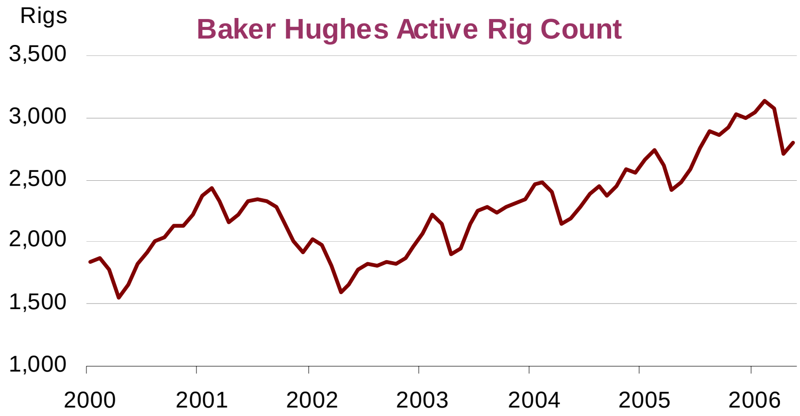
OPEC price aspirations and company expectations for income in the short to medium term may indeed be based on prices markedly higher than $35/bbl. However, ultimately the driver for future supply will be the resilience of baseload and new project supply to changes in price. On that basis, international operators appear willing to proceed with the bulk of the new projects assumed in this forecast so long as prices do not fall below a $30/bbl to $35/bbl range.

Spending and Activity Levels Also on the Increase

Although the impact of high prices on global oil supply is likely to have a lagged effect, there is little doubt that upstream activity is on the increase. The global rig count is one, albeit imperfect, barometer of this. This suggests that drilling activity has doubled in the period since the recent low seen in spring 2002. Active rig numbers in excess of 3000 are hitting levels not seen in 20 years. However, these remain below the 4000-5000 seen in the early 1980s and mid-2006 rig utilisation rates are estimated at 92% compared to a range in the low 80s earlier in the decade. This has occurred within an industry that began curbing capacity in the late 1990s against a backdrop of reduced activity.

The latest international upstream spending surveys produced by Lehman Brothers and Citigroup at mid-year 2006 both point to estimated spending this year rising by over 20% for the second year in succession. This is markedly higher than spending in previous years (12% in 2004) and the highest since

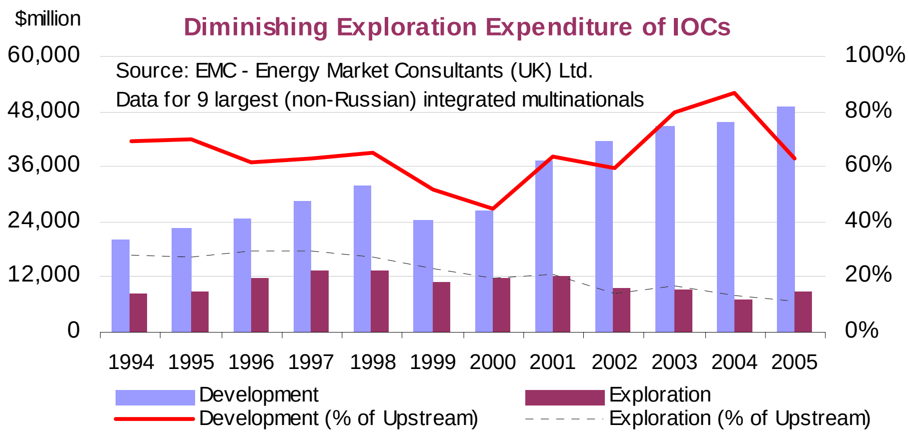
2001. Nor is it just the established growth areas that are seeing a rise in upstream spending. Increasing outlays in West Africa, Russia and the Caspian could have been predicted. However, outlays in the more mature North American and North Sea provinces are again showing renewed growth.



Interestingly, one study quoted a shift away from Latin America, in part reflecting the increased perception of political, fiscal and regulatory risk in that region. National oil company expenditure is being driven by sharply higher budgets, as it is for the IOCs. However, higher service and raw material costs also underpin the spending rise, and could limit the extent to which higher absolute spending levels can be translated into extra barrels of production. Furthermore, research has shown that capital spend, while rising, accounts for a diminishing share of upstream cashflow.

Exploration Rebound Needed to Sustain Longer-Term Growth

Of concern for the industry in the longer term is the declining trend in exploration outlays as a proportion of overall upstream capex. In 2005, 10% of all wells drilled were exploration, versus 20-25% throughout the 1990s. Aside from surging rig costs, spending surveys have tended to emphasise the growing proportion of development spending in the total. This is particularly true of the investment portfolio of the major IOCs, whose shift towards fewer, larger projects in frontier areas for both oil and gas increases capital intensity in the development phase and leaves less for investment in exploration. These companies also face competing claims on capital from elevated levels of M&A activity, share buybacks, mandatory environmental spend, and gas projects. In the case of major NOCs, the diversion of cashflow to social programmes and other government imperatives is also limiting exploration budgets. While it would be easy to level criticism at international companies for neglecting exploration recently, to be fair restricted access to reserves, notably within Russia, OPEC and, increasingly Latin America, has limited their options.

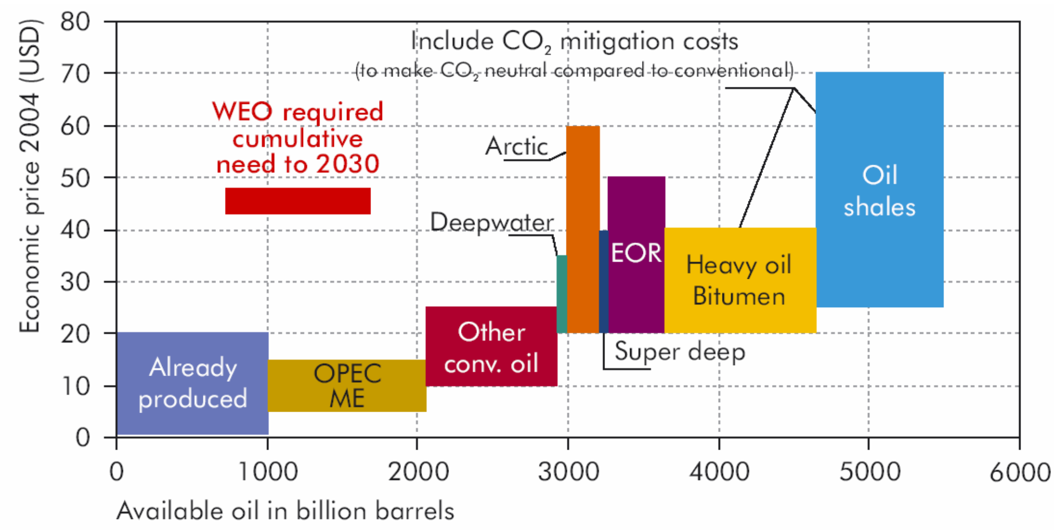


The major IOCs aside, there are anecdotal indications elsewhere of a shift back to exploration. This is reportedly the case in parts of Russia, within OPEC and amongst a number of NOCs in particular. The capital intensity of exploration relative to the rest of the upstream has also possibly come down, making an overemphasis on absolute spending levels only a partial answer. Advances in information technology have provided alternatives to the drill bit as a way of locating and appraising incremental reserves, at least in the first instance. Ultimately, there is no alternative to companies going out and drilling to verify the viability of discoveries. However, in the initial phases, less capital-intensive technologies can be employed. Despite this, exploration seems to have become the high cost, high risk 'poor relation' in the upstream investment portfolio, although ultimately signs in the past couple of years that major IOCs have seen worsening reserve replacement ratios are likely to ensure a swing back towards higher exploration activity once again.

Higher Costs Could Impede Direct Translation of Dollars into Barrels

While a rise in spending, upstream activity and initial evidence of a bottoming out of exploration are all healthy signs for future global supply, a number of cautionary caveats are in order. Not least is the sharp escalation in costs seen over the past two years in the upstream sector. Earlier IEA publications have stressed the fact that resource availability is unlikely to be a barrier to meeting future oil demand growth. There is plenty of oil which can be economically translated into the proven (therefore imminently developable) reserves category at oil prices well below the $70/bbl levels prevailing at mid-2006.

Available Oil Resources as a Function of Economic Price



Source: *Resources to Reserves - Oil and Gas Technologies for the Energy Markets of the Future*, IEA, 2005

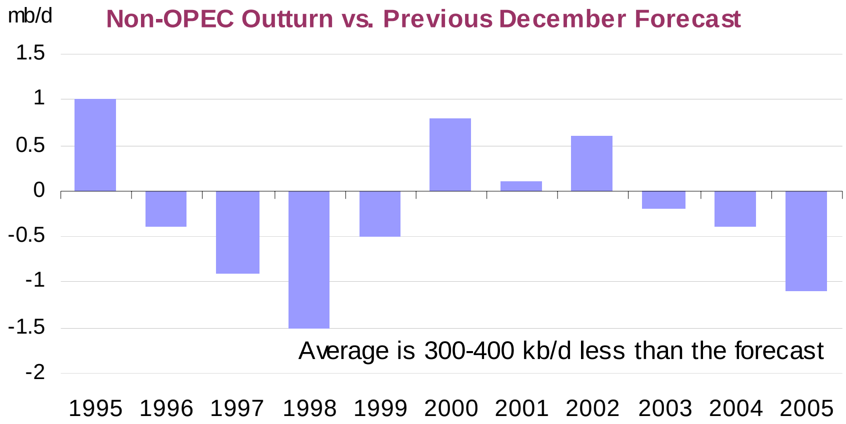
However, unrestricted access to those reserves for a wide range of operating companies, and the timely availability of adequate transportation infrastructure to bring this oil to market are issues which tend to cloud the supply outlook. In the shorter term, cost escalation due to shortages in raw material, drilling and service capacity and labour threaten to delay some incremental supply projects.

Steel prices have gained 50% since the mid-1990s. Drilling day rates have been rising by at least 10-15% per year, continuing into 2006, with deepwater facilities in particularly tight supply. Day rates for semi-submersible facilities have at times attained record levels near $550-600,000. There is a general perception that tightness in drilling facilities will persist for some time. However, there are reports of substantial increases in new build capacity becoming available from late 2007 onwards, albeit orientated more towards land rigs and shallow-water jack-ups than deepwater facilities. Some analysts see that market remaining constrained until 2009.

Worsening Delays Possible for Field Start-Up?

Quantifying the potential impact of cost inflation on new project start-ups is almost impossible within a bottom-up supply forecast apart from those projects for which possible delays have already been reported or suggested by developers. There have been claims that it could be 2008 or 2009 before sufficient new-build drilling capacity is available to support renewed rapid expansion in production capacity once again. However, this appears to conflict with oil company guidance on firm investment plans which show a 'bunching' of new field developments scheduled to attain first oil in 2006, 2007 and 2008.

The *OMR* prefaces its forecast every month with the proviso that unexpected field outages, exceptional weather-related or political events and technical delays can reduce expected non-OPEC supply by 300-400 kb/d in a given year. This aggregate downside risk derives from a comparison of out-turn non-OPEC supply with the initial forecast created 18 months previously for the year in question. A similar proviso can be applied to projections covering a five-year period.



As noted in the methodology section, above, the *OMR* also employs a cautious approach in estimating new field start-up dates and the pace of build to plateau production levels. Where individual projects have been identified as having specific political, infrastructural, technical or economic risks associated with their realisation, such projects are either pushed back in time in the forecast relative to initial company guidance (typically by three-12 months, depending on the degree of risk) or are excluded from the forecast altogether. That aside, it is almost impossible to quantify in advance how much future new capacity, currently at the tendering, engineering or construction phase, will be delayed or scaled back in size from original plans due to inadequate service and drilling capacity.

Some 250-300 kb/d of new production was 'lost' versus original 2005 projections due to delays affecting start-up at new fields in the USA, UK, Norway, Brazil and Sudan. In as much as hurricane activity impacted the former, and political developments played at least a partial role in the delays affecting Brazil and Sudan, it appears unwise to add an additional adjustment of this scale, over and above the typical annual 300-400 kb/d proviso, to account for potential future shortages of services capacity. Furthermore, while 2005 proved a 'bad year' versus original forecast (latest indications showing actual production coming in some 1.1 mb/d below original forecast), on a 10-year average basis this failed to push non-OPEC downside risk, as measured by forecast error, out of the typically assumed 300-400 kb/d range. In the absence of more concrete advance information from companies of changes in project schedules, historical forecasting record would appear to be the best indicator of potential aggregate shortfalls in the years ahead. Therefore we would not for the time being diverge from the 300-400 kb/d non-OPEC downside risk noted in the *OMR*. These projections are therefore judged to have a mean downside potential of 300-400 kb/d.

Fiscal/Regulatory Barriers

A number of analysts have cited political risk as an even greater threat to timely project realisation than the current, and perhaps temporary, surge in drilling and service costs. Political risk is ever-present and can take the form of labour strikes, attacks on production and transport facilities or, at a lower intensity, fundamental changes in the upstream investment regime. Alterations to production licences, changes in access and ownership clauses for reserves and increased fiscal offtake are all measures which governments have applied in recent years in response to higher-than-expected oil prices. Account has been taken in the forecast of known regime changes, although clearly the forecast is based on an assumption that the investment regime remains as it currently stands. In short, high oil prices are not by themselves a guarantor of an improved upstream investment environment.

Venezuela and Russia stand out as significant oil producers that have materially shifted resource ownership, project participation and fiscal offtake in favour of the state over the past two years. More generally in Latin America, recent political developments have seen a trend towards greater resource nationalism in Bolivia, Ecuador and Brazil, with Mexico for the time being also remaining off limits to direct foreign investment in upstream oil. Furthermore, despite a predominant upstream role in Venezuela and Mexico, NOCs in those countries face competing claims on their cashflow which will possibly impede upstream investment in the years ahead. Elections in Peru and a restructuring of the oil sector in Colombia have, in contrast, acted to boost prospects for international investment, and thus production expansion, in those countries. These considerations are taken into account when assessing the upside or downside supply potential in the 2009-2011 period.

Within OPEC, there are varying degrees of impediment to private and foreign company upstream involvement which, if unchanged, will act as a drag on the pace of new upstream capacity. These are discussed in more detail below, but in the cases of Indonesia, Iran, Kuwait, Nigeria and Venezuela are seen likely to hold future capacity levels well below officially announced government targets.

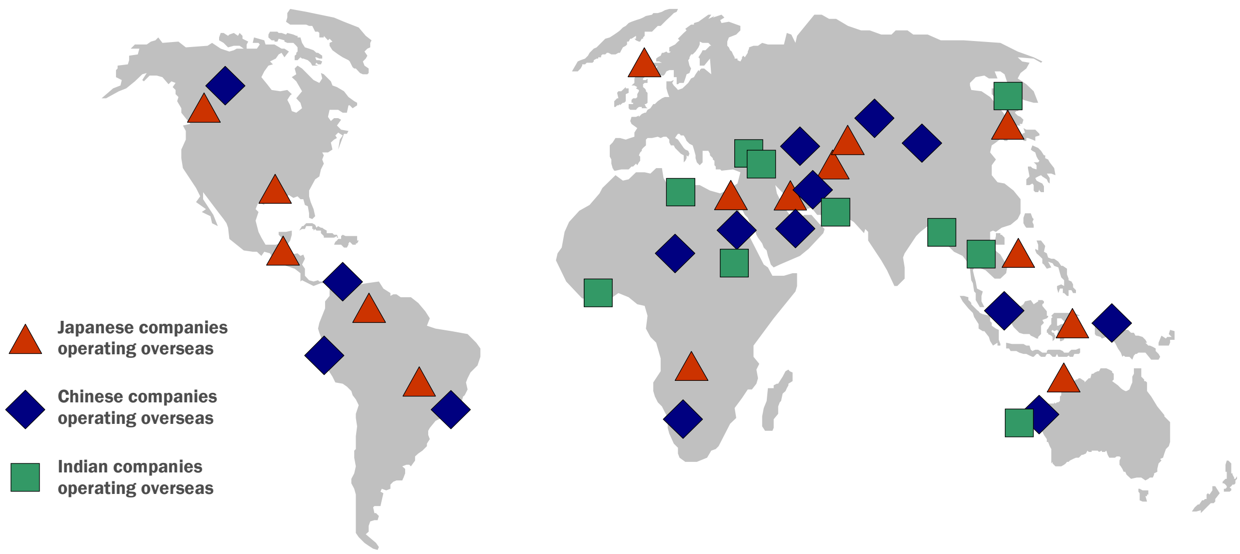
Infrastructure and Logistical Constraints

A further barrier to upstream oil developments is provided by delays in completion of export capacity infrastructure and the absence of associated gas utilisation capacity. These factors could, to a greater or lesser extent, reduce the medium-term oil supply potential from Canada, Russia, and the Caspian Republics as well as from a number of OPEC producers. By and large, the forecast assumes that adequate provision is made to ensure access to markets for produced oil and that sufficient gas processing and utilisation facilities in countries facing gas-flaring restrictions is brought on stream. Nonetheless, due account is taken of known delays or problems in this regard in specific cases.

Consumer Country Overseas Upstream Investment

Securing access to oil by direct investment in reserves overseas is not a new phenomenon. Indeed, Japanese companies for many years have successfully implemented such a policy. Initially investments were focused in the Middle East, but diversity of supply considerations now see Japanese companies represented in the upstream sector in more than 30 countries. More recently, an influx of capital amounting to some \$10-\$15 billion has flowed into overseas upstream properties from state oil producers based in China, India and Malaysia. While India has tended to restrict itself to investment opportunities in Asia, Middle East and Africa, China has pursued a more widespread expansion policy, with notable investments now also in the Americas. A key recent example of such a policy by all three Asian consumer countries is their co-operation in Sudan, where political risks deterred IOC participation but an active programme of exploration and development by Chinese, Indian and Malaysian interests has seen production increase to around 500 kb/d from negligible levels at the turn of the decade.

Consumer Countries Integrating Upstream

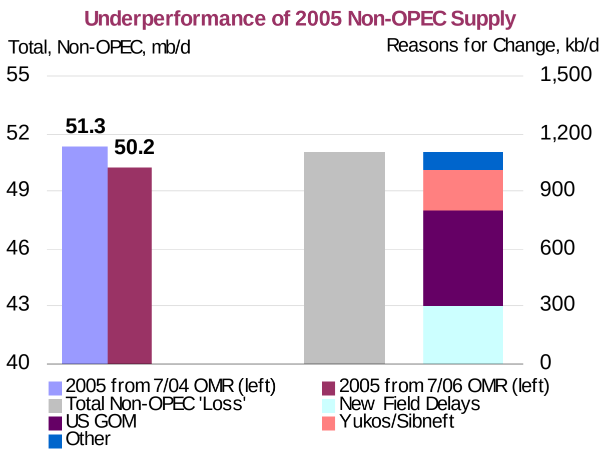


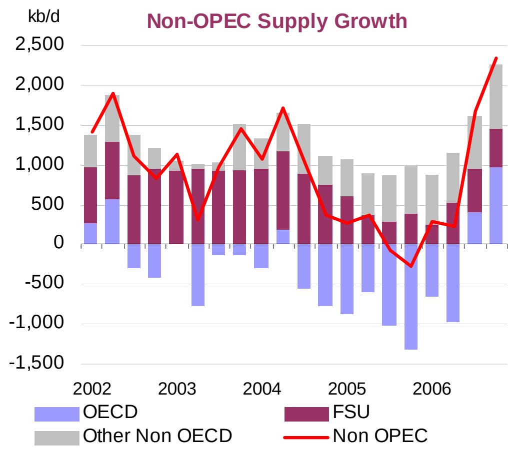
Participation in places such as Sudan and Venezuela illustrate that these producers are willing to countenance suboptimal economic returns in high risk provinces in exchange for guaranteed access to reserves to improve domestic supply security. This trend is expected to continue and will possibly sustain production growth in countries which might otherwise become bypassed by more commercially orientated IOCs. While this is positive for the medium-term supply outlook, there is a danger that it could undermine the incentive for producer host governments to liberalise their investment regime and thus could mitigate against longer-term reserves access and supply growth.

Non-OPEC Supply

Underperformance in 2005

Latest data suggest that non-OPEC oil production in 2005 averaged 50.2 mb/d. This is 1.1 mb/d below the *OMR*'s initial take on 2005 generated in July 2004. Some analysts have suggested that an era of irreversible non-OPEC decline is just around the corner, born of accelerating decline rates. Were this the key driver for 2005 non-OPEC performance, it would be necessary to account for this in the projections through to 2011. However, while it is superficially attractive to attribute the shortfall in this way, a number of equally important factors came into play in 2005 which account for a large part of the underperformance versus forecast.





The primary driver for non-OPEC was the impact of an exceptional hurricane season on the US Gulf Coast. This curbed US oil supply by some 0.5 mb/d compared to original estimates. Indeed, the impact of 2005 outages on the rolling five-year average assumed storm outages, employed by the *OMR*, also helped to cut early projections for 2006 by a similar amount. There is nothing to guarantee that 2006 and beyond will not again see exceptional outages due to hurricane activity. However, these projections are based on an assumption of typical seasonal scheduled maintenance and a rolling average of recent weather-related disruptions. Statistically therefore, such a level of unplanned outages persisting throughout the forecast to 2011 is unlikely.

A second component of the 2005 shortfall can be ascribed to production from the Russian producers Yukos and Sibneft, which came in some 200 kb/d below initial expectations. These companies effectively ceased oilfield investment as of mid-2004 for a variety of corporate, political and financial reasons. Once more, such an event could recur in Russia or elsewhere. However, this too can be seen as a particular, rather than systematic shortfall. It is also interesting to note that by mid-2006, decline from the production assets previously held by these companies was being reversed as investment levels have picked up again under new ownership.

We estimate that almost 300 kb/d of the shortfall in supply in 2005 can be attributed to delays in new field start-ups. These affected in particular the US Gulf of Mexico (GOM), UK, Norway, Brazil and Sudan. Again (as discussed above) unexpected delays can occur anytime for a variety of technical, economic, political or meteorological reasons. But by definition, a bottom-up, field-specific production forecast has to assume possible project start-up within a reasonable margin of error compared to officially announced plans. It is premature to assume that one year of pronounced start-up delays heralds an adverse trend in upstream project realisation. Tight upstream service capacity is a feature of today's market, but this too could prove cyclical. Therefore, no arbitrary downgrading of expectations for future non-OPEC field start-up is incorporated in the base case forecast.

This potentially leaves 200 kb/d of deviation from the original 2005 forecast which can be attributed to faster-than-expected decline, unscheduled stoppages, extended field maintenance and other factors. Accelerating decline is a problem for some of the more mature producing regions, and has been accounted for in forecast supply levels. However, the projections through to 2011 have not been based on a caveat of endemic and accelerating decline rates throughout non-OPEC as a whole.

Robust Growth Through to 2011

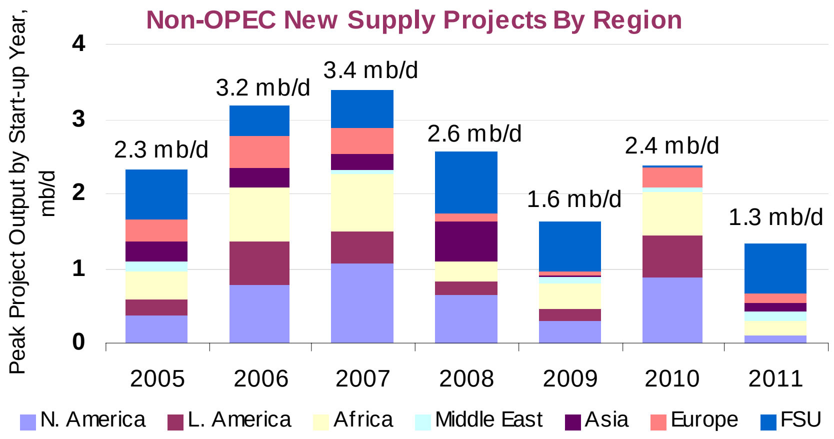
Strong growth in non-OPEC supply is expected to be re-established from 2006 onwards. The forecast takes no account of exceptional events which can typically reduce non-OPEC supply by 300-400 kb/d annually. Projections have been adjusted to account for average maintenance and other seasonal outages, while in general all firm new oilfield development projects have been phased in on a risk-assessed basis. Shortages in upstream drilling and services capacity are therefore not explicitly factored into the projections. The tail of the forecast is also adjusted to allow for countries and regions for which firm investment projects likely understate medium-term supply potential. As such, the forecast can be regarded as showing possible supply potential under current oil market conditions and prevailing investment environment. Non-OPEC supply may for unforeseen reasons, come in below this potential, albeit most likely within the 300-400 kb/d margin of error observed historically. This is reflected in the adjusted call on OPEC discussed in the executive summary.

Non-OPEC Oil Supply
(million barrels per day)

	2006	2007	2008	2009	2010	2011
North America	14.30	14.56	14.63	14.66	14.83	14.98
Europe	5.38	5.36	5.13	4.87	4.65	4.48
Pacific	0.54	0.62	0.72	0.81	0.75	0.68
Total OECD	**20.22**	**20.54**	**20.48**	**20.34**	**20.23**	**20.14**
Former USSR	12.09	12.61	13.00	13.51	14.01	14.53
Europe	0.15	0.13	0.12	0.11	0.10	0.09
China	3.70	3.73	3.74	3.75	3.77	3.79
Other Asia	2.72	2.75	2.78	2.88	2.89	2.85
Latin America	4.47	4.72	5.13	5.32	5.45	5.72
Middle East	1.80	1.75	1.70	1.67	1.66	1.66
Africa	4.10	4.60	5.06	5.31	5.47	5.47
Total Non-OECD	**29.04**	**30.29**	**31.53**	**32.55**	**33.37**	**34.11**
Processing Gains	1.90	1.92	1.95	1.98	2.00	2.03
Other Biofuels	0.15	0.26	0.40	0.40	0.40	0.40
Total Non-OPEC	**51.31**	**53.01**	**54.36**	**55.28**	**56.00**	**56.68**

Growth in supply averages 2% per year, compared to 1.9% during 2001 to 2006. Annual increases in supply average 1.4 mb/d during 2006-2008, but slow to 700-900 kb/d during 2009-2011. In part, this reflects a 'bunching' during 2006-2008 of known investment projects (see below). While high costs and shortages of drilling equipment may concentrate downside risk on the earlier phase of the forecast, there is the potential for persistent high oil prices to lift the tail end of the forecast above the levels shown here. Increases in exploration activity and yet-to-be sanctioned new field development projects could augment what is a deliberately conservative tail on the existing projections.

Regionally, the forecast reaffirms the already evident trend whereby non-OECD production accounts for a rising share of total non-OPEC supply. The non-OECD share rose from 50% in 2001 to 57% of the non-OPEC total in 2006 and is seen reaching 60% by 2011. As is the case in our shorter-term projections in the *OMR*, key increments come from the FSU, Latin America and Africa, all of which grow by between 3.5 and 6% per year. This is close to the trend observed over the past five years.

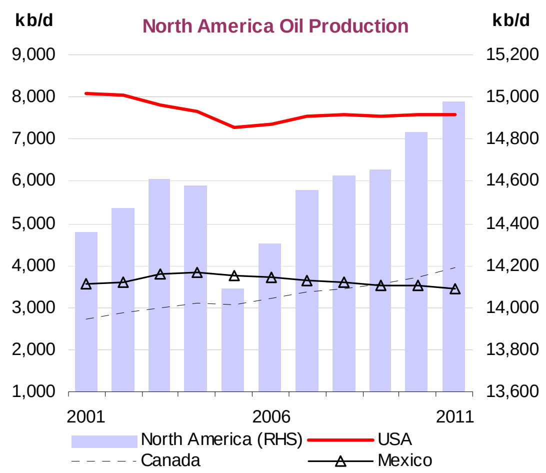


OECD supply is expected to stabilise within a 20.1-20.5 mb/d range, stemming a 1.5% per year decline seen during 2001-2006. The OECD Pacific fares best, with near 5% per year growth deriving from a number of new offshore and gas-related developments in Australia, while North American growth averages 0.9% annually after a static (but hurricane-disrupted and oilsands outages-affected) early decade. North Sea supply however is expected to repeat the 4% per year decline seen during 2001-2006.

Non-OPEC Regional Detail

North America

North American oil supply fell by some 0.5 mb/d in 2005 to 14.1 mb/d under the impact of prolonged outages affecting the Gulf of Mexico (GOM) and the Canadian oilsands. In all, supply is expected to rebound to 14.6 mb/d by 2008 and 15.0 mb/d by 2011, with stronger GOM performance in the early part of the forecast and then a rising contribution from new Canadian oilsands and US Alaskan supply later in the report. Mexican crude production is expected to continue to decline modestly throughout the forecast without a fundamental shift in government policy.



Progressive recovery is expected for US supply through to 2008, with oil production rising to 7.6 mb/d after 7.3 mb/d in 2005 before levelling off at 7.5-7.6 mb/d thereafter. New 2006 production from the Constitution and Marco Polo fields is augmented late in 2006 by the long delayed start-up of BP's deepwater Thunder Horse facility in the GOM. This is followed running throughout the forecast by King (2007), Blind Faith, Neptune and Tahiti (2008), Shenzi, Great White and Clipper (2009) and Puma, Tubular Bells and Trident in 2010. Total GOM supply is seen levelling off at 1.85 mb/d in 2010 but enters overall decline thereafter in the absence of significant new discoveries. Alaska takes up some of the slack in the longer term, with a number of offshore satellite field developments allied to an assumed modest contribution (150 kb/d) by 2011 from incremental onshore supply (potentially the ANWR) based on reserve estimates.

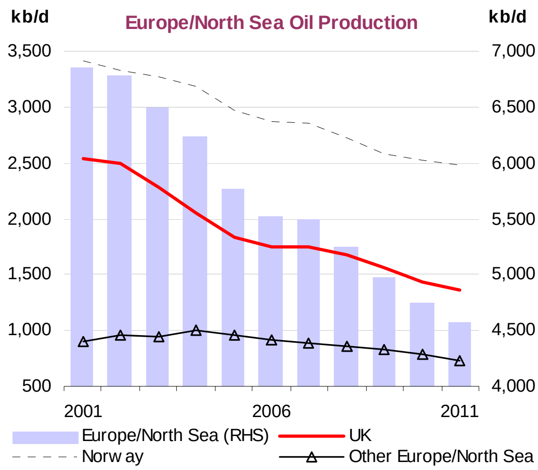
Incremental **Canadian** supply derives predominantly from scheduled oilsands developments. In all, Canadian supply rebounds to 3.2 mb/d in 2006, 3.4 mb/d in 2008 and 4.0 mb/d in 2011. Offshore east coast supply could plateau around 400 kb/d in 2007/2008, and offset to subsequent decline from reserves in the Hebron area is not now seen likely before 2012. In contrast, Albertan mining/syncrude supply is seen rising from 650 kb/d in 2006 to 760 kb/d in 2008 and potentially 1.25 mb/d in 2011. *In situ* bitumen projects contribute 490 kb/d in 2006, 670 kb/d in 2008 and 1.06 mb/d by 2011. Clearly, this projection assumes a substantial increase in pipeline capacity feeding US and Asian refining markets.

Given the constraints imposed by **Mexico's** constitutional ban on foreign upstream participation, it is difficult to see scheduled increments offsetting in full the decline expected for the country's baseload Cantarell field. The working assumption here is that state producer Pemex is granted some fiscal leeway to restrict decline at Cantarell to 10% per year. This however more than counteracts incremental supplies which are expected to come from the Tabasco littoral, from complex reservoirs onshore at Chicontepec and from deeper-water reserves at Sihil and Ku-Maloob-Zap. The latter will see the deployment of the first ever Floating Production, Storage and Offloading (FPSO) vessel in waters of the Gulf of Mexico. Chicontepec's complexity is reflected in the $6 billion allocated to it in Pemex's 2007-2009 investment plan. Ultra-deepwater discoveries at Nab and Noxal have been discounted from the forecast as they are unlikely to be developed prior to 2011 in the absence of a relaxation of restrictions on foreign company participation.

Europe/North Sea

European oil production is seen falling consistently throughout the forecast period, from 5.4 mb/d in 2006 to 5.1 mb/d in 2008 and 4.5 mb/d in 2011. Average decline for the region as a whole therefore averages some 3.6%, compared with 4.6% during 2001-2006.

The relatively high cost North Sea, despite a benign fiscal and regulatory regime, is now a maturing production province. Integrated operators have been offloading mature assets to independent players in the **UK** sector for some time. Although this holds some hope for sustaining production at some of these systems, there has also been evidence of smaller operators encountering technical problems associated with late-life reservoir performance. Major new field developments for the forecast period in the UK sector appear limited to the Buzzard field within BP's Forties system which is due on stream in late 2006 and which should reach peak output of 180 kb/d by 2008. Intermediate size developments of 20-50 kb/d each come from ongoing Clair field development west of the Shetlands, and a number of other Forties area developments including Brenda/Nicol, Brodgar/Callanish, Chestnut and Kessog. A number of other small-scale condensate developments associated with southern gasfields are also expected. Increased upstream spending for the first time in years in 2006 is encouraging, but is unlikely to alter the downward trend in UK supply.

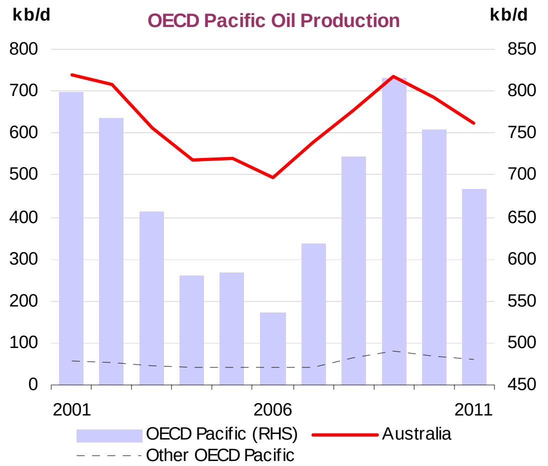


Norway also potentially faces a declining oil-production profile, although condensate and gas liquids developments (Kristin, Kvitebjorn and Ormen Lange) can moderate the pace of decline for 2006-2008. Northerly developments in the Haltenbanken area are also capable of partially offsetting decline further south in 2010 and 2011 (Tyrihans, Goliat and Skarv). Unlike the UK, key Norwegian operators Statoil and Norsk Hydro have tended to hold on to maturing assets rather than sell these on to independent operators. It has been suggested that the limited influx of independent operators has held back Norwegian supply, although the record of established producers in augmenting enhanced recovery and satellite field developments offshore Norway has been impressive. However, there are concerns that a more flexible and dynamic fiscal and licensing regime, allied to a more liberal approach to opening up environmentally sensitive frontier areas further north, is required before gradual decline in Norwegian supply can be reversed.

OECD Pacific

Australian oil production is expected to recover from a spate of weather and mechanical outages seen during 2004-2006 which pushed supply down from an early-decade level of 800 kb/d to 550 kb/d in 2005. A production 'spike' is expected to run through to 2010 driven by independent producers developing a series of new fields offshore western and north western Australia. Most of these fields are small in size (sub-50 mb), heavily capital-intensive to develop and are expected to have a relatively brief production plateau. However, gas-related developments are likely to sustain NGL production at

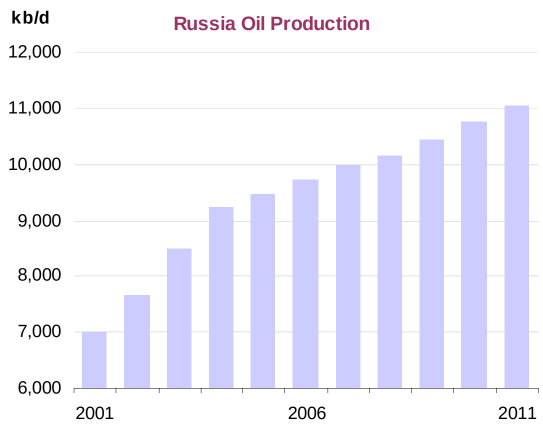
80-90 kb/d throughout the forecast period. In all, oil supply reaches a 2009 peak of 735 kb/d but enters decline thereafter in the absence of significant 2010-plus discoveries. Australia faces mature basin decline and has to stimulate exploration if it is to avoid the sharp drop in supply shown here. It is uncertain whether high prices will be sufficient to tempt back domestic operators who have increasingly turned to exploring overseas recently. Despite this, the government sees potential yet-to-find oil in frontier areas equivalent to the 6 billion barrels already discovered, suggesting some upside from the current forecast in the longer term.



Russia

For the five years between 2000 and 2004, **Russia** accounted on average for 65% of total non-OPEC oil supply growth. Annualised growth stood between 6% to 11%, peaking in 2003. Erstwhile independent producers Yukos and Sibneft saw the most consistent growth in this period, in excess of 20% per year, largely through the application of western recovery technologies at underexploited fields in western Siberia. However a combination of resource nationalisation, industry restructuring, deteriorating fiscal and regulatory environment and falling oilfield investment dramatically curbed Russian growth from mid-2004 onwards.

There are however preliminary signs of more modest and sustainable supply growth (in a 2-3% annual range) becoming established once again as former Yukos and Sibneft assets, now basically under state control, have stabilised investment and production levels. Unlike other regions, where the forecast employs field-by-field data where possible, a more aggregated company analysis is undertaken for Russia. Flagship new-field developments are incorporated (including the various phases of the eastern Sakhalin project, Kharyaga, Salym and Vankor), and combined with an overview of individual company supply growth plans (taking account of historical performance). Resulting crude oil and condensate supply totals are then checked against possible crude export capacity and the underlying resource base.



So far this decade, Russian production growth has largely been accommodated by expansion of Transneft's flagship Baltic Pipeline System (BPS) which has attained throughput capacity of some 1.0 mb/d. Going forward to 2011, we envisage a potential rise of nearly 1.5 mb/d in Russian crude export capacity, with notable increases including:

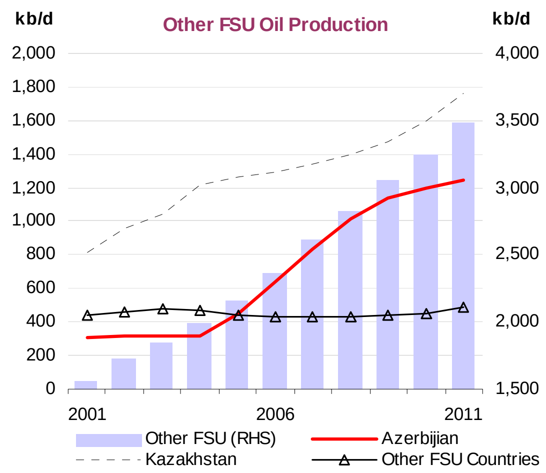
- An assumed late-decade 0.5 mb/d via the East Siberia-Pacific Ocean (ESPO) pipeline;
- An extra 100-150 kb/d by rail to China;
- Increased Russian access to Azerbaijan's BTC pipeline and to the newly-started Kazkah line to China (250 kb/d);
- A limited 200 kb/d using Transneft's northern route between Kharayaga and Indiga;
- Proprietary pipelines and terminals being developed by Lukoil, BP-TNK and others amounting to some 300 kb/d.

A variety of more tentative export schemes have been excluded from the forecast. Furthermore, firmly planned refinery investments in Russia through to 2011 suggest the capacity to process 0.75-1.0 mb/d of incremental crude domestically.

In all, Russian crude and gas liquids supply is seen increasing from 9.75 mb/d in 2006 to 10.2 mb/d in 2008 and 11.0 mb/d in 2011, representing average growth of 2.5% annually. This is markedly higher than forecasts from the Economy Ministry, although it should be noted that the latter's projections have been notoriously conservative in the past. While downside risk to the forecast exists, notably in the form of political, regulatory and fiscal uncertainty, the production profile holds Russia's reserves to production ratio fairly static at 20 years. With indications from service companies of resurgent exploration activity, notably in Eastern Siberia, there may be further upside supply potential from Russia in the longer term. Access to reserves for a range of operators, the evolving fiscal regime and progress on de-bottlenecking transport infrastructure will be key determinants of the pace at which such supplies can be brought to market.

Other FSU

The other FSU grouping has added some 0.8 mb/d to production on a net basis since 2001, reaching an estimated 2.35 mb/d in 2006. Azerbaijan (production 0.6 mb/d) and Kazakhstan (production 1.3 mb/d) are the key producers in the region. Looking forward, exploitation of extensive liquids reserves in the Caspian for both of the above plus, to a lesser extent, rising gas liquids output from Turkmenistan is expected to push total supply to 2.8 mb/d in 2008 and 3.5 mb/d in 2011. Growth averages 8% per year compared to some 9% during 2001-2006. These increases are of course subject to continued progress in developing infrastructure which allows the Caspian republics to diversify from their hitherto reliance on Russian export facilities.



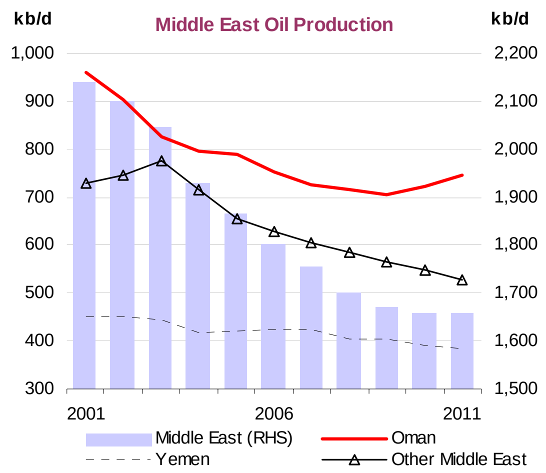
Further strong growth from **Azerbaijan** has been facilitated by the activation in 2006 of the 1.0 mb/d Baku-Tbilisi-Ceyhan (BTC) pipeline. This opens the way for a potential doubling, by 2009, of current 450 kb/d production at the BP-operated Azeri-Chirag-Guneshli (ACG) fields in the Caspian Sea. A further 50 kb/d of condensate is expected to come from the Shah Deniz gas development from late 2006, while the 2 billion bbl Inam and Yalama offshore discoveries should be developed by Lukoil in time for the tail end of the forecast, ultimately supplying upwards of 200 kb/d. Onshore production however looks likely to show continued decline throughout the forecast period. In total, Azeri oil production rises from 640 kb/d in 2006 to 1.0 mb/d in 2008 and 1.25 mb/d in 2011.

Production from **Kazakhstan**, which expanded from 0.8 mb/d to 1.2 mb/d between 2001-2004, has subsequently stabilised in a 1.2-1.3 mb/d range, with government sources forecasting a fairly flat profile for 2006. Export infrastructure and gas processing facilities hold the key to future expansion. The Tengiz and Karachaganak fields, which have underpinned Kazakh growth this decade, now face bottlenecks on offtake capacity. Critical in this regard is a planned expansion of the existing 600 kb/d CPC pipeline which feeds liquids to Russia's Black Sea port of Novorossiysk. Russia is now making expansion of CPC to 1.35 mb/d conditional on completion of a bypass route for the Turkish Straits. In an effort to diversify export routes, Kazakhstan has recently completed a 200 kb/d pipeline to China and has agreed to link in supplies to the BTC line from Azerbaijan. Limited export swap volumes also travel south to Iran. Assuming that progress is made on unblocking the CPC logjam by 2008/2009, Kazakh production should increase to 1.4 mb/d in 2008 and 1.8 mb/d by 2011. Production is augmented by early phase output of 450 kb/d from the ENI-operated Kashagan field, assumed to come on stream in 2010.

Middle East

Non-OPEC Middle East supply is likely to see ongoing decline, albeit at a pace around half that of the -3.4% per year evident during 2001-2006. From 1.8 mb/d in 2006, production reaches 1.7 mb/d in 2008 and 1.65 mb/d in 2011. Syria and Bahrain are expected to see steady decline from mature fields amidst a recent paucity of exploration success. However, Oman and Yemen have the potential to partially stem recent weakness through enhanced oil recovery and new field developments respectively.

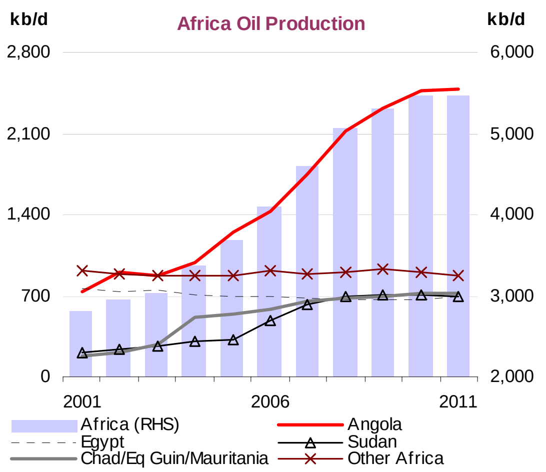
Oman is projecting a late-decade turnaround after steady decline evident since 2001. State Petroleum Development Oman (PDO) envisages an extensive programme of gas injection boosting supply from the southern Harweel area. Meanwhile, Occidental plans to raise production at the Mukhaizna field to 150 kb/d by 2011 from a current 10 kb/d using thermal injection. While total liquids production drops from 750 kb/d in 2006 to 715 kb/d in 2008, a rebound to 745 kb/d is expected by 2011, potentially rising further towards 800 kb/d again by the first half of the next decade.



Total **Yemeni** oil production slipped from a prevailing 450 kb/d to some 420 kb/d in 2004 with declining production from the onshore Marib and Masila fields. Output is thought to have subsequently stabilised around 420 kb/d. Further exploration contracts are scheduled to be awarded during 2006 after revisions to Production-Sharing Contracts (PSAs) are incorporated. Ongoing decline is expected for Yemen as a whole in the absence of significant new discoveries. However a growing contribution is expected from newer fields including Nexen's Block 51, the An Nagyah, Nabrajah, and Hiswah fields and Total's Block 10 discoveries. These should help offset mature field decline, resulting in output of 405 kb/d by 2008 and 385 kb/d in 2011.

Africa

African supply growth accounts for 21% of the expected non-OPEC increment for 2006-2011, second only in magnitude to the increase expected from the FSU. The region generates a net 1.35 mb/d of extra oil in the outlook period, taking total regional supply to just shy of 5.5 mb/d. Growth of 5.9% per year however is rather slower than the 8% seen during 2001-2006. During 2001-2006 Angola generated 55% of net regional growth and is expected to remain the mainstay for the forecast period, accounting for over 75% of the anticipated increment. Chad, Equatorial Guinea, Ivory Coast, Mauritania and Sudan all made significant contributions to growth during 2001-2006. While limited increments are also expected from a number of these for the forecast period, it is a measure of the region's perceived political and exploration risk that growth becomes much more concentrated during 2006-2011 on known developments in deepwater Angola.



Three of the region's newest producers illustrate some of the issues involved, and although each is expected to boost production in the forecast period, expectations are tempered for the time being by uncertainty over operating conditions for foreign producers. In **Chad**, the government has reached an interim agreement with the World Bank over allocation of revenues from the Doba crude export stream. Earlier deadlock had threatened to force ExxonMobil to shut in production. While the government envisages production potential in the next five years to be around 400 kb/d versus a current 170 kb/d, the forecast herein assumes that production will be limited by existing pipeline capacity of some 220 kb/d. Without further discoveries, decline from 2010 is seen likely.

In **Sudan**, disputes over revenue-sharing between authorities in the north and south continue. Long delays afflicted start-up of production from Blocks 3 and 7 in the southern Melut Basin, where ownership is split between Sudanese, Chinese, Malaysian and Indian interests. Slow progress in completing loading facilities at Port Sudan in the north was blamed. June saw production start at ONGC's Thar Jath field which will ultimately build in excess of 60 kb/d. Sudanese production is expected to plateau around 710 kb/d in 2009/2010. Although reserve potential suggests higher volumes, the forecast is constrained by continuing political instability.

Mauritania is seen to have the potential for producing some 300 kb/d in the medium term, with the Tiof and Tevet discoveries likely to follow on the heels of February 2006's start at Chinguetti. However, a recently resolved dispute between producer Woodside and the new government over production-sharing contracts undermined some confidence in investment terms for foreign operators. As a result, an upper limit of some 200 kb/d is forecast here for the medium term.

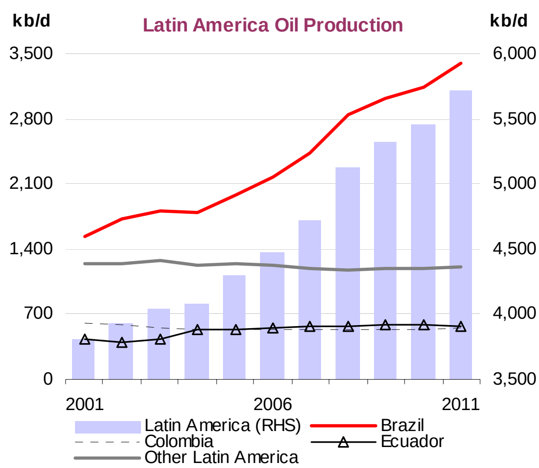
None of the above examples show the same magnitude of risk to supply as the current unrest in nearby Nigeria. However, should high prices open up greater investment opportunities, some international upstream operators are likely to favour territories with proven stability in the fiscal, regulatory and operating regime. As noted above, however, there are signs of less risk-averse independent operators and importer NOCs boosting new investment in geopolitically volatile regions, raising the potential for higher supply in a number of African countries.

For **Angola** itself, with a relatively stable investment model, a modest slow down in production growth from the doubling seen over 2001-2006 is expected. Nonetheless, production increases from 1.43 mb/d in 2006 to 2.12 mb/d in 2008 and 2.5 mb/d in 2011. Key increments derive from the BBLT, Dalia, Greater Plutonia and Rosa/Lirio fields during 2006 and 2008. Thereafter, the Kizomba C&D, Landana/Tombua, Pluto/Saturn and Acacia fields feed in to boost supplies during 2009-2011. Phasing in of these projects has been adjusted to account for multiple well completions where appropriate (gradual build to plateau). While large-scale deepwater projects such as these are always prone to cost and time overruns, in the case of Angola producers such as ExxonMobil have recently begun to benefit from the modular nature of some developments, allowing savings in time and cost compared to early phases. Nonetheless, where conflicting estimates of possible project start-up date exist, the projections here have erred on the side of caution.

Latin America

Regional supply is seen increasing by 1.2 mb/d during 2006-2011, growth of 4.8% annually compared to just over 3% in the previous five-year period. To an even greater extent than during 2001-2006, growth is dominated by Brazil, as minor changes elsewhere in the region cancel each other out. Based on encouraging recent exploration results and positive changes in the investment regime, there are prospects for longer-term growth in crude and gas liquids supplies from Colombia, Cuba, Peru, Surinam and Trinidad. However, firm new development projects are, as yet, thin on the ground and forecast supply shows only modest growth towards the tail end of the forecast to reflect underlying resource potential. In contrast, recent political developments in Ecuador and Bolivia reduce the prospect for increased foreign investment, suggesting supplies here will at best stabilise.

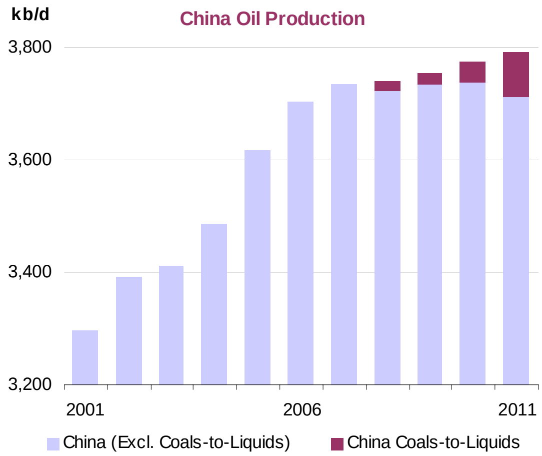
In **Brazil**, recent delays in new field start-ups have centred partly on mandatory local services content. However, significant expansion in deepwater Campos Basin production has been achieved largely through the efforts of the state-run operator Petrobras. A more benign fiscal regime than prevails in Mexico has provided Petrobras with sufficient capital for investment in major development projects. Recent high prices and a drive towards oil self-sufficiency are fuelling a $56 billion spending plan for 2006-2010, with a 50% increase in investment scheduled for 2006.



Overall, Brazilian crude supply rises from 1.8 mb/d in 2006 to 2.4 mb/d in 2008 and 2.8 mb/d in 2011. While both Petrobras and the Campos Basin continue to dominate the expansion programme, the Golfinho field in the Espirito Santo Basin and Piranema in the Sergipe Basin are notable examples of increments elsewhere (generating a combined 250 kb/d). Norsk Hydro's Chinook development and Chevron's Frade add a further 200 kb/d by the end of the forecast period. NGL supply increases by 25 kb/d during 2006-2011. A final component of Brazilian liquids growth is ethanol sold as a gasoline blendstock, seen increasing from 290 kb/d in 2006 to 480 kb/d by 2011.

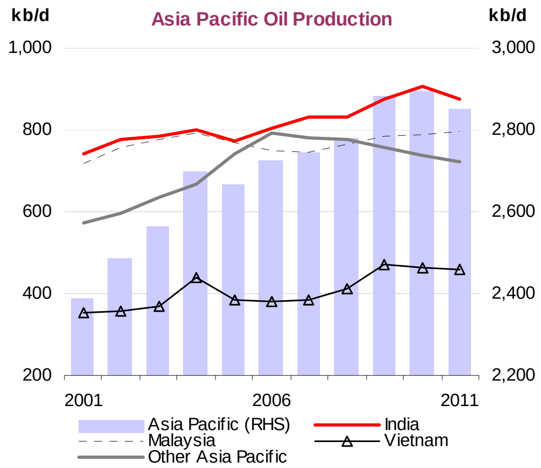
China

Expectations for Chinese crude production have increased since the last medium-term forecast conducted in the second half of 2005. Decline at the mature onshore Daqing and Shengli fields appears to have been brought under control by state producers PetroChina and Sinopec respectively. Offshore production is seen increasing by a further 150 kb/d, after having gained 180 kb/d to reach 590 kb/d in the five years to 2006. Further increases are expected from onshore western and north western areas including Changqing and the Tarim Basin. Offshore and western onshore production is therefore seen balancing out declines elsewhere, leaving Chinese crude supply largely unchanged at close to 3.7 mb/d by 2011. Meanwhile coal to liquids plans are seen augmenting supply by a further 80 kb/d by 2011. Overall, China plans for coal-to-liquids capacity reaching over 300 kb/d by the middle of the next decade and potentially 800 kb/d by 2020.



Other Asia Pacific

After healthy 2.5%-plus annual supply growth during 2001-2006, increments in the rest of the Asia Pacific region over 2006-2011 amount to a modest 1%, or 125 kb/d. Underpinning this modest growth is an increase in supplies from India, Malaysia and Vietnam. In **India**, redevelopment of the offshore Bombay High field pushes production in excess of 400 kb/d by 2008, while onshore, Cairn Energy's discoveries in Rajasthan should start production in 2008, building to an eventual 125 kb/d. Total Indian oil production rises from 800 kb/d in 2006 to 900 kb/d in 2010 before entering decline thereafter. **Malaysia** will see a steady rise in NGL supply, while Murphy Oil's Kikeh project will generate an eventual 150 kb/d, starting in 2007. Total oil supply including the existing 15 kb/d of GTL, gains a net 50 kb/d by 2011 to reach 800 kb/d. Meanwhile, **Vietnam** should see production rise from 380 kb/d in 2006 to 460 kb/d by 2011 with 100 kb/d of new production from the offshore Su Tu Vang development and a steady rise in NGL supply.



OPEC Supply

OPEC Gas Liquids and Non Conventional

Before considering possible developments in OPEC crude production capacity, which traditionally have a crucial bearing on its ability to manage surplus within the market, it is worth focusing on OPEC production of non-crude liquids. This element of the global oil balance is frequently overlooked, not least because of a scarcity of reliable and consistent data. For this medium-term forecasting exercise, the IEA has undertaken a detailed look at the production of gas liquids, condensates and, from 2006 onwards, gas-to-liquids (GTL) facilities on, where possible, a plant-by-plant basis. OPEC non-conventional liquids supplies, comprising Saudi MTBE and Venezuelan Orimulsion boiler fuel, are included in this category, although these are more limited in scale than gas liquids and are unlikely to exhibit the same growth in the forecast period.

In total, these liquids, which are not subject to production restrictions under OPEC quotas, are seen growing by some 2.1 mb/d, or by 7.5% per year. This is the same rate of growth as during 2001-2006, reflecting a continuation of the strong increase in natural gas supply throughout OPEC in the earlier period. Indeed, early-decade gas growth has tended to take precedence over crude capacity, by accident or design, although it would appear that a resurgence in crude capacity investment is now planned (see below).

OPEC Gas Liquids & Non-Conventional Oil Supply
(thousand barrels per day)

	2005	2006	2007	2008	2009	2010	2011	Increment[1] 06-11
Algeria	760	795	835	845	860	905	890	100
Indonesia	175	170	165	160	150	145	135	-35
Iran	340	395	425	575	650	645	805	415
Kuwait	125	125	130	140	190	195	230	105
Libya	90	130	145	145	140	140	140	10
Nigeria	195	225	230	255	445	565	570	340
Qatar	385	410	500	600	685	835	875	465
Saudi Arabia	1460	1495	1515	1635	1810	1870	1880	385
UAE	535	580	610	620	720	755	770	190
Venezuela	215	215	220	230	235	245	250	35
Iraq	20	25	25	30	30	30	30	5
Total OPEC	**4295**	**4560**	**4805**	**5230**	**5915**	**6330**	**6580**	**2015**
Saudi MTBE & Venezuelan Orimulsion	170	155	180	195	205	205	205	50
Total OPEC Non-Crude	**4465**	**4715**	**4985**	**5425**	**6120**	**6535**	**6785**	**2065**
Yearly Increment		250	270	440	695	415	250	

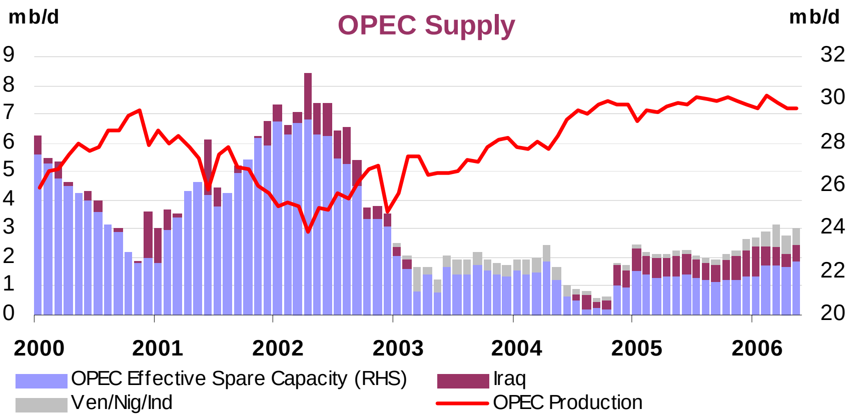
1 Increments may differ to those implied by displayed yearly data due to independent rounding.

In assessing possible gas developments, similar methodology has been applied as for the non-OPEC supply projections. Only committed condensate streams and associated gas processing facilities have been included in the projections. Generally, conservative start-up and build-up assumptions have been used, although it is assumed that facilities eventually build to installed capacity levels. No assumed additional extra supply has been included for the later years of the forecast. This raises the prospect that 2010/2011 supply could be higher than shown here, although this risk may well be balanced by downside risk earlier in the forecast period due to raw materials, drilling and service company shortages already discussed for oil projections. Five OPEC countries account for 85% of the increase in gas liquids supplies and developments there can be summarised as follows:

- **Qatar** sees a prospective doubling of gas liquids supplies to 875 kb/d by 2011. Major increments derive from the Dolphin gas export project (150 kb/d of condensate and NGL) from early 2007, 160 kb/d of condensate from the Qatargas 2 project from 2009 and a combined 100 kb/d of GTL from the Oryx project. A 35 kb/d phase 1 of Oryx begins in 2006, with the next phase assumed to come on stream in 2010. Tentative plans for additional GTL by ExxonMobil and the Pearl project are excluded for now;
- **Iran** is seen adding 415 kb/d of gas liquids capacity centred on the giant offshore South Pars development. Condensate supplies are seen reaching 650 kb/d from less than 300 kb/d currently with completion of phases 6-8 of South Pars in 2007, phases 9-10 in late 2008 and phases 11 and 13 in 2011. Only projects for which contracts have been awarded are included in this analysis. Associated NGL supplies rise accordingly from 120 kb/d now to 170 kb/d by late 2011;
- **Saudi Arabia** should see gas liquids supply (including ethane) rise from 1.5 mb/d currently to 1.9 mb/d by 2011. Increases derive primarily from NGL as opposed to condensate. The Hawiyah project in late 2007 should add an eventual 300 kb/d while Khurais gas liquids from third quarter 2009 boost supply by a further 70 kb/d;
- **Nigerian** supply grows by 340 kb/d, with an ultimate 180 kb/d of condensate from the Akpo field beginning in late 2008. Other increments are centred on LPG, including those deriving from the Amenam LNG project in 2006, the EA and Gbaran/Ubie fields in 2008 and an assumed start-up at the 35 kb/d Escravos GTL facility in late 2009;
- **The UAE** plans to significantly boost gas utilisation, thus lifting a restriction on Abu Dhabi crude capacity brought about by gas-flaring restrictions. Condensate supplies should increase by 130 kb/d on the commissioning of the OGD 3 (Habshan) facility in Abu Dhabi from 2008. NGL supply is seen rising by 80 kb/d to 395 kb/d in 2011. Overall UAE gas liquids capacity reaches 770 kb/d in 2011 from 580 kb/d in 2006, with increases in Abu Dhabi offsetting decline from Sharjah and Dubai.

Tight OPEC Crude Capacity is Nothing New

Low levels of OPEC spare crude capacity have been evident since producers began to increase output in light of the Venezuelan strike in late 2002. What has exacerbated the situation and turned this into a driving factor for oil prices has been the succession of exceptional (4%) global demand growth in 2004, followed closely by disappointing non-OPEC supply performance in 2005. There has therefore been little option but for OPEC producers to sharply raise short-term production to meet market demand, absorbing new capacity additions in the process. Moreover, this has spurred consumers to build inventories higher than would otherwise have been the case as a counterweight to low spare OPEC capacity.



During 2003-2005, installed OPEC capacity increased to 32.1 mb/d, a rise of some 1.5 mb/d. A further 800 kb/d increase expected for 2006 has so far been undermined by simultaneous production shut-ins in Nigeria and elsewhere. Forecast OPEC crude capacity levels are discussed in detail below, but there is the potential for capacity to increase to a level around 36.3 mb/d by 2011. Two things need to be pointed out here to place this in context. Firstly, capacity growth of 2% per year as envisaged for 2006-2011 compares to 1% for 2001-2006. However, the latter period saw the combination of collapsing upstream infrastructure in both Iraq and Venezuela. Those countries aside, OPEC capacity growth for 2001-2006 stood at 2.5% annually, rather higher than the rate of net additions of 2.0% expected here for 2006-2011.

A second fact is that while capacity may be physically installed, constraints of marketability, transportation infrastructure and refinery availability can undermine the utility of that capacity. Developments in early 2006 have amply demonstrated this. Saudi Arabia, Kuwait and Iran have faced problems marketing heavier/sourer crudes. Iraq and Nigeria have seen attainable production levels well below nominal capacity largely due to an inability to secure offtake because of unreliable pipeline export capacity and dysfunctional local refining systems. Installed capacity levels, while a useful guide, can nonetheless overstate the true degree of supply flexibility available to the market at a given point in time. A forthcoming medium-term supplement will address the issue of possible crude quality trends and the constraints these impose on effective spare capacity in more detail.

OPEC Crude Oil Capacity Developments

Saudi Arabia drives the expected increase in crude capacity, adding 1.6 mb/d on a net basis by 2011. *OMR* estimates of current Saudi capacity have typically come in lower than announcements from the Kingdom itself. However, this is more due to definitional differences than any inherent scepticism over Saudi physical capability. OMR estimates for OPEC correspond to capacity which can be activated within 30 days and sustained immediately thereafter for 90 days. Surge capacity is disregarded under this definition, as is capacity shut-in due to gas-flaring restrictions. In the case of the estimate for Saudi Arabia, the OMR also attempts to exclude condensate volumes and Bahrain's share of production from the Abu Safah field, amounting to a combined 300-400 kb/d.

Saudi Arabia has well documented plans aimed at pushing capacity to 12.5 mb/d by the end of the decade, with a further optional increase to 13.1 mb/d by 2013. The later increases are seen dependent on demand. Sequentially, the projections in this report assume new field start-ups as follows:

- Khursaniyah (Arab Light), 500 kb/d beginning in late 2007;
- Shaybah (Arab Extra Light), 200 kb/d starting in the second half of 2008;
- Nuayyim, (Arab Super Light), 100 kb/d from in the second half of 2008;
- Khurais (Arab Light), 1.2 mb/d starting from 3Q 2008;
- A 200 kb/d expansion of Partitioned Zone capacity shared with Kuwait, beginning in late 2009 and early 2010;
- A further 200 kb/d expansion from Shaybah entering service at mid-2010.

Estimated Average Sustainable OPEC Crude Production Capacity
(thousand barrels per day)

	2005	2006	2007	2008	2009	2010	2011	Increment[1] 06-11	National Government Forecast	National Government Applicable
Algeria	1345	1380	1380	1425	1510	1590	1595	215	2000	2010
Indonesia	990	990	975	985	1045	1090	1045	60	1150	2009
Iran	4035	4020	4235	4265	4155	4000	3930	-90	5200	2011
Kuwait	2525	2600	2645	2825	2840	2965	2945	345	4000	2020
Libya	1650	1730	1805	1820	1820	1820	1800	70	3000	2010
Nigeria	2545	2805	2935	2995	3050	3025	3120	315	4000	2010
Qatar	835	875	955	1055	1095	1165	1170	295	1175	2009
Saudi Arabia	10440	10725	10800	11170	11465	12260	12330	1605	12500	2010
UAE	2565	2675	2875	2885	2845	2900	3255	580	3500	2011
Venezuela	2705	2675	2620	2620	2620	2620	2620	-55	5400	2012
Sub-total OPEC 10	**29630**	**30470**	**31225**	**32045**	**32450**	**33430**	**33810**	**3335**	**41925**	
Iraq	2500	2500	2500	2500	2500	2500	2500	0	4000	2010
Total OPEC	**32130**	**32970**	**33725**	**34545**	**34950**	**35930**	**36310**	**3335**	**45925**	
Yearly Increment		840	755	820	405	980	375			

1 Increments may differ to those implied by displayed yearly data due to independent rounding.

Longer-term plans to add up to 1.0 mb/d of mothballed Arab Heavy crude at the Manifa development by 2013, with start-up in 2011, have been excluded from this forecast. Although this project has been sanctioned by Saudi Aramco, construction start in 2008 is believed subject to underlying demand. While increased volumes of Arab Heavy might be diverted by new-build complex refining capacity within the Kingdom, it is uncertain whether sufficient refiner demand will exist at that time in import markets elsewhere.

Decline rates for Saudi Arabia have been held within a 1-3% range depending on location. There has been much controversy lately over actual performance at baseload Saudi oilfields such as Ghawar. Clearly, if Aramco fails to meet its aspiration to boost drilling activity threefold by the end of the decade, it may struggle to attain target production levels. However, the company in the past has been adept at pre-ordering drilling capacity well ahead of requirements, making it well-placed relative to some of its competitors. With the bulk of Saudi expansions coming from onshore fields, for which prevailing global tightness in drilling capacity is less pronounced, so delays in obtaining rigs may be less prevalent than for other, notably non-OPEC, producers.

Probably the greatest uncertainty inherent in the OPEC crude capacity projections centres on prospects for **Iraq** and **Venezuela**. In the case of **Iraq**, hypothetically there seems the potential for capacity to reach levels between 3-4 mb/d by 2011, although latest government plans for 4.0 mb/d of capacity by 2010 appear optimistic, bearing in mind the absence of an investment framework and ongoing lack of security which plagues both export pipelines and domestic refineries.

There are upside and downside risks to this view on Iraqi capacity. On the upside:

- The key to short-term supply recovery, pipeline rehabilitation, could be quick;
- Iraq has a 'free pass' from OPEC, output unrestrained by quota below 3.5 mb/d;
- Ongoing reservoir studies for Kirkuk and Rumaila are being undertaken remotely by Shell and BP respectively, while Kurdish authorities have awarded development contracts for the Taq Taq and Tawke fields;
- Nine new 'priority' fields could add 1.9 mb/d of capacity (Majnoon, Nassiriyah etc.);
- 60% of proven reserves are located in yet-to-be developed fields;

- Iraq has very low costs – development costs are circa $1/bbl;
- Significant potential for increased recovery at existing fields with extra drilling;
- Established technical capability of Iraqi engineers;
- Iraq is under-explored (10% of country only) with significant reserve upside.

Downside risks, which underpin this report's more static capacity outlook, include:

- Sectarianism and the impact of Shia and alleged Iranian political agitation in the south;
- Corruption and oil products smuggling which are aiding the insurgency;
- Pipeline and refinery outages, power cuts and logistical problems;
- Widespread looting and sabotage, damage to gas-oil separator plants (GOSPs), compression stations, water injection facilities, pipelines and refineries;
- Extensive damage to Kirkuk reservoir through reinjection of crude and products;
- Ceyhan bottlenecks which could hamper northern export expansion;
- Lack of southern storage (<2 mb v 8-9 mb in the north);
- Recent lack of stability within the Oil Ministry and uncertainty over future constitutional/regulatory framework;
- No imminent prospect of IOC resumed 'on the ground' activity.

Until security and jurisdiction issues are resolved, it is impossible to be certain over any increase at all in capacity. For this reason, Iraqi capacity has been held steady at 2.5 mb/d, although upside potential into a range of 3-4 mb/d is possible if current instability recedes.

Expansion in **Venezuelan** capacity is also at risk following well documented retroactive changes to operating agreements with foreign producer companies. Previous service agreements have been converted into joint-venture companies in which state PDVSA holds a 60% interest, while royalty and corporation taxes have been increased to 33% and 50% respectively. Venezuela has struggled to deal with accelerating decline in western conventional crude output since a mass clear out of staff following the strike in 2002-2003. Partial offset has come from rising supplies of upgraded Orinoco synthetic crude however, which now amounts to some 630 kb/d. Oil policy currently appears designed to encourage participation of NOCs from politically sympathetic nations at the expense of the IOCs.

An examination of potential investment projects suggests that Venezuelan capacity could, under an optimistic scenario, reach 3-3.5 mb/d by 2011. This is based on a number of projects being brought to fruition to offset 10%-plus decline rates from mature areas. Nonetheless, national targets of 5.5-6.0 mb/d capacity by 2010 look hopelessly overoptimistic given the slant of upstream investment policy as it currently stands. That said, recent strong export revenue flows and the prospect of increased Latin American and importer country NOC activity hold out the prospect of some upstream progress relative to mid-decade stagnation. Increments to capacity could potentially come from:

- The western region with ongoing Tomoporo field expansion and commercial output from La Ceiba;
- Further east, Corocoro, Jusepin expansion, and new output from El Furrial and the Gulf of Paria;
- The San Cristobal project, with 200 kb/d of new heavy Orinoco output, and upwards of 150 kb/d of new syncrude capacity from 2010 (although ambitious Orinoco expansion plans by existing producers Conoco, Total and Chevron have been put on hold).

However, so uncertain is the political and investment framework going forward, that we do not feel comfortable assuming any net increase from Venezuela at the current time. Upside potential is clearly possible, notably if there is an influx of foreign NOC capital. However, a disengagement of private IOCs from the country, at least in terms of new investment, is also a distinct possibility.

In contrast, active foreign company involvement on comparatively benign economic terms could see recent capacity increases being sustained from **Algeria**, **Qatar** and the **UAE**. These three producers are expected to add over 1.0 mb/d of capacity on a net basis by 2011, led by the **UAE**. Abu Dhabi drives the increase here, with potentially another 300 kb/d of capacity from the onshore Murban stream, 100 kb/d at offshore Upper Zakum involving ExxonMobil, and another 200 kb/d from the offshore Umm Shaif complex, involving BP and Total. Significant gas development plans also promise to free up crude and gas liquids currently restricted by gas-flaring limitations. Dubai production however appears to be on a declining trend. UAE capacity is seen reaching 3.25 mb/d by 2011, only marginally below a government target of 3.5 mb/d.

A similar picture emerges in Algeria and Qatar. **Algerian** capacity rises further from 1.4 mb/d in 2006 to 1.6 mb/d by 2011 on the strength of expansions at Hassi Messsaoud and through EOR at Hassi Berkine North East. Algerian capacity has increased by 0.5 mb/d since 2000 and current output close to 1.4 mb/d is way above its OPEC production quota of 0.89 mb/d. **Qatar** too is producing some 100 kb/d above its quota level and has significant expansion plans based on Maersk's Al Shaheen development. Capacity here is seen doubling to 525 kb/d by 2011, taking the Qatari total to around 1.2 mb/d from 0.9 mb/d in 2006. Stability of investment regime, strong foreign operator presence and a raft of new development projects for both oil and gas are factors which these three producers have in common. Project attainment has been markedly closer to government plans in recent years. If repeated, the record of recent production increases could win for these producers greater internal influence within OPEC over the medium term.

Kuwait has longer-term plans of attaining 4.0 mb/d of capacity by 2020. Proposals for expansion of northern fields with hitherto-precluded foreign company involvement under the so-called 'Project Kuwait' have yet to gain political approval. Plans call for boosting capacity to 900 kb/d from 535 kb/d currently. Both KPC and the current cabinet firmly back the plans, but such has been the extent of delays here that these are excluded from our forecast until their political fate becomes clearer. The forecast does however assume a 200 kb/d increase to 1.7 mb/d in southern Burgan field capacity and the increments to Partitioned Zone capacity mentioned in the Saudi Arabia discussion, above. A modest, 100 kb/d net expansion is factored in for the western fields at Minagish and Umm Gudair also. This takes Kuwait's installed capacity from 2.6 mb/d to 2.8 mb/d in 2008 and 2.9 mb/d in 2011.

Nigerian capacity has been held unchanged in the *OMR* for some months at 2.6 mb/d, despite start-up at deepwater projects such as Bonga and Erha (developed by Shell and ExxonMobil respectively), originally scheduled to take capacity to around 2.8 mb/d this year. Shut-in production due to rebel activity in the Niger Delta has however offset the increases in the deepwater. Outages at times have hit 600 kb/d. The working assumption of this forecast is that damage to Delta facilities does not prove long lasting, and that a limited number of deepwater development projects allow capacity to attain 3.1 mb/d by 2011. Increases come from a build up in Bonga supply, enhanced recovery at the shallower water EA field, and Chevron's 250 kb/d Agbami project from 2008. More tentative projects are excluded. The rise in capacity versus current production near 2.2 mb/d looks ambitious, but is nonetheless well below the government's 2010 target of 4.0 mb/d.

Indonesia, Iran and Libya face the prospect of a fairly flat capacity profile during the 2006-2011 period, albeit for very different reasons. In **Indonesia**, an improving but still marginal investment regime has to date largely precluded the presence of the largest international companies. Mature fields offshore Java, Sumatra and Kalimantan are in decline, as is onshore Duri and Minas production in Sumatra. In the medium term, significant increments centre on the Cepu block onshore Java, which should attain peak 170 kb/d under phase one development by 2010. Lesser increases come from the Jeruk, Oyong, Attacka South and North Belut fields which should build to a collective 160 kb/d. However, these are only sufficient to counteract baseload decline, holding Indonesian capacity flat at 1.0 mb/d.

Iran has much more ambitious plans, which envisage capacity reaching 5.2 mb/d by 2011. However, even before recent geopolitical tensions took centre stage and placed additional uncertainty around investment prospects, there were real doubts that capacity could come close to such exalted levels. Decline rates at aging onshore fields are reported by the government to be around 8% annually. The 'buy-back' system of service contracts offered to foreign operators is widely seen as unattractive and revisions to the basic format are currently being examined. Mandatory local supplier content is reported to be delaying some development projects, and discoveries such as the long-delayed Azadegan are seen to be increasingly technically complex. The most recent attempt to increase capacity to 4.2 mb/d has been stalled by marketability and technical problems at the 190 kb/d offshore Soroush/Nowruz fields which produce very heavy/sour crude.

Short-term increments to supply are expected to come from the Karanj-Parsi, Darkhovin, Salman, Foroozan and Douroud projects plus assumed attainment of capacity at Soroush/Nowruz, all however over a longer time schedule than suggested by original plans. Longer-term increments come from

Azadegan and Yadavaran for a combined 350 kb/d. However, start-up at these two projects (involving Japanese and Chinese/Indian interests respectively) is assumed to be pushed back to 2010/2011.

The combination of political, economic, regulatory and technical delays, plus ongoing decline assumed at 8-10% annually restricts Iranian capacity to 4.25 mb/d by 2008 and 3.95 mb/d by 2011. Based on reserves, this is a very conservative forecast, but in the absence of significant improvements in Iran's upstream investment environment it is difficult to see higher capacity levels being attained.

Libya has the potential for significant capacity expansion but, after years of economic isolation affecting US companies, is only now seeing a broad based influx of foreign investment in upstream activity. To date, there is a paucity of firmly scheduled new field investment projects. Expansion comes from Al Jurf, the Waha EOR project, at El Shahara and Elephant and at the NC 186 group of fields. However these only offset declining production from older facilities, leaving Libyan capacity close to 1.8 mb/d throughout the forecast period. Physical potential is markedly higher, although a government target of 3.0 mb/d by 2010 for now looks over ambitious bearing in mind new project lead times.

REFINING

Summary

- Global crude distillation capacity is expected to increase by 11.7 mb/d during the 2006-2011 period. New investments should add 10.3 mb/d of crude distillation capacity from known refinery start-ups and the expansion of existing facilities. A further 1.4 mb/d of growth in distillation capacity is expected to come from capacity creep in North America, Europe and the Pacific.

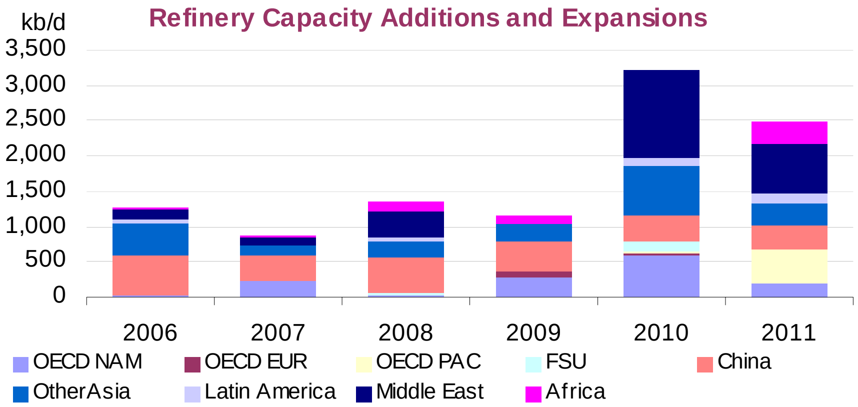
- Distillation capacity growth is expected to lag demand growth during 2006-2009. However, we expect to see a large number of world-class refineries start-up during the 2010-2011 period, with growth reaching a peak in 2010 at 3.2 mb/d. The 10 largest projects in 2010-2011 will deliver 3.7 mb/d of new capacity.

- The Middle East and Asia Pacific regions will account for 7.2 mb/d of new refining projects. Investment in the US and Europe will focus on refinery expansions and upgrading capacity, with no new-build refineries expected on-stream during the period.

- Significant increases are expected in global upgrading and hydrotreating capacity over the period. The incremental light product yields associated with this investment, combined with refinery expansions and the rising supply of biofuels may reduce the call on hydroskimmming refineries to meet incremental demand by 2011.

- Tighter quality specifications will become more common over the period. More restrictive quality specification have fragmented product markets and contributed to increased capital costs for new-build refineries.

- Gasoline supply potential is expected to outstrip demand in volumetric terms. However, tighter quality specifications may continue to support cracks at levels above historical norms. As highlighted elsewhere in this report, ethanol will capture an increasing share of the gasoline market, with supplies reaching 1 mb/d by 2011.



Source: IEA, Purvin & Gertz Inc.

- Diesel and jet/kerosene markets appear tighter relative to gasoline. Strong demand growth for diesel in Europe and Asia and the spread of ultra low sulphur diesel will keep jet yields under pressure. Towards the end of the decade distillate market tightness should ease, helped by the rise in biodiesel production which we assume will plateau at 213 kb/d post-2008.

- Fuel oil markets should see broadly stable demand over the period to 2011, while production is expected fall with the start of new upgrading capacity. Refineries are planning to increase flexibility to process heavy, sour crudes which are currently at significant discounts to light sweet grades and this will allow them to produce more of the feedstock required on-site. However, increases in Russian fuel oil exports, or hydroskimming refinery throughput, could perpetuate the current glut of fuel oil.

Methodology

The analysis of the growth prospects for the refining industry should give us an insight into the supply and demand balance for product markets in the medium term. Tight product markets in 2006 have witnessed light products cracks above $20/bbl in the US, Europe and Asia, with gasoline cracks above $50/bbl on the US West Coast. Conversely, fuel oil cracks have fallen below -$20/bbl. To assess how these markets will develop we have forecast additions to refinery capacity under three broad categories:

- New refinery construction and expansion of existing facilities, including condensate splitters;
- Stand-alone investment in upgrading capacity, including coking, hydrocracking, and catalytic cracking units;
- New capacity additions of desulphurisation and hydrotreating capacity.

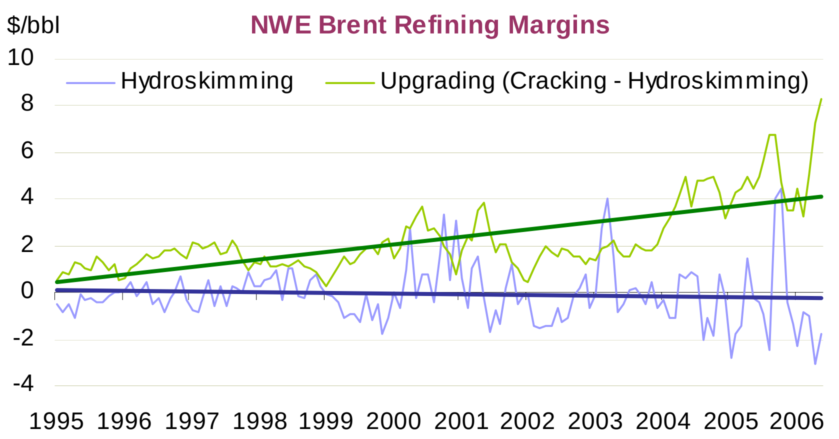
In addition to the named projects, we have assumed that capacity increases of 0.5% per year from capacity creep in North America, Europe and OCED Pacific. These increases are a result of debottlenecking and small-scale investments which are not publicly reported and form part of ongoing maintenance and investment programmes. For each of these investment categories we have applied a product yield matrix, based on existing refinery yields and the expected complexity of new units, to derive a forecast of incremental product supply. From this product supply estimate we have generated product market supply and demand balances using the forecast growth in demand.

Refinery Economics

Refining margins are the sum of the individual product cracks (the difference between the product and crude values) for various refinery configurations. The more complex refineries, producing a greater proportion of light products (and in the case of coking refineries this is almost 100%) generate higher margins, while hydroskimming refineries with fuel oil yields of up to 50% typically have had margins of around zero.

Margins can be thought to have two distinct components. Firstly, there is the profit generated by the simple process of distilling crude into its component parts: light and middle distillates and atmospheric residue (fuel oil). This is typically referred to as the hydroskimming margin. Secondly, there is the value added from upgrading the low value fuel oil, into higher value products either through cracking, hydrocracking or coking.

The difference between the complex and hydroskimming margins is referred to as the upgrading margin. As can be seen in the graph below, average Northwest Europe hydroskimming margins over the last 10 years have been approximately zero. Conversely, the upgrading margin has been rising steadily over the period, suggesting a decline in spare upgrading (and, more recently, desulphurisation) capacity.



Increasing global refinery utilisation rates suggest that complex refineries (and their upgrading capacity) which can produce virtually no fuel oil, are fully utilised and that hydroskimming refineries, where up to half the output can be fuel oil, have acted as the marginal supplier of products to meet demand. It follows that hydroskimming refineries are, therefore, the marginal buyer of crude. Because of the tight spare capacity and the need for simple refineries to help meet light product demand a glut of fuel oil has emerged. To compete with alternative fuel sources in the electricity generation sector (such as gas and coal) the price of fuel oil has to be discounted. Consequently, the marginal buyer of crude is prepared to pay a premium for light sweet grades, which have a lower fuel oil yield, compared to medium and heavy crudes.

Average Refining Margins in Major Refining Centres

($/bbl)

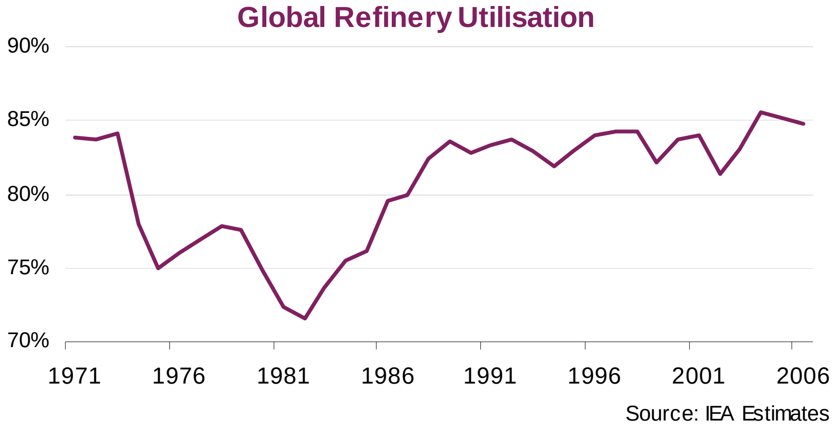
		1995-1999	2000-2004	2005	Last 12 Months
NW Europe	Brent (Cracking)	1.21	2.46	4.67	4.45
	Urals (Cracking)	1.11	4.08	7.41	6.80
	Brent (Hydroskimming)	-0.16	0.09	-0.16	-0.48
	Urals (Hydroskimming)	-0.82	0.36	0.33	-0.15
Mediterranean	Es Sider (Cracking)	1.07	2.84	5.79	5.13
	Urals (Cracking)	1.14	3.77	6.47	5.92
	Es Sider (Hydroskimming)	-0.50	0.22	0.72	0.07
	Urals (Hydroskimming)	-0.45	0.08	-0.88	-1.20
US Gulf Coast	Brent (Cracking)	-0.14	0.41	2.48	3.32
	LLS (Cracking)	0.13	1.16	5.02	6.11
	Mars (Cracking)	n/a	1.46	2.92	4.39
	Mars (Coking)	n/a	3.96	9.95	11.06
	Maya (Coking)	2.60	5.21	14.72	14.99
US West Coast	ANS (Cracking)	1.85	3.54	5.39	5.58
	Kern (Cracking)	3.40	3.71	6.11	5.94
	Oman (Cracking)	0.87	2.77	4.86	5.15
	Kern (Coking)	5.63	7.89	17.40	16.86
Singapore	Dubai (Hydroskimming)	0.07	-0.33	-0.33	-0.73
	Tapis (Hydroskimming)	-0.60	-1.46	-3.62	-4.16
	Dubai (Hydrocracking)	0.97	0.94	3.72	2.99
	Tapis (Hydrocracking)	-0.02	-0.81	-1.19	-1.92
China	Cabinda (Hydroskimming)	-0.48	-1.12	-2.33	-2.92
	Daqing (Hydroskimming)	-1.48	-1.82	-4.20	-3.41
	Dubai (Hydroskimming)	0.13	-0.55	-0.72	-1.18
	Daqing (Hydrocracking)	0.20	-0.06	-0.07	0.58
	Dubai (Hydrocracking)	1.24	0.77	3.33	2.55

For the purposes of this Report, refining margins are calculated for various complexity configurations, each optimized for processing the specific crude in a specific refining centre on a 'full-cost' basis. Consequently, reported margins should be taken as an indication, or proxy, of changes in profitability for a given refining centre. No attempt is made to model or otherwise comment upon the relative economics of specific refineries running individual crude slates and producing custom product sales, nor are these calculations intended to infer the marginal values of crudes for pricing purposes.

*The China refinery margin calculation represents a model based on spot product import/export parity, and does not reflect internal
Sources: IEA, Purvin & Gertz Inc.

The low price of fuel oil, relative to crude, has resulted in a widening of the differential between light sweet and heavy sour crude prices. This in turn has supported the higher margins and superior returns that complex refineries have seen on processing heavy, sour crudes in recent years. The prospects for fuel oil production, and for light/heavy crude price differentials, is central to the future level of refining margins and the returns that refiners can expect to receive on future investment in additional capacity.

Another major factor for margins in the medium term is the effectiveness of spare capacity acting as a protection against product supply disruptions and price volatility. This was clearly demonstrated in the autumn of 2005 when the US hurricane season shutdown a large proportion of Gulf Coast refining operations. Yet, despite the record-breaking margin environment that ensued, some refiners with apparent spare capacity failed to increase runs. Russia's nameplate spare capacity of 5.4 mb/d may overstate effective spare capacity by up to one million barrels per day. Elsewhere in the FSU, Ukrainian crude runs have been 300-400 kb/d below nameplate capacity for almost two years. Similarly, Nigerian crude runs, even before the first quarter sabotage of crude supplies to some refineries, have been more than 200 kb/d below nameplate capacity for several years. This suggests that effective spare capacity may be as much as 1.5 mb/d below what headline numbers suggest.



In Europe, the ongoing dieselisation of the car fleet is putting pressure on refiners to maximise diesel production at the expense of jet fuel and gasoline. In the short term, some optimisation of existing fluid catalytic cracking capacity (FCC units) can boost distillate yields, but this additional distillate production is of poor quality and requires further hydrotreating to be of use. Furthermore the associated reduction in FCC gasoline quality places a limit on refiners' flexibility.

Increased investment in hydrocracking units would appear to be the obvious solution to meet incremental diesel demand, as these are capable of producing ULSD and jet fuel. However, European refiners will remain cautious over such costly capital investment unless they can be reasonably confident about several key factors. Firstly, hydrocrackers compete with FCC units for vacuum gasoil (VGO) as a feedstock. As an existing FCC unit generates a substantial portion of the overall refinery margin by upgrading VGO primarily in to gasoline, expectations for future gasoline cracks would need to be substantially below those of diesel and jet fuel. Secondly, the additional hydrogen required to run a hydrocracker needs to be secured, either through long-term purchase or additional capital investment.

Refiners may opt to run both a hydrocracker and FCC together but this would require additional supplies of VGO, either from the market, or from higher on site production of VGO, by the expansion of atmospheric and vacuum distillation capacities. This latter option would increase the capital expenditure for the expansion. Ultimately, individual refineries in Europe or elsewhere are unlikely to remove the profitable upgrading process of catalytic cracking and replace it with a hydrocracker until such time as the prospects for gasoline cracks are materially weaker than those for diesel and jet fuel.

Refinery Capital Costs

Industry cost estimates for a new-build cracking refinery in Europe or the US have risen from around \$15,000 to \$20,000 per barrel per day of capacity. Hence the capital investment needed for a 200 kb/d refinery has increased from around \$3bn to approximately \$4bn. This reflects the rising cost of raw materials and tight oil service and fabrication markets. Furthermore, the tighter product specifications now in force in many parts of the world require additional processing and hydrotreating of fuel streams, further increasing costs. Lastly, in addition to the tighter fuel quality regulations, enhanced environmental emissions regulations have also increased refinery capital costs. Recent evidence suggests that escalating cost pressures for refinery construction has lead to the cancellation or postponement of projects and is one of the factors we consider for the viability of future projects.

Industry estimates indicate that a new 200 kb/d refinery, costing \$4bn, requires average margins in excess of \$6.50/bbl for the next 20-25 years to achieve a 10% internal rate of return. This level of profitability is comparable to the 2005 average margin for Urals cracking in Europe, but is 150% higher than its 10-year average. The recent increase in construction costs suggests that new-build refineries may still be uneconomic in Europe and the US despite historically high margins, limiting the region's prospects for new-build refinery capacity. Asian countries such as China have access to lower-cost domestic construction industries, which can reduce capital costs of a new refinery by as much as one-third, boosting regional prospects for new refineries.

There are two further alternatives to the high cost of a new-build refinery. Firstly, refiners can opt to build a condensate splitter at a small fraction of the cost of a modern complex refinery. These units process super-light crude, which yields a mixture of LPG, naphtha, jet and low-sulphur gasoil, but little or no fuel oil. The lower capital cost is offset by the higher feedstock costs and lack of exposure to changes in heavy crude discounts. Secondly, refiners can seek to reduce exposure to low value fuel oil production by investing in upgrading capacity. Here the capital and operating costs can be higher than a new-build refinery, but current price differentials offer higher margins as feedstock costs are at significant discounts to crude. The problem that refiners face is whether current incentives will be sustained long enough to justify the investment. Oil industry executives note that current margin levels are less relevant to investment decisions for new capacity, given the long planning and construction lead times.

Refinery operators acknowledge that the capital cost of increasing capacity through debottlenecking and capacity creep can be as much as be 60-70% less than new-build refineries, depending on the scale and type of investment. This lower capital cost provides existing operators with a competitive advantage over new entrants in terms of the margin level at which they meet their cost of capital on new investment. Furthermore, the gradual expansion of capacity allows better integration of facilities into petrochemicals and downstream operations, allowing refiners to capture revenue and cost synergies. The incremental approach to investment also allows operators to adjust capacity expansion plans to reflect changes in demand more rapidly. While the prospects for new-build refineries to deliver returns above their cost of capital look mixed, it is interesting to note that US independent refiners such as Valero estimate an average internal rate of return of 30% from current capital expenditure programmes.

The Impact of Tighter Product Specifications

The past decade has seen widespread and rapid changes to product specifications. Refiners within Europe, Japan and the US have been required to invest substantial amounts to keep their refinery output in line with the stricter quality specifications. Their governments' policies have reduced on-road diesel-sulphur levels from 350-500ppm to 15-50ppm, with Europe moving to 10ppm sulphur at the end of the decade. Gasoline quality specifications have been similarly tightened with lower sulphur, aromatics and benzene levels allowed.

Refiners within a region which tightens product specifications are effectively forced to upgrade facilities to meet new quality specifications. However, markets which rely on product imports to meet marginal product demand effectively reduce their ability to source alternative supplies. Previously imports could be sourced from many possible merchant refiners. However, now only those who have chosen to match the domestic refiners in investing in improved quality levels will be able to supply products. Hence tighter quality standards, while undoubtedly better for the environment, reduce industry flexibility and fragment product markets. The most obvious example in recent years has been the US where a proliferation of boutique fuel grades has led to reduced supply flexibility and thus probably contributed to higher margins. This is particularly true on the West Coast, where geographical issues and tight product specifications keep regional gasoline prices well above those in the rest of the US.

Conversely export refiners who fail to invest in a timely fashion have seen traditional markets move beyond their production capabilities. Alternative export markets must be found to absorb production above their domestic deliveries. Ultimately, they too may be forced into upgrading product quality through additional investments, or accept lower values for production which would be sold as intermediate blend-stock for further processing elsewhere.

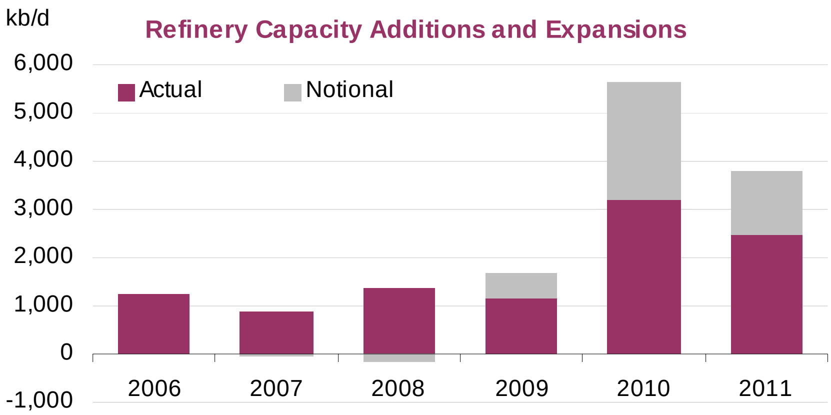
New technologies and catalysts offer the prospect of further increases in light product yields. Eni recently announced the start-up of its high pressure hydro-conversion using a slurry catalytic system, which treats heavy residues and achieves a 98% conversion into light products. Severe hydrotreating of distillates can produce ULSD and offers an alternative to investment in a coker. Similarly, new generation catalysts have improved hydrogen utilisation for distillate hydrotreating and, in combination with reduced capital and operating costs for managing hydrogen production and recovery, create opportunities for increased ULSD production.

Refinery Expansion Plans

Refinery expansion plans have historically required around three years from the final capital investment decision to start up. However, in the current tight market conditions in the oil service and fabrication industries and with some refinery construction firms having full order books for the next two to three years, it appears likely that 2010-2011 is a more realistic start-up for new-build refineries under consideration today. Depending on the scale and complexity of the project being considered, we expect to see longer lead times, of between three to five years. However, countries such as China remain capable of moving more quickly given their domestic fabrication capabilities.

The expansion of refining capacity exhibits certain regional trends. OECD-based refiners are investing in upgrading capacity, rather than new refineries, reflecting the lower domestic demand growth prospects, declining demand for fuel oil, and rising supply of biofuels. Industry executives have highlighted the easier planning and permitting process that refinery expansions face, in addition to the lower capital expenditure when compared to green-field projects.

Given the significant delays that can occur from obtaining permits and other regulatory hurdles, grass-root refinery project timing and viability is the hardest aspect to assess. The poor financial track record of the refining sector, coupled with rising capital costs, suggests a significant number of proposed projects will remain in the planning stages. Permitting delays appear most acute in the US where grass-root refineries are almost unheard of these days. Despite a recent survey suggesting that environmental permits are not a stumbling block, even senior US government officials admit it can be a tortuous process to get the required permits.



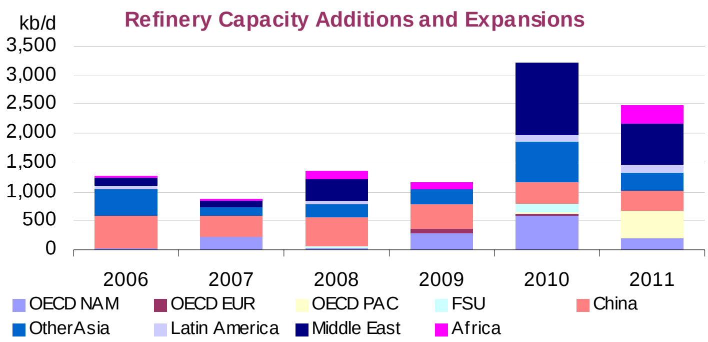
Source: IEA, Purvin & Gertz Inc.

We have assessed new-build refinery projects on a case-by-case basis to determine the likelihood that refineries that have been announced will ultimately be built within the time horizon. Factors influencing our opinion on whether a project will be completed include prior corporate track record, the location of the project and the sponsor's access to capital markets for project finance. In total, some 15.1 mb/d of new capacity has been announced for completion before 2011. We doubt, however, that many of these grass-root refineries will be completed and believe they are driven by a combination of political, nationalistic or competitive and strategic reasons, rather than a genuine need to refine oil.

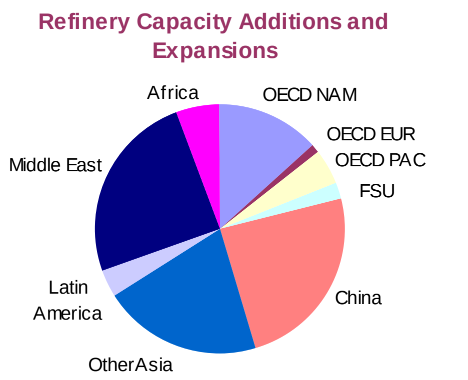
Consequently, we expect net additions to refinery capacity for the 2006-2011 period to be 10.3 mb/d. In addition to the named projects, we expect the refining industry to expand capacity by around 0.5% per year through capacity creep in North America, Europe and OCED Pacific. These increases are a result of debottlenecking and small-scale investments which are not publicly reported and form part of ongoing maintenance and investment programmes. Adjusting for these increases, the total increase in refinery capacity is 11.7 mb/d

Refinery capacity growth is centred on Asia (4.6 mb/d), the Middle East, (2.6 mb/d) and North America, (1.4 mb/d). OPEC member countries are expected to account for 3.0 mb/d of new-build distillation capacity, some 30% of total refining capacity additions. Similarly, national oil companies are involved in 7.1 mb/d of new capacity additions, around two-thirds of overall growth. The increase in Asian capacity is expected to occur primarily in China, (2.5 mb/d) and India, (1.7 mb/d).

China's lower construction costs, forecast strong demand growth, and security of supply issues, provides additional justification for refinery operators to build new capacity here; despite the fact that government product-pricing policies reduce the incentive to refine crude for domestic markets. Indian domestic product prices are also subject to price caps however refinery expansion plans are aimed at increasing product exports as well as meeting domestic demand, thus providing some incentive to invest. It is ironic that these two countries, as well as some Middle Eastern states, which account for



Source: IEA, Purvin & Gertz Inc.

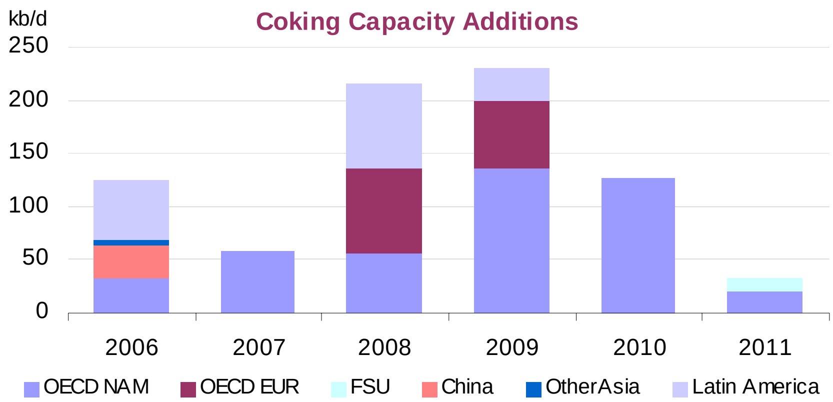


Source: IEA, Purvin & Gertz Inc.

much of the forecast increase in world refining capacity should have such poor domestic economic incentives for new refineries.

It should be noted that out of the 100 new projects we have included in our estimate, the 10 largest projects account for 3.7 mb/d of the growth. We expect all these projects to start in 2010-2011 and delays to these projects could substantially alter the outlook for product supply. It is also worth noting that there are further large increases to capacity proposed for the 2012-2015 period. While beyond the scope of this report, we remain sceptical about the viability of some of these additional projects given rising capital costs.

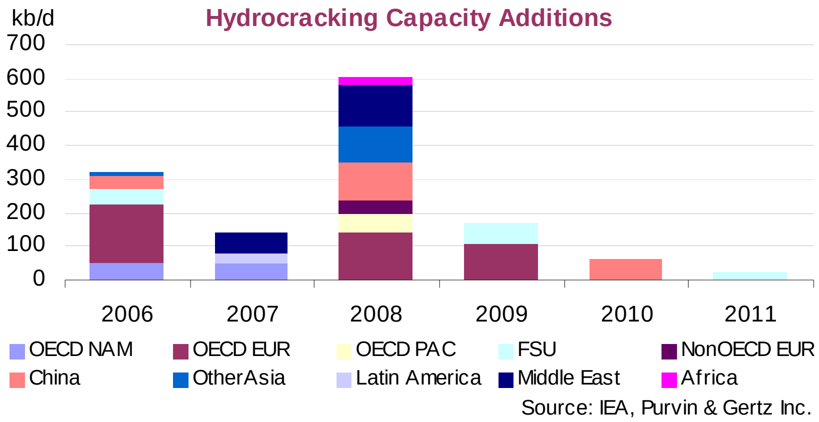
We have assumed that the majority of the announced upgrading or fuel quality-related projects will happen as many of these projects are needed to ensure that products meet tighter fuel quality specifications. Furthermore, the widening differentials between light products and fuel oil underpin the economics of upgrading units, with some reports suggesting an investment payback period of between one to three years is feasible.



Source: Purvin & Gertz, IEA

Additional coking capacity is expected to total close to 800 kb/d during 2006-2011. North America will account for more than half of this increase. Rising Canadian synthetic crude supply and the reversal of key crude oil pipelines have spurred refiners in the northern states to invest in coking capacity to capture widening heavy/sour crude differentials. This second wave of coking investment follows the Gulf Coast building programme, prompted by the increased availability of heavy Mexican and Venezuelan crudes, in the early to mid 1990s. Further additions to coking capacity will occur as part of the US refinery expansion programme, expected online in 2009-2010. During 2008-2009 new projects in Europe, driven by refiners minimising fuel oil production and in Latin America, where increasing supplies of heavy crude have encouraged investment, will match North American additions.

Additional hydrocracking capacity will be more geographical diverse than that seen for new cokers. It is forecast to be concentrated in Europe, Asia and the Middle East. We expect almost 1.3 mb/d of new capacity on-stream in the 2006 to 2011 period. One third of these new units are forecast to be in Europe, with a further 25% in Asia and 25% in the Middle East and FSU. New capacity additions are expected to be the peak in 2008, with some 584 kb/d due to start up. The adoption of tighter European sulphur specifications in 2009 and the prospect of some Asian countries, such as China, adopting lower sulphur specifications for diesel by the end of the decade should mean that these projects will become a reality.



Global distillation capacity utilisation rates are expected to remain strong during the 2006-2009 period as capacity additions lag demand growth. However 2010 and 2011 should see rapid increases in refinery capacity, suggesting average utilisation rates will fall over this latter period. The ratio of upgrading capacity to global demand is expected to rise over the balance of the decade, suggesting rising supplies of light products. However, while our projection is for a declining upgrading ratio post 2010, the shorter lead time for installing individual upgrading units suggests this may be a false indication and that further projects may be announced and brought into service by then.

Regional Analysis of Capacity Expansion

North America

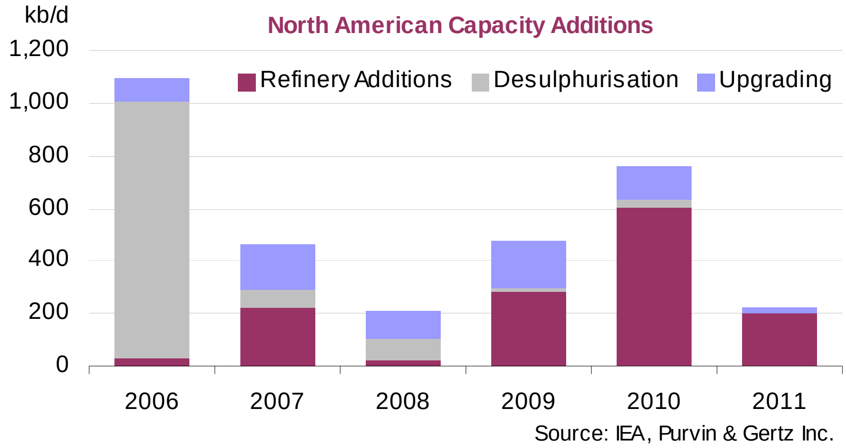
We expect North American refiners to add 1.36 mb/d of crude distillation capacity between 2006 and 2011 through announced projects, representing a compound annual growth rate of just over 1% from current levels. Including our expectation of a further 0.5% increase from capacity creep implies an overall increase in North American capacity of 2.0 mb/d over the period.

US refiners contribute, 1.2 mb/d of the 1.36 mb/d increase. The expansion of Mexico's Minatitlán refinery will account for the remainder of the growth. Provisionally, we have included this refinery expansion as starting in 2009, compared to recent PEMEX statements that it will be ready in 2008, but we recognise that further delays to our forecast are possible given the tight oil service sector and escalating cost pressures.

Investment in expanded crude processing in the US is, in many instances, closely linked to the expansion of upgrading capacity, as refiners seek to increase their plant's complexity and benefit from processing more of the cheaper, heavier, sour crudes. The bulk of this expansion is expected to come from recently announced projects due online after 2008. These projects are in response to the improved refining margin environment and increased willingness by private sector companies to commit capital to the sector.

Chevron's planned 200 kb/d expansion at its Pascagoula site and Marathon's 180 kb/d expansion of the Garyville refinery in 2009 plus Motiva's 325 kb/d expansion of its Port Arthur facility due for completion in 2010 are equivalent in size and complexity to new-build refineries. The operators are benefiting from the less-restrictive environmental permitting process and reduced capital cost of using existing sites for the expansion. These projects are expected to incorporate significant upgrading capacity, boosting light product yields. Further large-scale projects are possible with Kuwait considering the possible construction of a 250 kb/d refinery in the US and a new 300 kb/d refinery being considered for North-Eastern Canada. Currently however, we have excluded these two projects from our forecasts, pending further confirmation.

In addition to these named projects, we expect the North American refining industry to expand capacity by around 0.5% per year through capacity creep, arising from small-scale investments which are not publicly reported and form part of ongoing maintenance and investment programmes.



US refiners, in addition to the increased refinery capacity outlined above, continue to invest in upgrading and hydrotreating capacity. We estimate that 425 kb/d of stand-alone coking capacity will be brought on-stream before 2011, as refiners seek to add flexibility to their operations to benefit from the projected increase in Canadian sour and synthetic crude production. This expansion of coking capacity represents an increase of 17% from current levels and is centred on refineries in the Mid-West and Northern states. Further expansion of coking capacity is expected as part of the Chevron, Marathon and Motiva refinery expansions.

Tighter diesel-sulphur specifications in the US and Canada, which have both mandated 15ppm sulphur limits, has led to North America dominating worldwide investment in hydrotreating capacity in 2006. The installation of this capacity has led to the heavy spring turnaround programme seen in the first half of this year in the US. Investment in hydrocracking capacity, concentrated in the Mid-West and Northern states should add 99 kb/d of new projects during 2006-2007. Valero is adding hydrocracking capacity at its Lake Charles and Houston facilities, (although the timing of these investments is slipping due to tight construction and labour markets in the Gulf Coast). In addition, Marathon's Garyville refinery expansion in 2009 is expected to include a 40 kb/d hydrocracker.

Canadian expansion plans in the downstream look set to undershoot the expected increase in Canadian crude oil production. Limited local demand and the expansion of crude export pipeline capacity to move oil to the US Mid-West and as far as the Gulf Coast have removed much of the need for such investment. However, in the short term, Canadian refiners are investing to meet the more stringent product quality requirements.

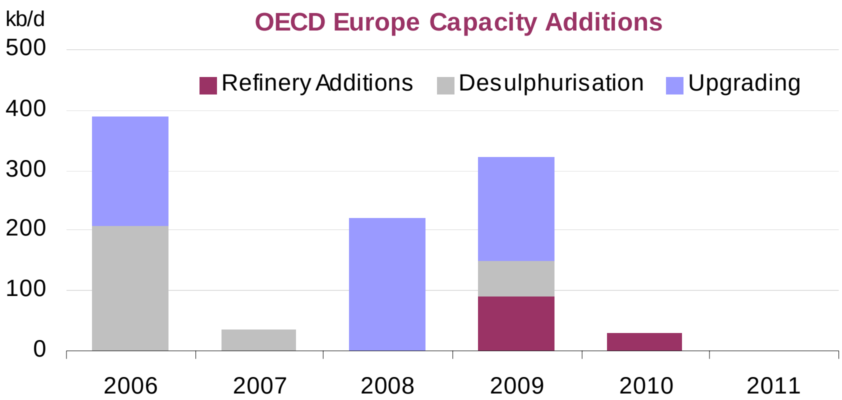
The recent switch by refiners to using ethanol instead of MTBE in gasoline production has increased the need for additional low volatility blending components to offset ethanol's higher volatility. This suggests that to compensate refiners are likely to need to invest in increased production of low volatility, high octane blending components such as alkylate or ETBE. Few such investments have been flagged, suggesting that conversion of existing MTBE capacity, or other low cost approaches, are being considered.

OECD Europe

There appears to be little prospect of large-scale expansion of European crude distillation capacity in the short to medium term. Only one new grass-roots project has been proposed, a 300 kb/d complex refinery at Sines in Portugal, but the tentative nature of the project precludes us from including it at this stage.

There are, however, a significant number of upgrading and product quality investments due to come on stream before 2011. Refiners in Europe appear to be wary of investing against a backdrop of growing biofuels market penetration and the threat from additional gas-to-liquids (GTL) projects. Some estimates suggest that biofuels could capture the majority of European volume growth over the next five years (and indeed 25 years) if the European Union pushes ahead with reported biofuels-friendly legislation.

GTL has the potential to supply large quantities of sulphur-free, high cetane distillate to European markets, in competition with refinery expansion plans which are focused on additional hydrocracking capacity. The start-up of the Oryx GTL plant in Qatar in 2006 will add 35 kb/d of light products supply when it reaches full capacity and is the equivalent of a new hydrocracker. We expect the expansion of Oryx GTL to 100 kb/d is still likely in 2010. Two further projects in Qatar, involving Shell and ExxonMobil are unlikely to come on-stream before 2011, as rising industry cost pressures, and more pragmatic approach from the government in Qatar may delay these projects. Essentially, European refiners appear wary of investing in a market with limited growth and in which they are likely to see a declining market share.



Source: IEA, Purvin & Gertz Inc.

Investment in hydrocracking capacity tops the list of planned European expansions, reflecting the region's reliance on middle distillate imports, particularly of diesel and jet fuel. We estimate that 426 kb/d of new hydrocracking capacity will be commissioned through to 2011, evenly split between the Mediterranean and North West Europe. All of the announced projects are due on-stream ahead of the EU mandated move to 10ppm sulphur diesel in 2009.

Several refiners, notably in Spain, are investing in coking capacity with approximately 145 kb/d due on-line before the end of 2009. These investments will boost gasoline and (in conjunction with new hydrocrackers) distillate yields at the expense of fuel oil production. Other investments include additional naphtha reforming capacity as refiners seek to boost gasoline quality and hydrogen production needed for distillate hydrotreating.

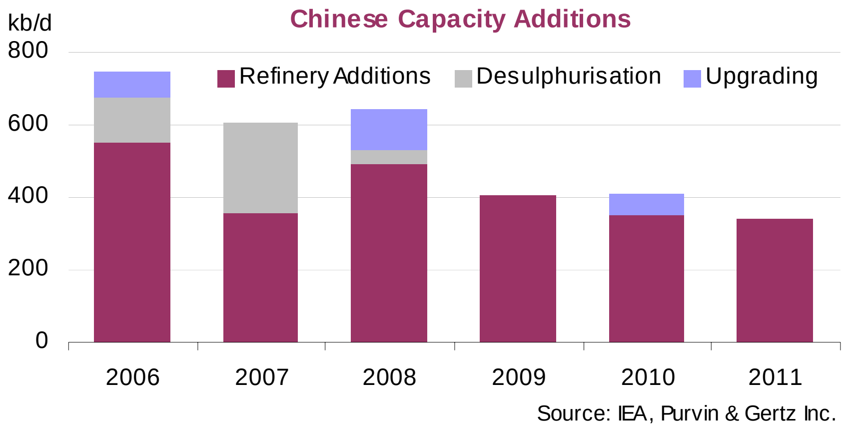
OECD Pacific

Visible expansion plans in the OECD Pacific region are among the lowest globally. This is partly due to recent investment to comply with the introduction tighter product specifications but also spare capacity and declining demand. Furthermore, the high levels of investment activity in the non-OECD Asia region (and the fact that the recovery in margins and throughputs in Asia Pacific has lagged behind other regions) may be swaying refiners to delay large investments in OECD Pacific countries.

Only one significant refinery expansion is expected during 2006 to 2011 in the region. We currently expect S-Oil's proposed 480 kb/d expansion in Daesan, South Korea to be commissioned in 2011. In addition to the designed distillation capacity of 480 kb/d, reports suggest the plant will include a 75 kb/d residue fluid catalytic cracker and a 75 kb/d hydrocracker to minimise fuel oil production.

China

China's refining industry is forecast to continue its recent role as one of the powerhouses of refinery capacity expansions. Total capacity growth from known projects is likely to be 2.5 mb/d, nearly 25% of global forecast growth. The expansion plans are dominated by the two national oil companies, PetroChina and Sinopec. The liberalisation of Chinese energy markets may allow increasing levels of participation by western international oil companies and Middle Eastern NOCs, but this is unlikely to result in additional projects.



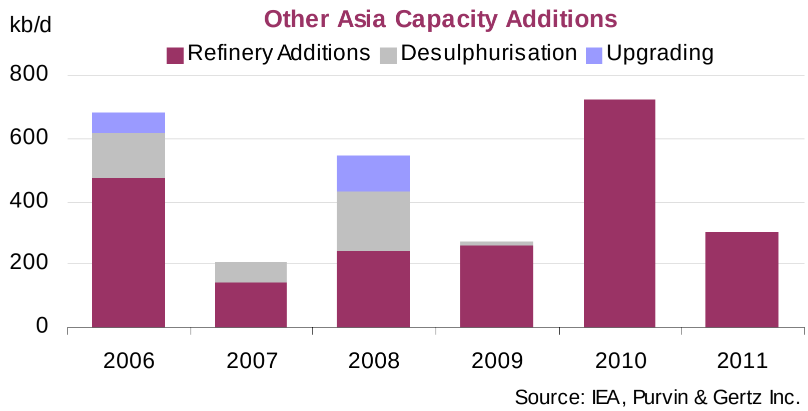
This year has already witnessed the start-up of several refinery expansions, including PetroChina's Dalian 200 kb/d and Sinopec's 160 kb/d Hainan plants. China's expansion of existing capacity appears more biased towards distillate production rather than gasoline, although we note that there is a significant increase in reforming capacity, which not only boosts gasoline quality, but supplies hydrogen for either hydrocracking or hydrotreating facilities.

Significant investment in desulphurisation and hydrotreating should occur in China in the next five years. Relative to other refining centres China is currently underweighted in hydrotreating capacity, with a ratio of only 7% of hydrotreating to crude distillation capacity. This compares to a ratio of 43% in Singapore, 77% in the US and 89% in Germany. Despite relatively high-sulphur specifications for diesel (500ppm) and gasoline, Chinese refiners appear limited in the type of marginal crude that they can run, relying on light and medium sweet grades. Known projects in 2006/2007 will add 413 kb/d of desulphurisation capacity, almost doubling existing capacity and we would expect to see further announcements as the industry continues to increase its flexibility in handling sour crude.

Other Asia

Other non-OECD Asian countries will contribute around 2.1 mb/d of new refinery capacity by 2011. India accounts for some 1.66 mb/d, or roughly 80%, of the region's increase with further capacity additions expected from Indonesia, Taiwan, Thailand and Vietnam. Indian state refiners, as well as ONGC and Reliance, are looking to expand their significant merchant refining industry which is focused on exports as well as meeting Indian demand growth. Despite the low domestic prices for some light products in India, the Government appears to support the expansion of the refining industry. The proposed 600 kb/d expansion of capacity at Reliance Petroleum's Jamnagar facility will almost double capacity to 1.26 mb/d. As such, it is the largest expansion project covered in this survey. We conservatively estimate the new capacity will be fully on-stream in 2010 and accounts for almost half of India's expansion.

Reports of a further 1.9 mb/d of new capacity in the region are not included in our forecasts as they are either unlikely to proceed due to political, economic and financial uncertainties, are beyond this report's timeframe. Almost one third of this capacity is in India, with the 300 kb/d Paradeep, 150 kb/d Barmer and 180 kb/d Bathinda refineries currently excluded from our projections. Elsewhere we remain unconvinced as to the likelihood of projects being completed in Indonesia (230 kb/d), Vietnam (150 kb/d) and Taiwan (600 kb/d).



Investment in secondary units in non-OECD Asian countries is low compared to other regions. Relatively relaxed product specifications and continued use of fuel oil in domestic markets should allow this to continue. Some exceptions to this rule are present in India, Taiwan and Pakistan, which have selective upgrading investments over the next five years.

Middle East

The Middle East is the largest contributor to refinery expansions over the next five years. Driven by the aggressive expansion plans of national oil companies, such as Saudi Aramco, we expect a net addition of around 2.6 mb/d. New refineries will contribute 1.7 mb/d of this increase, expansion of existing refineries will account for a further 605 kb/d and lastly new condensate splitters total some 466 kb/d. Strong regional demand growth will partly underpin these expansion projects, but ultimately the NOCs will need export markets to secure outlets for their crude oil production.

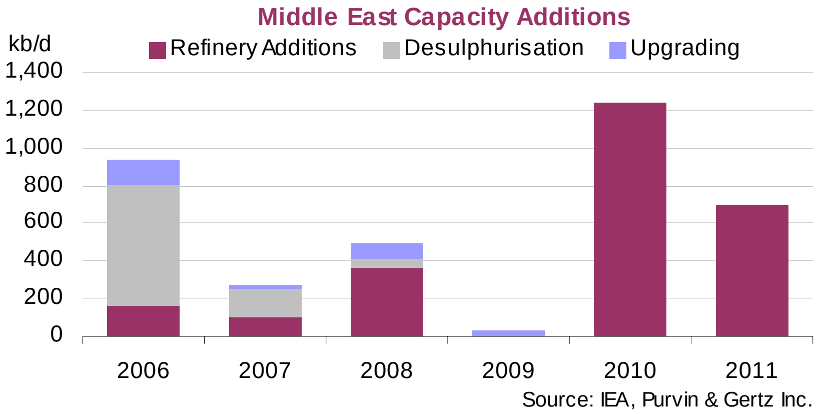
Before 2010, refinery additions and expansion in Oman, where the Sohar refinery is expected to be fully operational during the third quarter of 2006, Yemen and Iran will add 440 kb/d. From 2010 onwards we expect to see a number of world-class refineries start up in Saudi Arabia, Kuwait, the UAE and Qatar to add a further 1.3 mb/d of net capacity. The global expansion of condensate splitters is forecast to be focused on the Middle East, with approximately 70% of the world's 761 kb/d growth coming from the region.

Some of the new Middle East refineries are expected to produce a surprisingly high level of fuel oil, relative to expansions elsewhere, in order to meet domestic power generation requirements. In addition to the large-scale expansion of crude distillation capacity, several export-oriented refineries are investing to improve the quality of their product slate to meet European and US specifications. Tighter product quality requirements have left some Middle Eastern refiners unable to export to markets such as Europe and the US. With the growing trend in Asia to tighten product quality specifications, we would expect to continue to see Middle East refiners investing in desulphurisation and upgrading capacity over the next five years. Announced projects for hydrotreating total some 830 kb/d, a 40% increase from existing levels, but the final outcome maybe much higher.

We have included 600 kb/d of new refinery capacity in Saudi Arabia. The recently announced joint ventures with Total and ConocoPhillips, for two 400 kb/d full-conversion export refineries, drive much of this growth. The reported 2011 start date appears feasible for Total's Jubail refinery. However, we are more cautious on the start date of the ConocoPhillips project at Yanbu and have assumed it is completed by 2013, pending further confirmation by the company as to the viability of the project. The remainder of the growth is expected to come from the planned 100 kb/d expansion of existing facilities at Yanbu and Ras Tanura, scheduled for late in the decade. Furthermore, Saudi Aramco is set to revamp the 400 kb/d hydroskimming refinery at Rabigh into an integrated petrochemical and refinery complex. We have included this project within our forecast as a series of new upgrading unit investments, but have left the refinery capacity unchanged, as incremental crude capacity is expected to be negligible. Saudi Aramco is reported to be considering replicating the Rabigh style upgrade at its Ras-Tanura and Yanbu plants post-2010, suggesting further increases in light product supply are possible in addition to the forecasts contained in this report.

Lastly, it is worth reiterating that Saudi Aramco's international refinery expansion plans are as aggressive as their domestic refinery capacity growth. Projects discussed elsewhere in this report, in which Saudi Aramco is a partner, total in excess of 1 mb/d. All the projects are in Asia, except for the 325 kb/d expansion of the Motiva Port Arthur refinery, in the US.

The largest project expected to start up in the next five years is Kuwait's 615 kb/d Al-Zour refinery in 2010. This refinery will lead to the closure of Kuwait's oldest refinery, the 200 kb/d Shuaiba facility which, although extensively modernised following the first Gulf conflict, is starting to show its age. Kuwait is reported to be planning the expansion of the Mina Abdullah and Mina al-Ahmadi facilities by a total of 95 kb/d by 2010 and significantly improve the product quality. Consequently, Kuwait should add a net 510 kb/d within the next five years.



Interestingly, Kuwait is reported to be planning for the al-Zour refinery to be relatively simple compared to Saudi Aramco's full-conversion export refineries. The eventual design is expected to depend on Kuwait's need for continued fuel oil production for domestic electricity generation. Kuwait's progress in developing recently discovered gas reserves, as an alternative supply for domestic power generators, will largely determine the eventual configuration. Current estimates suggest fuel oil production will be in excess of 225 kb/d with naphtha, diesel and jet/kerosene accounting for the remainder of production. Development of Kuwait's gas reserves would allow for the subsequent construction of upgrading units to boost light product yields.

Iran's chronic shortage and high level of imports of gasoline are expected to spur the expansion of its refining sector, although raising retail prices, which are currently the lowest in the world, would curb demand and smuggling. Current political tensions notwithstanding we forecast the expansion at Bandar Abbas over the 2007-2008 period should total some 250 kb/d. Elsewhere in the Middle East, new refineries in Qatar (200 kb/d) and the UAE (300 kb/d) account for most of the remaining growth post 2010.

Condensate splitter capacity in the Middle East is set to grow by just over 466 kb/d. Two projects, in Qatar and Iran, which are linked to the development of gas from the North Field/South Pars field, should come online in 2009-2010 amounting to some 266 kb/d. In addition Saudi Arabia is forecast to looking at starting a 200 kb/d condensate splitter in 2010 at Riyadh.

Africa

African refining capacity is expected to increase by 577 kb/d in the medium term. Over 75% of the growth is expected to come from projects in Algeria and Morocco which will deliver 450 kb/d of new capacity between 2006 and 2011. Elsewhere in Africa we expect the Sonangol sponsored 200 kb/d Lobito refinery in Angola to start up in 2013, while Sudan's 100 kb/d Port Sudan facility may come on-line as early as 2008. In addition to these projects, a further 1.25 mb/d of new-build refinery capacity has been proposed by various parties, for which we see only a low probability of success within our time frame and have therefore excluded them from our estimates.

Investment in upgrading and hydrotreating capacity in Africa appears limited at this time. The expansion of the Mohammedia refinery in Morocco is expected to include substantial upgrading capacity investment but we see little evidence of additional projects elsewhere in Africa.

Former Soviet Union

The current prospects for significant investment in refining capacity appear minimal. Although recent comments from some industry participants are encouraging, we see only limited expansion over the next five years. We expect only two new refineries to come on-stream within the next five years. The 140 kb/d Niznekahmsk project being developed by Tatneft is due to be commissioned in 2010 and Rosneft's 40 kb/d Tuapse refinery should start up in 2009. However, the addition of 180 kb/d on 8.2 mb/d of notional capacity is negligible to the overall picture.

The prospects for a world-scale refinery in Kazakhstan, linked to the Kashagan field, are not sufficiently advanced to be included in our current forecasts, despite the prospect of ample regional crude availabilities at the end of the decade. Russia may have significant spare refining capacity, which could be upgraded to produce additional clean fuels. However, the scale of assets that are really available for improvement may be entirely different from a notional capacity figure left over from the Soviet era.

Investment between now and 2008 is skewed towards improving gasoline yields. Spending on vacuum distillation, catalytic cracking, alkylation, isomerisation and reformers are well above average compared to other regions. Some investment in hydrocrackers and associated hydrotreating is expected at a handful of refineries.

The lack of investment projects could reflect the heavy investment to upgrade refineries in recent years by Yukos, Sibneft, TNK-BP and Lukoil. The recent turbulence and consolidation within the private Russian oil sector might also explain the lack of reported projects. Yukos and Sibneft were both instrumental to the improvement in Russian refineries during the first part of this decade. With the absorption of these groups into a Rosneft/Gazprom monolith, it is possible that downstream investment may have been affected in the same way as upstream activity. However, recently there have been tentative signs of a recovery in oil production from these companies, raising the possibility of further increases in crude runs as they once again turn their attention to their downstream assets.

Crude throughputs at refineries appear to be constrained by a combination of logistical and strategic bottlenecks. Russian oil companies will seek, subject to changes in taxation, to maximise netback values of export volumes while maximising allocated capacity on crude export pipelines and (where economic) rail and barge shipments. Rising Russian refinery throughputs reflect the tax advantage that product exports have enjoyed recently. While refiners have an incentive to refine product under existing tax structures, future profitability can not be guaranteed when it is subject to policy changes. Such uncertainty can act to discourage investment when long lead times and substantial pay-back periods are required.

Realistically, we expect additional projects in the FSU to emerge over the coming years in Russia aimed at improving light product yields and improving fuel quality to meet European and US product specifications (much as operators such as TNK-BP and Lukoil have done). Russian refining, therefore, has the potential to make a contribution to if it receives significant investment and that investment conditions remain stable.

Latin and Central America

Refinery expansion in Latin America is dominated by Brazil and Venezuela. Expansion projects at Petrobras refineries will add 91 kb/d of new capacity by 2008 and the planned Rio de Janiero petrochemicals complex will add a further 150 kb/d of crude demand in 2011. In addition, Petrobras has recently acquired a 50% stake in Astra's 100 kb/d Pasadena refinery, with a view to double capacity by 2011 to handle Brazilian Marlim crude. We will not include Petrobras's proposed 200 kb/d refinery in Pernambuco state, until we are confident that its partner in the project, PDVSA, is able to proceed, as discussed below.

Venezuela's announced plans for refinery expansion are very impressive. However, the developments within the Venezuelan energy sector suggest that access to international finance for these new refineries may prove problematic if taxation changes undermine the heavy oil upgrading projects. Consequently, we expect the 50 kb/d projects at Caripito and Barinas to go ahead, but the proposed 400 kb/d refinery at Cabruta is excluded from our forecasts. Elsewhere in Latin America there are a further 1.8 mb/d of new-build refinery projects which we currently exclude due to uncertainty over finance, commercial viability or timing.

Recent developments in Ecuador and elsewhere have contributed to our cautious stance on the region's refinery expansion plans. Occidental's plans for a refinery in Panama seem unlikely given the problems it has encountered with the operatorship of their Ecuadorian upstream assets, the crude from which the refinery was intended to run. If the situation improves for this and other projects, we will revise our forecasts accordingly.

Significant investment in Latin American upgrading capacity is expected in the next five years. Petrobras is looking to add 120 kb/d of coking capacity in Brazil by 2009, boosting light product yields. Additional projects include investment by US firms Hess and Valero at their refineries in the Caribbean to boost light product yields.

Product Balances

Having assessed the investment outlook for the refining industry, we now consider the implications for product markets. While we are not publishing a product balance, some general trends seem clear.

Gasoline

Gasoline markets should see the current tight supply situation ease before the end of the decade. The supply potential from new-build refineries and upgrading capacity should exceed demand growth over the 2006-2011 period. Equally important is the fact that the refining industry should have adapted by then to the tighter quality specifications and the removal of MTBE from US reformulated gasoline. North America will see some improvement in gasoline supply during 2006-2007, as upgrading projects start to come on-stream. However, the need for imports will remain and may increase in the short-term. The wave of refinery expansions scheduled for 2009-2011 should further ease North American gasoline market conditions.

The continued dieselisation of the European car fleet will reduce gasoline demand and increase the gasoline surplus. Much of this surplus will continue to be exported to the US, with incremental high sulphur/low octane barrels finding demand in Africa and elsewhere. Aggregate Atlantic Basin gasoline supplies will improve as a result of the simultaneous increase in gasoline supply potential in both Europe and North America.

Biofuels are forecast to increase their gasoline market share, mainly through rising ethanol production in Brazil and the US. Recent initiatives by international oil companies point towards the increasing importance of biofuels and could contribute to easing market tightness. The recently announced BP project to look at converting an ethanol plant to produce biobutanol offers the prospect of capturing all the benefits of biofuels, without the logistical constraints associated with ethanol.

Asian markets should see rising supplies over 2006-07 thanks to the new-build capacity expected to start processing in the region. The pause in capacity expansion in 2007 may tighten markets again before the resumption of capacity growth in 2008-2011, when supplies are likely to exceed demand.

Middle Distillates

Middle distillate markets are likely to remain comparatively tight over the 2006-2011 period.

Jet fuel supply potential looks set to broadly match the rise in demand, although in the short term, jet yields will remain under pressure, because of gasoline and diesel production. In North America the supply of jet fuel may struggle to keep pace with forecast demand increases, particularly through to 2008. This suggests that imports may fill an increasing share of overall supply. With European supplies in only a slightly better position, incremental supplies of jet/kero will need to be met by rising production from existing suppliers in the Middle East and Asia.

Diesel markets are in a similar position to jet fuel. Supply growth in 2006 may be countered by a subsequent tightening in 2007. However, by the end of the decade the rapid expansion of refinery capacity plus the commissioning of hydrocrackers in Europe and the rise of biodiesel production will allow some relaxation in the supply picture.

OECD North America and Europe may see little improvement in the overall distillate supply balance, with robust economic growth underpinning demand growth. As mentioned in the other sections, the start-up of projects in China, the Middle East and India should relieve market tightness over the 2009-2011 period.

Fuel Oil

Fuel oil demand is not expected to see the same growth as light products, which are driven by transportation requirements. However, the ongoing investment in upgrading capacity will undoubtedly reduce the supply of fuel oil blending components and in particular vacuum gasoil (VGO). Investment in upgrading units will drive much of the increase in refinery use of fuel oil as a feedstock. These refinery expansions and enhancements (involving new coking and hydrocracking or hydrotreating capacity) are aimed at reducing fuel oil production and increasing the ability to handle of heavy sour. Therefore, some of these expansions will undoubtedly be accompanied by changes to produce incremental supplies of VGO without recourse to open market transactions. This may result in a narrower differential between light sweet and heavy sour crudes and lower upgrading margins.

With static demand and a probable decline in fuel oil production over the balance of the decade, fuel oil markets will probably tighten. However, rising Russian refinery crude runs or higher hydroskimming refinery throughputs could offset the impact of the investment in upgrading capacity during the 2006-2011 period.

BIOFUELS

Summary

- Ethanol and biodiesel output grew by 14% and 80% respectively in 2005 (the latter admittedly from a low base) and supplied about 2% of the world's gasoline and 0.2% of the world's diesel market. While there are numerous uncertainties regarding the medium-term supply outlook for biofuels, there is no doubt that capacity will continue to increase rapidly over the next few years given the current political and economic environment.

- Biofuel plants are relatively small, inexpensive and can be brought on stream fairly quickly. Biofuels can either be blended with conventional transportation fuels or used directly, removing the need for costly refinery investments and thus target an area of petroleum market tightness. However, with the exception of ethanol from sugar cane, they generally require high prices and/or subsidies to make them commercially viable. Further, the complex interrelationships between agricultural and petroleum economics create significant uncertainties for their future outlook. As such, biofuels are likely to become a rapidly growing, albeit marginal, source of supply.

- This report takes a conservative view on biofuels expansions after 2008. After rapid global growth between 2006 and 2008, we have allowed Brazil, with its clear agricultural, cost, topographical, climatic and historical advantage to grow, while holding everything else constant. Nevertheless, even under these assumptions we see biofuel supplies growing to 1.2 mb/d in 2011, almost double the 2005 production of 650 kb/d and four times larger than production in 2000. This could still be an understatement of biofuels growth: a study of proposed or existing projects shows a potential increase between 2006 and 2011 of 1 mb/d in ethanol and biodiesel supplies.

- Brazil, US (ethanol) and EU (biodiesel) will account for the largest share of biofuel production increases. Other countries, such as Malaysia, the Philippines and Thailand are targeting Europe and the US as potential new export markets for both ethanol and biodiesel.

- Research into second-generation biofuels, such as cellulosic ethanol, is currently receiving significant funding. The successful development of this technology could solve associated food/land problems and has the potential to increase ethanol yields. Although some demonstration plants are being built in Canada, Spain and the US, this technology is not expected to make a substantial addition to supplies within the timeframe of this report.

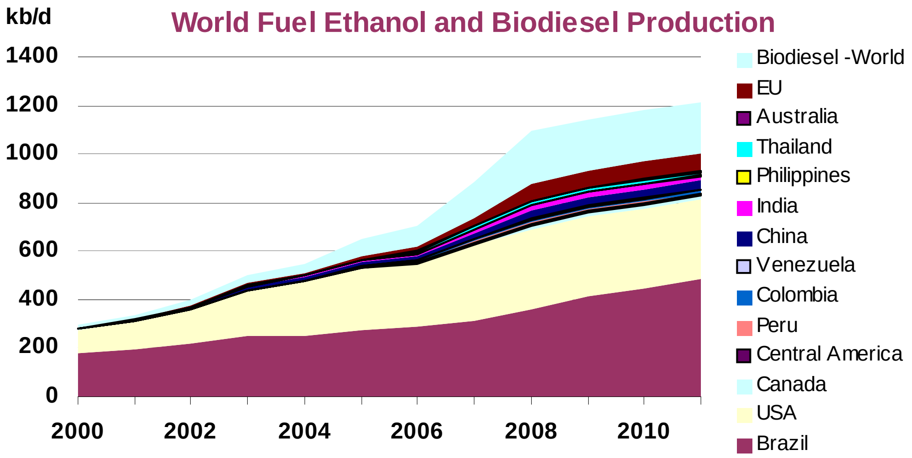
- The lower energy content of ethanol and biodiesel compared to conventional transport fuels will tend to inflate gasoline and diesel demand where they are used as a blendstock.

Outlook

High oil prices, energy supply security concerns, limited spare refinery capacity and targets for GHG emissions reductions have led to a surge in biofuel activity. Ethanol and biodiesel output grew by 14% and 80% respectively in 2005 (the latter admittedly from a low base) and supplied about 2% of the world's gasoline and 0.2% of the world's diesel market. While there are numerous uncertainties regarding medium-term supply projections for biofuels, there is no doubt that capacity will continue to increase rapidly over the next few years given the current political and economic environment.

The recent and projected growth in biofuel production can clearly be seen as a supply and policy response to high oil prices, but biofuels are also popular due to their environmental impact and implicit support for the farm sector. In contrast to conventional oil supplies (for which the development of new projects takes years and requires large investments) biofuel plants are relatively small, inexpensive and can be brought on stream fairly quickly. Biofuels can be blended with conventional transportation fuels or used directly, removing the need for costly refinery investments and target an area of petroleum market tightness. However, with the exception of ethanol from sugar cane, they need high prices and/or subsidies to make them commercially viable. As such, biofuels will become a rapidly growing but marginal source of supply.

A combination of high oil prices, government subsidies and attractive feedstock/food costs currently make biofuels profitable. However, the associated increase in demand for land and feedstocks by the ethanol and biodiesel industries has raised concerns that there could be an associated increase in food prices. The uncertainties regarding the complex interrelationship between biofuels and food prices and uncertainties in the relationship between biofuels and oil prices, mean the current economic attractiveness of biofuels could change very rapidly.



Source: F.O. Licht, IEA estimates

A study of the projects that are either planned or underway show that ethanol and biodiesel have the potential to add close to 1 mb/d to global product supply. However, given the low (relative) costs of biofuel plants, the fact that they should have a secondary call on agricultural land, and their complex economics, we have decided to take a conservative view on biofuel expansions after 2008. After rapid global growth between 2006 and 2008, we have allowed Brazilian output, with its clear agricultural, cost, topographical, climatic and historical advantage to expand, while holding everything else constant. Judging by the slew of projects being announced, our assumptions could ultimately understate biofuels growth. But given the numerous uncertainties and unknowns, it is likely that should current price relationships change, biofuel supply could be the first market to suffer. Nevertheless, even under these assumptions we see biofuel supplies growing to 1.2 mb/d in 2011, almost double 2005 production of 650 kb/d and four times larger than production in 2000.

Over the period from 2005 to 2008, the largest volumetric increase in biofuel supplies will come from established ethanol producers Brazil and the US. Although these two countries will lose market share as new producers enter the market, their combined share of the ethanol market will still be at 78% in 2008, compared to 92% in 2005. Outside the US and Brazil, the largest growth in biofuels will come in the EU, dominated by biodiesel. Expansions in Europe largely stem from ambitious targets set by the European Commission for 5.75% biofuels in transport fuels by 2010. These expansions are also attractive from a supply perspective due to their zero-sulphur and emissions qualities. European biodiesel production, based on announced construction and capacity expansion plans, are expected to more than double by 2008 from the 64 kb/d produced in 2005. There will also be some ethanol production in Europe, with output rising to 71 kb/d in 2008, from only 14 kb/d in 2005.

Although the bulk of biodiesel production will remain in EU countries, the US, Brazil and China are expected to add substantial capacities to comply with domestic mandates. Other countries, such as Malaysia, the Philippines and Thailand, eye increasing demand from Europe and the US as potential new markets for exports of both ethanol and biodiesel.

Research into second-generation biofuels, such as cellulosic ethanol, is currently receiving a lot of funding and the successful development of this technology could solve the food/land problems as well as increase ethanol yields. Although some demonstration plants are being built in Canada, Spain and the US, we don't see this technology making a substantial addition to supplies within the timeframe of these projections.

What are Biofuels?

Fuel ethanol and biodiesel as well as biogas or hydrogen, are transportation fuels derived from biological sources:

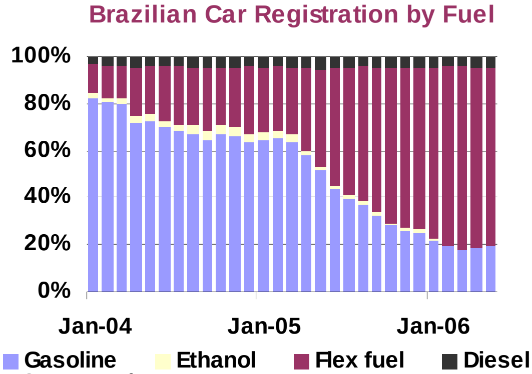
- Cereals, grains, sugar crops and other starches can be fairly easily fermented to produce ethanol which can either be used as a motorfuel in pure ('neat') form in modified engines or as a blending component in gasoline (as ethanol or after being converted to ethyl-tertiary-butyl-ether, ETBE).
- Cellulosic materials, including grasses, trees, and various waste products from crops, wood processing facilities and municipal waste can also be converted into alcohol, but the process is more complex than in the processing of sugars or grains. Techniques are being developed, however, to more effectively convert cellulosic crops and crop wastes to ethanol. Cellulose can also be gasified to produce a variety of gases, such as hydrogen, which can be used directly in some vehicles or can be used to produce synthesis gas which is further converted to various types of liquid fuels, such as dimethyl ether (DME) and even synthetic gasoline or diesel.
- Oil seed crops (e.g. rapeseed, soybean, and sunflower) can be converted into methyl esters, a liquid fuel which can either be blended with conventional diesel or used as pure biodiesel (in modified engines).
- Organic waste material can be converted into energy forms which can be used as automotive fuel: waste oil (e.g. cooking oil) into biodiesel; animal manure and organic household wastes into biogas (e.g. methane); and agricultural and forestry waste products into ethanol.

Current Status

Ethanol is by far the most commonly used biofuel in transport today. This is mostly due to large production volumes in Brazil and the United States, whose combined production amounted to 92% of total world ethanol supplies in 2005. This percentage is expected to decline to 81% in 2011 as countries such as China, India and Canada (among others) step up the production of ethanol to be used as transport fuel.

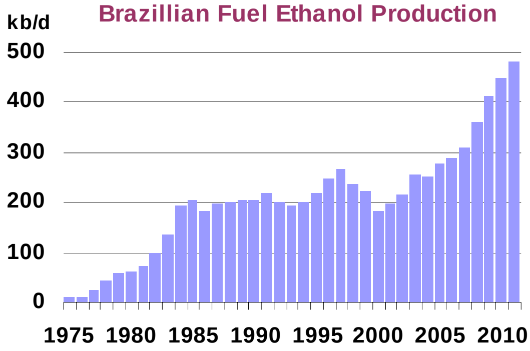
Although use of ethanol as a fuel in **Brazil** dates back to the early twentieth century, production of ethanol from sugarcane on a commercial scale only began in 1975 following the introduction of aggressive government policies. In response to the oil shock of 1973, the Brazilian government launched the *Proalcool* Programme, to reduce the country's dependence on imported oil and to find use for its surplus sugar cane supply. The programme provided incentives for ethanol producers, distributors and ethanol car manufacturers as well as subsidies to consumers.

Brazilian Car Registration by Fuel



Source: Anfavea

Brazillian Fuel Ethanol Production



Source: F.O. Licht

As the collapse of world oil prices in the late 1980s coincided with rising sugar prices, the economics of ethanol production became less viable. At the same time, government incentives were phased out and price subsidies removed as the government's focus shifted to other areas. In addition, a poor sugar cane harvest in 1989 led to an ethanol shortage, further limiting demand for ethanol-fuelled cars.

With the sharp rise in world oil prices over the last few years, the declining trend in Brazilian ethanol production has been reversed. Total fuel ethanol production in 2005 came to 280 kb/d, more than 50% higher than in 2000. An annual average increase of 10% is foreseen until 2011. All gasoline sold in Brazil contains between 20% and 26% ethanol by volume. The introduction of the flex-fuelled car, which can run on ethanol, gasoline or any combination of the two, in March 2003 has been a key driver for recent domestic demand growth. In 2005, 70% of the cars sold in Brazil were flex fuel.

Fuel ethanol produced from corn has been used as a transport fuel in **the US** since the early 1980s and contributed 250 kb/d to total transport fuel supplies in 2005. Although the US is catching up with Brazil in terms of ethanol production, and is set to surpass Brazil in 2007, as a percentage of total transportation fuel demand the US is lagging far behind. US ethanol only accounts for 2.7% of total gasoline demand compared to about 20% in Brazil (plus exports). According to the US Renewable Fuels Association (RFA), current ethanol capacity at the country's 101 ethanol distilleries amount to a total of 313 kb/d. Another 34 refineries are under construction and seven expansion projects are underway, projected to add another 145 kb/d to capacity within the next couple of years.

Ethanol production in **Europe** is still relatively limited. The European Bioethanol Fuel Association estimates EU production in 2005 at just under 16 kb/d. Due to recent policy targets (discussed later in this section), capacity is projected to grow rapidly over the medium-term period. A survey of ethanol production capacities in EU-25 countries estimates current capacity (mid-2006) at 35 kb/d with another 32 kb/d under construction and a further 95 kb/d of capacity expansions announced.

Biodiesel is predominantly produced in **Europe**. This is in large part due to a 'dieselisation' of the car fleet (see demand section, Europe), leading to a structural diesel deficit (as well as a gasoline surplus) in the region. The largest biodiesel producer in Europe is currently Germany with France, Spain and Italy set to take a larger share over the coming years. The fuel is typically used as a blend, 5% to 20%, but in **Germany** (and some other countries) niche markets for 'neat' or pure biodiesel have developed (public transportation, goods transport, government vehicles etc.).

World Biodiesel Production

(thousand barrels per day)

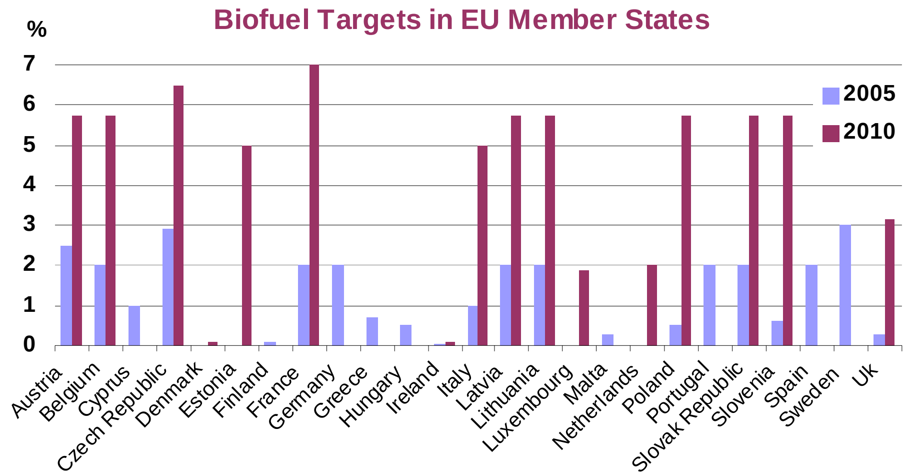
	2000	2001	2002	2003	2004	2005	2006
Germany	5.1	7.1	8.7	13.8	20.0	34.3	38.6
France	6.2	6.2	7.1	6.9	6.7	9.5	10.7
Italy	1.5	2.8	4.1	5.3	6.2	7.7	7.7
Czech Rep.	1.2	0.4	0.0	1.4	1.2	2.6	2.6
Poland	0.0	0.0	0.0	0.0	0.0	1.9	2.8
Spain	0.0	0.0	0.0	0.1	0.3	1.4	2.9
Other EU	0.4	1.0	0.8	1.6	3.0	6.2	5.1
Europe	**14.4**	**17.5**	**20.6**	**29.1**	**37.4**	**63.6**	**70.3**
USA	0.1	0.3	1.0	1.3	1.6	4.9	8.7
Brazil	0.0	0.0	0.0	0.0	0.0	1.2	1.9
Australia	0.0	0.0	0.0	0.0	0.0	1.0	1.5
Other	0.2	0.2	0.4	0.8	1.0	1.4	1.9
World	**14.7**	**18.0**	**22.0**	**31.2**	**40.0**	**72.0**	**84.4**

Source: European Biodiesel Board, F.O. Licht

Outside Europe, production of biodiesel is currently limited. Although still at a small scale (only 5 kb/d in 2005), US production capacity is seen increasing rapidly over the next few years, in part supported by recent policy developments. According to the National Biodiesel Board, as of May 2006, 65 biodiesel plants with a combined capacity of 26 kb/d were in operation. A further 47 kb/d (50 plants) are currently under construction and are due to be completed within the next 18 months and eight plants are expanding current capacity. Another 34 plants are in the planning stage, potentially adding another 50 kb/d to capacity. Based on current capacity expansion plans and announcements, we see world biodiesel production growing to 234 kb/d in 2008 from 72 kb/d in 2005. As for ethanol, we have not incorporated any growth for biodiesel from 2008 to 2011.

Recent Policy Developments

In early 2003, the European Commission (EC) issued a directive promoting the use of biofuels and other renewable fuels for transport. This initiative created two 'indicative' targets for EU member states: 2% biofuels penetration by December 2005 and 5.75% by December 2010. The targets are not mandatory, but governments are required to develop plans to meet them. Although only 1.2% of transport fuels were met by biofuels in Europe in 2005, there is no doubt that capacity will increase over the next five years. But with national targets indicating that some Member States have set targets below EC directives and considering the underperformance in terms of the 2005 target, strong market incentives or subsidies will be needed to meet the 2010 target.



In the US, recent biofuel capacity expansions have been supported by the passing of the US Energy Bill in August 2005. The Energy Policy Act (EPAct) represented the first overhaul of US energy policy in more than a decade. The legislation includes a Renewable Fuels Standard (RFS) which aims to increase the volume of ethanol and biodiesel in fuel to 179 mb by 2012, up from 93 mb in 2005. The bill also mandates the first use of six million barrels of cellulosic ethanol by 2013 as well as funding for research and development of cellulosic technologies. The RFS further includes a Credit Trading Programme (CTP) which allows ethanol refiners to sell surplus credits to underperforming refiners, intended to lower costs to refiners.

The EPAct also revoked the mandated use of oxygenates such as ethanol and MTBE in those metropolitan areas with the worst air pollution problems. As the EPAct 2005 offers no protection against product liability litigation for MTBE—and producers would be responsible for possible ground water contamination—MTBE has effectively been phased out as an oxygenate in the US fuel pool since May of 2006. California, New York and Connecticut had already banned MTBE in 2004. As MTBE has been replaced by ethanol, demand and capacity expansions are projected to rise rapidly.

In Canada, the main motivation for fuel ethanol expansion is the reduction of Green House Gas emissions. Federal excise tax exemption for the ethanol portion of the blended fuel amounts to C$0.10/litre. In addition, a Kyoto compliance plan includes funds to expand Canada's ethanol production. In 2001, Australia set a production target of 350 million litres biofuels for 2008 but the target was later pushed back to 2010. However, Prime Minister John Howard said earlier this year that the target could be reached as early as 2008 with a total of 500 million litres possible by 2010. Japan has made clear its interest in biofuels blending, even if biofuels must be imported. Japan is currently looking to Brazil as a long-term ethanol supplier to meet domestic blending needs.

Several non-OECD countries, such as China, India and Thailand have also recently adopted pro-biofuels policies. Several provinces in China have adopted E-10 ethanol blends (10% ethanol, 90% gasoline). In India, several states have adopted an E-5 blend. Other countries such as Malaysia and the Philippines as well as several Latin American countries are developing a biofuels industry in view of exporting product to a rapidly developing international biofuels market. In recent years, other countries, such as Canada, China, India as well as the EU have also shown a greater interest in ethanol production due to a variety of policy goals, be it energy supply security, environmental targets or agricultural and industrial policies.

Reasons to Promote Biofuels

As a fuel, most biofuels are more expensive than conventional transport fuels. So, if market prices are taken into account, political objectives come into play. There are several reasons why governments have decided to promote biofuels including energy security, environmental targets and rural and agricultural politics.

Biofuels can contribute to **energy security** by diversifying energy supply sources for transport. The displacement of petroleum fuels by biofuels would lead to a reduction in global oil consumption. This in turn would limit the need to import crude oil from unstable producing areas and reduce import spending. In addition, the blending of biofuels into traditional transport fuels increases product supply, which has been restrained this last year due to limited refinery upgrading capacity.

One of the most frequent arguments used to promote biofuels is that it is **renewable**. Ethanol and biodiesel provide significant reductions in greenhouse gas emissions compared to gasoline and diesel on a 'well-to-wheels' basis ('Well-to-wheels' refers to the complete chain of fuel production and use, including feedstock production, transport to the refinery, conversion to final fuel, transport to refuelling stations, and final vehicle tailpipe emissions). While a range of estimates exists, most studies find significant net reductions in CO2-equivalent emissions for both types of fuels. (See: *Biofuels for Transport - An International Perspective,* IEA, 2005 for a wider discussion on the subject).

There are large differences in potential carbon dioxide emissions avoidance by using biofuels. The critical factors are the amount of fossil fuels used to produce and transport the biomass feedstock and process it (including inputs into fertilisers, machinery and for irrigation); the share of zero and low emission energy inputs; the crop yields; and the efficiency of biofuel production. For bioethanol from sugarcane and crop residues and for biodiesel from animal fats, the whole process, from producing the biomass feedstock to combustion of the biofuel, can lead to 90% carbon emission reduction per kilometre of travel compared with using gasoline or diesel fuels. Where higher energy-intensive feedstocks are used (such as annual root and cereal crops), little if any renewable energy is consumed during the production and process, only around a 10-15% reduction in overall carbon emissions per kilometre may result.

Biofuels can also **improve vehicle performance**. Ethanol has a high octane number and can be used to increase the octane of gasoline. It has traditionally not been the first choice for octane enhancement because of its relatively high cost, but as other options (lead and MTBE) fall increasingly out of favour due to safety/environmental reasons, demand for ethanol for this purpose is on the rise. Biodiesel can improve the diesel lubricity and raise the fuel's cetane number, aiding performance.

In developing economies, biofuels have the potential to stimulate and sustain rural development, create jobs and reduced import costs.

Economics

The present costs of biofuels vary with feedstock and location. Commercial bioethanol production costs currently range from $0.25/litre ($0.94/US gallon) of gasoline equivalent (lge), (sugarcane, Brazil) to $0.80/lge ($3.0/US gallon) (sugar beet, UK) with corn ethanol around $0.60/lge ($2.27/US gallon) (USA) and ligno-cellulosic ethanol from pilot scale plants claimed to be between $0.80 to 1.00/lge ($3.0-3.8/US gallon). Biodiesel costs range from $0.42/l ($1.6/US gallon) (animal fats, New Zealand) to $0.90/lge ($3.4/US gallon) (oilseed rape, Europe; soybean, USA; palm oil, Malaysia).

Based on the range of literature, technology development and larger-scale plants could lower production costs of bioethanol to $0.23-0.65/lge and biodiesel to $0.38-0.75/lge by 2030.

The retail price of biofuels is greatly influenced by competition for the feedstock, such as sugar in Brazil, and by government policies on agricultural subsidies, excise tax exemption etc. Sugar cane prices have risen sharply in recent months, no doubt partly for this reason. The graph below presents a comparison between current and future prices for biofuels at the plant gate versus gasoline and diesel ex-refinery (fob) for a range of crude oil prices over the past 16 months. Ethanol from sugar cane (ES) competes once the oil price reaches around $40/bbl and biodiesel from animal fats (BA) around $60/bbl. Other biofuels will only compete when oil is above $70/bbl unless the production costs can be significantly reduced by plant scale-up, research and development investment, learning experience, or the introduction of carbon charges for net emissions. Otherwise they will continue to be dependent on government support mechanisms.

Current and Future Biofuels Prices vs. Daily Gasoline and Diesel ex-Refinery (Free on Board) Prices and Related Crude Prices (US dollars)

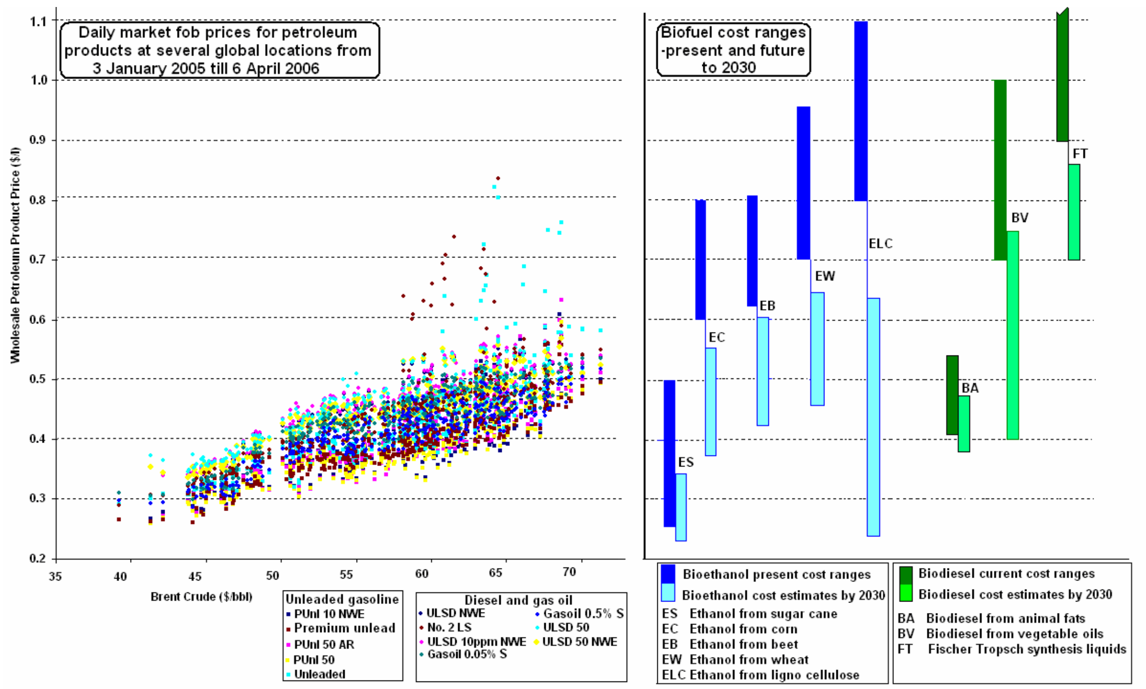


Table 1

WORLD OIL SUPPLY AND DEMAND

(million barrels per day)

	1Q06	2Q06	3Q06	4Q06	2006	1Q07	2Q07	3Q07	4Q07	2007	1Q08	2Q08	3Q08	4Q08	2008	2009	2010	2011
OECD DEMAND																		
North America	25.1	25.4	25.9	26.0	25.6	25.9	25.8	26.1	26.2	26.0	26.3	26.1	26.5	26.5	26.3	26.7	27.0	27.4
Europe	15.7	14.9	15.5	15.7	15.5	15.5	15.1	15.5	15.7	15.4	15.5	15.2	15.5	15.7	15.5	15.5	15.6	15.7
Pacific	9.3	7.9	8.2	9.0	8.6	9.3	8.0	8.1	8.9	8.6	9.3	8.0	8.1	8.9	8.6	8.6	8.7	8.7
Total OECD	50.1	48.2	49.5	50.7	49.7	50.7	48.9	49.8	50.8	50.0	51.1	49.3	50.1	51.1	50.4	50.8	51.3	51.8
NON-OECD DEMAND																		
FSU	3.9	3.7	3.8	4.0	3.9	3.9	3.7	3.9	4.1	3.9	4.0	3.7	3.9	4.1	3.9	4.0	4.0	4.1
Europe	0.8	0.7	0.7	0.7	0.7	0.8	0.7	0.7	0.7	0.7	0.8	0.8	0.7	0.8	0.8	0.8	0.8	0.8
China	6.8	7.0	7.1	7.2	7.0	7.2	7.3	7.4	7.7	7.4	7.5	7.7	7.8	8.2	7.8	8.2	8.7	9.1
Other Asia	8.9	9.0	8.8	9.0	8.9	9.1	9.1	9.0	9.2	9.1	9.4	9.4	9.3	9.6	9.4	9.7	10.1	10.5
Latin America	5.1	5.2	5.3	5.2	5.2	5.2	5.3	5.4	5.4	5.3	5.3	5.4	5.5	5.5	5.4	5.6	5.7	5.8
Middle East	6.4	6.4	6.7	6.4	6.5	6.7	6.7	7.0	6.8	6.8	7.1	7.1	7.4	7.1	7.2	7.5	7.9	8.3
Africa	3.0	3.0	2.9	3.0	3.0	3.1	3.1	2.9	3.1	3.0	3.1	3.1	3.0	3.1	3.1	3.2	3.3	3.4
Total Non-OECD	34.8	35.0	35.2	35.6	35.1	35.9	36.0	36.4	37.0	36.3	37.2	37.3	37.6	38.3	37.6	39.0	40.4	41.9
Total Demand[1]	84.9	83.3	84.7	86.3	84.8	86.7	84.9	86.1	87.7	86.4	88.3	86.6	87.7	89.4	88.0	89.8	91.7	93.7
OECD SUPPLY																		
North America	14.2	14.2	14.3	14.5	14.3	14.8	14.5	14.4	14.5	14.6	14.9	14.6	14.5	14.6	14.6	14.7	14.8	15.0
Europe	5.5	5.2	5.2	5.5	5.4	5.5	5.3	5.2	5.4	5.4	5.4	5.1	5.0	5.1	5.1	4.9	4.6	4.5
Pacific	0.5	0.5	0.6	0.6	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.7	0.7	0.8	0.7	0.8	0.8	0.7
Total OECD	20.2	19.9	20.1	20.6	20.2	21.0	20.4	20.2	20.6	20.5	20.9	20.3	20.2	20.5	20.5	20.3	20.2	20.1
NON-OECD SUPPLY																		
FSU	11.7	12.0	12.2	12.4	12.1	12.4	12.5	12.7	12.8	12.6	12.9	12.9	13.0	13.1	13.0	13.5	14.0	14.5
Europe	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
China	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.8	3.8	3.8
Other Asia	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.8	2.7	2.8	2.7	2.8	2.8	2.8	2.9	2.9	2.8
Latin America	4.3	4.4	4.5	4.6	4.5	4.6	4.6	4.7	4.9	4.7	5.1	5.1	5.2	5.2	5.1	5.3	5.5	5.7
Middle East	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.7	1.7	1.8	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
Africa	3.9	4.0	4.2	4.3	4.1	4.4	4.5	4.7	4.8	4.6	5.0	4.9	5.1	5.2	5.1	5.3	5.5	5.5
Total Non-OECD	28.4	28.8	29.3	29.7	29.0	29.8	30.0	30.5	30.9	30.3	31.3	31.3	31.7	31.9	31.5	32.6	33.4	34.1
Processing Gains[2]	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
Other Biofuels[3]	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total Non-OPEC[4]	50.6	50.7	51.5	52.4	51.3	53.0	52.5	52.9	53.7	53.0	54.5	54.0	54.2	54.7	54.4	55.3	56.0	56.7
OPEC NGLs[5]	4.6	4.7	4.8	4.8	4.7	4.9	4.9	5.0	5.1	5.0	5.2	5.3	5.5	5.7	5.4	6.1	6.5	6.8
Memo items:																		
Call on OPEC crude + Stock ch.[6]	29.7	27.9	28.5	29.1	28.8	28.8	27.4	28.2	28.9	28.4	28.5	27.2	28.1	29.0	28.2	28.4	29.2	30.2

1 Measured as deliveries from refineries and primary stocks, comprises inland deliveries, international marine bunkers, refinery fuel, crude for direct burning, oil from non-conventional sources and other sources of supply.

2 Net volumetric gains and losses in the refining process (excludes net gain/loss in former USSR, China and non-OECD Europe) and marine transportation losses.

3 Comprises Fuel Ethanol and Biodiesel supply from outside Brazil and US.

4 Non-OPEC supplies include crude oil, condensates, NGL and non-conventional sources of supply such as synthetic crude, ethanol and MTBE. No allowance is made in the non-OPEC forecast for exceptional events which have, at certain times historically, reduced non-OPEC supply by 300-400 kbd on an annual basis

5 Includes condensates reported by OPEC countries, oil from non-conventional sources, e.g. Venezuelan Orimulsion (but not Orinoco extra-heavy oil), and non-oil inputs to Saudi Arabian MTBE.

6 Equals the arithmetic difference between total demand minus total non-OPEC supply minus OPEC NGLs.

Table 2

Summary of Global Oil Demand

	1Q06	2Q06	3Q06	4Q06	2006	1Q07	2Q07	3Q07	4Q07	2007	1Q08	2Q08	3Q08	4Q08	2008	2009	2010	2011
Demand (mb/d)																		
North America	25.13	25.40	25.89	26.05	25.62	25.93	25.78	26.15	26.16	26.01	26.27	26.11	26.47	26.47	26.33	26.68	27.05	27.43
Europe	15.73	14.92	15.45	15.70	15.45	15.48	15.11	15.50	15.67	15.44	15.47	15.15	15.52	15.69	15.46	15.51	15.57	15.65
Pacific	9.29	7.91	8.20	8.95	8.59	9.33	7.99	8.14	8.93	8.60	9.33	7.99	8.14	8.94	8.60	8.62	8.65	8.69
Total OECD	50.15	48.23	49.55	50.70	49.66	50.74	48.88	49.79	50.76	50.04	51.07	49.25	50.14	51.11	50.39	50.81	51.28	51.78
FSU	3.87	3.67	3.84	4.03	3.85	3.92	3.67	3.87	4.07	3.88	3.99	3.74	3.89	4.09	3.93	3.98	4.03	4.09
Europe	0.79	0.73	0.67	0.73	0.73	0.80	0.74	0.69	0.74	0.74	0.81	0.75	0.70	0.75	0.75	0.77	0.78	0.80
China	6.77	7.03	7.05	7.25	7.03	7.15	7.35	7.43	7.73	7.42	7.55	7.74	7.80	8.15	7.81	8.22	8.66	9.09
Other Asia	8.90	9.00	8.75	8.96	8.90	9.14	9.14	9.01	9.25	9.14	9.39	9.43	9.30	9.59	9.43	9.75	10.09	10.45
Latin America	5.08	5.21	5.30	5.23	5.21	5.16	5.33	5.40	5.37	5.32	5.28	5.45	5.52	5.50	5.44	5.57	5.71	5.85
Middle East	6.38	6.40	6.67	6.41	6.47	6.72	6.75	7.02	6.76	6.81	7.07	7.09	7.38	7.11	7.16	7.52	7.90	8.29
Africa	2.97	2.99	2.86	2.98	2.95	3.05	3.05	2.93	3.05	3.02	3.13	3.13	3.01	3.13	3.10	3.18	3.27	3.37
Total Non-OECD	34.77	35.03	35.16	35.60	35.14	35.94	36.03	36.36	36.97	36.33	37.21	37.32	37.60	38.33	37.62	38.99	40.44	41.93
World	84.92	83.26	84.70	86.30	84.80	86.67	84.91	86.14	87.73	86.37	88.28	86.58	87.73	89.43	88.01	89.80	91.72	93.70
of which:																		
US50	*20.48*	*20.84*	*21.14*	*21.22*	*20.92*	*21.13*	*21.07*	*21.36*	*21.33*	*21.22*	*21.40*	*21.32*	*21.62*	*21.58*	*21.48*	*21.76*	*22.05*	*22.35*
Euro4	*8.37*	*7.87*	*8.12*	*8.19*	*8.14*	*8.15*	*7.89*	*8.15*	*8.15*	*8.08*	*8.10*	*7.88*	*8.12*	*8.14*	*8.06*	*8.05*	*8.06*	*8.07*
Japan	*5.96*	*4.81*	*5.07*	*5.53*	*5.34*	*5.89*	*4.82*	*4.99*	*5.51*	*5.30*	*5.85*	*4.78*	*4.96*	*5.49*	*5.27*	*5.24*	*5.23*	*5.23*
Korea	*2.28*	*2.03*	*2.06*	*2.32*	*2.17*	*2.36*	*2.08*	*2.06*	*2.31*	*2.20*	*2.39*	*2.11*	*2.08*	*2.33*	*2.23*	*2.25*	*2.28*	*2.31*
Mexico	*2.08*	*2.04*	*2.13*	*2.16*	*2.10*	*2.12*	*2.15*	*2.17*	*2.15*	*2.15*	*2.17*	*2.20*	*2.21*	*2.19*	*2.19*	*2.24*	*2.29*	*2.34*
Canada	*2.19*	*2.19*	*2.27*	*2.30*	*2.24*	*2.29*	*2.22*	*2.27*	*2.31*	*2.27*	*2.31*	*2.24*	*2.29*	*2.33*	*2.29*	*2.31*	*2.34*	*2.36*
Brazil	*2.17*	*2.19*	*2.30*	*2.26*	*2.23*	*2.21*	*2.27*	*2.32*	*2.34*	*2.28*	*2.27*	*2.33*	*2.38*	*2.40*	*2.35*	*2.41*	*2.48*	*2.56*
India	*2.74*	*2.75*	*2.53*	*2.65*	*2.67*	*2.84*	*2.75*	*2.62*	*2.75*	*2.74*	*2.93*	*2.85*	*2.71*	*2.87*	*2.84*	*2.95*	*3.06*	*3.18*
Annual Change (% per annum)																		
North America	-1.7	0.2	1.5	2.4	0.6	3.2	1.5	1.0	0.4	1.5	1.3	1.3	1.2	1.2	1.3	1.3	1.4	1.4
Europe	0.9	-1.5	-0.6	0.4	-0.2	-1.6	1.2	0.3	-0.2	-0.1	-0.1	0.3	0.2	0.2	0.1	0.3	0.4	0.5
Pacific	-1.6	-1.9	1.6	1.9	0.0	0.4	1.0	-0.8	-0.2	0.1	0.0	0.0	0.0	0.1	0.1	0.2	0.4	0.5
Total OECD	-0.9	-0.6	0.8	1.7	0.3	1.2	1.3	0.5	0.1	0.8	0.7	0.8	0.7	0.7	0.7	0.8	0.9	1.0
FSU	1.4	-1.1	1.3	3.5	1.3	1.2	0.0	0.8	1.0	0.8	1.9	1.9	0.4	0.4	1.1	1.3	1.4	1.4
Europe	2.5	1.4	1.6	1.6	1.8	0.7	1.7	1.7	1.4	1.4	1.5	1.8	1.8	1.8	1.7	1.8	1.8	1.9
China	2.9	8.8	6.1	6.8	6.1	5.6	4.4	5.4	6.7	5.5	5.5	5.3	5.0	5.4	5.3	5.3	5.3	4.9
Other Asia	-0.2	1.4	0.9	2.5	1.2	2.6	1.6	3.0	3.2	2.6	2.8	3.2	3.1	3.7	3.2	3.4	3.5	3.6
Latin America	2.2	1.5	2.1	2.3	2.0	1.6	2.5	1.8	2.6	2.1	2.2	2.1	2.3	2.4	2.3	2.4	2.5	2.5
Middle East	5.5	5.4	5.1	5.6	5.4	5.3	5.4	5.3	5.3	5.3	5.2	5.1	5.1	5.2	5.1	5.1	5.0	4.9
Africa	2.4	2.3	2.4	2.4	2.4	2.6	2.0	2.3	2.4	2.4	2.7	2.5	2.5	2.7	2.6	2.7	2.8	2.8
Total Non-OECD	2.2	3.4	3.1	4.0	3.2	3.4	2.9	3.4	3.9	3.4	3.6	3.6	3.4	3.7	3.6	3.7	3.7	3.7
World	0.4	1.0	1.8	2.6	1.4	2.1	2.0	1.7	1.7	1.8	1.9	2.0	1.8	1.9	1.9	2.0	2.1	2.2
Annual Change (mb/d)																		
North America	-0.44	0.06	0.39	0.61	0.16	0.80	0.38	0.26	0.11	0.39	0.34	0.33	0.32	0.31	0.33	0.35	0.37	0.38
Europe	0.15	-0.22	-0.10	0.07	-0.03	-0.25	0.18	0.05	-0.04	-0.01	-0.01	0.04	0.02	0.03	0.02	0.05	0.07	0.08
Pacific	-0.15	-0.15	0.13	0.16	0.00	0.04	0.08	-0.07	-0.02	0.01	0.00	0.00	0.00	0.01	0.01	0.02	0.04	0.04
Total OECD	-0.44	-0.31	0.42	0.85	0.13	0.59	0.65	0.24	0.06	0.38	0.33	0.37	0.35	0.35	0.35	0.41	0.47	0.50
FSU	0.05	-0.04	0.05	0.14	0.05	0.05	0.00	0.03	0.04	0.03	0.07	0.07	0.02	0.02	0.04	0.05	0.05	0.06
Europe	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
China	0.19	0.57	0.40	0.46	0.41	0.38	0.31	0.38	0.49	0.39	0.39	0.39	0.37	0.42	0.39	0.41	0.43	0.43
Other Asia	-0.02	0.12	0.08	0.22	0.10	0.24	0.14	0.26	0.28	0.23	0.25	0.29	0.28	0.34	0.29	0.32	0.34	0.36
Latin America	0.11	0.08	0.11	0.12	0.10	0.08	0.13	0.09	0.14	0.11	0.11	0.11	0.13	0.13	0.12	0.13	0.14	0.14
Middle East	0.33	0.33	0.33	0.34	0.33	0.34	0.34	0.35	0.34	0.34	0.35	0.34	0.36	0.35	0.35	0.36	0.38	0.39
Africa	0.07	0.07	0.07	0.07	0.07	0.08	0.06	0.07	0.07	0.07	0.08	0.08	0.07	0.08	0.08	0.08	0.09	0.09
Total Non-OECD	0.75	1.14	1.05	1.36	1.08	1.17	1.00	1.20	1.37	1.19	1.28	1.29	1.24	1.36	1.29	1.38	1.45	1.48
World	0.31	0.82	1.46	2.21	1.21	1.75	1.65	1.44	1.43	1.57	1.61	1.67	1.59	1.71	1.64	1.79	1.92	1.99
Revisions to Oil Demand from Last Medium Term Report (mb/d)																		
North America	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Europe	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Pacific	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total OECD	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FSU	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Europe	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
China	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Other Asia	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Latin America	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Middle East	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Africa	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total Non-OECD	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
World	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Revisions to Oil Demand Growth from Last Medium Term Report (mb/d)																		
World	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Table 3
WORLD OIL PRODUCTION
(million barrels per day)

	1Q06	2Q06	3Q06	4Q06	2006	1Q07	2Q07	3Q07	4Q07	2007	1Q08	2Q08	3Q08	4Q08	2008	2009	2010	2011
OPEC																		
Total NGLs[1]	4.62	4.66	4.76	4.83	4.72	4.91	4.93	5.02	5.13	5.00	5.24	5.35	5.46	5.66	5.43	6.12	6.54	6.79
NON-OPEC[2]																		
OECD																		
North America	14.18	14.16	14.34	14.52	14.30	14.79	14.50	14.40	14.54	14.56	14.87	14.55	14.46	14.62	14.63	14.66	14.83	14.98
United States	7.19	7.33	7.48	7.44	7.36	7.69	7.65	7.46	7.43	7.56	7.71	7.69	7.53	7.48	7.60	7.56	7.59	7.57
Mexico	3.78	3.77	3.69	3.62	3.72	3.63	3.64	3.63	3.64	3.63	3.62	3.61	3.58	3.55	3.59	3.54	3.51	3.45
Canada	3.20	3.06	3.17	3.47	3.23	3.47	3.21	3.30	3.48	3.36	3.53	3.25	3.36	3.59	3.44	3.56	3.73	3.96
Europe	5.54	5.24	5.23	5.52	5.38	5.54	5.28	5.22	5.41	5.36	5.38	5.09	4.96	5.10	5.13	4.87	4.65	4.48
UK	1.84	1.72	1.63	1.80	1.75	1.87	1.73	1.63	1.77	1.75	1.80	1.67	1.57	1.66	1.67	1.57	1.44	1.36
Norway	2.93	2.75	2.83	2.96	2.87	2.91	2.80	2.83	2.89	2.86	2.83	2.68	2.65	2.71	2.72	2.58	2.52	2.48
Others	0.77	0.77	0.77	0.76	0.77	0.76	0.75	0.76	0.75	0.75	0.75	0.75	0.74	0.73	0.74	0.72	0.69	0.64
Pacific	0.49	0.49	0.55	0.61	0.54	0.62	0.61	0.62	0.63	0.62	0.64	0.68	0.74	0.81	0.72	0.81	0.75	0.68
Australia	0.45	0.45	0.51	0.57	0.49	0.58	0.57	0.58	0.58	0.58	0.59	0.62	0.68	0.73	0.65	0.74	0.69	0.62
Others	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.05	0.04	0.06	0.06	0.07	0.08	0.07	0.08	0.07	0.06
Total OECD	20.21	19.89	20.12	20.65	20.22	20.95	20.39	20.24	20.58	20.54	20.89	20.33	20.17	20.53	20.48	20.34	20.23	20.14
NON-OECD																		
Former USSR	11.72	12.04	12.22	12.37	12.09	12.42	12.54	12.71	12.77	12.61	12.89	12.94	13.04	13.11	13.00	13.51	14.01	14.53
Russia	9.53	9.68	9.81	9.91	9.73	9.90	9.97	10.07	10.06	10.00	10.12	10.13	10.19	10.21	10.16	10.46	10.77	11.04
Others	2.19	2.36	2.42	2.46	2.36	2.51	2.56	2.63	2.72	2.61	2.77	2.81	2.85	2.90	2.83	3.05	3.24	3.49
Asia	6.40	6.41	6.44	6.46	6.43	6.47	6.46	6.48	6.50	6.48	6.51	6.49	6.53	6.56	6.52	6.64	6.67	6.64
China	3.68	3.69	3.72	3.73	3.70	3.74	3.73	3.74	3.73	3.73	3.75	3.75	3.74	3.73	3.74	3.75	3.77	3.79
Malaysia	0.77	0.75	0.74	0.73	0.75	0.74	0.73	0.74	0.77	0.75	0.76	0.75	0.77	0.76	0.76	0.78	0.79	0.79
India	0.77	0.80	0.82	0.83	0.81	0.83	0.83	0.83	0.84	0.83	0.84	0.83	0.83	0.83	0.83	0.87	0.91	0.88
Others	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.17	1.16	1.17	1.16	1.16	1.19	1.24	1.19	1.23	1.20	1.18
Europe	0.15	0.15	0.14	0.14	0.15	0.14	0.14	0.13	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.11	0.10	0.09
Latin America	4.35	4.40	4.50	4.64	4.47	4.65	4.61	4.70	4.93	4.72	5.09	5.09	5.16	5.18	5.13	5.32	5.45	5.72
Brazil	2.07	2.10	2.20	2.34	2.18	2.35	2.32	2.40	2.64	2.43	2.80	2.81	2.88	2.91	2.85	3.02	3.14	3.39
Argentina	0.76	0.76	0.75	0.74	0.75	0.74	0.73	0.73	0.73	0.73	0.72	0.72	0.72	0.71	0.72	0.72	0.73	0.73
Colombia	0.53	0.53	0.53	0.54	0.53	0.54	0.53	0.53	0.53	0.53	0.53	0.53	0.53	0.54	0.53	0.54	0.54	0.55
Ecuador	0.52	0.55	0.55	0.56	0.55	0.56	0.56	0.56	0.56	0.56	0.57	0.57	0.57	0.57	0.57	0.58	0.58	0.58
Others	0.47	0.46	0.46	0.46	0.46	0.47	0.46	0.47	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.47	0.47
Middle East[3]	1.81	1.81	1.80	1.79	1.80	1.77	1.76	1.75	1.73	1.75	1.73	1.71	1.69	1.68	1.70	1.67	1.66	1.66
Oman	0.76	0.76	0.75	0.74	0.75	0.73	0.73	0.72	0.72	0.72	0.72	0.72	0.71	0.71	0.71	0.70	0.72	0.75
Syria	0.44	0.43	0.43	0.42	0.43	0.42	0.42	0.41	0.41	0.41	0.40	0.40	0.40	0.39	0.40	0.38	0.37	0.35
Yemen	0.41	0.42	0.43	0.43	0.42	0.43	0.43	0.42	0.41	0.42	0.41	0.40	0.40	0.39	0.40	0.40	0.39	0.38
Africa	3.93	3.99	4.21	4.28	4.10	4.37	4.46	4.72	4.84	4.60	4.96	4.95	5.12	5.22	5.06	5.31	5.47	5.47
Egypt	0.69	0.70	0.69	0.69	0.69	0.69	0.69	0.68	0.68	0.68	0.68	0.67	0.67	0.67	0.67	0.66	0.66	0.69
Angola	1.42	1.33	1.48	1.49	1.43	1.56	1.62	1.85	1.95	1.75	2.03	2.01	2.15	2.27	2.12	2.32	2.47	2.49
Gabon	0.24	0.24	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Others	1.58	1.72	1.81	1.86	1.74	1.89	1.92	1.96	1.98	1.94	2.02	2.04	2.07	2.06	2.05	2.10	2.11	2.06
Total Non-OECD	28.36	28.80	29.32	29.67	29.04	29.82	29.96	30.49	30.89	30.29	31.30	31.30	31.66	31.87	31.53	32.55	33.37	34.11
Processing Gains[4]	1.92	1.89	1.88	1.92	1.90	1.92	1.92	1.92	1.92	1.92	1.95	1.95	1.95	1.95	1.95	1.98	2.00	2.03
Other Biofuels[5]	0.15	0.15	0.15	0.15	0.15	0.26	0.26	0.26	0.26	0.26	0.40	0.40	0.40	0.40	0.40	0.40	0.40	0.40
TOTAL NON-OPEC	50.64	50.73	51.48	52.40	51.31	52.95	52.53	52.91	53.65	53.01	54.54	53.98	54.18	54.75	54.36	55.28	56.00	56.68

1 Includes condensates reported by OPEC countries, oil from non-conventional sources, e.g. Venezuelan Orimulsion (but not Orinoco extra-heavy oil), and non-oil inputs to Saudi Arabian MTBE.

2 Comprises crude oil, condensates, NGLs and oil from non-conventional sources. No allowance is made in the non-OPEC forecast for exceptional events, which have, at certain times historically, reduced non-OPEC supply by 300-400 kbd on an annual basis.

3 Includes small amounts of production from Israel, Jordan and Bahrain.

4 Net volumetric gains and losses in refining (excludes net gain/loss in FSU, China and non-OECD Europe) and marine transportation losses.

5 Comprises Fuel Ethanol and Biodiesel supply from outside Brazil and US.

Table 4
WORLD REFINERY CAPACITY ADDITIONS
(thousand barrels per day)

	2006	2007	2008	2009	2010	2011	Total
Refinery Capacity Additions and Expansions[1]							
OECD North America	31	226	21	280	605	200	1,363
OECD Europe				90	30		120
OECD Pacific					20	480	500
FSU			43		140		183
Non-OECD Europe							
China	552	356	492	407	350	340	2,496
Other Asia	474	140	243	260	725	300	2,142
Latin America	35	20	38	18	100	150	361
Middle East	161	105	366		1,240	700	2,572
Africa	3	25	150	100		300	578
Total World	1,256	872	1,352	1,155	3,210	2,470	10,315
Upgrading Capacity Additions[2]							
OECD North America	90	167	102	177	127	20	683
OECD Europe	181		220	173			574
OECD Pacific			73	80			153
FSU	88	18	50	92		38	286
Non-OECD Europe			42				42
China	69		112		60		241
Other Asia	66		110				176
Latin America	136	29	79	30			274
Middle East	105	60	200				365
Africa			25				25
Total World	735	274	1,013	552	187	58	2,819
Desulphurisation Capacity Additions[3]							
OECD North America	975	68	84	20	30		1,177
OECD Europe	209	36		58			303
OECD Pacific	231	94		80			405
FSU	34	87	43			51	215
Non-OECD Europe	32		8				40
China	125	248	40				413
Other Asia	144	70	190	10			414
Latin America	230	145	249	145			769
Middle East	643	142	45				830
Africa	61	4	20				85
Total World	2,684	894	677	313	30	51	4,649

1 Comprises new refinery projects or expansions to existing facilities including condensate splitter additions. Assumes zero capacity creep.
2 Comprises stand-alone additions to coking, hydrocracking or FCC capacity. Excludes upgrading additions counted under 'Refinery Capacity Additions and Expansions' category.
3 Comprises stand-alone additions to hydrotreating and hydrodesulphurisation capacity. Excludes desulphurisation additions counted under 'Refinery Capacity Additions and Expansions' category.

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