# Investment

**in**

# exploration-production

**and**

# refining

# 2012

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## EDITORIAL

2012 has been marked by uncertainty and contrasts. In Europe, the debt crisis has threatened the economic stability of the entire Eurozone. This has had consequences for other countries in the European Union as well. World economic growth is increasingly sluggish. This is affecting industrialised countries first and foremost, as well as a number of emerging countries - albeit to a lesser degree.

Political and social stability has not yet returned to those countries that were affected by the Arab spring, with the region covered by North Africa and the Middle East still very vulnerable. The wave of revolutions in this region has been followed by international tension over Iran's growing nuclear capability, and its regular threats to blockade the Strait of Hormuz - through which a significant percentage of the world's petroleum passes.

Economic, financial and geopolitical uncertainty has a tendency to drive oil prices up or push them down, creating a highly fluctuating oil market. Prices remain high overall, because of all the geopolitical uncertainty.

The exponential growth of shale gas initially, and then tight oil over the last few years in the US, are dramatically transforming the landscape and have significantly changed our way of thinking about the oil and gas sector in the medium term. The increasing use of shale gas is accentuating the contrast between the world's three main gas markets - North America, Europe and Asia - and is challenging received wisdom about how international gas flows are changing.

The word “contrast” also springs to mind when looking into how investment in hydrocarbons has changed, with an upstream sector that is flourishing and a downstream sector that is treading water.

In spite of the uncertain economic context, investment in exploration-production is still increasing at a healthy rate, with activity reaching record levels in all areas. The decline in activity of 2009/2010 now seems a long way off.

As far as refining is concerned, investment has only risen very modestly, despite a somewhat encouraging 2011. It has only been driven by Asia and the Middle East and - to a lesser extent - South America.

## SUMMARY TABLE OF INVESTMENTS AND MARKETS:

| **$ billion** | **2011** | **2012** |
|---|---|---|
| **Global investments in E&P** | **566** | **640** |
| North America | 154 | 164 |
| Rest of the world | 412 | 476 |
| **Upstream markets analysed** | **271** | **311** |
| Geophysical market | 12 | 16 |
| Drilling market (*) | 210 | 240 |
| of which | | |
| *Onshore drilling* | *25* | *28* |
| *Offshore drilling* | *39* | *44* |
| Offshore construction market | 49 | 55 |
| **Refinery investments** | **68** | **69** |
| Investment spending | 25 | 25 |
| Maintenance spending | 27 | 28 |
| Catalyst and chemical spending | 16 | 16 |

(*) Including equipment for servicing the wells

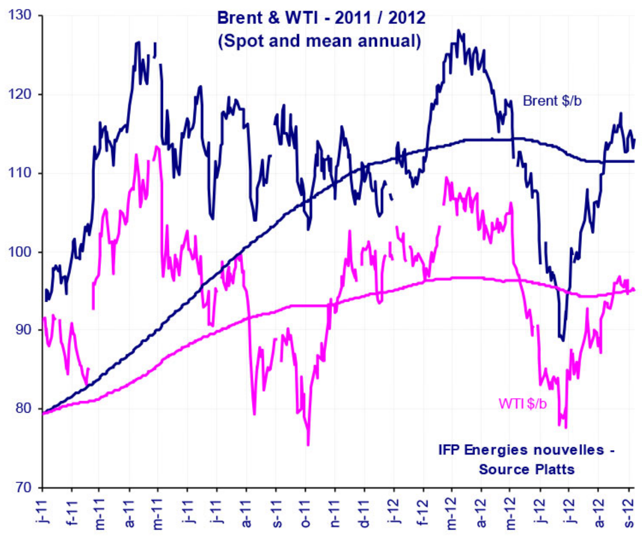
Sources:
- Upstream oil sector, IFPEN from
  - global investments: Barclay's, DTI, NPD, DEA, figures published by various companies and States, IFPEN forecasts
  - geophysical market: IHS Energy, First Break, Spears & Associates, IFPEN
  - drilling market: Baker Hughes, IHS energy, Offshore Rig Locator, Spears & Associates, IFPEN
  - offshore construction market: IHS energy, Spears & Associates, IFPEN
- Downstream oil sector: IFPEN from HPI Market data, IFPEN forecasts

# 1 Oil and gas prices - exacerbated instability

❖ **Increasing reactivity of oil prices, a barometer of extreme risks**

2011 had been marked by extreme variation in the price of Brent crude, with prices oscillating between US$100 and US$125 per barrel as the crisis in Libya unfolded and economic and financial concerns took hold. 2012 has been subject to the same geopolitical and financial shake-ups, resulting in even more dramatic oil price fluctuations than in 2011. The price of Brent fluctuated between US$88 and US$128 per barrel, while WTI (still selling at lower prices because of an influx of Canadian oil) has fluctuated between US$77 and US$109 per barrel. These movements illustrate exactly how the market works - it is forever speculating about the future. The greater the levels of uncertainty and concern, the more dramatic the market's movements are - as has been the case in 2012.

***Figure* 1*: Price of Brent and WTI (2011/2012) - Brent delicately balanced at US$110/barrel***

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These movements are evidence of the world's geopolitical and economic uncertainty - two forces with opposite effects that have been making themselves felt for two years. The increase at the start of the year (up to US$128 in March) was due to tensions with Iran. The oil embargo imposed by the European Union in January - which started to make itself felt in July - was the main factor behind this increase. Iran's renewed threats to close the Strait of Hormuz and the possibility of Israeli intervention which is once again on the table increased the risk of potentially high tensions.

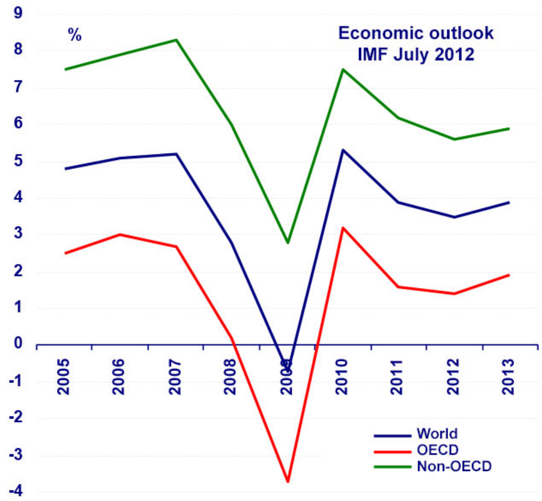
The increase in prices was followed by a linear decrease, with a very marked fall in June. There were three reasons for this. First of all, feverish concern over the effects of the embargo on Iran at a time when a number of countries such as Libya, Iraq and Saudi Arabia were stepping up their production. Secondly, concern over the likelihood of an Israeli military intervention (which is still being talked about, given the regional implications that that would have). And thirdly, European financial concerns, particularly in relation to the Spanish banking sector, which resulted in oil prices plunging to less than US$90 per barrel in June.

These fears regarding Europe's financial stability were partly allayed by the summit held on 30 June which provided a solution to the bank recapitalisation problem (Spanish issue). The statements that the ECB made at the end of July and in early August about safeguarding the Euro and the likelihood of its buying back bonds on the secondary market - a policy that was confirmed in September - also gave a boost to the financial markets. Brent, which is tightly correlated to movements on the world's money markets, rapidly rose to more than US$110 per barrel.

Across the year as a whole, the price of Brent should settle at around US$110 per barrel (as opposed to US$96 for WTI) - close to its level for the previous year (US$111). This value of US$110 per barrel seems to be a delicately balanced threshold figure, which rises or falls with the world's geopolitical and financial events. In the absence of any clear picture, the markets are predicting prices of around this figure for 2013. Dramatic surprises remain probable - given the contentious relationship between Israel and Iran and the economic situation in Europe and the US.

Evidence would suggest that high oil prices are affecting world economic growth. It is difficult to quantify this impact with any degree of accuracy, but - if we only focus on oil costs - it has reduced the GDPs of OECD countries by somewhere between 0.3% and 0.4% for each US$10 rise in the price of oil. For information, the price of Brent has risen by approximately US$30 since 2010 (US$79 per barrel). This would go some way towards explaining the fact that world economic growth has been slowing since 2011.

***Figure** 2: **World economic outlook: sluggish since 2011***




A fall in oil prices - which currently does not look very likely - would give growth a much-needed boost. The shale oil revolution which is currently under way on the US market may help reduce market tensions in the mid-term. But the geopolitical context in North Africa and the Middle East - regions which are still reeling from the effects of the Arab spring in 2011 - is still a source of significant pressure.

- **Gas prices: increase in popularity of spot markets**

The price variations to which the main markets have been subject since 2009 have remained relatively pronounced, and even increased in 2012. Prices are around:

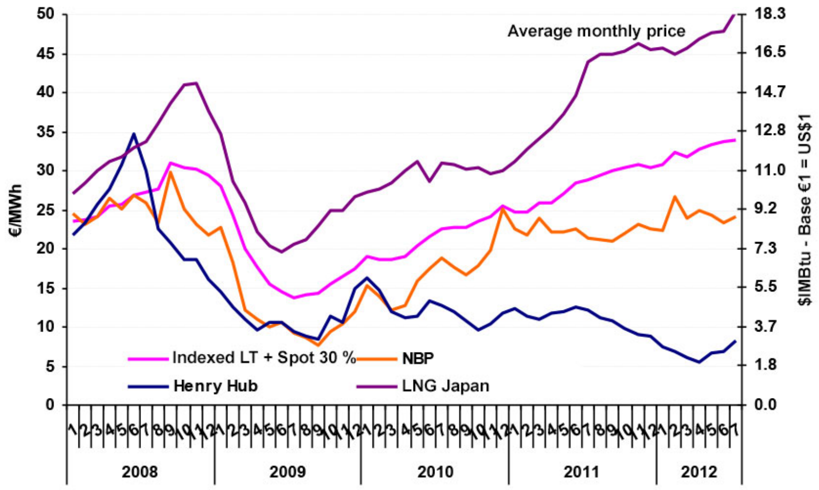
- US$2.7/MBtu (€7.2/MWh) in the US which is still taking advantage of the shale gas effect; this price is lower than in 2011 (US$4/MBtu; €9.9/MWh)
- US$9/MBtu (€25/MWh) for the spot European market (NBP price leader), price slightly higher than the previous year (U$9/MBtu; €22/MWh). The fall in consumption due to the recession has had no impact. The lower threshold of US$9/MBtu seems to be a reflection of production costs in the region. It should be noted that this lower threshold is still too high compared with coal prices - which have been falling since the end of 2010. The result is a lessening in the competitivity of gas in the electricity sector.

- US$12/MBtu (€33/MWh) for long-term European contracts (with 30% spot share), which have been affected - through prices still being high on the oil market - by the increase in the price of Brent The price differential with spot prices (NBP), which have been high since 2009 - is resulting in purchasers renegotiating contracts. An analysis of mean import prices in Germany shows that more than 50% of spot prices are now more representative of real supply costs (2011 average: US$11/MBtu; €28/MWh)
- US$17/MBtu (€45/MWh) in Japan for indexed prices; spot prices, which had risen dramatically in the wake of the Fukushima disaster resulting in the need to step up purchases of liquefied natural gas, are now falling (US$13/MBtu in September). For its imports, Japan is now considering looking to the US in order to take advantage of more favourable prices.

2012 has seen the continued rise in popularity of spot markets in Europe. This trend may eventually spread to Japan and more generally Asia as a whole. This is the result of a natural evolution to do with the deregulation of the market and - more especially at the moment - the dramatic rise in oil prices. Spot prices are not subject to the same pressures, particularly given the low rate of economic growth in Europe. The resulting price variations lead to charges that are too heavy for buyers.

Two factors could result in the spot markets becoming increasingly important: pressure on the gas market and a lessening of tension on the oil market. This scenario does not currently seem the most likely.

***Figure 3: Divergence in gas prices – indexed Europe, United Kingdom (NBP), United States (Henry Hub) and Japan (LNG)***



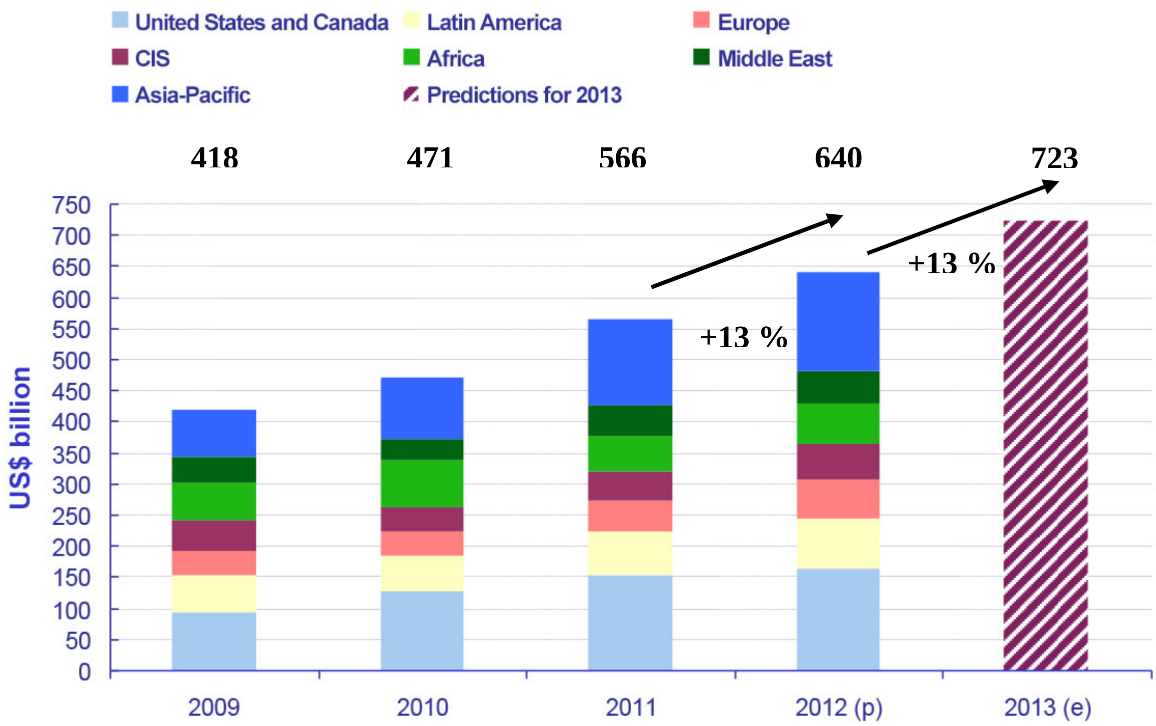
# 2 Exploration Production: continuation of the boom cycle

## 2.1 A rise in investment

Investments in exploration/production should increase by nearly 13% in 2012 to reach **US$640 billion** (**G$**), continuing the boom cycle that got under way in 2010. This increase represents an additional US$73 billion of investment compared with the previous year. Europe and the Commonwealth of Independent States are the most dynamic regions, with growth rates of 26% and 22%, respectively. Asia and Latin America follow, with increases of the order of 15% to 16%. North America and the Middle East have posted the lowest growth rates - around 6%. 2011 was a difficult year for Africa, but investment is now on the increase once again, with a growth rate of nearly 10%.

Activity should remain at high levels into 2013, with growth rates continuing to hover at around 13%, sustained by a number of major projects and the general good health of exploration. In North America, the development of source hydrocarbons, Canadian oil sands and deep offshore fields in the Gulf of Mexico will stimulate investment in the long-term. In Latin America, the development of offshore fields off the coast of Brazil will require substantial investments over several years. In Australia, LNG projects that are already under way or which have been approved represent a total of US$170 billion of investment over 5 years. Current projects in Iraq should maintain activity at high levels for at least five years. In Europe, an increase in investment spending is forecast in Norway in order to mitigate against the fall in oil production in the North Sea and develop new resources in the Barents Sea.

***Figure 4:4 Increase in global investment in E&P***




E&P investment has increased in all regions in 2012 compared with 2011. This increase has been the most significant in Europe - in the British North Sea in particular. Investment in this region has risen sharply by 33% from US$13.6 billion (£8.5 billion) in 2011 to US$18.1 billion (£11.5 billion) expected this year. A significant percentage of this investment goes on major maintenance and renovation operations for existing assets. But the sharp rise over the last two years is from investments in a small number of major projects[1] which were green-lit in 2010 and 2011, before the UK tax rises which were introduced in April 2011[2]. This high concentration of major projects in such a short period is unusual for this very mature region and is not likely to recur. Investments are therefore expected to fall over the next few years. In Norway, however, following a sharp increase of 21% this year, the authorities are forecasting a further rise of 10% for 2013. In Russia, Gazprom's investment looks set to fall by around 23%. But this fall is more than compensated for by other companies - by Lukoil and Surneftegaz first and foremost. The tax breaks that Vladimir Putin promised last April could help stimulate investment in offshore projects in the Arctic sea, with Rosneft and ExxonMobil having recently joined forces for an Arctic exploration project. In the Asia-Pacific region, the increase in activity can mainly be attributed to Chinese companies stepping up their investments (CNOOC and Sinopec in particular) and the continuation of LNG projects in Australia. In Latin America, the development of deep offshore fields off the coast of Brazil is having a positive effect on investment. Petrobras' new five-year plan provides for US$142 billion worth of investment in E&P between 2012 and 2016 - an 11% increase on the previous plan. Africa - where activity had suffered in 2011 as a result of the Arab Spring and all the uncertainties associated with the elections in Nigeria - returned to growth in 2012. The Middle East, which had seen a sharp rise in investment in 2011, returned to a more modest rate of growth in 2012. In this region, the main factors driving growth have been the development of Iraqi fields and increased production in Saudi fields in order to compensate for the fall in production in Iran resulting from the embargo. In United States, the fall in the price of gas - which fell to its lowest level in April at less than US$2/MBtu - has led to a fall in the money being invested in gas drilling. However, this money has been redeployed and has been invested in deposits that are rich in oil and condensates, ensuring that growth has remained positive.

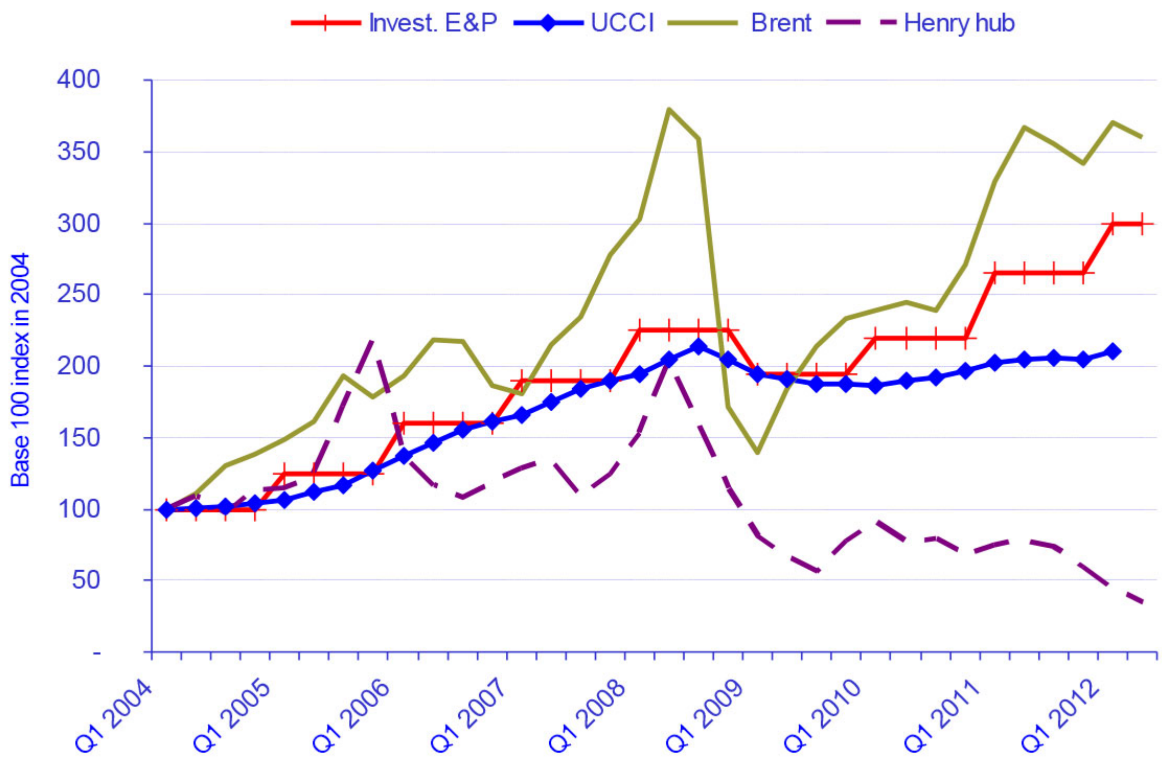
Companies of all types (national, international, major or independent) have increased their investments:

- The 5 majors all increased their investments in E&P by 10% in 2012. Total, BP and Chevron have seen the highest growth rates - between 15% and 17%, while ExxonMobil's and Shell's increases in investment have been more modest (5% and 3%, respectively).
- The budgets of independent companies have increased by an average of 19%. However, growth has been lower in North America where gas prices remaining at historic lows for the US has led to a number of US independents redeploying part of their investment budgets at international level.
- National companies have increased their investments by an average of 14%. But the situation varies considerably from region to region. In Asia, China's CNOOC (56%) and Sinopec (33%), and Thailand's PTTEP (55%) stand out in particular. In Latin America, PDVSA announced an increase of 50% in investment for 2012, while Ecopetrol looks set to increase its own investment budget by 33%. In the Middle East, KOC has increased its budget by 27%.

[1] including Laggan-Tormore, Clair Ridge, Jasmine, Schiehallion and Golden Eagle

[2] The tax rate was increased from 50% to 62% for new fields and from 75% to 81% for fields the development of which was approved prior to 1993

***Figure* 5*: Change in E&P investment, prices and costs***




In 2012 - as was also the case in 2011 - crude oil remaining at high prices in spite of the gloomy economic climate, has helped stimulate investment in E&P. Despite this favourable climate, a number of heavy crude oil projects in Canada have been jeopardised by the increase in the price of heavy/light spread and the Brent/WTI differential. This state of affairs has arisen because of the increase in shale oil production in US, and transport infrastructure being clogged. The increase in demand has also been putting pressure on the labour market and construction costs - which has delayed a number of projects. The IHS/CERA Upstream Capital Costs Index (see Figure 2) rose by 2.3% over the first half of 2012, and is now close to the maximum level it reached in 2008. This rise is mainly due to the increase in daily rates for leasing deep offshore drilling platforms, as well as the price of equipment (particularly in Brazil and North America) and labour costs (particularly in emerging countries). In the United States, the fall in the price of gas has led to investments being redeployed in liquid rich assets. The most exposed companies have been experiencing difficulties - like Chesapeake, the second-largest gas producer in the United States thanks to its shale gas acreage - which has had to sell some of its assets in order to resolve its cash flow issues.

## 2.2 In the news

- **East Africa: a new gas province with considerable potential.**

For a number of years now, the Rovuma offshore basin – which extends from southern Tanzania into the North of Mozambique – has been one of the most prolific regions for gas exploration. In 2011, it was in third position in terms of discovered hydrocarbon volumes, just behind the Santos basin (Brazil) and the Zagros basin (Iraq/Iran). In 2012, given the announcements that have been made by ENI and Anadarko, it could well end up ranking in first place. This good fortune has given rise to a measure of envy on the part of companies that are not operating in the region. Evidence of this can be seen in Thai oil and gas company PTTEP's recent buyout (for £1.22 billion - US$1.9 billion) of British company Cove Energy after a long bidding war with Shell. Cove Energy owns an 8.5% stake in block 1

There has been a succession of gas discoveries in Mozambique since Anadarko's first announcement in February 2010. The discovery of Mamba North East 2, the most recent one, was announced by ENI in early 2012. This means at least another 280 bcm of gas (according to ENI) in block 4, bringing the total up to nearly 2000 bcm. According to Wood Mackenzie, the recoverable reserves within this block now stand at 1100 bcm. In block 1, Anadarko currently controls an estimated 1300 bcm of recoverable reserves. In total, the reserves that have already been discovered in both blocks represent more than half of all the reserves discovered in Algeria. So far, success rates have been impressive (90% for Anadarko and 100% for ENI). And a number of other discoveries are expected before the exploration licences expire at the end of 2014 (for block 1) and the start of 2015 (for block 4). ENI is planning on drilling at least 8 more exploration wells, while Anadarko is intending to drill up to 14 more - to explore the southern section of block 1 in particular, where the Ironclad-1 wells which were drilled in August 2010 revealed the presence of oil. According to Wood Mackenzie, blocks 1 and 4 could contain at least another 2300 bcm of undiscovered recoverable reserves. In 2013, Statoil and Petronas are intending to explore the oil prospects in blocks 2 to 6, which are located a little further to the south. Another series of permits will be granted this year, which should enable a number of new players to express their interest.

Success rates have also been quite spectacular in Tanzania: 100% for BG with 6 wells in blocks 1, 3 and 4… and 100% for Statoil with 2 wells in block 2. Only Petrobras has had a failure - in block 5 with the only well that it has so far drilled. But discoveries have been much smaller - an average of 57 bcm, as opposed to 200 bcm in Mozambique. The fields are also a lot more dispersed than in Mozambique, which would make developing the zone more complicated.

The reserves that have so far been revealed are sufficient to justify construction of 14 liquefaction trains in Mozambique. This would turn the country into a major liquefied natural gas exporter - on a par with Qatar and Australia. In Tanzania, according to Wood Mackenzie, none of the reserves so far discovered by the operators are of the critical size needed in order for commercial operation to begin - at least two LNG trains would be needed for any given project to be profitable. The consultancy group believes that BG is the closest to meeting this threshold - they only need another 30 bcm of the total 300 bcm required. Wood Mackenzie believes that finding these additional reserves should not be a problem - according to them, there are still another 1400 bcm to be discovered in Tanzania.

Anadarko and ENI have both announced that they are aiming to produce LNG in Mozambique starting in 2018. BG is aiming to begin LNG production in Tanzania by 2020. But there are still a number of technical, administrative and financial obstacles that will need to be overcome. These include the lack of qualified labour, the absence of any appropriate port infrastructure, the risk of piracy and the absence of any legislative and fiscal framework. Furthermore, the exploitation of fields extending on both sides of the licensed areas could require negotiations which could further delay the project. And a considerable amount of investment will be needed. The cost of the first projects to build two LNG trains looks set to exceed US$25 billion, and developing all the reserves that have potentially been discovered could require around US$150 billion. But the region does possess confirmed assets. The reservoirs are of excellent quality, the gas is dry and requires relatively little in the way of processing, and the geographical location is ideal for supplying Asia and India - both fast-growing markets.

Anadarko is currently making good progress in its development projects. A final investment decision on a two train LNG development is expected in 2013. The US independent oil company and its partners have a significant advantage: they control a complex (together with the Golfinho/Atum field) that is entirely contained within their own licensed area and that is large enough to justify independent development. Technip and KBR have been entrusted with the pre-FEED study. At the end of 2011, ENI announced plans to invest US$50 billion in Mozambique in order to develop the Mamba gas field discovery. But it has not yet given details about this project.

***Juan de Nova Island: could France benefit from the Mozambique bonanza?***
Juan de Nova, a tiny island in the narrowest part of the Mozambique Channel, about one-third of the way between Madagascar and Mozambique, belongs to France. Two offshore exploration licences were granted in December 2008 - one to the Global Petroleum (30%)/Wessex Exploration (70%) partnership, the other to the Marex Petroleum (25%)/Roc Oil (70%) partnership. The former set about reprocessing data acquired from a multi-client 2D seismic survey that was carried out by Nopec in 2006. A new 2D seismic survey is scheduled for between now and the end of the year, the aim being to identify a prospective drilling zone for 2013. The Marex Petroleum/Roc Oil partnership should soon carry out a 3D seismic survey. Only once this initial exploratory phase has been carried out will it be known whether or not Tanzania’s and Mozambique's favourable offshore geological conditions extend further east towards Madagascar.

### ❖ Levant Basin: significant resources, but not easy to develop

Since 2009, Noble Energy has discovered more than 1000 billion m³ of gas in the offshore Levant Basin. Most of this gas is located in three giant fields: Tamar and Leviathan off the coast of Israel, and Aphrodite in Cypriot waters.

| Field | Year | Reserves (bcm) |
|---|---:|---:|
| Tamar | 2009 | 275 |
| Dalit | 2009 | 10 |
| Leviathan | 2010 | 570 |
| Aphrodite | 2011 | 200 |
| Tanin | 2012 | 35 |
| Shimson | 2012 | 65 |
| **Total** | | **1155** |

Tamar was the first field to be discovered in 2009. Production is expected to begin in mid-2013. At depths of more than 1600 m, the field is estimated to contain a probable 275 bcm of natural gas, according to the Israeli group Delek Energy - enough to meet Israel's needs for 30 years. The investment needed to develop the field is relatively modest - around US$3 billion. This is because the development will use some of the Mari-B field's existing infrastructure. Developing Leviathan and Aphrodite, on the other hand, will be more challenging and costly.

Leviathan, discovered in 2010, contains approximately 570 bcm of recoverable gas - enough to turn Israel into a gas exporter. Given the size of the field, its economic viability is contingent on Israel being able to export, according to Noble Energy, the field's operator. In a recent presentation, the American independent operator suggested that it would commence operation in 2016 for the local market, with the project to export gas following afterwards, announcing that it was investigating various export options using LNG. The field is located at depths of more than 1600 m and it has so far proved difficult to find a suitable site on the Israeli coast (because of opposition from the people living on Israel's densely urbanised coast). Nobel could therefore favour a development design based on an FLNG unit. There are not yet any examples of such operations in service: Prelude, the first project of this type in Australia, is not scheduled to commence production until 2017.

There are around 200 bcm of recoverable resources in the Aphrodite gas field that were discovered off the southern coast of Cyprus in 2011 - enough to make the island energy-independent. However, projects to develop it have come up against the same technical and economic difficulties as Leviathan - it's located at depths of more than 1600 m, and the gas surplus will need to be exported once domestic needs have been met if the project is to be profitable. For the time being, the reserves that have so far been discovered are not yet sufficient for a viable LNG project, and laying a gas pipeline to Europe does not appear to be a practical solution. Diplomatic tensions between Nicosia and Ankara mean that gas cannot transit through Turkey. A seabed pipeline through Greek waters is possible, but not very probable because of the depths involved (more than 3000 m in some sections) and the distance that would need to be crossed (more than 1000 km through a seismically active zone).

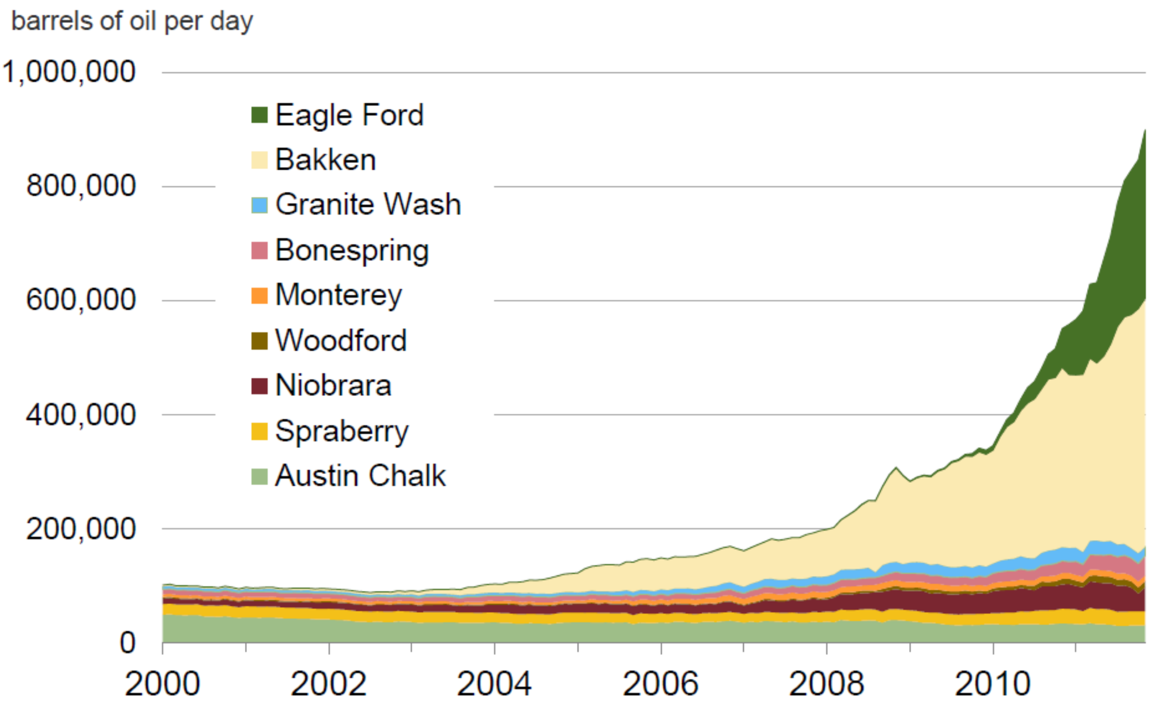
- **Shale hydrocarbons in the United States: the oil rush.**

With the influx of shale gas (production rose again by 24% between May 2011 and May 2012), gas prices have stayed low in US, even reaching a decade-low of US$1.9/MBtu last April. With production costs generally estimated at US$5/MBtu or more, dry gas wells will not be profitable at current price levels. In order to maintain their profits, US producers have massively redeployed their investments towards deposits that are rich in oil or natural gas liquids, and which are more lucrative. Those operators that are the most exposed to gas are now in serious difficulties. For example, Chesapeake, the second largest gas producer in the United States thanks to its shale gas operations, now plans to sell US$14 billion worth of its assets in order to finance its debt and is counting on the Eagle Ford and Utica shale reserves (which contain wet gas and oil) in order to push it back into profit.

The collapse of natural gas prices is generating a great deal of discussion about exporting natural gas. There are currently around a dozen or so LNG export projects in the US, representing total potential of more than 120 Mt/year. This is considerably more than Qatar’s current capacity (77 Mt/year), the world's leading LNG exporter. It is still not known how many of these projects will be approved by the US government, which is keen to curb the increase of domestic prices. To date, only Cheniere Energy has been granted authorisation to build up to 4 liquefaction trains and export LNG from the Sabine Pass in Louisiana. As far as the other projects awaiting authorisation are concerned, the US Department of Energy is still waiting for the results of a study into the consequences of large-scale export operations before reaching a decision. This report was initially to be published in spring, but it now does not look as though it will emerge until after the US presidential elections.

Companies redeploying their investments into liquid-rich provinces (which started in 2011) has resulted in an impressive increase in oil production. Between 2010 and 2011, production in North Dakota increased by 60% from an average of 260,000 barrels per day to 419,000 barrels per day over the whole year, while production in Eagle Ford (Texas) increased by a factor of four (from an average of 31,000 barrels per day to 139,000 barrels per day over the whole year). In November 2011, total shale oil production in the US was nearing 900,000 barrels per day according to the US Department of Energy - an increase of 450% in four years. This increase has become even more pronounced in 2012. North Dakota is now the second largest oil-producing state in the US, with record production of 674,000 barrels per day in July, 610,000 barrels of which were from the Bakken shale formation. And according to the Department of Energy, Eagle Ford's liquid hydrocarbon production exceeded 500,000 barrels per day at the end of April.

***Figure** 6 – Shale oil and tight gas production in the United States*




*Source: DOE - April 2012*

The increase in production has been sustained by technical improvements. These in turn have resulted in lower costs per metre drilled, an increase in well productivity and an increase in ultimate per-well recovery - meaning lower drilling costs per barrel. In North Dakota, for example, average per-well production has doubled in 5 years. At the same time, estimated ultimate per-well recovery has increased by a factor of 4 and per-barrel drilling costs have been halved.

This increase in oil production is resulting in transport infrastructure becoming saturated. In North Dakota, for example, a growing share of production has to be transported by train (25% in January 2012), or even lorry (7%). The situation could well continue - the planned timetable for extending the network of oil pipelines will most likely not be enough to keep pace with the predicted increase in production over the next few years.

- **Shale hydrocarbons and tight gas outside the US.**

In Europe, Bulgaria, Romania and the Czech Republic have all joined France in enacting moratoriums on hydraulic fracturing.

In Germany, despite current discussions about the use of hydraulic fracturing, several *länders* have issued permits for unconventional hydrocarbon exploration. Germany's Federal Institute for Geosciences and Natural Resources (BGR) recently put the country's quantity of technically recoverable reserves at between 700 and 2300 m³.

In Poland, where shale gas exploration is continuing, the quantities of resources being revised downwards by the National Geological Institute (PIG) in March, followed three months later by ExxonMobil abandoning its exploration projects having drilled only two wells, have cast some doubt over the country's unconventional hydrocarbon potential. There has also been some more encouraging news recently, such as the discoveries of gas by BNK Petroleum and oil by San Leon Energy - both announced in August.

In the United Kingdom, the exploratory operations carried out by Cuadrilla Resources had to be stopped after two small earthquakes which occurred near the prospection site in April and May 2011. Despite having been given the go-ahead in April by a group of independent experts, operations have not yet resumed.

In Canada, where 2% of gas production is already from shale gas and 34% from tight gas, Apache has announced the discovery of a giant shale gas deposit in the Liard basin in British Columbia. The American independent oil and gas corporation has put the volume of marketable gas contained in its acreage at 1360 bcm. Furthermore, the reservoir's properties appear to be excellent: Apache has described it as the "best unconventional reservoir in North America". This discovery could double the capacity of Kitimat’s future LNG export terminal (two LNG trains are currently planned). Apache is one of its three partners and is due to commence exports to Asia in 2017.

In Argentina, the expropriation of Repsol's assets, newly nationalised YPF is planning on investing US$37 billion between now and 2017 on developing unconventional hydrocarbons. An agreement with Chevron is in the planning stage under the terms of which the Vaca Muerta formation in the Neuquén Basin would be explored - where Repsol-YPF last year discovered 927 Mboe of recoverable unconventional resources, including 741 Mb of shale oil. According to the Department of Energy, Argentina has the third most extensive reserves of shale hydrocarbons, behind the US and China.

At the end of August, Santos in Australia announced it was commencing the first commercial production of shale gas in the country using the vertical Moomba-191 well in the north-eastern part of South Australia, in the Cooper Basin. The Australian company will begin horizontal drilling trials in early 2013.

In China, where the government has set the rather ambitious production target of 6.5 billion $m^3$/year by 2015 and between 60 and 100 billion $m^3$/year by 2020, Sinopec recently announced the launch of its first shale gas exploitation project. It is forecasting production of between 300 and 500 million $m^3$/year between now and the end of 2012, increasing to 1 billion $m^3$/year by 2013. In March, Shell entered into an agreement to share production with CNPC, the first agreement of its kind with a non-Chinese company. The Anglo-Dutch group already invested more than US$400 million in 2011 in shale gas exploration alongside CNPC, drilling 15 wells with encouraging results. CNOOC, another major Chinese national oil company, commenced drilling operations for its first shale gas project at the end of 2011.

In the North Africa and Middle East region, BP will most likely invest US$24 billion in Oman in order to develop the tight gas resources in block 61, the aim being to commence production in early 2017 and reach 10 billion $m^3$/year by 2019. In Algeria, the first shale gas well has been drilled in collaboration with Shell. The government has put the quantity of recoverable resources at 17 billion $m^3$, and is planning on offering companies that get involved in exploring shale gas resources fiscal incentives.

In the CIS region, the Ukraine has announced its plans to start up shale gas production in 2017 and granted two exploration-production licences to Shell and Chevron last May. In Russia, Rosneft and ExxonMobil entered into an agreement in June to jointly develop the tight oil resources located in Western Siberia.

- **Iraq: oil production on the increase against a background of tension with Kurdistan.**

Production in Iraq has increased considerably, reaching 3.03 Mb per day in April, as opposed to 2.6 Mb per day 12 months earlier, a level of production that has not been seen for several decades. In July, Iraq even became OPEC's second largest oil-producing country, overtaking Iran where production has suffered under the effects of the embargo.

As expected, Iraq brought two floating export terminals into service in the first quarter of 2012, both with a nominal capacity of 900,000 barrels per day. However, for the time being, the export capacity of both terminals together is plateauing at around 300,000 per day because of onshore infrastructure problems. In fact, growth in production being able to continue is contingent on appropriate infrastructure being developed. According to a statement issued by an Iraqi official in June, the country's oil production should increase from 3.4 Mb/day at the end of 2012 to 4.4 Mb/day in 2014... and then 9 million b/day by 2020. Although below the 12 Mb/day initially suggested for 2017, this new target is still highly ambitious. According to consultancy group Wood McKenzie, current infrastructure development projects will not be enough to get beyond 5.8 Mb/day. Reuters has recently reported on the negotiations between Baghdad and Shell which seems unable to meet production targets for the end of 2012 in the Majnoon field. This is because of delays in building the pipeline required to transport the crude oil to the storage facilities.

Relations between Baghdad and the autonomous region of Kurdistan remain tense. The Kurdistan authorities interrupted their oil exports for four months following a financial dispute with central government - which had not made any payments for 10 months. According to the Kurdish authorities, the government is US$1.5 million in arrears. Baghdad is accusing the region of not having honoured its obligation to increase production and supply 175,000 barrels of crude oil per day. Crude oil deliveries resumed in early August and it would appear that an agreement has recently been reached (announced mid-September, but not yet signed). Under the terms of this agreement, Kurdistan undertakes to export 200,000 barrels of oil per day until the end of the year in exchange for an advance of US$850 million from Baghdad.

There is another bone of contention: last November, ExxonMobil signed six production sharing contracts with Kurdistan without central government's approval. The government had originally expressed an intention to terminate the company's contract on the West Qurna field but was legally unable to do so. Nevertheless, ExxonMobil has been banned from future Iraqi bidding processes. Following Exxon’s example, Chevron, Gazprom and more recently Total have established a presence in Kurdistan without Baghdad's authorisation. Like Exxon, they have all been banned from any future bidding processes.

According to certain analysts, this new attitude that the major oil companies are now adopting towards central government is evidence of a shift in the balance of power between international oil companies and their host countries. The situation has changed since 2009, which was when the first service contracts were awarded in Iraq. Today, with a barrel of Brent costing an average of US$113, many development projects are becoming profitable, and oil companies can choose from a range of investment options and be more demanding when it comes to payment. Indeed, the Iraqi government's last invitation to tender last May met with relatively little success. A dozen oil and gas exploration blocks were put up for sale, but only three contracts were entered into. The companies did not judge Baghdad's service contracts to be particularly appealing; Kurdistan's production sharing contracts, on the other hand, were seen as considerably more lucrative. Iraq is planning to hold a fifth licensing auction for exploration blocks by the end of this year or at the beginning of 2013, with terms that are more advantageous for the oil companies.

# 3 Main markets in the upstream oil equipment and services sector

## 3.1 Introduction

The funds that oil companies invest in exploration and production are used to look for new oil and gas reserves, assess just how expensive they are and then put them into production.

The exploration phase involves a series of geophysical tests, all of which require instrumentation and data measurement equipment (seismic, electromagnetic, etc.). The data acquired is then processed and interpreted in a bid to locate hydrocarbon reservoirs. In 2011, the geophysical exploration market was worth around US$14 billion.

If an area is deemed likely to contain oil, an exploration well is drilled in order to ascertain whether or not it actually does. If the presence of oil is indeed confirmed, an assessment phase follows before the field is eventually developed.

Drilling is essential - either onshore or offshore - in order to reach the depths at which the reservoirs lie. A whole set of services and products are involved in drilling (logging, directional drilling, chemicals, etc.), which together generated total turnover of more than US$200 billion throughout the world in 2011.

Because of their distance from the coast and their locations out at sea, offshore discoveries require the construction of production platforms and pipeline connections so that the crude oil can be exported. In 2011, the offshore construction market was worth nearly US$50 billion.

## 3.2 Drilling

The numbers of active rigs is rising again following the 2009 world financial crisis. 2011 saw an overall increase of 16%: an increase of 11% in the numbers of onshore wells being drilled, and 6% in the numbers of offshore wells being drilled.

Overall, rig day rates and utilisation rates have risen over 2012, and the total number of rigs (onshore and offshore) will most likely have increased by 9%.

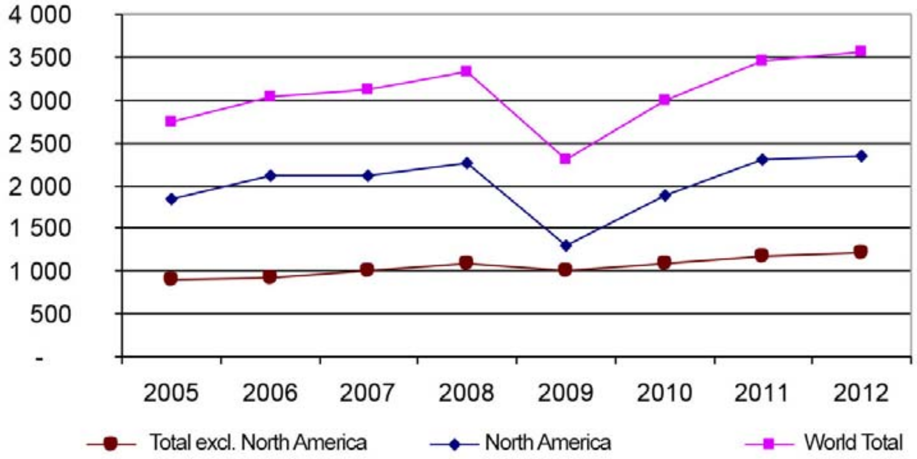
The drilling and associated services market grew by 23% in 2011. Growth of an additional 13% is predicted for 2012, with the hydraulic fracturing segment growing particularly fast. In three years, the hydraulic fracturing and pumping market has grown by 150% and is now larger than the offshore drilling market.

### *3.2.1* Drilling activity

#### *3.2.1.1Number of working rigs*

Every month, the Baker Hughes international rig count gives the number of working rigs throughout the world. This is also an indicator of the quantities of products being used for drilling and other well-related services.

***Figure 7: Increase/decrease in the number of working rigs throughout the world***

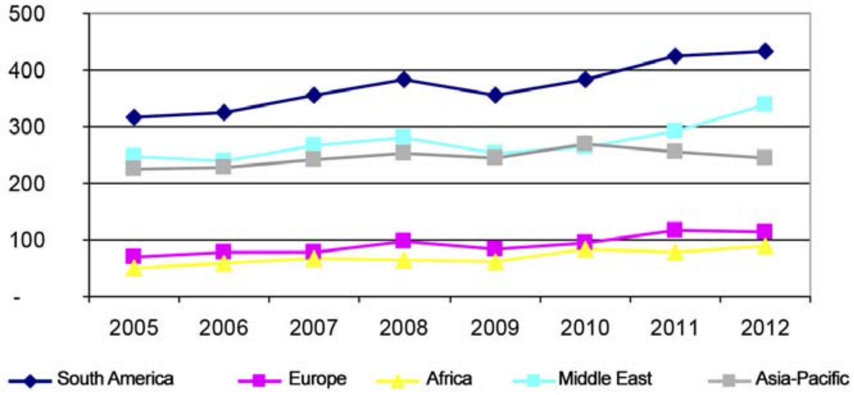



*(Sources: IFPEN, Baker Hughes)*

In 2012, the number of working rigs should increase by 9%. In 2011, numbers increased by 16% back up to their 2008 levels - prior to the world economic and financial crisis.
The regions that have seen the most significant increases are Africa and the Middle East, with 14% and 16% increases in the number of working rigs, respectively. Asia and Europe have seen the most significant fall in numbers - 5% and 3% lower respectively, compared with 2011.

In 2011, numbers had grown significantly in Europe (20%), and Africa had been the only region to see a fall (-6%).

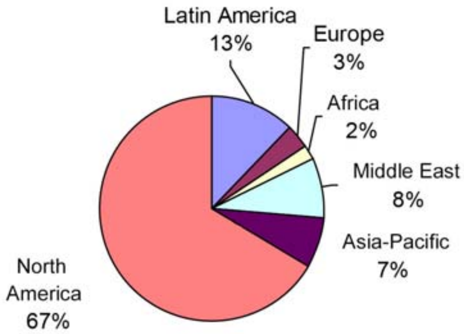
***Figure 8: Increase/decrease in the number of working rigs throughout the world's regions, except North America***




*(Source: Baker Hughes)*

North America still accounts for two-thirds of the world's working rigs, followed by Latin America (13%), the Middle East (8%) and Asia Pacific (7%).

***Figure 9:*** **Distribution of working rigs in 2011 (onshore and offshore) by region**




*(Source: Baker Hughes)*

### *3.2.1.2 Number of wells drilled*

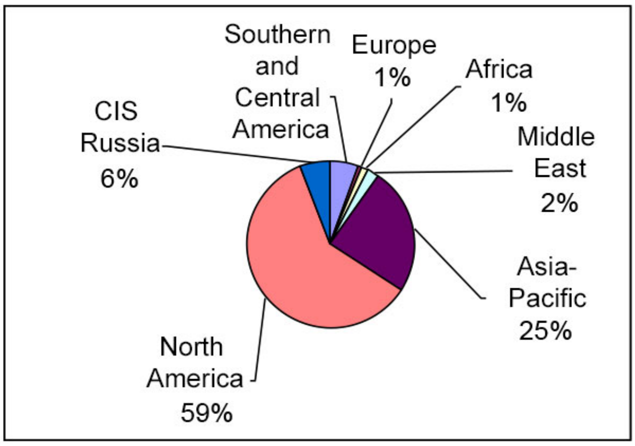
A total of 98,500 new onshore wells and 3700 new offshore wells were drilled in 2011 - an increase of 11% and 6%, respectively.

- **Onshore**

Europe saw the strongest increase in onshore drilling in 2011 (20%). Poland in particular saw a marked increase, with a number of shale gas exploration projects.

The number of drilling operations in North America is still increasing (+16%). Having first been interested in shale gas, many companies are now looking into drilling for shale oil - which is more profitable because of the high price of oil. For the first time in 2011, the number of gas drilling operations in the US was lower than the number of oil drilling operations.

***Figure 10: Distribution of onshore wells by region (a), and growth in 2011 compared with 2010 (b)***




| **Onshore** | **2011/2010** |
|---|---:|
| Central and South America | 8% |
| Europe | 20% |
| Africa | -3% |
| Middle East | 15% |
| Asia Pacific | 3% |
| North America | 16% |
| FSU Russia | 3% |
| **Total** | **11%** |

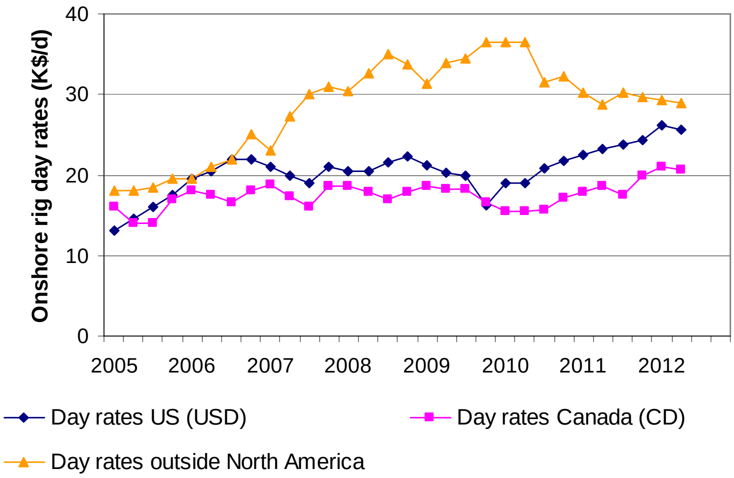
*(Sources: IFPEN, Spears & Associates)*

In 2012, with the end of the Arab Spring, drilling operations have resumed in Egypt and Libya. Despite the geopolitical uncertainty associated with Iran (the international embargo and Iran's threats to blockade the Strait of Hormuz) and the war in Syria, the number of drilling operations in the Middle East is rising.

### Onshore rates

In 2011, annual onshore rig rates across the world (except North America) were slightly down (-3%), but they were up by 17% in North America.
Rates were stable throughout 2012 except for in North America, where they increased by 10%.

***Figure 11: Onshore rig day rates across the whole world and in North America (United States and Canada)***

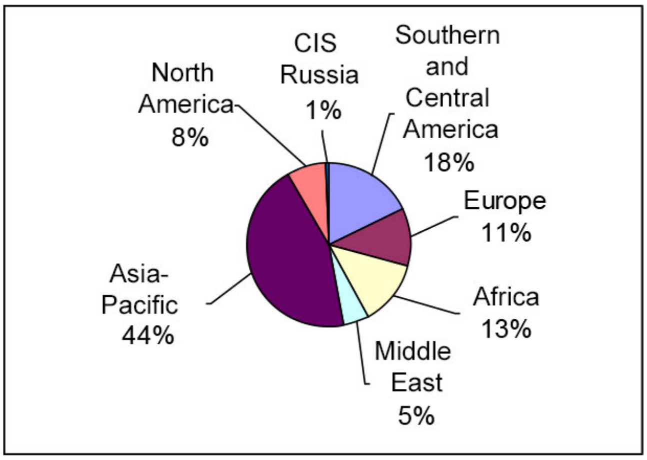



*(Sources: IFPEN, Spears & Associates)*

- **Offshore**

South America saw particularly high levels of drilling activity in 2011, with the new fields being developed in Brazil. Saudi Arabia was also particularly active in the Red Sea: its onshore Wasit gas plant is going to be developing the Aribiyah and Hasbah fields.

*Figure 12: Distribution of offshore wells by region (a), and growth in 2011 compared with 2010 (b)*




| Offshore | 2011/2010 |
|---|---|
| Central and South America | 20% |
| Europe | -4% |
| Africa | 7% |
| Middle East | 19% |
| Asia Pacific | 4% |
| North America | -1% |
| FSU Russia | 5% |
| **Total** | **6%** |

*(Sources: IFPEN, Spears & Associates)*

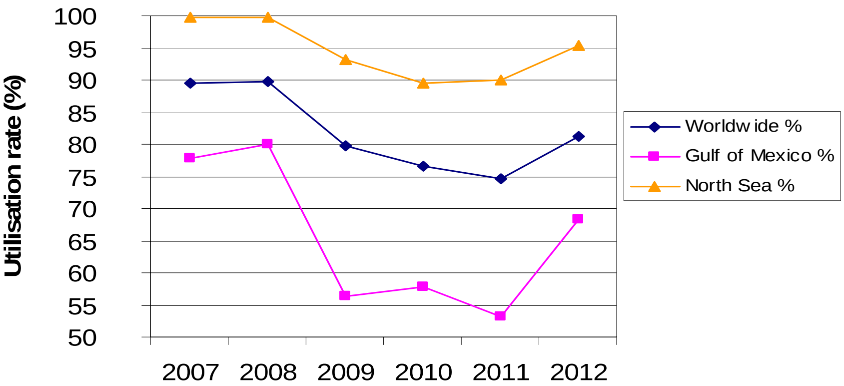
Drilling activity returned to high levels in the Gulf of Mexico in 2012 - off the coast of the United States, as well as Mexico. Drilling activity also increased in Africa: in East Africa with gas prospects in Mozambique and Tanzania, and in West Africa where a number of new oil fields have been developed. A number of exploratory drilling operations are now also under way in Cyprus, the Lebanon and Israel in the eastern Mediterranean.

**Offshore rig utilisation rates**

2012 saw a mean annual increase of 9% in offshore rig utilisation rates (all types together). The Gulf of Mexico even saw an increase of 28%, whereas the North Sea only saw an increase of 6%.

Drilling activity has recovered strongly in the Gulf of Mexico - particularly as far as the floating rigs used for deep offshore operations are concerned. It should be remembered that activity was still suffering from the effects of the post-Macondo oil spill moratorium throughout 2011 and the granting of deep offshore drilling licences had been suspended.

***Figure 13: Mean annual offshore rig utilisation rates for the whole world, the Gulf of Mexico and the North Sea***



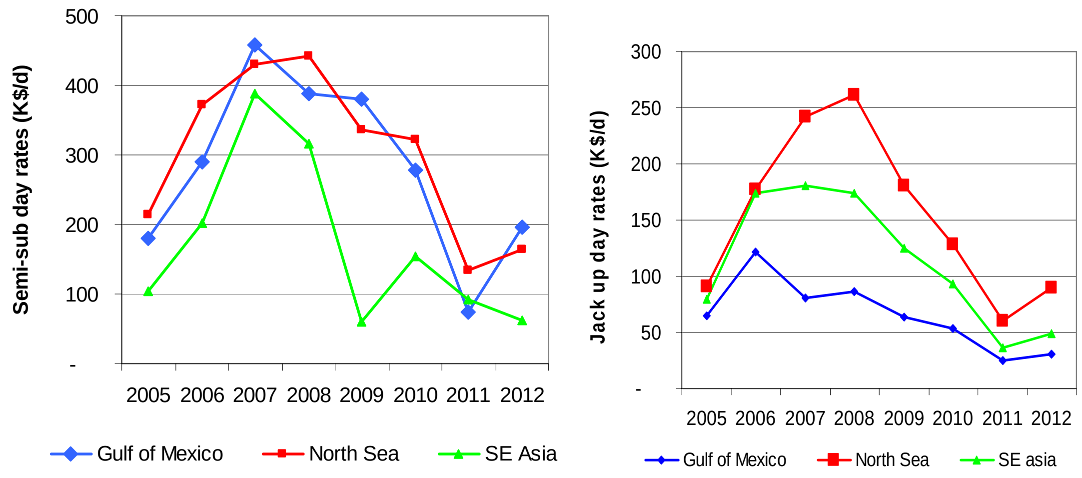

*(Sources: IFPEN, Spears & Associates)*

**Offshore rig rates**

Offshore day rates across the whole world increased in 2012, except in Southeast Asia which saw a fall of 33% (it had already seen a decline in 2011).

The Gulf of Mexico saw the greatest increase with a resumption of drilling licences being granted.

***Figure 14: Mean annual day rates for semi-sub and jack-up rigs in the Gulf of Mexico, the North Sea and Southeast Asia.***




*(Sources: IFPEN, IHS energy)*

***Figure 15: Annual growth in 2012 for semi-sub and jack-up rates by region***

| | Semisub GOM | Semisub North Sea | Semisub SE Asia | Jackup GOM | Jackup North Sea | Jackup SE Asia |
|---|---|---|---|---|---|---|
| 2012/2011 | 161% | 22% | -33% | 24% | 48% | 32% |

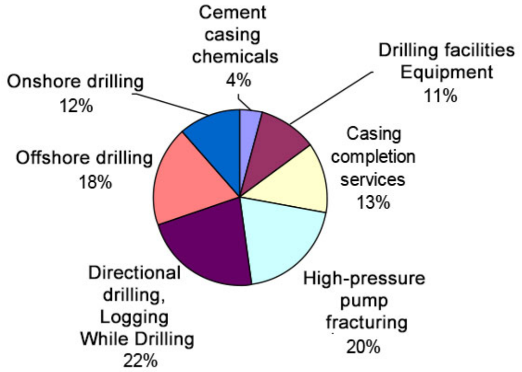
### *3.2.2* Drilling markets

In 2012, the drilling and associated services market was worth an estimated US$240 billion - 14% more than in 2011. It had already grown by 23% in 2011. The onshore market accounts for 72% of the drilling market's total worth, offshore activity for the remaining 28%.

In 2011, offshore and onshore drilling operations accounted for 18% and 12% of the global market, respectively - US$39 billion and US$25 billion. Other segments of this major market include:

- drilling services for directional drilling, wireline logging and drilling while logging (22% of the global market),
- fracturing and pumping operations (20% of the global markets) which have kept pace with the development of shale gas operations.

***Figure 16: distribution of the various segments of the drilling market in 2011***

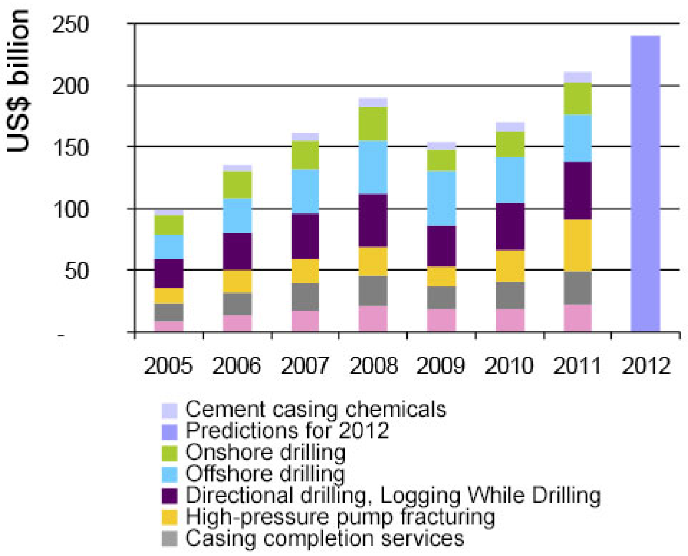



*(Sources: IFPEN, Spears & Associates)*

By the end of 2012, all the segments should have returned to and exceeded their 2008 levels.

In 2011, the directional and logging drilling market increased by 37% compared with 2009 levels - the lowest point of the world economic crisis. Over the same period, the increase in hydraulic fracturation and pumping operations was even more spectacular - an increase of 150% in three years.

*Figure 17**: Increase/decrease in size of the various drilling market segments and forecasts for 2012***



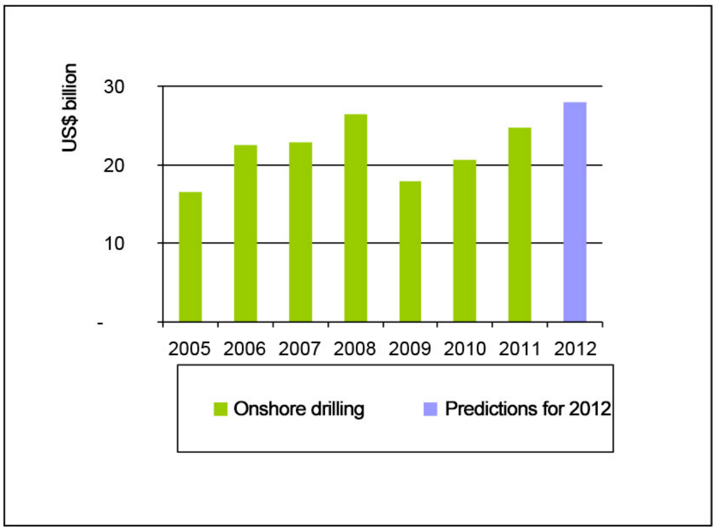

*(Sources: IFPEN, Spears & Associates)*

The drilling market should grow by approximately 10% in 2013, with rig rates recovering to their pre-2009 levels for offshore operations and - with the exception of North America - onshore operations

#### *3.2.2.1 Onshore drilling market*

10 major groups account for two-thirds of the world onshore drilling market. The sector leader is Nabors Industries, with a 14% share of the market.

*Figure 18:* ***Increase/decrease of the onshore drilling market and market share of the major onshore drilling companies in 2011***




| Companies | % | Total |
|---|---|---|
| Nabors Industries | 14% | 14% |
| Helmerich & Payne | 10% | 24% |
| Ensign | 7% | 31% |
| Patterson-UTI | 7% | 37% |
| Eurasia Drilling Co. | 6% | 44% |
| Precision Drilling | 6% | 50% |
| Weatherford | 4% | 54% |
| Saipem SPA | 4% | 58% |
| Schlumberger | 4% | 62% |
| Trinidad Drilling | 3% | 65% |
| San Antonio | 2% | 68% |
| KCA Deutag | 2% | 70% |
| Unit Corporation | 2% | 72% |
| Pioneer Drilling | 2% | 73% |

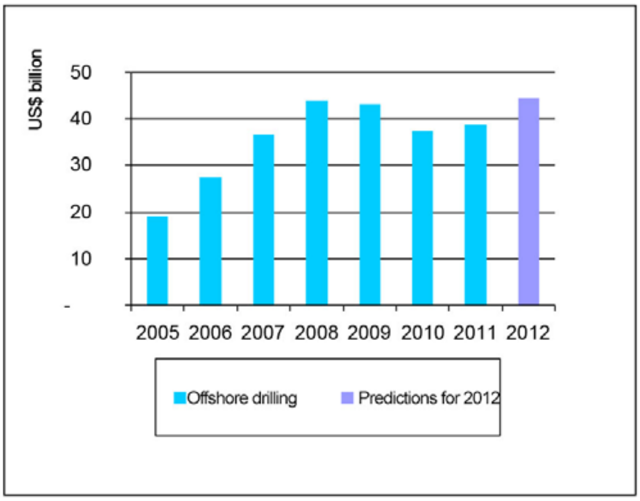
*(Sources: IFPEN, Spears & Associates)*

### *3.2.2.2 Offshore drilling market*

Transocean remains the leading offshore drilling company, with a 21% share of the world market. The company suffered a 3% fall in market share after the Macondo oil spill in the Gulf of Mexico.

Seadrill's market share rose by 2% between 2010 and 2011. Over the same period, ENSCO and Diamond Offshore, the sector's second and third companies respectively, remained stable. Transocean's fall in market share has mainly benefited the smaller companies operating in the sector.

*Figure 19:* ***Increase/decrease of the offshore drilling market and market share of the major onshore drilling companies in 2011***




| Companies | % | Total |
|---|---|---|
| Transocean, Inc. | 21% | 21% |
| ENSCO | 9% | 31% |
| Diamond Offshore | 9% | 39% |
| Seadrill | 9% | 48% |
| Noble Drilling | 7% | 54% |
| Maersk Group | 4% | 58% |
| China Oilfield Services | 4% | 62% |
| KCA Deutag | 3% | 65% |
| Saipem SPA | 3% | 68% |
| Fred. Olsen Energy | 3% | 71% |
| Rowan Companies | 2% | 73% |
| Odfjell Drilling Group | 2% | 75% |
| Ocean Rig | 2% | 77% |
| Atwood Oceanics | 2% | 79% |

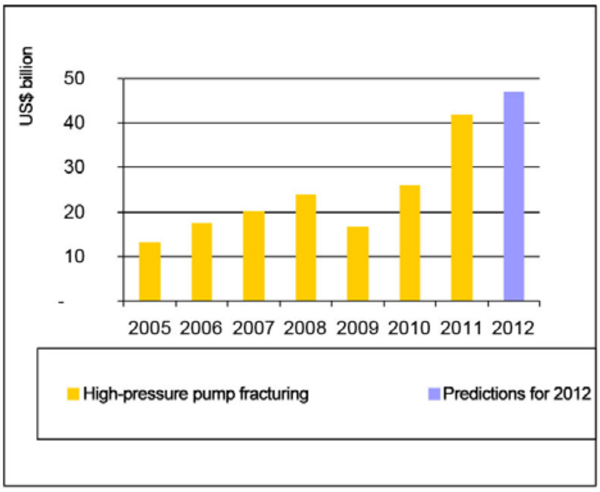
*(Sources: IFPEN, Spears & Associates)*

### 3.2.2.3 Fracturation market

The fracturation market is highly concentrated: 10 companies (the majority of which are located in North America) account for an estimated 90% of total world turnover.

Halliburton is the leading company in the sector, with a 27% share of the world market. The sector includes a number of the major groups that are involved in onshore drilling, such as Weatherford, Narbors Industries and Patterson-UTI.

*Figure 20*: ***Increase/decrease in the fracturation market and market share of the main companies involved in it in 2011***




| Companies | % | Total |
|---|---|---|
| Halliburton | 27% | 27% |
| Schlumberger | 21% | 48% |
| Baker Hughes | 15% | 63% |
| Frac tech Services | 6% | 69% |
| Trican Well Service | 5% | 73% |
| Weatherford | 4% | 77% |
| Calfrac Well Services | 3% | 81% |
| Nabors Industries, Inc. | 3% | 84% |
| Cudd Pumping | 2% | 86% |
| Patterson-UTI | 2% | 88% |

*(Sources: IFPEN, Spears & Associates)*

## 3.3 Geophysical market

With high oil prices and investment in exploration/production having grown by more than 10% since 2010, activity on the geophysical market (data acquisition, processing and equipment) is continuing to grow - driven mainly by the need to find new reserves, particularly in new exploration zones: difficult zones, such as ultra-deep offshore, the new provinces being explored in the Arctic, etc.

The complexity of new oil and gas prospects requires increasingly sophisticated data acquisition equipment which in turn requires the very latest vessels to transport it.

Nevertheless, 2012 saw a fall in onshore activity (except in North America), which can be attributed to a number of major exploration campaigns in the Middle East coming to an end.

There was an 8% increase in the number of offshore test campaigns. Overcapacity in acquisition vessels is being absorbed and the costs of seismic surveys are rising.

2012 should see a 13% increase in global turnover on the geophysical market, a 15% increase on the data acquisition/processing market and a 9% increase on the equipment market.

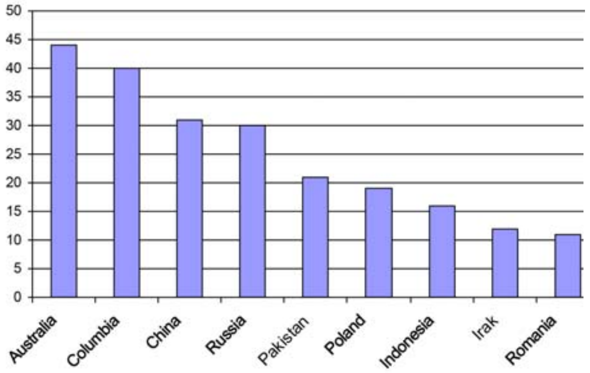
### *3.3.1* Geophysical activity

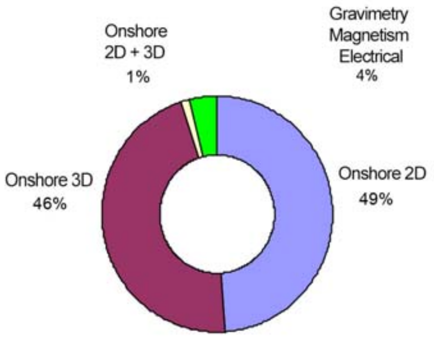
#### *3.3.1.1 Onshore*

The first eight months of 2012 saw approximately 300 onshore data acquisition projects across the whole world (with the exception of North America). This represents a 9% fall compared with 2011, which can mainly be attributed to a number of major exploration campaigns coming to an end in Iraq.

Outside North America, half of all onshore data acquisition projects are located in 6 countries - Australia, Colombia, China, Russia, Pakistan and Poland, in decreasing order of importance.

***Figure 21: Main countries in which onshore geophysical test campaigns have been carried out, excluding North America (a), and breakdown by types of surveys:2-D, 3-D and other campaign (b)***




*(Sources: IFPEN, IHS energy)*

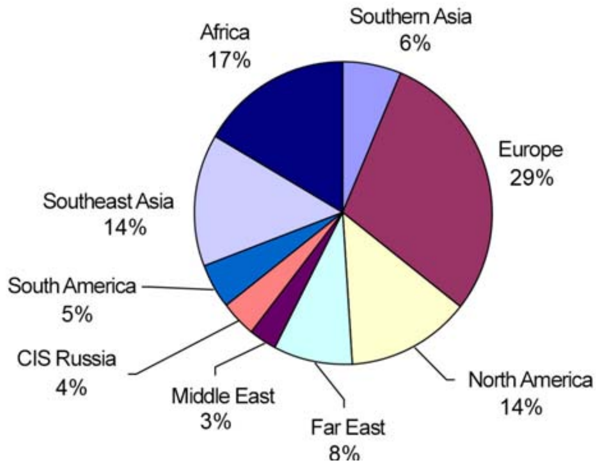
Seismic methods still account for most geophysical activity, accounting for 96% of all data acquisition operations. Half of these are 2-D and the other half are 3-D data acquisition operations. The remaining 4% of non-seismic data acquisition operations involve gravimetric, magnetic and electrical methods.

### *3.3.1.2 Offshore*

The four main regions of marine activity are the North Sea in Europe, the Gulf of Guinea in West Africa and the Gulf of Mexico in North America in equal place with Southeast Asia.

Mean annual marine activity grew by an estimated 8% throughout the world based on the first nine months of 2012. There was strong growth in the Eastern Mediterranean region (Cyprus, the Lebanon and Israel), as well as in South America off the coast of Brazil (50%), in China (where the number of offshore test campaigns increased by 50%) and in the Gulf of Mexico (23%).

***Figure 22: Distribution of marine seismic surveys over the first 8 months of 2012***




*(Sources: IFPEN, IHS energy)*

As of mid-2012, there were an estimated 140 vessels in the world's seismic fleet. It has been increasing every year since 2008 at a regular rate of 4 to 5% per year.

Less than half of this 3-D seismic fleet has more than 6 streamers. The number of vessels in this category has been growing at a rate of 9 to 10% per year - twice as fast.

Despite the drive to develop increasingly sophisticated technologies, problems of overcapacity are still dogging the world fleet - although it is being absorbed. Usage rates for the whole marine fleet were around 65% in 2011.

There was, however, an improvement of around 5% in usage rates in mid-2012. This correlates with the improvement in boat day rates.

In mid-2012, it cost around US$200,000 to hire a 3-D vessel for a day, up from US$180,000 in autumn 2011 - an increase of around 10% in 9 months. This increase in rates is more apparent with smaller acquisition vessels - marine 2-D, in particular.

### 3.3.2 Geophysical market

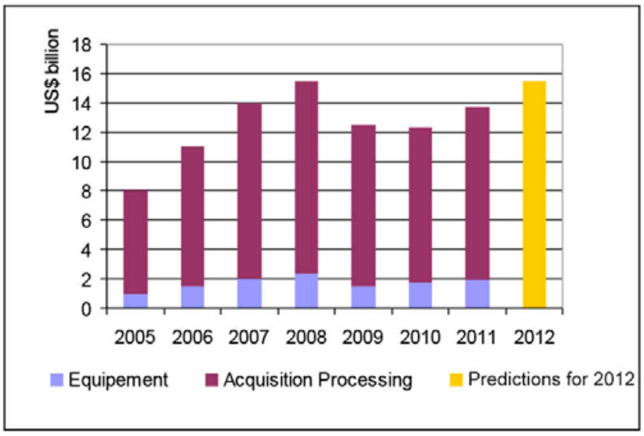
This market is closely linked to activity on the oil exploration market and is very affected by oil and gas prices. Higher prices mean that more costly and sophisticated technologies can be used.

In 2012, turnover on the geophysical market should return to its 2008 levels (before the world economic and financial crisis) and be worth more than US$15 billion across all segments - up 13% on 2011.
The equipment segment - which accounts for 14% of the market - should grow by 9%, and the acquisition/processing market by 15%.

The marine and equipment markets are still the most lucrative. There is still a great deal of competition on the onshore seismic market, particularly from China, with low acquisition prices generating very little margin.

For 2013, given continued efforts to reabsorb ship overcapacity and given that acquisition prices are rising again (marine in particular), growth could reach 15%

***Figure 23: Geophysical market (equipment and data/acquisition) and market share of the major companies in 2011***




| Companies | % | Total |
|---|---|---|
| CGGVeritas | 25% | 25% |
| Schlumberger | 19% | 44% |
| PGS | 9% | 53% |
| Fugro | 7% | 60% |
| Geokinetics | 5% | 66% |
| Halliburton | 5% | 71% |
| TGS-NOPEC | 4% | 75% |
| ION | 3% | 78% |
| Global Geophysical | 3% | 81% |
| Dawson Geophysical | 3% | 84% |
| China Oilfield Services | 3% | 87% |
| Integra | 2% | 89% |
| Seitel | 1% | 90% |
| OYO Geospace | 1% | 92% |
| EMGS | 1% | 93% |
| Paradigm | 1% | 94% |

*(Sources: IFPEN, Spears & Associates)*

#### *3.3.2.1 Companies*

Four geophysical service companies accounted for 60% of the world's geophysical market in 2011. CGGVeritas is the leading company (with its subsidiary Sercel). WesternGeco is in second place, followed by PGS and Fugro.

Geokinetics, which is specialised in acquiring data in transition zones (shallow waters), is in fifth place. EMGS, which is specialised in electromagnetic acquisition, is now in 15th place.

As far as equipment is concerned, Sercel is still the market leader with a 66% share in the world market, followed by ION and OYO Geospace.

#### *3.3.2.2 News*

2012 saw a number of mergers and acquisitions:

- At the end of July, CGGVeritas announced it was going to join forces with Russian service company SevMorNefteGeofizika (SMNG) in order to take advantage of growth in the marine sector, for Arctic exploration.

- GEDCO, a Canadian seismic analysis software company, has been acquired by Westerngeco.
- Sercel has taken over Geophysical Research Company (GRC), an American company that is specialised in pump operation equipment.
- CCGVeritas has entered into an agreement to buy Fugro’s Geoscience division, acquiring 7 ships - including 4 latest-generation 3-D data acquisition boats - in the process. Fugro and CGGVeritas are going to create a joint company for acquiring deep-water multicomponent data (Seabed). Fugro will have a 60% share in the resulting entity, and will contribute its Ocean Bottom Nodes activity.

## 3.4 Offshore construction

2011 saw an increase in activity for pipeline and subsea installation construction. Only floating platform activity fell (-30%).

In 2012, this fall was more than adequately compensated for by the increase in the number of FPSOs being built. Pipeline construction and subsea activity continued to grow in 2012, with 19% and 17% rate growth expected, respectively.

Having grown by 10% in 2011, the offshore construction market should grow by 14% overall this year.

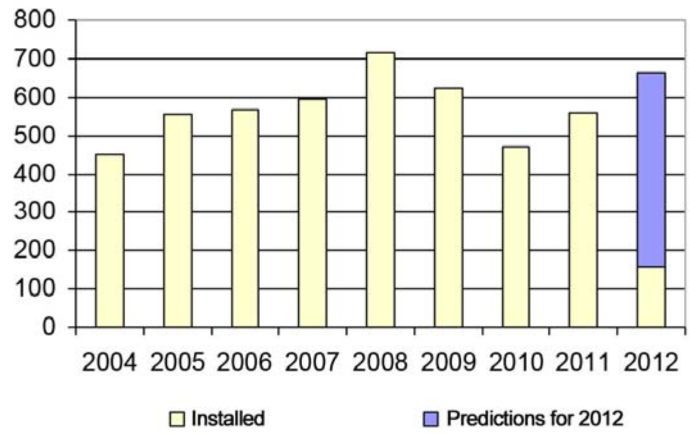
### *3.4.1* Offshore construction activities

#### *3.4.1.1 Pipeline construction activity*

In 2011, there were 560 pipeline construction projects under way - an increase of 18% on the 2010 low point.

In 2012, as far as all pipelines already laid are concerned, or pipelines in the process of being built or which have been deemed feasible - be they export pipelines, main pipelines, flow pipelines or umbilical pipelines, the total reaches more than 650. This is a potential increase of 19% on 2011.

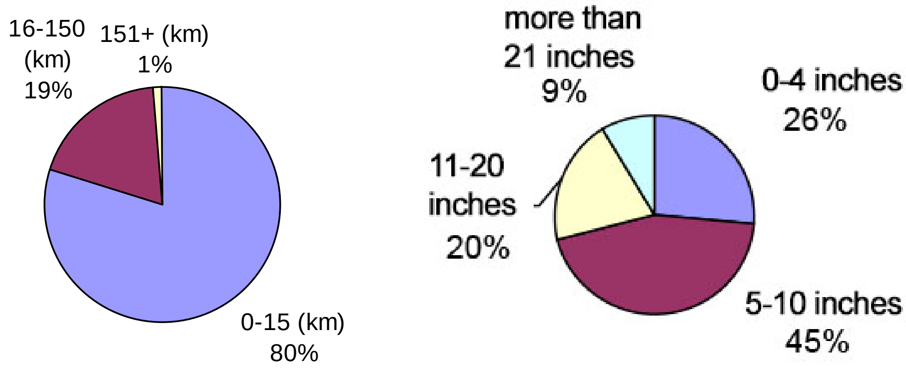
***Figure 24: Number of pipeline projects completed or planned***




*(Sources: IFPEN, IHS energy)*

80% of all pipelines built between 2005 and 2011 were less than 15 km long. 19% were between 15 and 150 km long. Only 1% of them were “tie-back" pipelines in excess of 150 km long.

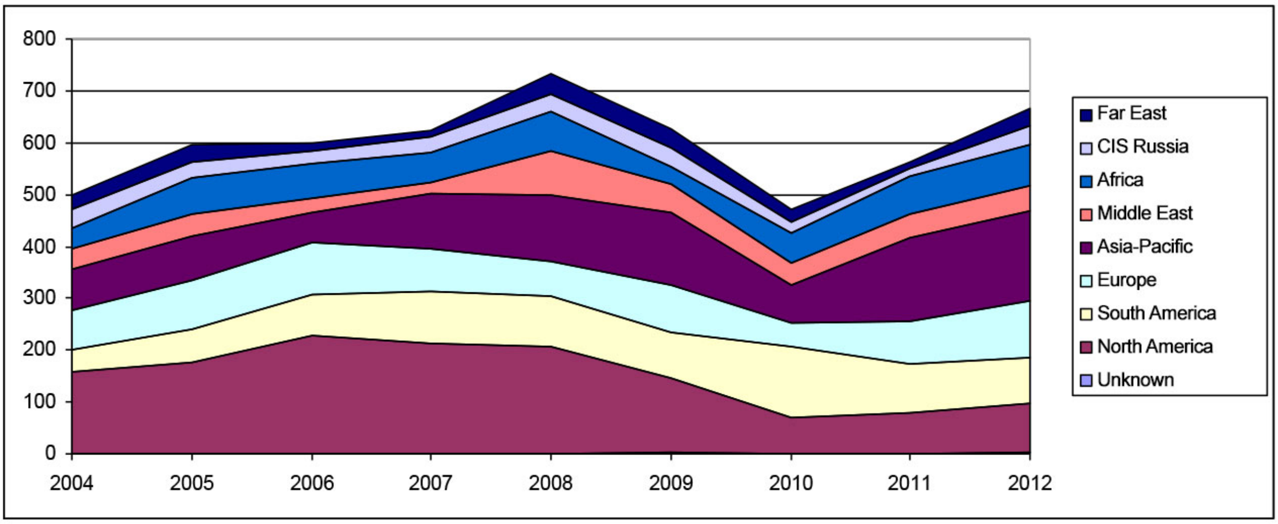
***Figure 25: Lengths (a) and diameters (b) of pipelines built between 2005 and 2011***




*(Sources: IFPEN, IHS energy)*

On average, 70% of the pipelines are less than 10 inches in diameter. Intermediary diameters of 11 to 20 inches account for a little under 20% of all pipelines. The remaining 9% are very large pipelines of 21 inches and greater.

***Figure 26: Increase/decrease in the number of pipeline construction projects between 2004 and 2012***

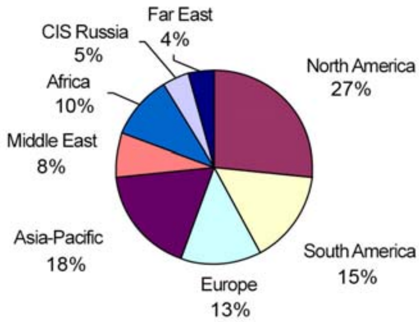



*(Sources: IFPEN, IHS energy)*

In 2012, the regions that have seen the highest increase in the number of pipeline projects are Asia-Pacific and CIS, followed by Europe and North America.

Between 2005 and 2011, North America was where the highest number of constructions were under way, accounting for 27% of global activity. Asia-Pacific was just behind it with 18%, followed by South America and Europe with 15% and 13%, respectively.

***Figure 27: Geographical distribution of the number of pipeline constructions***




*(Sources: IFPEN, IHS energy)*

- ***Pipeline laying boats***

The race to develop deep and ultra-deep offshore fields requires increasingly large pipeline laying boats.

The record for the deepest ever subsea well is held by Shell for the Perdido field in the Gulf of Mexico at a depth of 2934 m. There are currently more than 40 projects being developed at depths of more than 2500 m, and more than 100 being developed at depths of more than 2000 m.

Only a limited number of service companies have vessels that can operate at depths of 3000 m. Technip has five ships that are suitable for such operations, and Saipem has two. Subsea 7 and Aker Marine can be used for such operations, but only partially.

Another five pipeline laying ships are scheduled to come into service between now and 2013 which will add to the fleet.

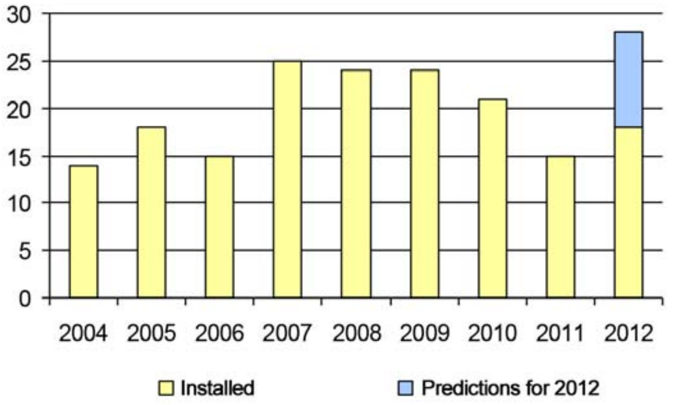
### *3.4.1.2 Floating Platform Systems*

After a period of two years during which activity was in decline (2010, which saw a fall of 13% and 2011, which saw a fall of 29%), 2012 saw a recovery with a 90% growth in activity for floating platform systems.

More than 25 floating platform systems will have been built in 2012 - as many as between 2007 and 2009 before the world economic and financial crisis.

2013 looks set to be an even better year. As of mid-2012, 22 contracts have already been signed and a further 18 are being negotiated.

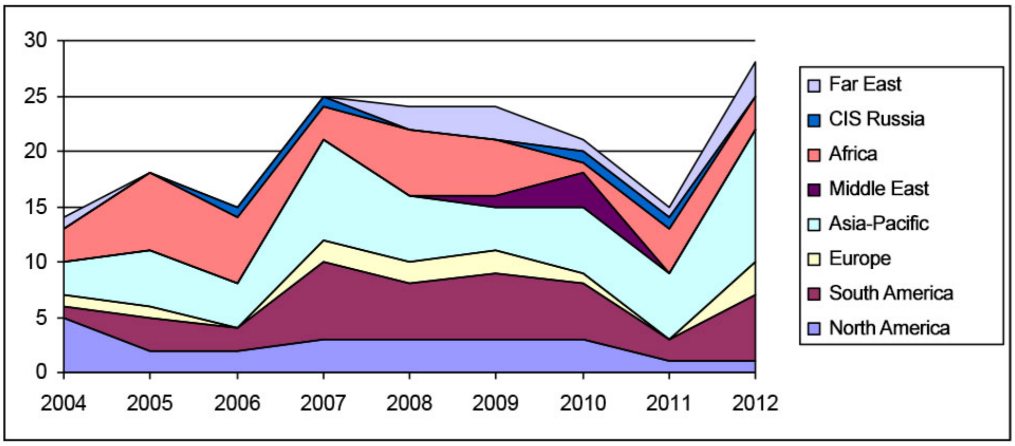
***Figure 28: Number of floating pipeline projects completed or planned***




*(Sources: IFPEN, IHS energy)*

As far as the various types of floating supports built between 2005 and 2011 are concerned, 80% of them were ships, 10% were semi-submersible rigs, and the remaining 10% were Spars, Tension Leg Platforms (TLP) and barges.

***Figure 29: Increase/decrease in the number of floating platform projects between 2004 and 2012 by region***

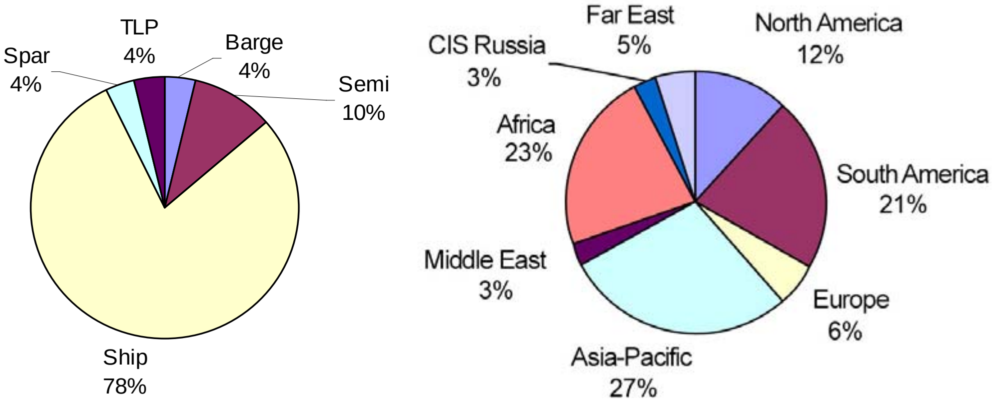



*(Sources: IFPEN, IHS energy)*

The regions which have seen strong growth in 2012 are South America with the continuation of a number of major pre-salt basin projects and south-east Asia, particularly Indonesia, Thailand, Malaysia and Vietnam. In the Pacific, a number of LNG projects are under way: Ichthys for Inpex, Wheatstone for Chevron.

Floating platform activity had fallen considerably in the Gulf of Mexico in the wake of the 2010 Macondo oil spill, but now looks set to recover significantly between now and 2014 with 7 projects planned.

***Figure 30: Types (a) and geographical distribution (b) of platforms built between 2005 and 2011***




*(Sources: IFPEN, IHS energy)*

Over the six-year period between 2005 and 2011, Asia Pacific was the region which saw the highest numbers of floating platform systems being built (27%). It was followed by Africa (23%), South America (21%) and North America (GOM) with 12%.

South America built 30 FPSO facilities during this period and is planning another 24 in the short term. Eventually, numbers will exceed those in Asia Pacific and Africa.

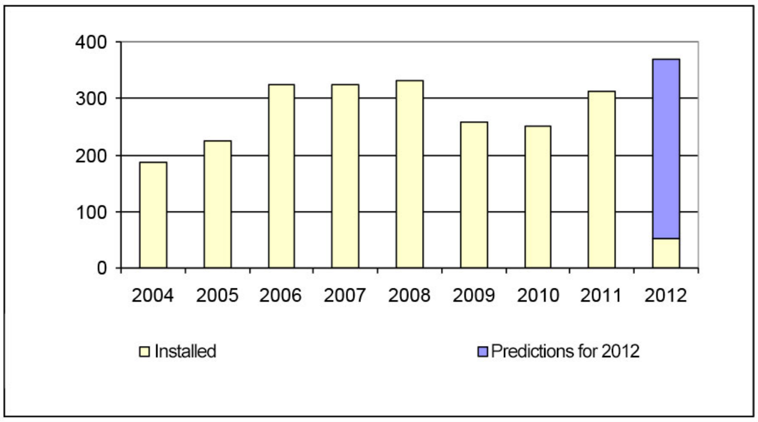
As far as the construction of FPSO facilities is concerned, the numbers built in 2012 should at least be similar to those built in 2011. Indeed, 8 FPSO contracts had already been granted by mid-2012 - whereas 14 had been granted for the whole of 2011.

### *3.4.1.3 Subsea construction activity*

Subsea construction activity should increase by 17% in 2012 - a little less than in 2011 (26%). The level of activity in 2012 should exceed pre-world financial crisis levels (which saw around 325 units being built) to reach 370 subsea installations.

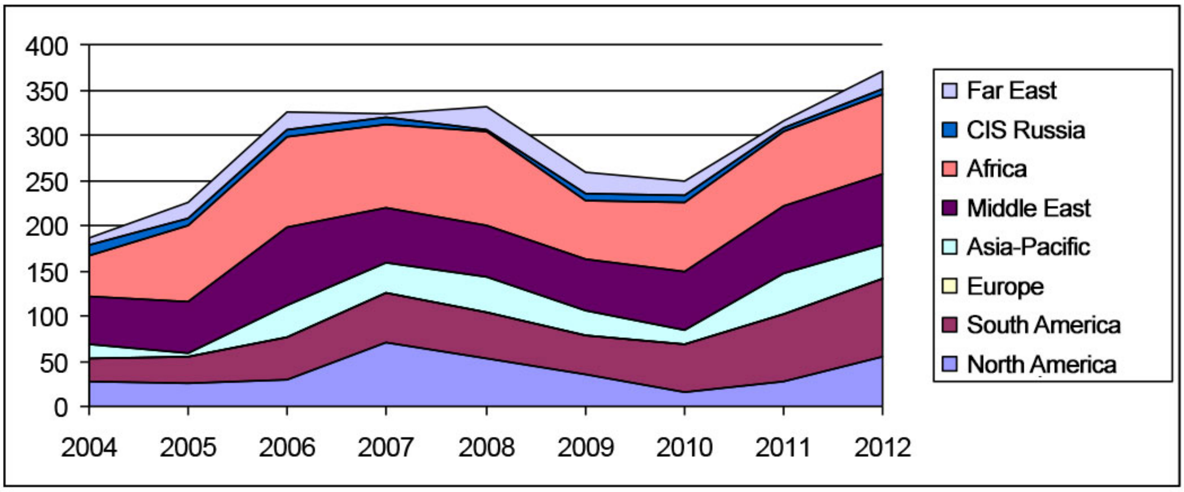
If all known projects are actually developed, the number of subsea constructions in 2014 should be double that of 2011.

***Figure 31: Number of subsea construction projects completed and planned***




*(Sources: IFPEN, IHS energy)*

***Figure* 32*: Increase/decrease in the number of subsea construction projects between 2004 and 2012***



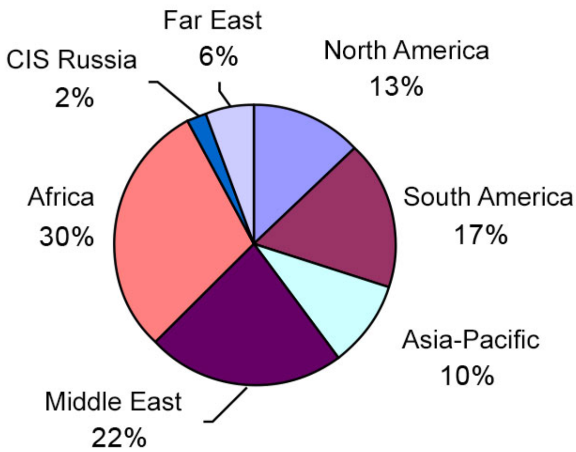

*(Sources: IFPEN, IHS energy)*

More than half of all activity is concentrated in two regions: West Africa (Gulf of Guinea) and the Middle East (22%).

In 2012, most of the growth in this activity has been concentrated in North America (Gulf of Mexico) and Southeast Asia. South America is next with a number of subsea developments off the coast of Brazil.

Subsea developments at depths of more than 2000 m account for a dozen or so units, and this figure could increase by 400 or 500% over the next 3 years. The numbers of developments at depths of less than 500 m will also increase, and are set to double over the next 3 years.

***Figure* 33*: Geographical distribution of subsea constructions between 2005 and 2011***



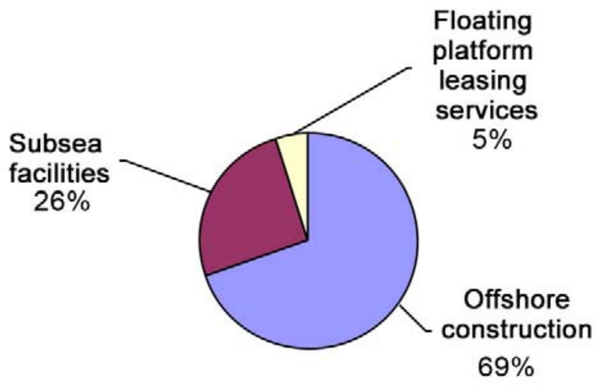

*(Sources: IFPEN, IHS energy)*

### *3.4.2* Offshore construction market

The offshore construction market should grow by 15% in 2012. It had already seen growth of 10% in 2011 after two relatively gloomy years in the wake of the 2009 world financial crisis.

The market is made up of three segments: the actual offshore construction market, subsea equipment and services associated with the leasing of platforms. These three segments account for 70%, 25% and 5% of the total market, respectively.

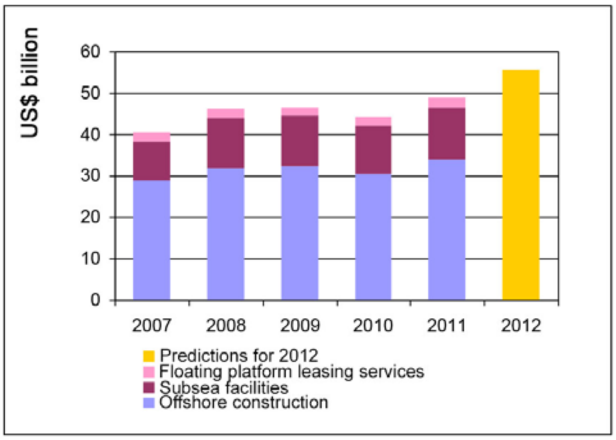
***Figure 34: Share of the three segments that make up the offshore construction market***




*(Sources: IFPEN, IHS energy)*

In 2011, these three segments grew by 11% for offshore construction, 6% for subsea facilities and 7% for services.

***Figure 35: Offshore construction market (a) and market share of the companies operating on it in 2011 (b)***




| Companies | % | total |
|---|---|---|
| Saipem | 14% | 14% |
| Subsea 7 | 10% | 24% |
| KBR | 8% | 32% |
| Oceaneering International | 7% | 39% |
| McDermott | 7% | 45% |
| FMC | 6% | 52% |
| SBM Group | 7% | 56% |
| Aker Contractors | 4% | 60% |
| Technip | 4% | 64% |
| Cameron | 4% | 67% |
| Aker Solutions | 3% | 70% |
| Fugro | 3% | 77% |
| Technip | 3% | 80% |

*(Sources: IFPEN, Spears & Associates)*

50% of total world turnover is generated by 6 companies, which are mainly involved in offshore construction. Saipem is the leading company in this field. FMC is the leading company involved in subsea facilities.

The offshore construction market should grow by 15% in 2013. In fact, according to *Infield*, US$210 billion will be invested in deep offshore construction between 2011 and 2015. The largest share of this money will be invested in pipelines (38%). 36% will be invested in subsea projects and 20% will be invested in platform construction.

Petrobras, Total, Chevron, BP, Shell and ExxonMobil will provide 75% of this investment.

### 3.5 Conclusion

The recovery in exploration and production investment that began in 2011 continued into 2012. All of the various markets that make up the sector returned to their pre-2009 world economic crisis levels. This growth looks set to continue into 2013 at a similar rate - around 13%.

As far as the geophysical market is concerned, the increase in day rates and utilisation rates would suggest that 2013 is going to be a good year for the sector.

Regarding offshore drilling, day rates, which have still been relatively low, will most likely increase with a number of fields scheduled to be developed.

Regarding onshore drilling, a number of gas and shale oil reserves are being developed in North America, and similar reserves are being sought in other regions, which should ensure that activity remains at healthy levels. Given that shale gas and oil wells have a relatively low life expectancy, ensuring that the reservoirs in question are properly produced and that production in the fields remains high involves sustained drilling.

As far as offshore construction is concerned, the race to develop ultra-deep offshore projects, create FPSOs and develop subsea installations, together with the fact that fields are increasingly far from coasts and so require pipelines are all factors which should maintain this market and ensure that it grows.

***Table 1: Summary table of the change in investments and markets analysed***

| | 2011 | 2012 | 2013 |
|---|---|---|---|
| **E&P investment** | **20%** | **+13%** | **13%** |
| North America | **21%** | **+6%** | |
| Rest of the world | **20%** | **15%** | |
| **Geophysical market** | **+11%** | **13%** | **15%** |
| **Drilling Market** | | | |
| onshore | **+20%** | **+13%** | **+5%** |
| offshore | **+3%** | **+15%** | **+10%** |
| **Offshore construction market** | **+10%** | **14%** | **15%** |

# 4 Refining consolidating the imbalance between long-term demand and capacity

The whole world was affected by an economic slowdown in 2011. But even though all countries were affected, the more mature economies suffered more than the world’s emerging companies in the Asia-Pacific, Middle East and South America & Caribbean regions. The refining sector has reflected these trends.

While demand has continued to increase in these regions, it has fallen in the more industrialised countries. Refining capacity has continued to grow in Asia-Pacific and the Middle East. It should also see growth in Brazil in the mid-term. Capacity has been stagnating - or even falling - in industrial countries (mainly the US, Europe and Japan). The outlook suggests that this trend is likely to continue.

Under the impetus of certain leading countries, refining capacity throughout the world has slightly increased and is still generating a surplus. Given these circumstances, refinery utilization rates are still relatively low across the board (scarcely more than 80%), illustrating the low global pressure on refining. But the situation is not the same for countries with mature economies as it is for the world's emerging countries. These countries, encouraged by the strong demand, are continuing to invest in new refining capacity.

Unlike the industrialised countries (Europe in particular), which are currently experiencing a fall in demand and lower exports (to the US in particular, which has long been a traditional destination for surplus gasoline from Europe), it seems highly likely that policies to rationalise refining capacity will be brought in. These policies may well be accompanied by heavy investments in hydrocracking units that will help these countries reduce their dependency on diesel, lower their gasoline surplus and keep pace with the expected changes in the quality of the “bunkers" in Europe's maritime zones.

In a "business as usual" context, overcapacity will continue to increase in the mid-term, despite a fall in the number of planned projects and reductions in capacity. Massive investments in emerging countries - and possibly in Russia so that it can modernise its production facilities - are running the risk of stimulating competition on the petroleum export market, both in the Atlantic basin and in the Asia-Pacific region. As far as oil producing countries are concerned, the situation is relatively similar to the one in which emerging countries find themselves in terms of investment. While guaranteeing supplies to their fast-growing domestic market, their strategy also involves export markets (major export refinery projects).

In a global context that has seen a fall in demand, investments continuing to be made in new refining capacities and refinery utilization rates holding steady or falling, margins deteriorated in 2011. Surprisingly, though, they have increased on the US markets (the "shale oil" effect and the decoupling of the price of WTI from the price of Brent crude) and on the European markets. This can most likely be attributed to a number of refineries having been closed or transformed - thus reducing overall refining capacity.

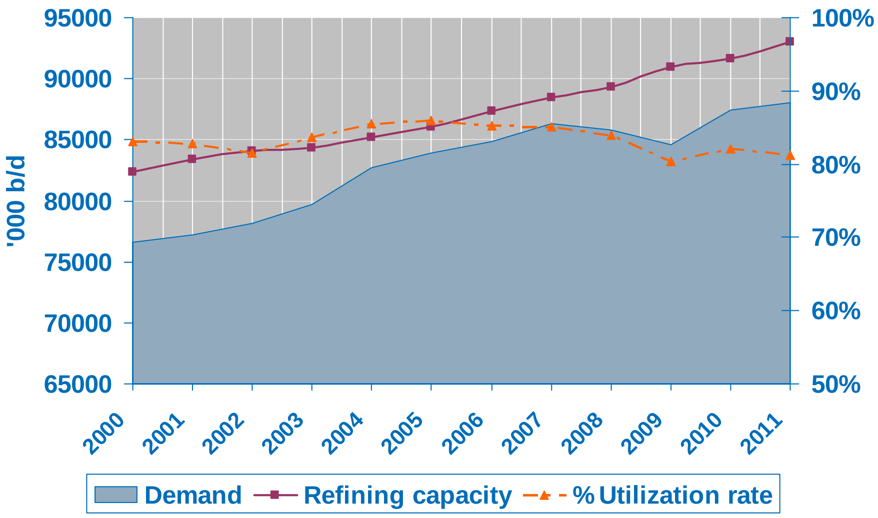
A slight increase in spending is forecast for 2012, and an abrupt slowdown in capital expenditure. This trend is evidence of refineries exercising caution, preferring to postpone some of their projects in the short term.

Lastly, it's worth mentioning the development of unconventional hydrocarbons in North America (Canadian heavy oils and shale oil and gas) and the consequences that they are having on the refining sector in the United States and Europe. The cumulative effects of the increase in competitivity that inexpensive crude and natural gas is having for US refineries and the structure of the output from shale oil (which is very rich in gasoline) is strengthening the US refining sector, but weakening the European refining sector - European refineries no longer have anywhere to send their gasoline surpluses.

### 4.1 Increase in world refining overcapacity and decrease in refinery utilization rates

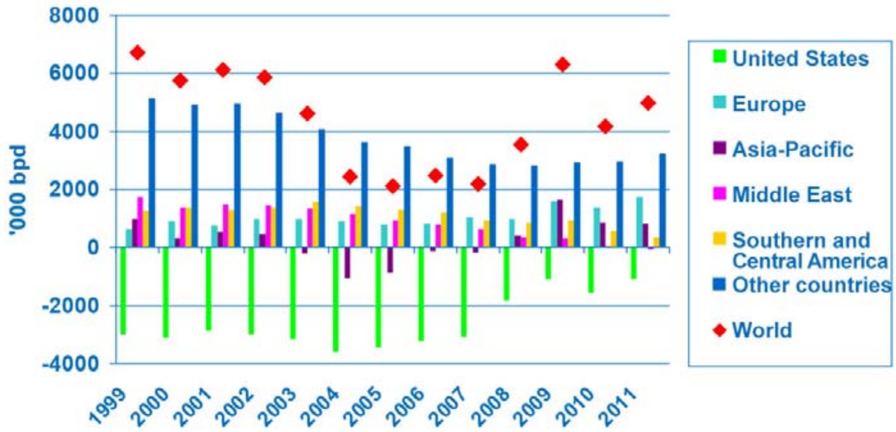
After a brief pause in 2010 during which refining overcapacity fell throughout the world, **2011** saw a new increase: surplus increased from 4.2 Mb/day in 2010 to 5.0 Mb/day in 2011 - an increase of nearly 20%. This trend can be explained by refining capacity continuously increasing (+1.5%) at a rate greater than demand (+0.7%). The world economic slowdown in 2011 (3.9% growth in world GDP in 2011, down from 5.3% the previous year) has had a noticeable effect on oil demand, but has not influenced the development of new refining capacity. This global situation obviously hides specific situations in different regions across the world which are extremely contrasted.

***Figure 36: Oil demand, refining capacity and refinery utilization rates throughout the world***




*Source: IFPEN based on the BP Statistical Review of World energy 2011*

***Figure 37: Refining capacity surplus/shortage, by major region***

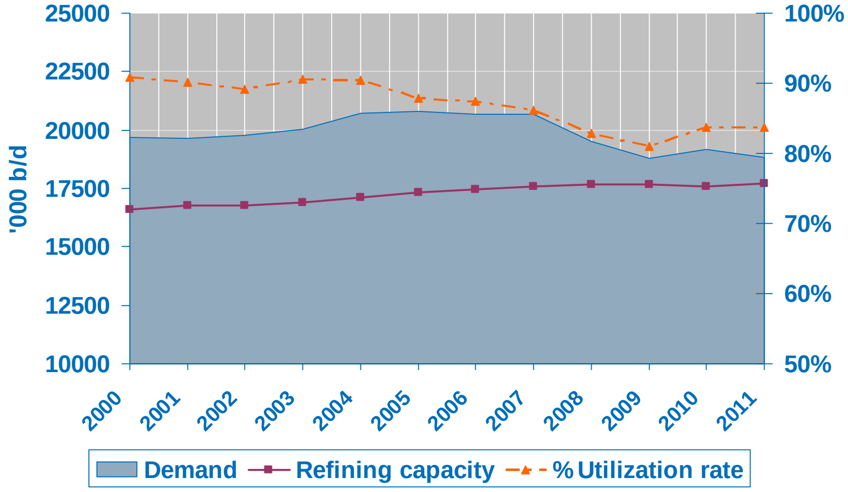



*Source: IFPEN based on the BP Statistical Review of World energy 2011*

All regions show overcapacity, except the **US** which has decreased its level of dependency on refining: demand is continuing to fall. Gasoline and residual fuel oil consumption has fallen by -2.8% and -11%, respectively. At the same time, refining capacity has remained stable. Refinery utilization rates remained stable in 2011. This equilibrium looks more or less set to be sustained in the mid-term, especially if long-term demand continues to fall.

Despite the US's overall deficit, the situation varies significantly from region to region within the country (PADD[3]): although regions on the Pacific and Atlantic coasts import oil products, the Gulf of Mexico has now become a clear exporter of oil products: 3 Mb/day were exported in October 2011 from this market. Among the factors behind this phenomenon are the increase in North American oil production, access to competitive crude oil prices, lower energy costs in refineries and access to fast growing Latin American markets.

***Figure 38: Oil demand, refining capacity and refinery utilization rates in the United States***



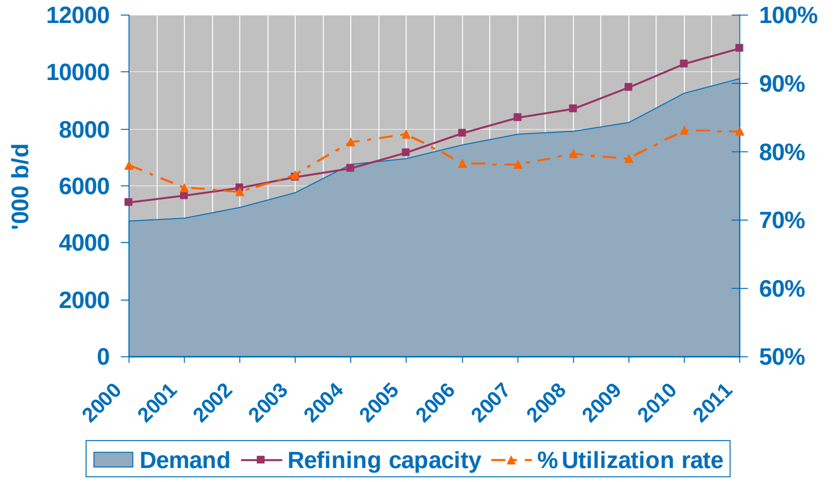

*Source: IFPEN based on the BP Statistical Review of World energy 2011*

The situation in the **Asia-Pacific** region is very different. Demand and refining capacity have been increasing at comparable rates (2.6% and 2.7% respectively between 2010 and 2011). This leaves a very modest - but stable - surplus of around 0.85 Mb/day, close to a state of equilibrium. Economic growth in these countries - largely dominated by China - remains strong, stimulating both supply and demand of oil products. Increase in production capacities in this region is driven more by investment programmes than by any real pressure from demand - refinery utilization rates remain modest (85%) and did not change between 2010 and 2011. Globally, excluding cyclical economic fluctuations, demand will continue to increase, driven by the emergence of middle-class consumers of petrochemical products and automotive vehicles (cars, motorcycles and heavy trucks), stimulating demand for oil products. Future increases in capacity will be structured so as to keep pace with this increasing energy demand.

Slightly poorer economic performance in 2011 also explains the contradictory trend between the constant increase in production capacity (that responds to long-term goals) and refinery capacity holding stable (which is more dependent on the economic conditions). The weight of a number of major economic powers, such as China and India, is hiding what is really happening in other countries such as Japan, Indonesia, New Zealand and even South Korea, all of which have been affected - to varying degrees - by the world economic crisis. Both oil product demand and production capacity stagnated or even fell in 2011. In Japan, for example, despite the increase in demand for oil products in order to power generation in the wake of the Fukushima disaster, refining capacity fell (closure of Toa Oil Co. refinery, 114 kb/day).

[3] PADD: US Petroleum Administration for Defence Districts. The PADDs were created during World War II in order to help organise the allocation of fuels derived from a petroleum products. There are five PADDs.

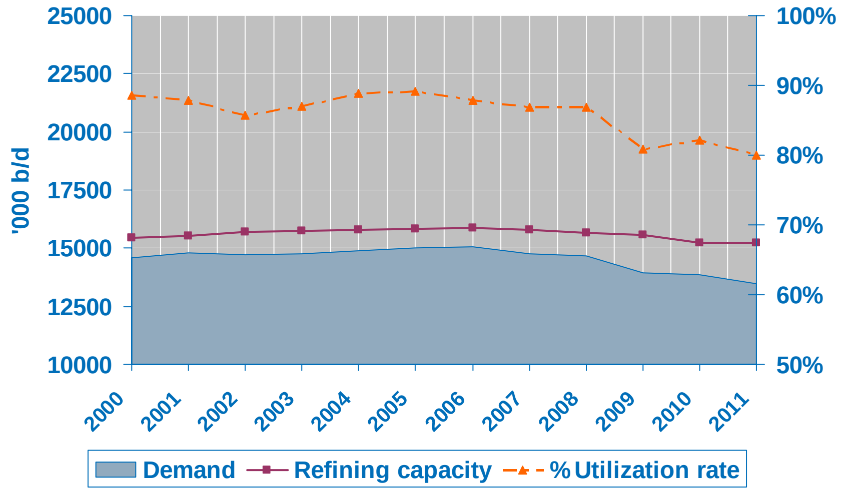
***Figure 39: Oil demand, refining capacity and refinery utilization rates in China***




*Source: IFPEN based on the BP Statistical Review of World energy 2011*

The difficulties that **Europe**'s refining sector has been experiencing are well known. For several years now, both supply and demand have been falling. These are major trends. Over the last few years, with demand falling faster than production capacity, surplus has had a tendency to increase: it rose from 1.0 Mb/day in 2008 to 1.7 Mb/day in 2011. Given the fall in demand (in 2011, demand for all products fell only the consumption of middle distillates remained stable), and refining capacity practically stagnating, refinery utilisation rates have also fallen to around only 80%. Very rapidly, starting in 2012, we should see a significant decrease in the surplus. Several refineries should stop producing between 2011 and 2012 resulting in a decrease of 375 kb/d[4]. This trend should continue for another few years.

***Figure 40: Oil demand, refining capacity and refinery utilization rates in the European Union***




*Source: IFPEN based on the BP Statistical Review of World energy 2011*

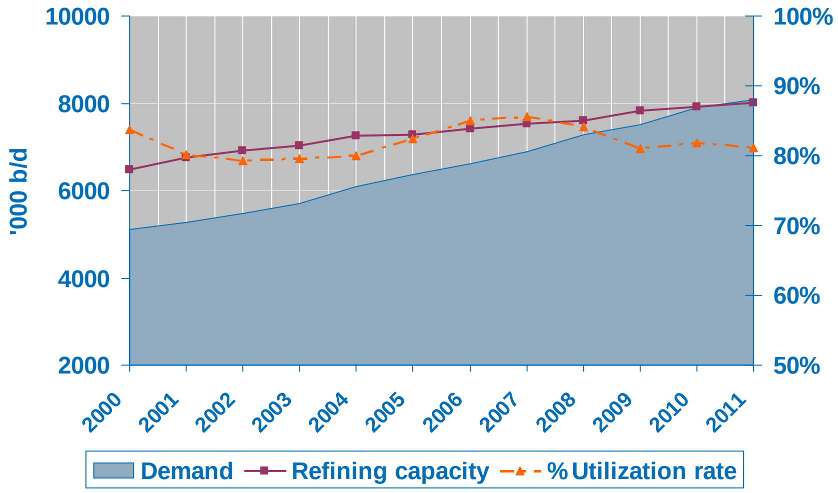
Alongside the structural fall in demand throughout Europe, a long term decline in fuel consumption is under way in the United States, with gasoline sales in particular falling. The United States has long been a traditional destination of the European surplus. This is a new short-term and mid-term issue for the refining sector in Europe, a sector that has already been significantly penalised by various environmental constraints and the tightening of product specifications[5], energy-saving requirements, etc.

[4] See insert on page 57

[5] In compliance with annex VI of the MARPOL convention, the maximum of sulphur content of bunker fuels used in emission control zones SO2 (SECZ) will be set at 1% until 31 December 2014, and then 0.1% from 1 January 2015 onwards. From 2020

In the **Middle East**, there is a balance between refining capacity and demand. Demand has been strong for a long time: between 2000 and 2011, it increased by 58% and the IEA believes this trend will continue. The atypical situation in Saudi Arabia should be noted, however, where oil is used directly for the country's electricity generation requirements. This has inflated data about domestic consumption. Refinery utilization rates remain low, which would seem to suggest that there is no particular pressure on the refining sector. However, the situations in Iran and Iraq are creating a great deal of instability in the region. Iraq, which has very low utilization rates (63% in 2010) as a result of all the destruction caused by the war, is considering an ambitious investment programme which would double current refining investment capacity between now and 2020. Construction getting under way will be a major test of just how stable the country is. In Iran, there is a pronounced mismatch between the country's refining facilities and domestic demand. Very few refineries are properly equipped with conversion facilities, resulting in a gasoline deficit and a significant surplus of fuel oil. Major investments are needed. But given the current economic sanctions applied to the country, it is not possible to even consider bringing in any major investment programmes.

***Figure 41: Oil demand, refining capacity and refinery utilization rates in the Middle East***




*Source: IFP, based on the BP Statistical Review of World Energy 2011*

In **South and Central America**, production capacity has remained stable, while demand continues to increase at a regular rate, reducing the capacity surplus. With the exception of 2009, economic growth has been strong in this region (+8.5% in 2010 and +4.0% in 2011), maintaining pressure on demand. Paradoxically, refinery utilization rates have remained low (in spite of a slight increase in 2011), rising from 69% in 2010 to 73% in 2011. These low refinery utilization rates have been compensated by importing products (+10% in 2011 after +37% in 2010). On-going maintenance problems and difficulties to do with the many shutdowns that have affected refineries in Venezuela can go some way towards explaining these overall low utilization rates. Refining capacity should increase in the mid-term as capacity increases in Brazil between now and 2020 (chapter 1.2). Brazil - which already exports ethanol - could start exporting other petroleum products in the future. Globally, the region is on a path towards a better balance between supply and demand.

onwards, ships outside sulphur emissions control zones navigating through EU waters will have to respect the IMO standard which sets the maximum sulphur content in ship exhaust emissions at 0.5%. The same will apply to passenger ships operating outside sulphur emissions control zones, to which the current maximum level of 1.5% will continue to apply until this date. A general standard prohibits the use of ship fuels within the European union the sulphur content of which is greater than 3.5%. This does not apply to fuels used by ships fitted with alternative systems for purifying their exhaust gases (also known as gas scrubbers, which operate within a closed circuit).

The world's "**other countries**" all have significant surpluses (+3.2 Mb/day). Among these countries are a certain number which have traditionally been oil exporting countries, such as Russia and countries in the CIS region, where refining capacity remains historically high.

Globally, the increase in refining capacity has been relentless for more than 10 years, fed by massive investments in regions experiencing high economic growth which are very energy hungry. The more moderate investments in other regions, in OECD countries in particular, does not seem to be having much of a bearing on the global trend. Demand, however, is suffering the effects of the economic crisis. This is particularly the case in major consumer countries/regions, such as the United States, Europe and Japan, inflating surplus capacity throughout the world, while global refinery utilisation rates remain more or less stable at just under 85%.

Regarding **2012 and 2013**, the IAE has recently once again revised its world oil demand forecasts downwards[6]. The reasons it gives are sluggish economic growth, the high prices of crude oil and a fall in oil requirements in China and the United States. According to the Agency, growth in oil demand should be no higher than 0.8 Mb/day in 2012 and 0.9 Mb/day in 2013 - i.e., 0.3 Mb/day and 0.4 Mb/day less than was forecast in the previous report. Oil consumption is likely to reach 89.6 Mb/day in 2012 and 90.5 Mb/day in 2011. Oil demand in the United States and China has also been revised downwards by the Agency - by 0.1 Mb/day and 0.6 Mb/day respectively. Total world refining capacity should continue to increase (given the various projects which are planned), particularly in emerging countries, reinforcing the role they are now playing in driving world growth.

In the world's **industrialised countries**, the difficult economic situation and the various policies that are being brought in to support alternative energies will hinder any recovery in demand and so will adversely affect initiatives to invest in new capacity. In Europe, the process of reducing capacity, driven by the structural slowdown in demand and competition from imports of middle distillates from Russia, Asia and most likely Brazil[7] and by the increasing difficulty of finding new outlets for gasoline surplus, will be stepped up. Major investments are being planned for refineries in Russia in response to the recent reforms in the export price structure. These improvements could result in additional exports (to which markets?) of finished products in compliance with European specifications. Russia and countries in the CIS region all have refining capacity that is almost twice as great as their domestic demand for oil products and there are currently no plans to reduce capacity in this region - quite the opposite. In the United States, efforts designed to save energy - particularly in the transport sector - and the penetration of competing energies are counter to investments in new capacity.

Also to be factored in are the expected tightening of global quality standards for ship fuels, taxes and increasingly stringent regulations for carbon dioxide emissions. These factors will all doubtless lead to additional production costs in a context in which players in the refining sector are seeing their margins shrink dramatically.

Conversely, the world's **emerging countries** - which are driving growth and consuming energy (including oil products - the petrochemical and transport sectors) are now an ideal environment within which to develop refining activities. More refining capacity will be installed in these countries in the years to come. Regulations in these countries are not yet quite so stringent as they are in the world's industrialised countries, despite marked progress.

Globally, new capacity should continue to be built. But the rapid rate at which new assets are being brought into operation - combined with the slowdown in demand - will result in an increase in overcapacity in the medium-term. This in turn will reduce the utilization rates of refining facilities, weakening margins.

[6] Oil Market Report IEA, August 2012
[7] Brazil is planning to add an additional 1.2 Mb/day of refining capacity between now and 2020. This is so it can export its rapidly-growing locally produced products.

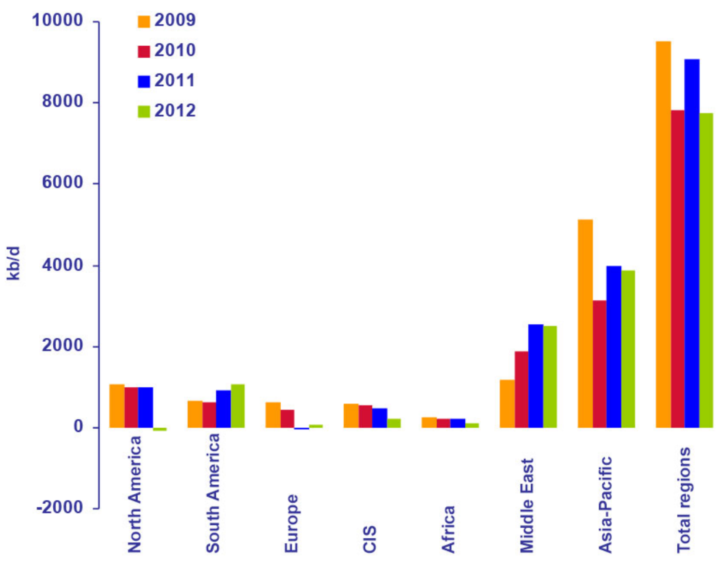
## 4.2 Economic break on proposals for new capacity

A distinction should be made between two types of projects. **"Probable" projects** have a high likelihood of being carried out whereas **"possible" projects** tend to be announced for their effect and are less likely to materialise[8]. The annual rise or fall in the numbers of projects under way is measured in production capacity (kb/d).

### *4.2.1* Distillation capacity projects: fall

If only probable projects are considered, **new distillation capacity (which more often than not means new refineries) worldwide would total 7.75 Mb/day in 2012. This is significantly down (-15%) on the projects identified in 2011,** and is actually closer to 2010 levels - the year the world economic slowdown took a hold. This global slowdown can be attributed to a wave of closures (1.9 Mb/day). This equates to nearly 20% of all projects to increase capacity - particularly in the US (842 Mb/day) and in the Asia-Pacific region (475 Mb/day), as well as in Europe (215 Mb/day), the Middle East (200 Mb/day) and in the CIS (135 Mb/day).

***Figure 42: Refining projects – distillation capacity by geographical region***




*Source: IFP based on data from KBC*

The majority of these projects are still concentrated in Asia-Pacific and the Middle East, even though the numbers remained stable and even fell slightly between 2011 and 2012 (-3% and -1%, respectively). The picture in Latin America has been very healthy, with the numbers of projects increasing significantly (by 17%). Brazil in particular is driving growth, investing massively in a number of new refinery projects (Maranhao, Rio de Janeiro, Pernambuco).

The other regions - Africa, North America, Europe and the CIS - have all seen a fall in the numbers of projects for the third year running. North America is the most affected, and has seen a fall in production capacity (in 2012, there were more projects to close or shut down production than to develop new capacity).

The worldwide situation regarding distillation projects is significantly affected by trends in the Asia-Pacific region: China alone accounts for nearly 40% of all projects to build new capacity throughout the world. Globally, mid-term prospects are still considerably healthier - despite

[8] This analysis involves projects that were identified in April 2012

the likelihood of a further decline in capacity, mainly in the world's industrialised countries (see insert).

The main projects in expanding or stable regions:

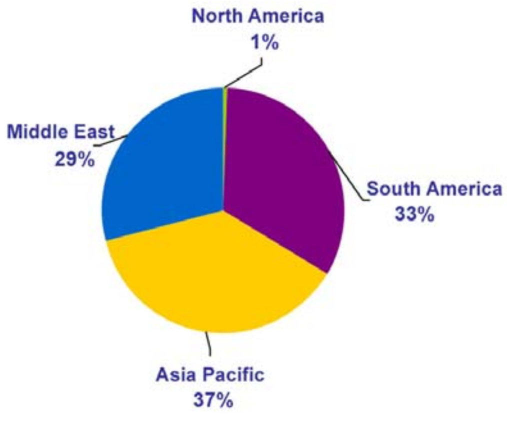
| | | |
|---|---|---|
| o Nagarjuna, Cuddalore (Tamil Nadu), Inda | 120 kb/d | 2012 |
| o IOC Paradip (Orissa), India | 300 kb/d | 2013 |
| o PetroChina Sichuan (Pengzhou), China | 200 kb/d | 2013 |
| o PetroChina / Aramco (Yunnan), China | 200 kb/d | 2013 |
| o Sinochem (Quanzhou, Fujian), China | 240 kb/d | 2014 |
| o Sinopec Zhenhai Refinery, China | 300 kb/d | 2015 |
| o Sinopec KPC/toal (Guangdong), China | 300 kb/d | 2015 |
| o CNOOC Huizhou, China | 200 kb/d | 2015 |
| o PetroChina/PDVSA (Jienyang), China | 400 kb/d | 2016 |
| o PetroVietnam/KPC/Mitsui/Idemitsu - Nghi Son, Vietnam | 200 kb/d | 2016 |
| o SATORP, Saudi Aramco/Total Jubail-2, Saudi Arabia | 400 kb/d | 2013 |
| o YASREF, Saudi Aramco Yanbu, Saudi Arabia | 400 kb/d | 2014 |
| o Takreer, Ruwais, (expansion), Abu Dhabi | 417 kb/d | 2014 |
| o Saudi Aramco Jazan (Pase I), Saudi Arabia | 400 kb/d | 2016 |
| o KNPC, Mina Abdullah, Kuwait | 264 kb/d | 2016 |
| o South Refineries Co. Maissan, Iraq | 120 kb/d | 2017 |
| o Petrobras/PDVSA Pernambuco, Brazil | 230 kb/d | 2013 |
| o COMPERJ, Rio de Janeiro (Phase I), Brazil | 165 kb/d | 2014 |
| o Petrobras Maranhao, Premium I, Brazil | 300 kb/d | 2016 |
| o COMPERJ, Rio de Janeiro (Phase II), Brazil | 165 kb/d | 2018 |

The following are outside the world’s fast-expanding regions:

| | | |
|---|---|---|
| o Motiva, Port Arthur, United States | 325 kb/d | 2012 |
| o Pemex Tula, Mexico | 250 kb/d | 2016 |
| o Turcas / Socar, Aliaga, Turkey | 200 kb/d | 2015 |
| o South Refineries Co. Maissan, Iraq | 120 kb/d | 2017 |

The effects of the world economic crisis and uncertainty over the future are still foremost in the minds of investors: **more than 30% of the projects identified in 2012 have now been postponed to a later date** - the equivalent of 2.3 Mb/day of new refining capacity; In terms of volumes, more projects were postponed in 2012 than in 2011 (1.9 Mb/day), distributed relatively uniformly across three regions: Asia-Pacific (37%), South America (33%) and Middle East (29%). China accounts for 50% of the new capacity the construction of which has been postponed in this region.

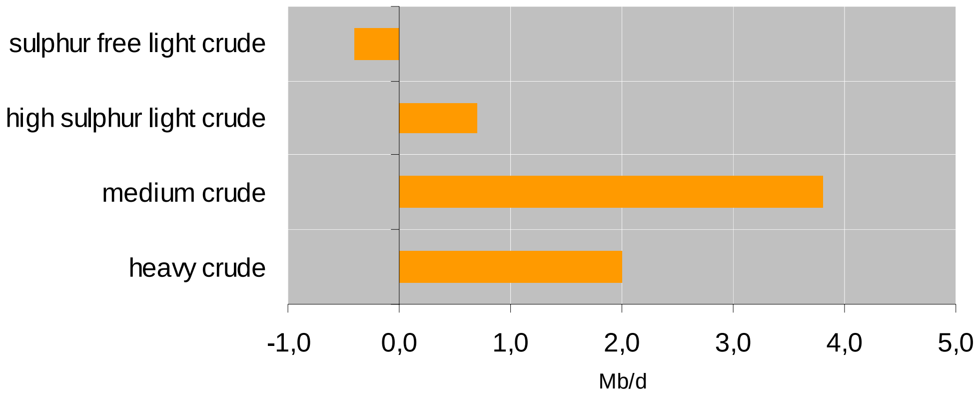
***Figure 43: Refining projects – distillation capacity that has been postponed by geographic region***




*Source: IFP based on data from KBC*

As far as supply prospects are concerned, **there has been a notable shift towards heavier crudes and crudes with a high sulphur content.** Processing units will need to be very flexible in order to process the various different types of crude - something which will require major investments. Overall, most of the projects identified meet this requirement: the new capacities are clearly geared towards processing medium and heavy crude oils and this will ensure greater levels of flexibility for production facilities.

***Figure 44: Refining projects - new capacities by type of crude, 2011-2017***



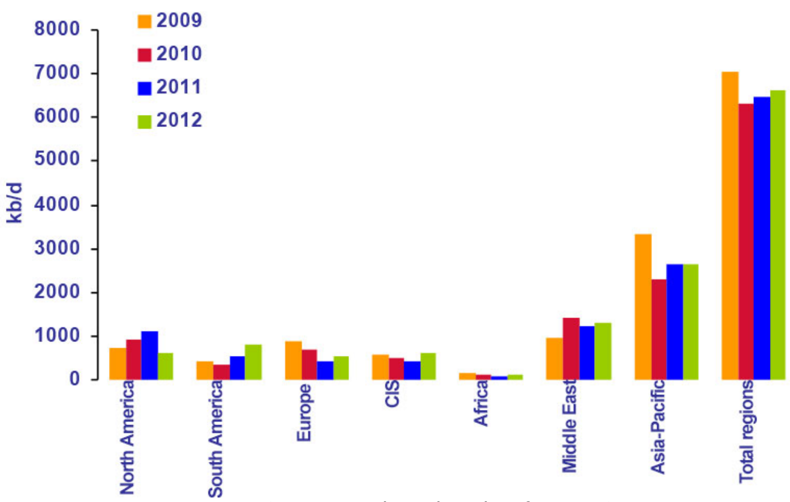

*Source: IFP based on data from KBC*

### *4.2.2* Conversion capacity projects: stability

**If we consider "probable" projects only, new conversion capacity stood at 6.6 million Mb/day in 2012**, almost the same as the number of project identified in the same period the previous year (+2%). Overall, the refining sector currently appears to be giving priority to conversion projects.

Of the world's major regions, once again in 2012, the majority of new projects have been concentrated in the Asia-Pacific region (40%) and the Middle East (20%). North America has dramatically reduced its conversion projects, with a fall of 46% compared with the previous year. This represents a significant change compared with previous years, when the trend was towards investment. The availability of shale oil type standard quality crude goes a long way towards explaining this shift. For the second year running, Latin America has experienced the fastest growth: in two years, the number of projects under way has increased by 120% from 360 kb/d in 2010 to 810 kb/d in 2012.

***Figure 45: Refining projects – conversion capacity by geographical region***




*Source: IFP based on data from KBC*

The main projects in fast-growing regions:

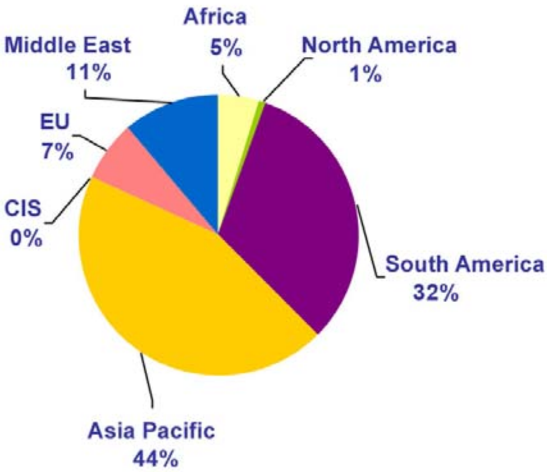
| | | | | |
|---|---|---|---|---|
| o | Petrobras/PDVSA, RNEST, Brazil | delayed cokefaction | 80 kb/d | 2013 |
| o | Petrobras/PDVSA, RNEST, Brazil | Hydrocracking | 50 kb/d | 2013 |
| o | Petrobras, Maranhao, Train I, Brazil | delayed cokefaction | 120 kb/d | 2016 |
| o | Petrobras, Maranhao, Train I, Brazil | Hydrocracking | 80 kb/d | 2016 |
| o | Pemex, Tula, Hidalgo, Mexico | delayed cokefaction | 181 kb/d | 2016 |
| o | Pemex, Tula, Hidalgo, Mexico | FCC | 110 kb/d | 2016 |
| o | Essar, Vadinar, Inde | Delayed cokefaction | 98 kb/d | 2012 |
| o | IOC, Paradip, India | FCC | 90 kb/d | 2013 |
| o | IOC, Paradip, India | delayed cokefaction | 82 kb/d | 2013 |
| o | PetroChina/PDVSA, Jieyang, China | Delayed cokefaction | 120 kb/d | 2016 |
| o | PetroChina/PDVSA, Jieyang, China | Hydrocracking | 120 kb/d | 2016 |
| o | PetroVietnam/KPC/Mitsui/Idemitsu, Vietnam | RFCC | 100 kb/d | 2016 |
| o | SATORP Saudi Aramco/Total, Jubail 2, Saudi Arabia | FCC | 120 kb/d | 2013 |
| o | YASREF Saudi Aramco/Total, Yambu, Saudi Arabia | Hydrocracking | 124 kb/d | 2014 |
| o | Takreer, Ruwais (expansion), Abu Dhabi | RFCC | 127 kb/d | 2014 |
| o | Saudi Aramco, Jazan Ohase II, AS | Hydrocracking | 106 kb/d | 2018 |

The following are outside the world's fast-expanding regions:

| | | | | |
|---|---|---|---|---|
| o | Motiva – Port Arthur, TX, United States | Hydrocracking | 75 kb/d | 2012 |
| o | Motiva – Port Arthur, TX, United States | delayed cokefaction | 95 kb/d | 2012 |
| o | Rosneft, Tuapse, Russia | Hydrocracking | 81 kb/d | 2014 |

**Conversion projects have also been postponed -** but to a lesser extent than distillation projects: as was the case in 2011, nearly 20% of all projects were postponed in 2012 - the equivalent of 1.35 Mb/day of conversion capacity. South America (32%) and Asia-Pacific (44%) have been the most affected by these postponements. Three-quarters (0.32 Mb/day) of all projects postponed in South America are in Brazil, while in the Asia-Pacific region, China and India are home to more than 80% of the delayed projects - the equivalent of 0.5 Mb/day.

***Figure 46: Refining projects – postponed conversion capacity by geographical region***

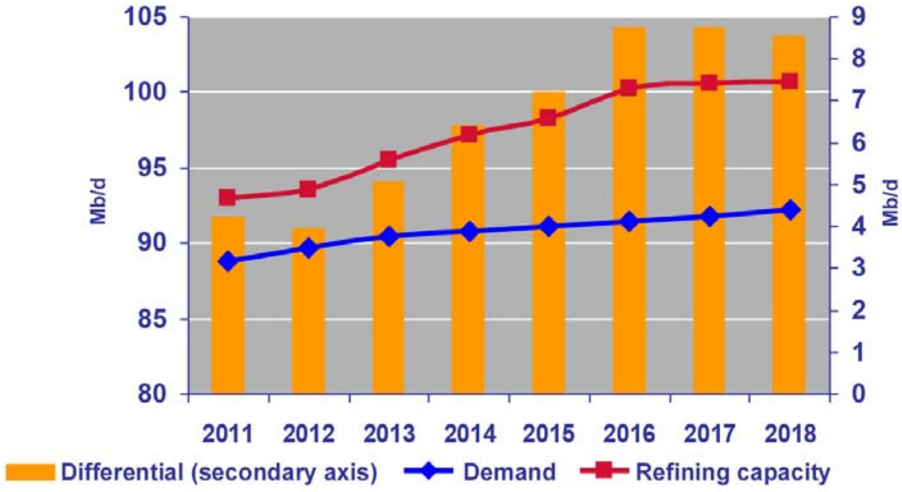



*Source: IFP based on data from KBC*

### *4.2.3* Increased overcapacity in the medium-term

Globally, the medium-term outlook for demand and refining capacity shows that - after something of a tightening - the difference between the two values is widening, meaning that refining overcapacity will once again be pushed up starting in 2013. In view of additional capacity, medium-term operating capacity and projected oil demand according to the IEA[9] , which foresees a downward trend in world oil demand over the long term[10], the situation is likely to continue to deteriorate until 2016, with overcapacity increasing still further.

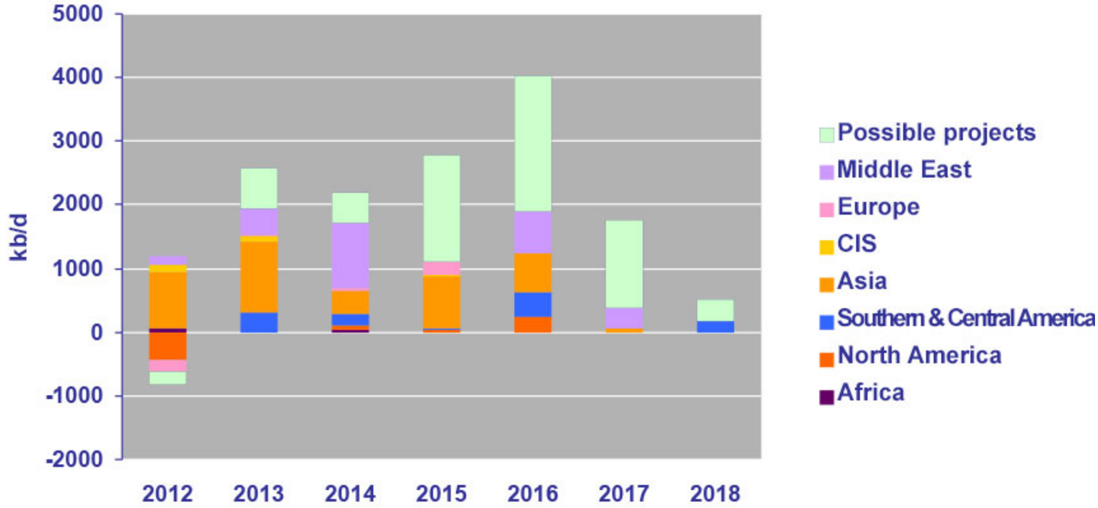
***Figure 47: 2010, mid-term trend in refining capacity (current capacity and identified projects) and demand***




*Source: IFP based on data from KBC and IEA*

Looking beyond 2016 once a number of new projects have come into operation (particularly in Asia Pacific and the Middle East: 1.9 Mb/day worth of probable projects to which a further 2.1 Mb/day worth of possible projects can possibly be added), providing total capacity of 4.0 Mb/day for this year alone, it is unclear how many new projects will be under way. But it is worth remembering the wave of investment that could lead to new fiscal measures affecting export tariffs on oil products to Russia and which could result in a further easing of the pressure on refinery utilisation rates in Europe, followed by a weakening of refining margins.

***Figure 48: 2010, mid-term trend in refining capacity projects, possible projects (global) and probable projects by major region***




*Source: IFP based on data from KBC*

[9] WEO 2011
[10] Average annual growth in oil demand of 0.5% between 2010 and 2035 under the "New Policies Scenario". In 2009, the WEO projections in the reference scenario included 1% growth in demand between 2008 and 2030, and 0.6% growth between 2009 and 2035 ("New Policies Scenario").

For the period between 2012 and 2018, more than 80% of all projects throughout the world will be concentrated in the Asia-Pacific regions and the Middle East. Brazil, a relatively new arrival, will play an increasingly important role in increasing overall refining capacity. North America is the only region currently in deficit and is not showing any signs of trying to change this situation in terms of increasing its own refining capacity. Current forecasts for the next 12 years or so show a reduction in the number of future projects. This means that there will be more projects to close (or transform) refineries than projects to increase capacity (-78 kb/d).

So a phenomenon observed in recent years - whereby refinery projects involving distillation or conversion capacity are relocated to the most active emerging regions - has not changed, and will even become more pronounced in the wake of the slowdown forecast in the world's industrialised countries.

## 4.3 Overall improvement in refining margins in 2012

In a global context that saw a fall in world demand in 2011, investments continuing to be made in new refining capacities and refinery usage rates (which were not terribly high to begin with) falling had helped perpetuate conditions under which refining margins could not increase. According to the IEA[11], their mean annual fluctuation has been between US$0.62/barrel for Brent cracking (NWE) and US$1.47/barrel for Dubai Hydrocracking (Singapore). Even though this is an increase on 2010 levels, these margins are still very low.

Margins for Brent (NWE) and LLS cracking in particular improved in 2012, while margins for Dubai Hydrocracking saw a significant fall in the Singapore region:

- On the NWE market, the Brent/product differential showed an improvement in the first quarter of 2012, initially driven by diesel and then by petrol, which was experiencing a delayed reaction to the April fall in Brent prices. Refinery closures/transformations which always result in a reduction in capacity can partly explain these margins holding up better.
- In the US Gulf zone, the spectacular recovery under way since the start of the year is probably a reaction to the improvement in product differentials, petrol and diesel. It's worth pointing out that with WTI being listed considerably below LLS (sub-chapter 1.6), the margins generated by this benchmark crude are still considerably higher.
- In the Singapore region, despite a number of products, such as petrol, diesel and kerosene being healthily valued, margins are still low because of the negative differentials for naphtha and high-sulphur content fuel oil.

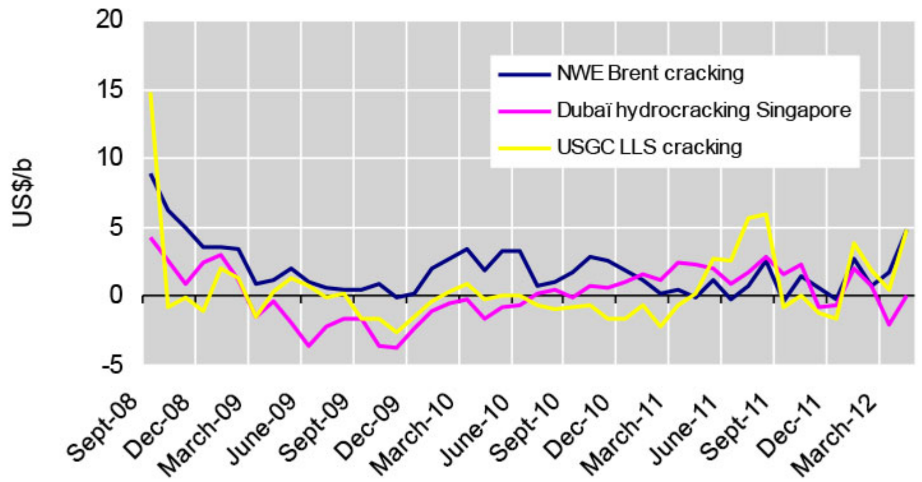
***Table 2: Complex refining margins (annual average in billions of $)***

| | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 (p)** |
|---|---|---|---|---|---|---|---|---|---|
| Brent–Cracking (North-west Europe) | 3.77 | 4.98 | 4.04 | 5.09 | 4.90 | 1.22 | 2.30 | 0.62 | 2.48 |
| LLS* Cracking (US "Gulf Coast") | 1.69 | 5.37 | 5.21 | 4.83 | 2.18 | -0.23 | -0.48 | 0.86 | 3.56 |
| Dubai Hydrocracking (Singapore) | 3.74 | 3.96 | 2.19 | 3.47 | 3.06 | -1.52 | 0.16 | 1.47 | 0.11 |

** Light Louisiana Sweet; ** average over the first 6 months of the year.*
*Source: Oil Market Report (IEA), IFP Énergies nouvelles*

[11] OMR - IEA

***Figure 49: Change in complex refining margins (in billions of $)***




*Source: IFP from the Oil Market Report (IEA)*

In 2013, the combined effect of a global increase in refining capacity and a slowing down of demand as a result of the low levels of economic growth that are forecast will do little to help margins recover. Consequently, they risk being highly volatile. These are global conditions: margins are influenced by many factors other than crude/product price differentials and the way in which the refining sector is configured or the international context (geopolitical events, climate, etc.). Maintenance shutdowns of varying levels of frequency and duration, changes in various fixed and variable costs, taxes, etc. are all factors that can affect margin positively or negatively, and which can vary from one site to another and from one year to the next. The margins published are useful for giving an idea of order of magnitude and variation.

## 4.4 New slowdown in refinery industry spending in 2012

2011 had seen a recovery in spending in the refinery sector - despite the world economic slowdown - in the world's more mature countries in particular. The effects of this spending have been felt in nearly all regions throughout the world in 2012.

***Table 3: Refining industry global spending (in billions of $)***

| | 2009 | 2010 | 2011 | 2012 (p) | 2013 (e) |
|---|---|---|---|---|---|
| Investments | 25.4 | 23.9 | 25.1 | 25.0 | 25.5 |
| Maintenance* | 24.6 | 25.9 | 26.9 | 27.6 | 28.3 |
| Catalysts and chemicals | 15.0 | 15.0 | 15.9 | 16.4 | 16.8 |
| Total | 65.0 | 64.8 | 67.9 | 69.0 | 70.6 |

*Source: IFP based on HPI Market Data; (p) projected*
** 40% for facilities and equipment and 60% on labour and services.*

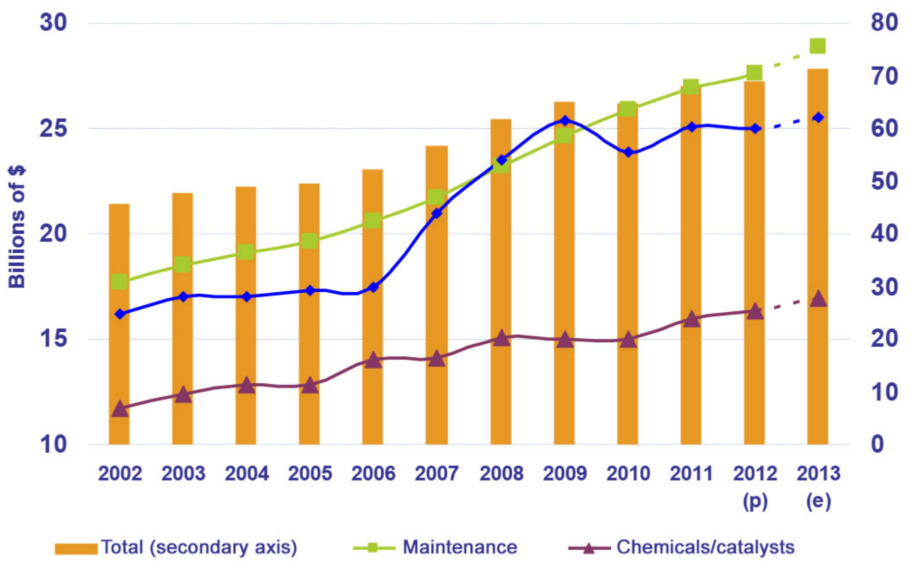
In **2011**, spending increased for the three budgets under consideration - capital, maintenance, catalysts and chemical products - totalling $68 billion - an increase of 4.8% compared with the previous year. Capital spending increased by 5% - the equivalent of the delay incurred during the previous year, evidence of a clear recovery in activity.

Globally throughout the world's industrialised countries, most of the money spent went on relieving bottlenecks and modifying processing procedures. In emerging countries, capital spending has been on both projects to increase the capacity of existing refineries (revamping, relieving bottlenecks, various other modifications) and on building new facilities (refineries or grassroots units). The maintenance budget (which is for keeping equipment and processing units in a good state of repair) has increased less rapidly (3.9%) after many years hovering at an annual rate of around 5%. Spending on chemicals/catalysts, which is globally proportional to refinery processing, has increased by 6%. This is something of a paradox given the fall in refinery utilisation rates in 2011. Many new facilities have been built in emerging countries. Despite their relatively low utilisation rates, this can explain this trend, maintaining a certain level of activity in these regions. Generally speaking, 2011 was not affected by the various events to do with the sovereign debt crises in the world's industrial countries: given that budgets had already been set, the effects of the economic crisis did not start to make themselves felt until the following year.

The increase in spending in the refining sector looks set to be considerably more modest in **2012** - up 1.5% to US$69 billion. A sudden end to the increase in capital spending is forecast for this year, holding steady at around US$25 billion. Spending on maintenance and chemicals, however, is predicted to rise (by 2.6 and 2.7%, respectively). In the face of all the risks to do with the world economic crisis, companies in the refining sector are preferring to postpone some of our projects (30% in 2012, up from 20% in 2011)[12].

As far as **2013** is concerned, the current economic situation would suggest that considerable caution is required in terms of estimating spending. Given the slight fall in demand forecast for next year, any major increase in spending is highly unlikely.[13]. The world's emerging countries - mainly in Asia (China and India) and the Middle East, as well as Brazil - will be driving growth, both in terms of demand and production capacity. According to the IEA's predictions for 2013, there will be a 2.5% increase in demand in non-OECD countries (and a fall of 0.3% for OECD countries). And the vast majority of the projects planned for this year are in these countries/regions. Given this context in which growth is driven by these countries/regions, there could be a moderate increase in spending in the three areas under consideration. As far as spending on maintenance and chemicals is concerned, it seems likely that the 2012 trend will continue into 2013 - with an increase of 2.6% and 2.7%, respectively. Regarding capital spending, a 2% increase is expected - the same as the rate of growth in total refining capacity between 2012 and 2013. This would mean total spending of US$70.6 billion - an overall increase of 2.4%.

***Figure 50: Change in refining industry global spending (in billions of $)***




*Source: IFP based on HPI Market Data; (p) projected, (e) estimated*

[12] Furthermore, the numbers of projects that were planned for 2012 is considerably lower than for 2011. This is the case in regions throughout the world, with the notable exception of South America and the United States, where additional refining capacity is falling

[13] The IEA's predictions for world demand in 2012 suggest an increase of 0.9% in 2013 - 0.1% lower than for 2012

In the mid-term, overall trends should not vary from region to region. There is considerable uncertainty regarding the future of certain refineries in the OECD countries, where declining demand for oil is a structural development (as a result of energy efficiency initiatives, competition from alternative energy sources, oil industry standards, etc.).

***Refineries that have been sold, are for sale, or which are likely to be completely overhauled or closed:***

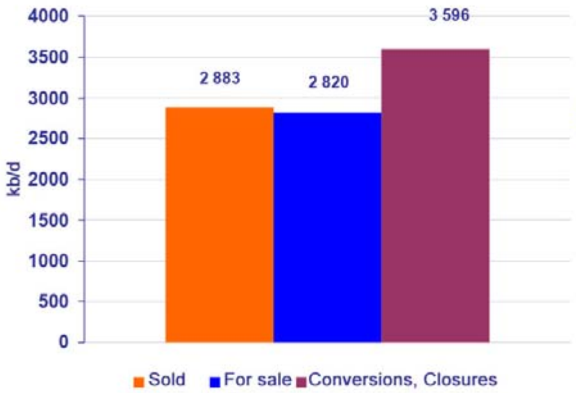
The process whereby oil companies (integrated and straightforward refiners) are turning away from refining activities in Europe and the United States - a process that started in the wake of the 2008/2009 world economic crisis - carried on into 2012 and looks set to continue in the short term. This process is a reaction to both the poor economic conditions offered by the refining sector and to the considerably higher profits enjoyed by oil companies upstream, moving their investments into exploration-production activities.

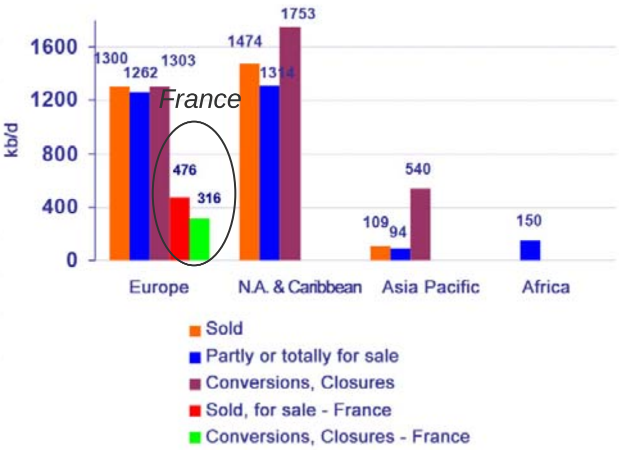
The structural fall in demand is likely to create new surplus and so will generate new overcapacity that will inevitably need to be reduced. Furthermore, when there is overcapacity, margins fall, further weakening the financial results of the refineries.

Since the world economic crisis of 2008/2009, this trend has become more pronounced. This "disinvestment" has taken various forms - such as selling, modifying/converting or partly/completely closing industrial facilities. Transformations and closures are counted together, since both result in the destruction of refining capacity. Refineries that are for sale or have already been sold currently account for 5.7 Mb/day - 2.6 Mb/day more than last year; those that have closed or undergone dramatic overhauls account for 3.6 Mb/day - 2.0 Mb/day more than last year. This makes for a grand total of 9.3 Mb/day. The process was stepped up considerably in 2012.

These restructuring operations affect the world's industrialised countries almost exclusively - particularly North America and Europe. 49% of the assets being sold, restructured or closed in this way are in North America. 42% of them are in Europe. These two regions are where 90% of all sales transactions and capacity destruction operations are located. 85% of all operations to destroy capacity are in North America and Europe. The remaining 15% are in Japan.

In France, a total of 316 kb/d worth of capacity has so far been removed, involving three refineries: Petroplus – Reichstett, Total – Dunkerque and Total – Gonfreville (a 94 kb/d atmospheric distillation plant). There is a measure of uncertainty in relation to the LyodellBasell - Berre (105 kb/d) and Petroplus – Petit Couronne (161 kb/d) refineries, which could end up being added to the capacity being removed. There is also the Ineos-Lavera (210 kb/d) refinery in which PetroChina acquired a 50% stake, setting up a framework agreement between the two major groups. This agreement, which covers the Grangemouth refinery (Ineos' other refinery), is a reaction to the Chinese company's intention to take advantage of technology transfers, particularly in the area of petrochemicals, and to maximise its presence in Europe.



### 4.5 Future investments, heightened competition on the export markets in the mid-term

Given the gloomy outlook for the refining sector on the world's **mature economies**, increasing numbers of European and American oil companies are ceasing their downstream activities in these regions. There is a significant drive to restructure the refining sector and consolidate it around the most high-performance industrial facilities, and the investment needed is still considerable[14] if the many well-known constraints are to be tackled. These include: adapting the refineries in terms of volume, demand and end products, taxes on hydrocarbons, the search for a different energy mix, more stringent norms and specifications for products and regulatory standards governing the operation of refineries[15]. We can therefore expect:

- a reduction in refining capacity. There is a strong likelihood that the current wave of refinery closures/transformations will continue for at least another few years. Smaller refineries that are simpler in terms of what they can convert are now on borrowed time.
- the commissioning of hydrocracking units to keep pace with the increasing number of cars running on diesel, reducing the production of petrol for which the outlets are in stiff competition. However, there are two factors which could change this trend: the trend towards diesel being reversed (because of the consequences of the Euro 6/7 standard) and more quantities of Russian diesel being available.

It is very important to maintain a balance between investment (in terms of both capacity and complexity) and demand in **emerging countries**. Investments in new distillation and conversion capacity that can both meet domestic needs (which are subject to increasingly stringent environmental constraints) and external needs in order to ensure better positioning on export markets. Refineries in the Middle East are increasingly adapting their facilities to produce clean fuels. Examples are the major projects currently under way in Saudi Arabia and Abu Dhabi. These have been designed to produce large volumes of fuel with very low sulphur content. These products will compete with refineries in Europe which are having difficulties disposing of their petrol surplus. Similarly, there are new export refinery projects under way in Brazil. Competition is going to be stiff in the Atlantic Basin, which will also have to count on American refineries in the Gulf of Mexico (US Gulf Coast), the distillate production capacity of which is increasing. This is giving rise to surpluses that will most likely go to markets in Europe and Africa… and even Latin America.

As far as China is concerned, it is currently increasing its refining capacity in order to keep pace with its own domestic demand and is not planning on becoming a petroleum product exporter in the mid-term. This is not the same as India’s strategy. India is using its investments to target export markets - in Asia, West Africa and Europe in particular. At the same time, other Asian countries (Indonesia, Malaysia, and Vietnam) are investing in projects to meet their own domestic demand in the mid-term. This is tending to shrink the markets for export refineries. As is the case in the Atlantic Basin, the mid-term will see a fresh upsurge in competition for exporting light products (petrol, diesel, jet kero).

A global slowdown in the numbers of new projects would be needed in order to create the conditions needed for improved profitability in this sector. But given the drive to increase

[14] Depending on the various crude oil supply forecasts for Europe between 2005 and 2030, and factoring in the various policies that have been adopted and are now being applied by the EU, the investment required in order to bring European refining capacity up to the desired level is between 18 and €29 billion (depending on the various scenarios). Between €3.3 and €12 billion of this is earmarked for ensuring that the future specifications for marine fuels are complied with. "Oil refining and the supply of petroleum products in the EU" – Commission Working paper, Brussels.

[15] As far as greenhouse gas emissions - CO2 in particular - are concerned, it should be remembered that middle distillate production units consume significant quantities of energy, and so release more CO2 than other units. Through Europe's emissions trading scheme, the refining sector will have to pay more for its CO2 emissions generated by more complex facilities required to produce the products requested in the European Union.

capacity in the world's emerging countries, this is not likely to happen. In most cases, this new capacity is being built by public companies which are able to take advantage of specific economic conditions, generally working within the framework of centrally fixed prices. As a strategic sector, the State guarantees the continuation of its operations. In such conditions, the margin constraint is less of a factor. If current forecasts are to be believed, a slowdown in the number of new projects does not look likely.

## 4.6 Impact of the development of unconventional oil refining in the US and Europe

The increasing popularity of unconventional oils is having a number of major benefits on the refining market in the United States. The price advantage of Canadian heavy oils which is being accentuated by a lack of capacity in transport infrastructure, heightened competitivity resulting from shale gases and the specific performance effect that shale oils have are all factors that are helping the US refining sector. The European refining sector, on the other hand, appears vulnerable in its current state.

### *4.6.1* Economic advantage of non-coastal refineries supplied by heavy Canadian crude

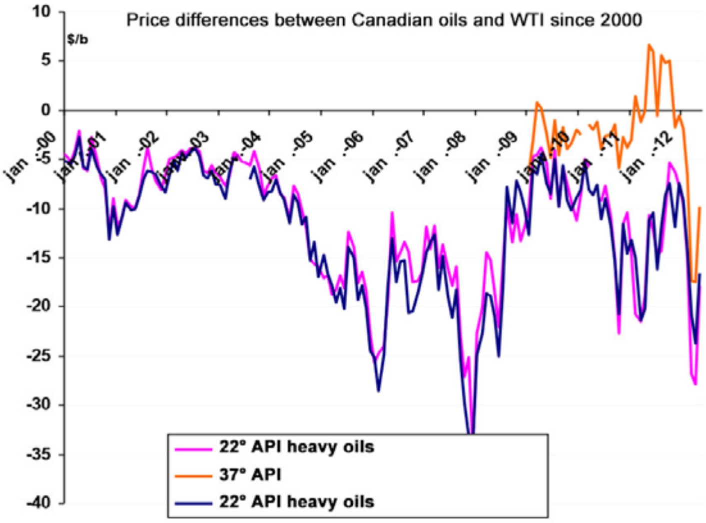
This double decoupling of Canadian heavy crude/WTI and then WTI/Brent prices gives a supply price advantage to refineries inside the US which process Canadian heavy crude relative to the country's coastal refineries which are supplied by the international market.

- **Impact of Canadian heavy crudes on refining**

Production of heavy oils in Canada is constantly increasing and has now exceeded the country's domestic requirements. Most of the surplus is therefore exported to the United States, mainly to PADDs II and IV, by pipeline 1 Mb/d of oil is now exported. There has always been a price difference between Canadian crudes and WTI. This can be justified by the difference in quality. But the difference in price between these two types of crude has become considerably more pronounced since 2005.[16]This difference is currently fluctuating between US$10 and US$30 per barrel (instead of between US$5 and US$10 per barrel). This is because of deliveries of heavy oils and the lack of sufficient transport infrastructure (no pipeline) for carrying the oil to the refining zones of Texas (PADD III), which is where 50% of the US refining sector is located. The competitive prices of heavy oils which have resulted from this have led American refiners to bring in investment programmes designed to modify production facilities so that they can process heavy Canadian oils. Profitability is in fact increased by the below par rating of the acquisition price of crude.

[16] Well before this, the price differential between WTI and Brent was the result of the new influx of shale oils and the lack of transport infrastructure for carrying oil to the refinery zones - PADD III - historically dependent on the international market.

***Figure 51: Price differences between Canadian oils and WTI since 2000***



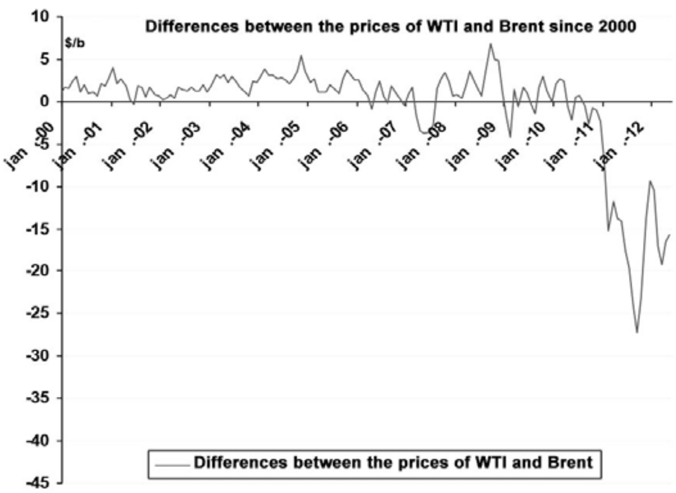

*Source: Platt's*

- **Sharp decline of oil price (WTI) in certain States**

The start of 2011 was marked by a break with the norm in the formation of international oil prices. Brent - a barometer of just how balanced the European market is, and WTI - a good marker of the US markets, started to decouple. Historically, WTI was always slightly above the price of Brent. But this is no longer the case. WTI prices are now being negotiated with a below par rating of between US$10 and US$15 per barrel, even reaching US$25 per barrel in September 2011.

The below par rating of WTI is also linked to the lack of sufficient transport capacity between the refining zones (PADD) and the Canadian heavy oil import market. This trend has had a bearing on the mean prices at which American refiners acquire oil[17], giving American refiners a comparative advantage.

***Figure 52: Differences between the prices of WTI and Brent since 2000***




*Source: Platt's*

However, not all regions are able to benefit from this advantage, and the situation varies within the United States, from PADD to PADD. Analysing these price differences within each PADD reveals a very contrasted picture. For PADDs I, III and V, the increase in these price

[17] . It should be pointed out that WTI is only a local valuation (at the strategic point of Cushing in Oklahoma), and most importantly, just one valuation among others. Other American oils, such as LLS (Light Louisiana Sweet Crude Oil) produced in the Gulf of Mexico are following the same global trends.

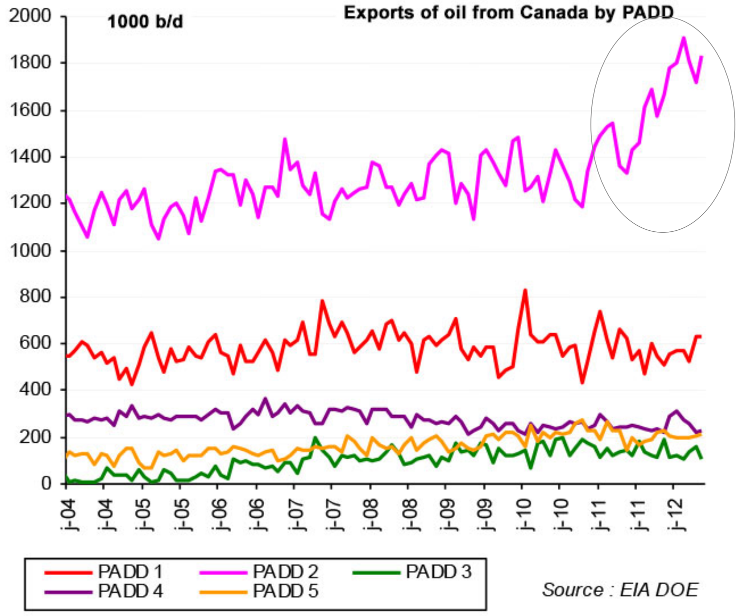
differences relative to Brent is considerably less pronounced than for PADDs II and IV. The situations in these two PADDs are therefore quite specific.

Although the increase in shale oil production (the production volumes of which are currently considerably lower than the volumes of heavy oils being produced - particularly in PADDs III, II and IV) has obviously played a role, the rapid increase in exports of Canadian oil to PADD II in early 2011 can probably go a long way towards explaining the upheaval on the US markets in terms of prices. The differences in price relative to Brent are the most pronounced in the regions which are heavily dependent on Canadian oil.

These differences will continue as long as it remains impossible to move the surpluses from PADDs II and IV to PADD III (Texas), these being the largest zones in terms of refining capacity and which import more than 50% of their oil from overseas. This link means it will be possible to make decisions between domestic purchases and purchases from Canada, relative to imports. This mechanism can be used to rebalance the differences in price between WTI and Brent in particular. Many projects are currently under way in order to tackle this issue[18].

Only refineries which are supplied by Canadian crude and shale oil are able to take advantage of this. These refineries are in PADDs II and IV. The benefits are not being felt by refineries in PADDs I, III and V where supply is aligned against the international market. But given the fact that the petrols produced by the refineries are sold at prices that are in keeping with international rates, the bonus on the price of crude directly affects the refining margin.

***Figure 53: Exports of oil from Canada by PADD***




### *4.6.2* Effects of the development of shale oil/gas on the European refining sector

If the most recent forecasts issued by the Department of Energy are to be believed, the US market should see a structural change in its oil sector, particularly in relation to its imports of oil products and crude. This change is obviously due to the expected increase in production,

[18] One of the first projects announced is the project to reverse the *Seaway pipeline* and relieve its bottleneck. This should be effective sometime in 2013, but it will not be enough to meet all crude oil transport requirements. This phenomenon should, however, become less pronounced as the funds needed are invested in the oil pipeline network

as well as to the relative stability of its consumption[19] (after two years of decline), to on-going drives to develop renewable fuels (ethanol[20]), and to the increase in production of condensate oil and natural gas liquids[21]. None of the scenarios predict complete autonomy for the American market. However, in all scenarios as far as production is concerned, the level of net imports (oil and products) should fall considerably. They stood at 9 Mb/day in 2010 (50% of total consumption) and should fall to between 8 Mb/day and 4 Mb/day by 2035.

The future fall in American imports could have more of an effect on the European market. Petrol imports are currently falling significantly, while diesel exports are rapidly increasing. In this context, Europe would no longer be able to export its petrol surpluses, particularly if the connection issues between the five PADDs are resolved, which would force the zone to further reduce its refinery utilisation rates.

Development of shale oils is intensifying this trend. These oils are actually excellent petrol crudes. Comparing mass yields obtained from a standard configuration refinery shows that Bakken crude (which is representative of these oils) produces nearly 4% more petrol than WTI crude (light, low sulphur content benchmark crude in the US), and produces a similar amount of diesel. So simply replacing 1 million barrels per day of WTI crude (2011 data) with the same volume of Bakken systematically results in an increase in petrol production of approximately 70 Kb/d.

Like all industries throughout the country, the American refining sector is also benefiting from particularly low natural gas prices - between US$2.5 and US$4/MBtu as opposed to between US$8 and US$10/MBtu in Europe - a difference of nearly US$7/MBtu. Whether it is for satisfying heating requirements or producing hydrogen, a refinery consumes a large amount of fuel. And some US refineries have converted their liquid fuel burners into natural gas burners in order to take advantage of these particularly low gas prices. Depending on how it is configured and whether or not it has conversion capacity… and depending on the quality of the crude refined (whether it is light or heavy), it is estimated that a refinery in the US can consume between 1% and 5% natural gas relative to the weight of the crude processed. Given this situation, the difference in the price of natural gas between Europe and the United States is equivalent to a margin increase of between US$0.7 and US$4 per barrel, depending on the case.

To sum up, the US refining sector is benefiting significantly from the gas and oil shale hydrocarbons. All of the country's refineries are recovering their competitivity - between US$0.7 per barrel and US$4 per barrel - through the development of shale gas. In addition to this, for the refineries located within PADDs II and IV (which are supplied by shale oils and Canadian crude), there is a bonus linked to the present economic climate of between US$10 and US$16 per barrel compared with the "benchmark" bonus of US$2 per barrel. These differences are considerable given what the gross margin of a European refinery is, differences that are structurally around US$3 per barrel. The specific performance impact of shale oils, which are depriving our refineries of the US market, is having a significant negative effect on the performance of the European refining sector - as is the mining of shale gas in America. This could also lead to a closing off of petrochemical markets - vital for the European refining sector.

[19] around 19 Mb/day, partly due to the slight decline in petrol consumption. This, which accounts for nearly 45% of the total, should fall from 8.7 to 8 Mb/day between now and 2035 as a result of the policies being brought in designed to dramatically reduce vehicle petrol consumption
[20] approximately 3 Mb/day by 2035
[21] production should rise from 8 Mb/day in 2011 to 9 Mb/day according to the reference scenario, bearing in mind that this is probably a conservative forecast

***Refineries that have been sold, that are for sale, in the process of being transformed, or closed:***

- ***Europe:***

- *Bayernoil Ref. – Ingolstadt – Ger (215 kb/d), (closed, sold to India – Haldia ref.), 2010*
- *Chevron – Pembroke –UK (210 kb/d), sold (Valero), 2011*
- *ConocoPhillips – Wilhelmshaven – Ger. (260 kb/d), transformed or for sale, (Hestya Energy BV (?))*
- *ConocoPhillips – Humber –UKl. (221 kb/d), sale under consideration,*
- *ENI – Ceske ref. – It (170 kb/d), for sale*
- *ENI – Livorno – It (84 kb/d), for sale*
- *ENI – Gela – It. (84 kb/d) closure (temporary), 2012,*
- *Ineos – Grangemouth - (200 kb/d), sold (50% Petrochina JV), 2011*
- ***Ineos – Lavéra - (210 kb/d), sold (50% Petrochina JV), 2011***
- ***LyondellBasell – Berre – Fr (105 kb/d), for sale (currently mothballed)***
- *Murphy Oil - Milford Haven - UK (130 kb/d), for sale.*
- *Petrom - Arpechim Pitesti Ref – Roum. (70 kb/d) for sale,*
- *Petroplus – Teeside – UK (117 kb/d), modifications/conversions (storage), 2009*
- ***Petroplus – Reichstett – Fr (85 kb/d), modifications/conversions (storage), 2010***
- *Petroplus – Cressier – Switzerland (68 kb/d), sold (Varo Refining SA), 2012*
- *Petroplus – Ingolstadt – Ger (100 kb/d), sold (Gunvor), 2012*
- ***Petroplus – Petit Couronne – Ger. (161 kb/d), for sale (2 potential buyers),***
- *Petroplus – Antwerp – PB (100 kb/d), sold (Gunvor), 2012*
- *Petroplus – Coryton – UK (175 kb/d) sold (JV Shell UK Ltd, Vopak and Greenergy), 2012.*
- *Shell – Gothenburg – Sweden (78 kb/d), sold (ST1 Group), 2010*
- *Shell – Stanlow – UK (233 kb/d), sold (Essar), 2011*
- *Shell – Hamburg – Ger. (110 kb/d), modifications/conversions (terminal),*
- *Shell – Heide – Ger. (91 kb/d), sold (Klesch Group),*
- *Tamoil – Cremona - It (101 kb/d), modifications/conversions (storage), 2011*
- *Total – Lindsey – UK (221 kb/d), for sale,*
- ***Total – Dunkerque – Fr (137 kb/j), modifications/conversions (storage), 2010***
- ***Total – Gonfreville – Fr (94 kb/d), closure (distillation unit)***
- *TotalErg – Raff. de Rome – It (100 kb/d), conversions (storage and marketing hub), 2012*

- ***North America and the Caribbean:***

- *AGE Ref & marketing Inc. – San Antonio – US (14 kb/d), sold,*
- *Big West – Bakersfield –US (68 kb/d), sold,*
- *BP – Texas City Ref. – US (475 kb/d), for sale*
- *BP – Carson Ref – US (265 kb/d), for sale (Tesoro), 2012*
- *Chevron – Kapolei –US, Hawaii (54 kb/d), closure,*
- *Connacher O&G – Great Falls – Canada (10 kb/d), for sale (Calumet Speciality Prod. Part., US) 2012,*
- *ConocoPhillips – Trainer Ref. – US (180 kb/d), sold (Delta Air Airlines), 2012*
- *Ergon Inc; - El Dorado - US (83 kb/d), sold,*
- *Frontier Oil Ref. - El Dorado – US (138 kb/d), sold,*
- *Frontier Oil Ref. - Cheyenne – US (47 kb/d), sold,*
- *Gary Williams Co. – Wynnewood – US (75 kb/d), sold,*
- *Holy Corp. – Wood Cross – US (25 kb/d), sold,*
- *Holy Corp. – Navajo Ref. – US (105 kb/d), sold,*
- *Hovensa – US Virgin Island Ref. – US (500 kb/d), conversion into a storage terminal, 2012*
- *Imperial Oil Ltd – Dartmouth Ref. – Canada (88 kb/d), for sale, 2013*
- *Midsouth Enrgy LLC – Somerset – US (5.5 kb/d), sold,*
- *Murphy Oil – Meraux, Louisianne (125 kb/d), sold (Valero), 2012*
- *Murphy Oil - Superior, Wisconsin (35 kb/d) for sale,*
- *Murphy Oil – Wisconsin ref. US (35 kb/d), for sale,*
- *Shell – Montreal – Can (13 kb/d), modifications/conversion (terminal),*
- *Shell – Saint Rose Ref. – US (55 kb/d), sold,*
- *Sunoco – Tulsa Ref. – US (155 kb/d), sold (Holly corporation), 2009*
- *Sunoco Inc. – Eagle Point – US (150 kb/d), modifications/conversion,*
- *Sunoco Inc.- Toledo- US – (160 kb/j), sold,*
- *Sunoco – Philadelphia – US (330 kb/d), conversion into a hub (Philadelphia Energy Solutions JV) 2012,*
- *Sunoco – Marcus Hook Ref. – US (175 kb/d), closure, 2012,*
- *Tenby Inc. – Oxnard – Canada (2.8 kb/d), closure,*
- *Valero – Delaware – US (190 kb/d), sold,*
- *Valero – Paulsboro – US (166 kb/d), modifications/conversion,*
- *Valero – Corpus Christi – US (20 kb/d), closure (FCC),*
- *Valero – Aruba – US (275 kb/d), for sale (Petrochina), 2012/2013*
- *Western Bloomfield – US (17 kb/d), closure.*
- *Western Ref. – Yorktown – US (66 kb/d), closure*

***Refineries that have been sold, that are for sale, in the process of being transformed, or closed (cont'd):***

- ***Asia and the Pacific:***

- *Cosmo Oil – Sakaide Ref. - Japan (140 kb/d), storage conversion, 2013.*
- *CPC Corp Kaohsiung – Taiwan (25 kb/d), closure (FCC),*
- *JX Holdings Negishi – Japan (70 kb/d), closure (distillation unit),*
- *JX Holdings Mizushima – Japan (110 kb/d), closure (distillation unit),*
- *Nihonkai Oil Toyama – Japan (60 kb/d), modification/conversion (terminal),*
- *Shell Parsden Pt – New Zealand (109 kb/d), sold,*
- *Shell – Clyde Ref. – Australia (75 kb/d), conversions,*
- *Showa Shell Keihin – Japan (60 kb/d), closure (distillation unit).*
- *Tesoro Corp.- Kapolei Ref. – Hawaii (94 kb/d), for sale, 2013*

- ***Africa:***

- *Shell – several countries (approx. 150 kb/d), modifications/conversions.*