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INCLUDES 10-YEAR FORECASTS TO 2020

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CONTENTS

Executive Summary

The latest Libya Oil & Gas Report from **BMI** forecasts that the country will account for 7.56% of African regional oil demand by 2015, while providing 15.56% of supply. African regional oil use of 3.06mn barrels per day (b/d) in 2001 will rise to an estimated 3.81mn b/d in 2010. It should average 3.90mn b/d in 2011 and then rise to around 4.40mn b/d by 2015. Regional oil production was 7.93mn b/d in 2001, and will in 2010 average an estimated 10.18mn b/d. From an estimated 10.52mn b/d in 2011, it is set to rise to 12.08mn b/d by 2015. Oil exports are growing steadily, because demand growth is lagging behind the pace of supply expansion. In 2001, the region was exporting an average of 4.87mn b/d. This total rises to an estimated 6.36mn b/d in 2010 and is forecast to reach 7.68mn b/d by 2015. Angola has the greatest production growth potential, with Nigerian exports set to climb if it can resolve recent quasi-political issues.

In terms of natural gas, the region in 2010 will consume an estimated 123.4bn cubic metres (bcm), with demand of 175.9bcm forecast for 2015. Production of an estimated 219.5bcm in 2010 should reach 322.6bcm in 2015, which implies net exports rising from an estimated 96bcm to 147bcm in 2015. In 2010, Libya will consume an estimated 5.11% of the region’s gas, with its market share forecast at 5.68% by 2015. It will have contributed 7.38% to estimated 2010 regional gas production and by 2015 will account for 7.75% of supply.

For 2010 as a whole, we assume an average OPEC basket price of US$77.00/bbl (+26.5% y-o-y). The 2010 US WTI price is now put at US$9.16/bbl. **BMI** is assuming an OPEC basket price of US$80.00/bbl in 2011, with WTI averaging US$82.25, Brent at US$82.46/bbl, Urals delivering around US$81.21 and the Dubai average being US$80.74/bbl. Our central assumption for 2012 is an OPEC price averaging US$85.00/bbl, delivering WTI at approximately US$87.40 and Brent at US$87.60/bbl. From 2013 onwards, we are using an average OPEC price of US$90.00/bbl.

For the whole of 2010, the **BMI** assumption for the global gasoline price is an average US$87.49/bbl, representing a y-o-y rise of 24.7%. The global gasoil forecast is for an average price of US$88.00/bbl, probably peaking in December 2010 at more than US$95/bbl. The full-year outturn represents a 27.6% increase from the 2009 level. For 2010, the annual jet price level is forecast to be US$89.500/bbl. This compares with US$70.66/bbl in 2009. The 2010 average naphtha price is put by **BMI** at US$77.65/bbl, up almost 31% from the previous year’s level.

Libyan real GDP is assumed by **BMI** to rise by 3.2% in 2010. We are assuming average annual growth of 4.5% in 2010-2015. We expect oil demand to rise from an estimated 279,000b/d in 2010 to 333,000b/d in 2015. State-owned **National Oil Corporation** (NOC) accounts for some 40% of oil production and all gas production, but it has a growing number of international oil company (IOC) partners contributing to a forecast rise in oil production from an estimated 1.66mn b/d in 2010 to 1.88mn b/d by 2015. The state itself has far more ambitious volume goals that may be frustrated by OPEC quota policy. Gas production should reach 25bcm by 2015, up from an estimated 16bcm in 2010. Consumption is expected to rise from around 6bcm to 10bcm by the end of the forecast period, allowing exports of 15bcm.

Between 2010 and 2020, we are forecasting an increase in Libyan oil and gas liquids production of 36%, with volumes rising steadily to 2.25mn b/d by the end of the 10-year forecast period. Oil consumption between 2010 and 2020 is set to increase by 45.2%, with growth slowing to an assumed 4% per annum towards the end of the period and the country using 405,000b/d by 2020. Gas production is expected to rise to 27bcm by the end of the period. With demand rising by 92.8% between 2010 and 2020, there should be export potential increasing to around 15bcm, via pipeline and in the form of LNG. Details of **BMI**'s 10-year forecasts can be found in the appendix to this report.

Libya now shares third place with Egypt in **BMI**'s composite Business Environment (BE) ratings table, which combines upstream and downstream scores. It continues to occupy first place in our updated upstream Business Environment ratings. The country's score benefits from its proven oil reserves and a region-topping oil reserves-to-production ratio (RPR). The competitive landscape features numerous non-state companies, and licensing terms are generally good. However, country risk factors undermine some of the hydrocarbons-specific strength. Libya is in the middle of the league table in **BMI**'s downstream Business Environment ratings, with a few high scores but near-term progress up the rankings unlikely. It is ranked fifth thanks to poor country risk factors, a largely state-controlled industry and reasonable oil and gas demand growth prospects.

Libya Energy Market Overview

Libya is a member of OPEC and as such its production of oil is influenced by the cartel's output policy. In September 2010, the country produced 1.55mn b/d – some way below its estimated sustainable capacity of 1.70mn b/d, but above the production ceiling allocated by OPEC in December 2008. Over the next few years, Libya would like to see oil production capacity increase to 3.0mn b/d. The country in December 2009 deferred its 3.0mn b/d target from 2012 to 2015/2016, according to Shokri Ghanem, CEO of state-owned NOC. Speaking to Reuters, Ghanem said that the delay was due to 'changes in the market and budget constraints'.

Proven oil reserves estimated at 44.3bn barrels (bbl) in 2009 (according to the June 2010 BP Statistical Review of World Energy) provide considerable potential to raise output. Large tracts of Libyan territory have yet to be explored, with only a relatively modest amount of territory so far licensed to international companies. This suggests scope for significant and sustained reserves upgrades over the longer term. The main customers for Libyan crude are Italy, Germany and France, although the US began to import Libyan oil following the lifting of sanctions.

Libya is also rich in natural gas, with 1,540bcm (BP Review) of proven reserves that provide an estimated 15bcm of annual output. Most gas is exported by pipeline, with limited volumes of liquefied natural gas (LNG). Libyan gas exports to Europe have increased, with the Western Libyan Gas Project (WLGP) and US$6.6bn, 32-inch diameter, 595km Greenstream underwater gas pipeline coming online in October 2004. Previously, the only customer for Libyan gas was Spain's **Enagas**. However, the WLGP has now expanded these exports to Italy and beyond. Currently, more than 8bcm of gas is being exported from a processing facility at Mellitah, on the Libyan coast, via Greenstream to south-eastern Sicily.

Having been hampered by UN sanctions following the Lockerbie airliner bombing in 1988, Libya's energy industry has grown more slowly than most in spite of substantial IOC involvement. US firms returned once sanctions were lifted, but have more recently been reducing their involvement thanks to changes in licensing terms and a lack of exploration success.

There is 378,000b/d of refining capacity in Libya (according to the December 2009 Oil & Gas Journal refining survey), above domestic oil consumption of an estimated 274,000b/d, providing a useful export capability. There are more than five gigawatts (GW) of electricity generating capacity, most of which is oil or gas fired.

Libya's top energy official has claimed a 1.26bn bbl rise in proven oil reserves and a 50bcm increase in proven gas reserves, on the back of successes at new exploratory wells drilled in the country in 2009 and H110. In an interview with Dow Jones republished by news agencies in July 30 2010, Shokri Ghanem said that Libya's oil and gas reserves increased respectively by 653mn bbl and 22bcm in 2009, and 612mn bbl and 28bcm in H110. Ghanem claimed that NOC and international companies operating in Libya recorded a 51% success rate at the 65 new wells drilled in 2009, but did not specify the drilling success rate for H110. Ghanem also said that Libya has identified 20 new highly prospective areas to be drilled in 2010.

Four IOCs including US-based **Chevron** and **Occidental Petroleum** have decided not to renew their five-year exploration leases in Libya, effectively ending their involvement in the country. The four entered Libya in 2005 in the country's first licensing round following the end of international sanctions. The decision to leave appears to have been largely due to a lack of discoveries, although changes to the PSC in 2007 are likely to have played a role as well.

In a Reuters article on October 2 2010, Fitouri said that four of the winners from the first licensing round had decided not to extend their Libyan licences. Fitouri said that the companies – Chevron, Occidental, **Woodside Petroleum** and the UAE's **Liwa Energy** – were now preparing to leave Libya. He said that five companies had decided to renew their licences at a total cost of US$133mn, namely US independent **Hess**, **Oil India**, Brazil's **Petrobras**, Indonesia's **Medco Energi** and Algeria's **Sonatrach**.

UK-based **BG Group** has announced plans to exit Libya, following a lack of exploratory success. The company is in the process of relinquishing its two Libyan licences and will formally leave the country pending approval from Libya's state-run **National Oil Corporation** (NOC), a BG company spokesperson said on August 20 2010. The spokesperson also indicated that BG intends to transfer its 50% interest in its exploration licence in the onshore Kufra Basin to Norway's **Statoil**.

Global Oil Market Review

Regaining Momentum

As with Q2, the third quarter started with encouraging oil market strength, which then dissipated rapidly. If anything, oil market fundamentals improved, with demand assumptions rising. The US driving season was disappointing, but the real damage was done as macroeconomic uncertainty crept back into the market and investors turned their backs on oil. Ongoing eurozone economic woes, fresh China jitters and a general sense of macroeconomic fragility meant that oil prices were dragged lower with equities and currencies. We remained convinced that there would be a belated rally, as the world heads towards winter in a higher-demand quarter. Thus far, our confidence has been rewarded by a recovery that began in September and accelerated into October.

Demand projections for 2010 continued to firm up during the third quarter, with some upgrades coming through for 2011, even though the jury is out regarding the strength and sustainability of the economic recovery. After rising steadily in the first half of the year, OPEC volumes appear to have levelled out in Q3. The organisation has done and said little to change the supply/demand landscape, although some members at the October 14 ministerial gathering were arguing the case for a US$100/bbl target to compensate for the weakening of the US dollar, which is undermining their revenues.

According to the International Energy Agency (IEA) in its October 2010 monthly Oil Market Report (OMR), OECD end-August commercial oil inventories stood at 2,790mn bbl, reaching their highest level since August 1998. However, a very significant fall looks to have been recorded in September – during a period when a small stock rise is the norm. With demand having strengthened and supply having stalled, a continuation of this inventory trend could support an oil price recovery throughout Q4.

September saw global oil supply fall by some 150,000b/d according to the IEA. Non-OPEC producers saw volumes fall during the month, while a modest increase in OPEC production failed to compensate. Crude oil supply from OPEC averaged 29.3mn b/d in September (IEA estimate), up by 40,000b/d when compared with the previous month. Much of this increase, however, reflects Iraqi output gains, with the 11 core members actually reducing supply by some 150,000b/d. Quota compliance of around 54% is a definite improvement on the year’s low of around 50%, even if well short of the 59% historical OPEC ‘norm’.

Non-OPEC supply in September fell by just 20,000b/d, with the US hurricane season doing little to disrupt output. During the third quarter, non-OPEC supply was fairly stable when compared with Q2 – and not significantly above the Q1 level. Output of around 52.6mn b/d in Q3 compares with 52.7mn b/d in Q2 and 52.3mn b/d in the opening quarter of the year. September volumes are put at 52.4mn b/d.

Given positive demand-side developments, a capping of recent supply growth and some evidence of a fall in stock levels, it is hardly surprising that the end of Q3 saw oil prices gaining ground. At the time of our

July 2010 quarterly oil price report, the OPEC basket was just below US$73/bbl. It reached almost US$79/bbl in early August, before collapsing to less than US$70/bbl later in the month. September then saw a steady increase from around US$72/bbl to US$77/bbl, with momentum being retained into early October and the OPEC price reaching US$80/bbl by the time this report was written.

Quarterly Trends

The Energy Information Administration (EIA) in its October 2010 monthly report suggested that Q310 global oil demand was 86.22mn b/d, compared with 86.18mn b/d in Q210 and 84.56mn b/d in Q309 (+1.96% y-o-y). Non-OECD demand is reported at 41.02mn b/d, compared with 41.22mn b/d in the previous quarter and 39.59mn b/d in Q309 (+3.61% y-o-y). The OECD states saw a 0.24mn b/d quarter-on-quarter rise in consumption during Q310, with demand amounting to 45.20mn b/d. In Q309, OECD demand was 44.97mn b/d, based on EIA data.

According to the Paris-based IEA, Q310 global consumption averaged 87.60mn b/d, compared with 86.76mn b/d in Q210 and 85.19mn b/d in Q309. The y-o-y change was put at +2.83%. OECD demand in Q310 is reported at 45.97mn b/d, compared with 45.22mn b/d in Q210 and 44.99mn b/d in Q309. Non-OECD consumption in Q310 was reportedly up 3.58% y-o-y at 41.64mn b/d. In Q210, non-OECD consumption was 41.55mn b/d.

OPEC's October 2010 monthly oil report states Q310 global oil demand at 85.87mn b/d, up from 84.91mn b/d during the previous quarter and up from 84.75mn b/d in Q309 (+1.13%). OECD demand is said to have risen by 0.2% y-o-y to 45.19mn b/d, with North American consumption higher by 0.4%. Non-OECD demand was up 2.31% y-o-y to 40.68mn b/d, according to OPEC data.

The EIA Q310 estimates suggest that non-OPEC oil supply was 51.43mn b/d, compared with the Q210 level of 51.48mn b/d and the 50.49mn b/d recorded in Q309 (+1.86% y-o-y). Russia, the US and China were significant contributors to the supply increase. OPEC output for Q310 is put at 35.06mn b/d (including natural gas liquids), up from 34.69mn b/d in Q210 and the 34.24mn b/d delivered in the third quarter of 2009.

Global Q310 production based on IEA data was an average 87.04mn b/d. This compares with 86.76mn b/d in Q210. The non-OPEC element for the most recent quarter is 52.57mn b/d, easing lower from 52.74mn b/d in Q2. Overall OPEC volumes, including gas liquids, are said to have risen from 34.01mn b/d to 34.47mn b/d between Q210 and Q310.

OPEC itself believes that non-OPEC oil supply averaged 52.03mn b/d in Q310. OPEC crude output was assessed at 29.12mn b/d during the quarter, with the cartel pumping an average 29.08mn b/d in September.

Global Oil Market Outlook

Sitting Comfortably

Autumn has brought with it some renewed optimism regarding macroeconomic prospects and the oil price outlook. As the bears head indoors to hibernate, there is scope for a sustained Q4 recovery. For 2011, however, uncertainty still weighs heavily on the market. We believe the supply/demand balance can support a modest rise in crude prices, but we do not subscribe to the 'US$100' view that prevails in some circles.

Admittedly, the most bullish of macroeconomic projections could deliver demand above current expectations. With non-OPEC supply unlikely to rise quickly during the coming year, OPEC could no doubt engineer higher prices. With quotas unchanged at the October meeting, however, and little evidence of serious concern over compliance, it is realistic to assume that higher demand will be met by increased OPEC supply. A basket price somewhat in excess of US$80 per barrel (bbl) seems to suit most members, providing a degree of comfort for producers and consumers alike.

In our September 2010 monthly update we took the unusual step of flagging up a change to our oil price assumptions. It had become apparent by that point that achieving more than US$80 in 2010 was unlikely, thanks to the dull summer market. With a predicted Q4 rally, we revised our 2010 target to US$77/bbl and that view is reiterated in this quarterly assessment. Given that OPEC crude has already averaged more than US$75/bbl, we are confident that the eventual full-year outturn will be close to our forecast.

Although we have reduced our 2011 OPEC basket price expectation to US$80/bbl, there is arguably some upside potential. Macroeconomic forecasts may be somewhat fragile for the year, but there are also supply risks that could offset demand-side disappointments. Outside the non-OPEC producers, where volumes are vulnerable to project over-runs, post-Macondo backlash, hurricanes and maintenance problems, there is still a question mark over Nigeria, Iran and Iraq. Achieving a market balance that allows for some inventory erosion and moderate price growth will be a complicated process.

We remain confident in the medium-term trend towards a somewhat tighter market, resulting in further price progress in 2012/2013. A dramatic move to higher levels will simply wipe out demand as motorists in particular choose fuel economy over performance. Relative price stability, even in challenging economic circumstances, will largely support traditional driving patterns and slow the rate of migration towards costly hybrids, range-limited electric cars and high-economy diesels. A move back to US$85-90/bbl seems entirely possible by 2012 onwards, with supply expansion and demand growth settling at a modest but sustainable level.

Oil Price Forecasts

In terms of the OPEC basket of crudes, the average price in Q310 was around US$73.80/bbl, down from the US$76.60/bbl recorded during the previous three months. This was a disappointing outcome, given that the underlying demand trends were relatively healthy. However, bearish sentiment overwhelmed market fundamentals to drive prices below the appropriate level. In Q309, the OPEC price averaged US$67.70/bbl, so the most recent quarter has seen a y-o-y gain of just 9%. Weekly averages had peaked initially at US$78.20/bbl in early August, providing false hope that the summer rally was finally under way. This petered out, with a weekly low of US$70.90/bbl seen by the end of August. September then saw a steady recovery, with the price breaking above US$75 as sentiment improved. October has got off to a good start, in spite of a featureless OPEC meeting, with the basket price breaking back above US$80/bbl.

The monthly averages for the third quarter of 2010 were US$72.51, US$74.15 and US$74.63/bbl. **BMI** is currently assuming that October will deliver an average close to US$80.60 if the current strength is retained. We are assuming November and December averages of US$81.70 and US$84.40/bbl respectively, providing a Q4 outturn of US$82.23/bbl. This will represent a quarter-on-quarter (q-o-q) gain of 11.5% and a y-o-y increase of 10.6%. The full-year average will therefore work out at around US$77.00, compared with about US$60.90/bbl in 2009.

In terms of other marker prices, North Sea Brent averaged US$76.86/bbl during Q3, with WTI achieving a surprisingly low US$76.04. This is a clear indication that WTI is much more prone to speculative activity and market sentiment than the other crudes, reducing its usefulness as a barometer of underlying fundamentals. Urals (Mediterranean delivery) in Q3 averaged US$75.54/bbl and Dubai realised US$73.90. These averages have been calculated using OPEC data and monthly prices from the IEA.

For 2010 as a whole, we assume an average OPEC basket price of US$77.00/bbl (+26.5% y-o-y). The 2010 US WTI price is now put at US$79.16/bbl. The October 2010 monthly report from the US-based EIA predicts a 2010 average WTI crude price of just under US$78/bbl, rising to US$83.00 in 2011. **BMI** is assuming an OPEC basket price of US$80.00/bbl in 2011, with WTI averaging US$82.25, Brent at US$82.46/bbl, Urals delivering around US$81.21 and the Dubai average being US$80.74/bbl.

Our central assumption for 2012 is an OPEC price averaging US$85.00/bbl, delivering WTI at around US$87.40, Brent at US$87.60/bbl, Urals averaging around US$86.30 and Dubai delivering US$85.80/bbl. From 2013 onwards, we are using an average OPEC price of US$90.00/bbl. The WTI, Brent, Urals and Dubai assumptions are US$92.53, US$92.77, US$91.37 and US$90.84/bbl respectively.

Oil Supply, Demand And Price Outlook

Short-Term Demand Outlook

The **BMI** oil supply and demand assumptions for 2010 and beyond have once again been revised for all 71 countries forming part of our detailed coverage, reflecting the changing macroeconomic outlook and the impact of environmental initiatives. Investment in exploration, development and new production has continued to rise as a result of relatively stable crude prices, but deepwater activity has been set back by events in the Gulf of Mexico (GoM). Costs associated with oil field development and exploration/appraisal drilling continue to rise, with deepwater programmes now particularly vulnerable as a result of equipment shortages, lack of personnel and the post-Macondo regulatory environment.

We have once again made some changes to forecast oil production levels, in line with recent OPEC output and known project delays, with no clear evidence of large-scale spending changes by international oil companies (IOCs) or national oil companies (NOCs). Even in the US, the backlash from **BP**'s Macondo disaster has led to only minor revisions to the production outlook. Other deepwater-focused regions appear to be re-examining procedures and legislation, but continuing with most exploration and development programmes.

According to the updated **BMI** model, 2010 global oil consumption will now increase by 2.36% from the 2009 level. This represents an upgrade to the forecast contained in the July 2010 quarterly report, which had assumed an increase of 2.06%. The 2010 forecast represents slightly higher OECD demand (+1.12%) and a revised non-OECD increase of 3.55%. The overall increase in demand is estimated at 1.99mn b/d. North America is now expected to see expansion of 364,000b/d (+1.74%), with OECD European demand set to recover by 137,000b/d (+1.06%). Non-OECD gains are expected to be 2.88% in Asia, 2.21% in Latin America, 4.29% in Central/Eastern Europe, 3.58% in the Middle East and 1.60% in Africa.

The IEA, in its October 2010 OMR, predicts a slightly more bullish rise in 2010 oil demand of 2.48%, or 2.10mn b/d. The organisation's assumptions suggest an impressive 4.65% rise in non-OECD consumption (+1.80mn b/d). This points to 0.67% higher OECD oil demand, which lags the economic recovery.

October 2010 EIA estimates suggest that world demand will rise y-o-y from 84.33mn b/d to 86.06mn b/d, with the 1.73mn b/d increase in consumption amounting to a gain of 2.05%. While there has been a significant upgrade, this view still sits below the somewhat more optimistic **BMI** and IEA estimates. Non-OECD demand is predicted to increase by 4.42% (1.72mn b/d), while OECD demand is expected to rise by just 10,000b/d to 45.43mn b/d. Consumption in the US is expected to increase by 200,000b/d

(1.07%). With Canadian demand 3.26% higher and that of Europe 1.52% lower, it is in Japan that the US energy body sees the greatest risk of a decline – forecasting a fall of 2.75%.

OPEC's October 2010 report suggests a likely increase in 2010 global oil consumption of 1.13mn b/d, or 1.34%. OECD demand is forecast to rise by 80,000b/d (0.17%). Non-OECD demand is expected to average 40.04mn b/d, compared with 38.93mn b/d in 2009 (+2.85%).

Table: Global Oil Consumption (000b/d)

	2008	2009	2010e	2011f	2012f	2013f	2014f	2015f
Africa	3,710	3,753	3,813	3,904	4,001	4,131	4,262	4,403
Middle East	6,864	7,146	7,404	7,698	7,973	8,230	8,442	8,699
NW Europe	13,545	12,964	13,101	13,141	13,197	13,287	13,292	13,288
N America	21,785	20,881	21,245	21,170	21,210	21,327	21,446	21,565
Asia/Pacific	25,994	26,348	27,108	27,669	28,385	29,146	29,900	30,641
Central/Eastern Europe	6,121	5,801	6,050	6,213	6,337	6,505	6,711	6,882
Latin America	7,724	7,631	7,800	7,955	8,047	8,205	8,354	8,487
Total	85,744	84,525	86,518	87,749	89,149	90,829	92,405	93,964
OECD	43,399	41,509	41,976	41,827	41,867	42,034	42,167	42,307
non-OECD	42,345	43,015	44,541	45,923	47,282	48,796	50,238	51,657
Demand growth %	(0.32)	(1.42)	2.36	1.42	1.60	1.88	1.73	1.69
OECD %	(3.55)	(4.35)	1.12	(0.36)	0.10	0.40	0.32	0.33
Non-OECD %	3.23	1.58	3.55	3.10	2.96	3.20	2.96	2.83

f = forecast. Historical data: BP Statistical Review of World Energy, June 2010/BMI. All forecasts: BMI.

Short-Term Supply Outlook

According to the revised **BMI** model, 2010 global oil production will rise by 2.91%, representing an OPEC increase of 4.31% and a non-OPEC gain of 1.85%. The overall increase in supply is estimated at 2.55mn b/d in 2010, an upgrade from the July 2010 quarterly report. We continue to assume that the current OPEC production ceiling will be retained for the whole of 2010 (and into 2011), but that actual output will remain close to the Q310 level. Should quota adherence improve further then OPEC volumes could emerge slightly lower.

The EIA was in October 2010 forecasting a 900,000b/d y-o-y rise in non-OPEC oil output, representing a gain of 1.78%. World oil production is predicted to be 86.21mn b/d in 2010, up from 84.33mn b/d

(+1.88mn b/d) in 2009. The US organisation expects a 0.98mn b/d (2.89%) upturn in OPEC oil and NGL output.

OPEC itself sees 2010 non-OPEC supply rising by 1.01mn b/d to 52.23mn b/d. In 2010, OPEC NGLs and non-conventional oils are expected to increase by 0.44mn b/d over the previous year to average 4.79mn b/d. The October 2010 OPEC monthly report argues that the call on OPEC crude is expected to average 28.6mn b/d, representing a downward adjustment of 100,000b/d from its previous assessment and a decline of 300,000b/d from the previous year.

The IEA's 2010 assumption for non-OPEC oil supply is 52.6mn b/d, representing a rise of 1.76%. This view is based on output declines in Mexico, the UK and Norway, which partly offset the growth predicted for Brazil, Russia, China, India and Colombia. OPEC production of NGLs is expected to rise sharply from 4.65mn b/d to 5.15mn b/d. Increased biofuels supply (+15.92%) and a 3.93% downturn in processing gains implies a need for OPEC crude volumes of 29.19mn b/d in 2010. This is somewhat below OPEC's estimated Q310 output of 29.24mn b/d.

Table: Global Oil Production (000b/d)

	2008	2009	2010e	2011f	2012f	2013f	2014f	2015f
Africa	10,190	9,671	10,177	10,519	10,801	11,164	11,566	12,080
Middle East	26,229	24,406	24,956	25,221	25,553	25,966	26,576	27,240
NW Europe	4,912	4,657	4,353	4,208	4,040	3,843	3,693	3,653
N America	10,002	10,408	10,705	10,725	10,665	10,615	10,600	10,700
Asia/Pacific	8,689	8,568	8,909	8,944	9,080	9,239	9,069	8,887
Central/Eastern Europe	13,045	13,417	13,678	13,910	13,966	14,106	14,482	14,871
Latin America	9,857	9,749	10,019	10,171	10,227	10,603	11,139	11,681
OPEC NGL adjustment	4,600	4,660	5,260	5,870	5,981	6,139	6,329	6,584
Processing gains	2,084	2,290	2,200	2,230	2,275	2,320	2,366	2,414
Total	89,608	87,828	90,382	91,808	92,653	94,176	95,992	98,306
OPEC	35,568	33,076	34,104	34,519	35,172	36,100	37,221	38,720
OPEC inc NGLs	40,168	37,736	39,364	40,389	41,153	42,238	43,550	45,304
Non-OPEC	49,440	50,092	51,018	51,419	51,499	51,938	52,442	53,001
supply growth %	1.05	(1.99)	2.91	1.58	0.92	14.68	1.93	2.41
OPEC %	3.15	(6.05)	4.31	2.61	1.89	37.93	3.11	4.03
Non-OPEC %	(0.59)	1.32	1.85	0.78	0.16	0.85	0.97	1.07

f = forecast. Historical data: BP Statistical Review of World Energy, June 2010/BMI. All forecasts: BMI.

Longer-Term Supply And Demand

The **BMI** model predicts average annual oil demand growth of 1.78% between 2010 and 2015, followed by 1.39% between 2015 and 2020. After the forecast 2.36% global demand recovery in 2010, we are assuming 1.42% growth in 2011, followed by 1.60% in 2012, 1.88% in 2013, 1.73% in 2014 and 1.69% in 2015.

OECD oil demand growth is expected to remain relatively weak throughout the forecast period to 2020, reflecting market maturity, the ongoing effects of recent demand destruction and the greater commitment to energy efficiency. Following the 4.35% decline in 2009 OECD oil consumption and the forecast 1.12% rise in 2010, we expect to see a decrease of 0.36% in 2011. On average, OECD demand is forecast to rise by 0.32% per annum in 2010-2015, then fall by 0.23% per annum in 2015-2020.

For the non-OECD region, the demand trend in 2010-2015 is for 3.10% average annual market expansion, followed by 2.66% growth in 2015-2020. Demand growth is forecast to recover from 1.58% in 2009 to 3.55% in 2010 and 3.10% in 2011.

BMI is forecasting global oil supply increasing by an average of 1.90% a year between 2010 and 2015, with an average yearly gain of 1.35% predicted in 2015-2020. We expect the trend to be at its weakest towards the end of the 10-year forecast period, with gains of just 0.44% and 0.26% predicted in 2019 and 2020.

Non-OPEC oil production is expected to rise by an annual average of 0.95% in 2010-2015, then just 0.02% in 2015-2020. OPEC volumes are forecast to increase by an annual average of 3.10% between 2010 and 2015, easing to 2.85% per annum in 2015-2020.

In 2011, the IEA is predicting world oil demand growth of 1.2mn b/d, although it warns that if global GDP growth were to emerge a third lower, demand might increase by just 0.4mn b/d. Its current base case sees the world consuming 88.2mn b/d next year, up around 1.4%, which is in line with the latest **BMI** projection.

The EIA is assuming world demand of 87.44mn b/d in 2011, up 1.38mn b/d, or 1.60%. This represents a more bullish view of likely macroeconomic and oil market events. OECD consumption is expected to continue falling, but the non-OECD countries are tipped to deliver 3.52% growth, with Chinese demand up by 5.88% – well above our own view.

OPEC's assumption for 2011 is an increase in demand of around 1.22% to 86.64mn b/d, with this modest 1.05mn b/d rise in consumption the most conservative of third-party forecasts. It sees some growth among

OECD states, but a more cautious 2.47% increase from the non-OECD segment. Given that China's growth is put at 4.90%, this implies a very weak performance among the other developing countries.

In terms of non-OPEC demand growth in 2011, the OPEC assumption is 360,000b/d, or 0.69%. The EIA is forecasting a decrease of 240,000b/d to 51.12mn b/d, which would allow OPEC to regain market share and inventories to fall. The IEA's prediction for 2011 is non-OPEC supply rising by 0.5mn b/d to 53.1mn b/d.

In all cases, non-OPEC supply expansion fails by a wide margin to match likely growth in demand. This means that, even if the global economy falters and consumption fails to rise as quickly as expected, the slow growth in supply should still support robust crude prices.

Oil Price Assumptions

The OPEC basket price, having averaged US$73.76/bbl in Q210, is forecast to be US$82.23 in Q4. The full-year forecast is an average of US$77.00/bbl. Brent, WTI and Urals prices for 2010 are put at US$79.37, US$79.16 and US$78.17/bbl respectively.

Table: Crude Price Assumptions 2010

	Q110	Q210	Q310e	Q410f	2010f
Brent (US$/bbl)	76.24	78.30	76.86	86.07	79.37
Urals – Med (US$/bbl)	75.32	76.89	75.54	84.90	78.17
WTI (US$/bbl)	78.67	77.78	76.04	84.14	79.16
OPEC basket (US$/bbl)	75.40	76.59	73.76	82.23	77.00
Dubai (US$/bbl)	75.83	78.12	73.90	83.01	77.71

e/f = estimate/forecast. Source: BMI.

In 2011, there should be further (1.42%) growth in oil consumption. Non-OPEC supply is expected to increase by 0.78%, making room for OPEC to regain market share and for inventories to fall. We are assuming a further increase in the OPEC basket price to an average US$80.00/bbl, implying Brent at US$82.46, WTI at US$82.25/bbl and Urals at US$81.21. The basis here is for differentials to remain around the level of those seen in 2010, although greater volatility in the WTI and Brent markets could mean a different outcome. For 2012, we expect a further price rise to US$85 for OPEC crude thanks to still lower non-OPEC supply expansion and a slight strengthening of demand growth. Beyond 2012 we continue to use US$90.00/bbl for the OPEC basket.

Table: Oil Price Forecasts

	2008	2009	2010f	2011f	2012f	2013f	2014f	2015f
Brent (US$/bbl)	96.99	61.51	79.37	82.46	87.62	92.77	92.77	92.77
Urals – Med (US$/bbl)	94.49	61.04	78.17	81.21	86.29	91.37	91.37	91.37
WTI (US$/bbl)	99.56	61.68	79.16	82.25	87.39	92.53	92.53	92.53
OPEC basket (US$/bbl)	94.08	60.86	77.00	80.00	85.00	90.00	90.00	90.00
Dubai (US$/bbl)	93.56	61.69	77.71	80.74	85.79	90.84	90.84	90.84

f = forecast. Source = BMI.

Regional Market Overview

West and North Africa have an important role to play in terms of global oil supply, with Angola's offshore deepwater wealth an increasingly important factor. Nigeria is struggling to contend with domestic political problems that have been hampering oil expansion. Gas is another important export product for the region, largely in the form of LNG. North Africa and Nigeria play a growing role in the supply of the world's gas. The likes of Nigeria, Libya and Algeria have been renegotiating contract terms with foreign partners so as to retain a greater share of hydrocarbons revenues.

Oil Supply And Demand

Perennial problem child Nigeria and West African rival Angola face further OPEC-related friction if they continue to push for a revised output ceiling. A return by Nigeria to higher production levels has been taking place, and further progress is possible during 2011. Thanks to this and the Angolan trend, our data suggest that Africa is set to play an increasingly important role in world oil supply, with Angola remaining a magnet for foreign investment – in spite of deepwater drilling concerns.

Overall African oil production will average an estimated 10.18mn b/d in 2010. By 2015, we see output rising to at least 12.08mn b/d, when Angolan volumes are likely to have reached a plateau. We are assuming steady growth from Algeria and Libya, with Nigeria seeing recovery from recent depressed levels. African demand is set to increase from an estimated 3.81mn b/d in 2010 to 4.40mn b/d by 2015, providing an export capability increasing from an estimated 6.36mn b/d to 7.68mn b/d.

Table: Africa's Oil Consumption, 2008-2015 (000b/d)

Country	2008	2009	2010e	2011f	2012f	2013f	2014f	2015f
Algeria	311	331	341	355	369	383	399	415
Angola	81	85	94	108	124	149	179	215
Cameroon	31	33	34	36	38	40	42	44
Republic of Congo	6	7	7	7	8	8	8	9
Egypt	693	720	734	756	779	810	835	860
Equatorial Guinea	1	1	1	1	1	1	1	1
Gabon	13	14	14	15	15	16	17	18
Libya	**268**	**274**	**279**	**287**	**296**	**308**	**320**	**333**
Nigeria	286	280	288	303	318	342	367	395
South Africa	532	518	523	531	539	547	555	564
Sudan	89	84	87	92	96	101	106	111
BMI universe	2,311	2,345	2,404	2,491	2,584	2,706	2,830	2,964
Other Africa	1,399	1,408	1,409	1,413	1,417	1,425	1,432	1,439
Regional total	3,710	3,753	3,813	3,904	4,001	4,131	4,262	4,403

f = forecast. Source: Historical data: BP Statistical Review of World Energy, June 2010; BMI

Oil use of 3.06mn b/d in 2001 will have risen to an estimated 3.81mn b/d in 2010. It should average 3.90mn b/d in 2011 and then rise to around 4.40mn b/d by 2015. Libya will have accounted for an estimated 7.32% of 2010 regional oil consumption, with a likely market share of 7.56% by 2015.

Table: Africa's Oil Production, 2008-2015 (000b/d)

Country	2008	2009	2010e	2011f	2012f	2013f	2014f	2015f
Algeria	1,993	1,811	1,855	1,905	1,955	1,995	2,050	2,200
Angola	1,875	1,784	1,810	1,900	1,995	2,100	2,250	2,375
Cameroon	84	73	67	58	70	83	95	98
Republic of Congo	249	274	340	360	353	346	339	332
Egypt	722	742	733	722	697	700	698	681
Equatorial Guinea	350	307	335	385	415	430	447	455
Gabon	235	229	240	252	255	250	245	240
Libya	**1,820**	**1,652**	**1,655**	**1,670**	**1,705**	**1,750**	**1,815**	**1,880**
Nigeria	2,116	2,061	2,340	2,395	2,450	2,535	2,600	2,750
South Africa	15	11	12	15	17	16	16	15
Sudan	480	490	545	605	630	691	735	770
BMI universe	9,939	9,434	9,932	10,267	10,542	10,896	11,290	11,796
Other Africa	251	237	245	252	259	269	277	285
Regional total	10,190	9,671	10,177	10,519	10,801	11,164	11,566	12,080

f = forecast. Source: Historical data: BP Statistical Review of World Energy, June 2010; BMI

Regional oil production was 7.93mn b/d in 2001, and will have in 2010 averaged an estimated 10.18mn b/d. From an estimated 10.52mn b/d in 2011, it is set to rise to 12.08mn b/d by 2015. Libya in 2010 will have accounted for an estimated 16.26% of regional oil supply, and its market share is expected to be 15.56% by the end of the forecast period.

Oil exports are growing steadily, because demand growth is lagging behind the pace of supply expansion. In 2001, the region was exporting an average 4.87mn b/d. This total had risen to an estimated 6.36mn b/d in 2010 and is forecast to reach 7.68mn b/d by 2015. Angola has the greatest production growth potential, with Nigerian exports set to climb if it can resolve recent quasi-political issues.

Oil: Downstream

Table: Africa's Oil Refining Capacity, 2008-2015 (000b/d)

Country	**2008**	**2009**	**2010e**	**2011f**	**2012f**	**2013f**	**2014f**	**2015f**
Algeria	450	462	462	462	494	494	494	794
Angola	39	39	39	39	39	39	39	139
Cameroon	37	37	37	37	37	70	70	70
Republic of Congo	21	21	21	21	21	21	21	21
Equatorial Guinea	na	na	na	na	na	na	na	na
Egypt	726	726	726	726	726	726	976	976
Gabon	24	24	24	24	24	24	30	30
Libya	**378**	**378**	**378**	**378**	**578**	**578**	**578**	**725**
Nigeria	505	505	505	505	505	540	540	720
South Africa	485	485	485	485	485	485	485	485
Sudan	122	122	122	122	122	122	122	152
BMI universe	2,787	2,799	2,799	2,799	3,031	3,099	3,355	4,112
Other Africa	441	441	463	510	510	510	536	562
Regional total	3,228	3,240	3,262	3,309	3,541	3,609	3,891	4,674

f = forecast. Source: Historical data: BP Statistical Review of World Energy, June 2010; BMI

Refining capacity for the region was 3.14mn b/d in 2001, rising gradually to an estimated 3.26mn b/d in 2010. Angola, Algeria and Nigeria are all expected to increase significantly their domestic refining capacity, with the region's total capacity forecast to rise to 4.67mn b/d by 2015. In 2010 Libya will have had an estimated 11.59% of regional refining capacity, and its market share is forecast at 15.51% in 2015.

Gas Supply And Demand

Table: Africa's Gas Consumption, 2008-2015 (bcm)

Country	2008	2009	2010e	2011f	2012f	2013f	2014f	2015f
Algeria	25.4	26.7	27.5	28.9	30.5	32.1	33.7	35.1
Angola	3.5	4.0	5.0	6.0	7.0	8.1	9.3	10.6
Cameroon	0.0	0.1	0.2	0.2	0.2	0.2	0.2	0.3
Republic of Congo	0.5	0.5	1.0	1.0	1.2	1.5	2.0	2.0
Egypt	40.8	42.4	45.0	47.2	49.8	52.3	54.4	56.6
Equatorial Guinea	1.5	1.5	1.6	1.7	1.8	1.9	2.0	2.1
Gabon	0.1	0.1	0.2	0.5	1.0	1.0	1.0	1.0
Libya	**5.5**	**5.8**	**6.3**	**7.0**	**7.8**	**9.0**	**9.6**	**10.0**
Nigeria	12.3	8.9	13.0	15.0	17.0	19.5	23.0	26.0
South Africa	6.5	7.0	7.0	9.0	10.0	10.5	12.0	14.0
Sudan	na	na	na	na	na	na	na	na
BMI universe	96.1	97.1	106.8	116.5	126.3	136.1	147.2	157.6
Other Africa	16.6	16.6	16.6	16.6	16.6	16.6	17.4	18.2
Regional total	112.7	113.6	123.4	133.1	142.8	152.7	164.6	175.9

f = forecast. na= not applicable. Source: Historical data: BP Statistical Review of World Energy, June 2010; BMI

Table: Africa's Gas Production, 2008-2015 (bcm)

Country	2008	2009	2010e	2011f	2012f	2013f	2014f	2015f
Algeria	85.8	81.4	83.0	90.0	103.0	111.0	116.5	122.0
Angola	3.5	4.0	5.0	6.0	12.0	15.0	16.3	17.6
Cameroon	0.0	0.1	0.2	0.2	0.2	0.2	0.2	0.3
Republic of Congo	0.5	0.5	1.0	1.0	1.2	1.5	2.0	2.0
Egypt	59.0	62.7	64.0	66.0	70.0	73.0	75.0	77.0
Equatorial Guinea	6.7	6.2	6.4	6.4	6.5	6.6	6.7	6.8
Gabon	0.1	0.1	0.2	0.5	1.0	1.0	1.0	1.0
Libya	**15.9**	**15.3**	**16.2**	**17.0**	**18.0**	**19.5**	**20.5**	**25.0**
Nigeria	35.0	24.9	35.0	38.0	40.0	48.0	52.0	59.0
South Africa	3.3	3.5	3.5	3.5	5.0	7.0	7.0	7.0
Sudan	na	na	na	na	na	na	na	na
BMI universe	209.8	198.7	214.5	228.6	256.9	282.8	297.2	317.7
Other Africa	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Regional total	214.8	203.7	219.5	233.6	261.9	287.8	302.2	322.6

f = forecast. na = not applicable. Source: Historical data: BP Statistical Review of World Energy, June 2010; BMI

In terms of natural gas, the region in 2010 will have consumed an estimated 123.4bcm, with demand of 175.9bcm forecast for 2015. Production of an estimated 219.5bcm in 2010 should reach 322.6bcm in 2015, which implies net exports rising from an estimated 96bcm to 147bcm in 2015. In 2010, Libya will have consumed an estimated 5.11% of the region's gas, with its market share forecast at 5.68% by 2015. It will have contributed 7.38% to estimated 2010 regional gas production and by 2015 will account for 7.75% of supply.

Liquefied Natural Gas

Table: Africa's LNG Exports, 2008-2015 (bcm)

Country	2008	2009	2010e	2011f	2012f	2013f	2014f	2015f
Algeria	21.9	20.9	20.5	21.1	21.5	27.9	27.8	27.9
Angola	0.0	0.0	0.0	0.0	5.0	7.0	7.0	7.0
Cameroon	na	na	na	na	na	na	na	na
Equatorial Guinea	5.2	4.7	4.8	4.7	4.7	4.7	4.7	4.7
Egypt	14.1	12.8	13.5	13.3	14.7	15.2	15.1	14.9
Libya	**0.5**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**0.7**	**4.0**
Nigeria	20.5	16.0	20.0	21.0	21.0	26.0	27.5	30.0
Regional total	62.2	55.1	59.5	60.8	67.6	81.4	82.8	88.6

f = forecast. na = not applicable. Source: Historical data: BP Statistical Review of World Energy, June 2010; BMI

The highest growth in LNG exports by 2015 will come from Nigeria (+50% from 2010) and from Algeria (+36%) thanks to its IOC-partnered schemes. There will also be growing volumes from Libya and Egypt, although the latter is struggling against rising domestic gas demand. Angola has significant longer-term gas export potential, although the first volumes have yet to flow and the most rapid growth phase will occur in the next decade. Equatorial Guinea aims to become a regional LNG export hub, while Cameroon looks set to become an LNG exporter by around 2016.

Business Environment Ratings

The African region comprises 11 countries, including all major West and North African states. Government influence remains very high, with limited privatisation activity. Oil production growth for the period 2010-2015 ranges from a negative 7.2% for Egypt to a positive 46.3% in Cameroon, while oil demand growth ranges from 7.7% to 128.5% across the region. Gas output is forecast to rise in most countries, led by a 400% rise in Gabon (from a very low base), 252% in Angola and 100% in Congo. The spread of gas demand growth estimates ranges from 3.6% to 112.9%. The political and economic environment varies, depending partly on market maturity and specific factors such as the quasi-political oil disruptions in Nigeria and sanction-prone Sudan.

Composite Scores

Composite Business Environment scores are calculated using the average of individual upstream and downstream ratings. Algeria now shares the top slot with South Africa, and Sudan is at the bottom of the league table. The composite upstream and downstream scores are 60 points and 41 points respectively, out of a possible 100. The range is narrow, compared with other regions.

South Africa has once again been caught by Algeria, and both now lead Egypt and Libya by four points that should see them safe for a few quarters. Egypt and Libya are just two points clear of Nigeria, which is edging away from Gabon. Angola is capable of moving higher if the risk outlook improves, breaking away from Gabon with which it currently shares sixth place. Congo is hot on the tail of Cameroon, while remaining clear of regional laggards Equatorial Guinea and Sudan at the foot of the table.

Table: Regional Composite Business Environment Rating

	Upstream Rating	Downstream Rating	Composite Rating	Rank
Algeria	55	56	60	1=
South Africa	57	63	60	1=
Egypt	52	60	56	3=
Libya	**62**	**50**	**56**	**3=**
Nigeria	57	51	54	5
Gabon	61	41	51	6=
Angola	56	46	51	6=
Cameroon	52	41	47	8
Rep of Congo	51	40	45	9
Equatorial Guinea	44	41	42	10
Sudan	38	44	41	11

Source: BMI. Scores are out of 100 for all categories, with 100 the highest.

Upstream Scores

Libya and Sudan are now the best and worst performers in this segment, showing that the overall pecking order is quite different from that for combined scores. Gabon has slipped below Libya to take second place, and is a comfortable four points clear of South Africa and Nigeria. Angola has longer-term potential to climb higher, with South Africa a realistic near-term target. Algeria is closing in on Angola, holding sixth place with 55 points.

Republic of Congo and Egypt are bickering over eighth and ninth places with 51 and 52 points respectively. Cameroon has edged ahead of both and could next make a play for Angola or Algeria. Equatorial Guinea may be six point clear of Sudan at the foot of the table, but languishes seven points behind Congo, so is unlikely to move higher over the near term.

Table: Regional Upstream Business Environment Ratings

	Rewards			Risks				
	Industry Rewards	Country Rewards	Rewards	Industry Risks	Country Risks	Risks	Upstream Rating	Rank
Libya	**64**	**70**	**65**	**60**	**43**	**54**	**62**	**1**
Gabon	58	65	59	80	37	65	61	2
Nigeria	65	50	61	55	33	47	57	3=
South Africa	38	70	46	95	62	83	57	3=
Angola	59	60	59	60	28	49	56	5
Algeria	49	85	58	55	39	49	55	6
Cameroon	56	20	47	80	35	64	52	7=
Egypt	40	70	48	75	42	63	52	7=
Rep of Congo	45	55	48	70	37	58	51	9
Equatorial Guinea	28	55	34	75	46	65	44	10
Sudan	35	30	34	60	21	47	38	11

Scores are out of 100 for all categories, with 100 the highest. The Upstream BE Rating is the principal rating. It comprises two sub-ratings ‘Rewards’ and ‘Risks’, which have a 70% and 30% weighting respectively. In turn, the ‘Rewards’ Rating comprises Industry Rewards and Country Rewards, which have a 75% and 25% weighting respectively. They are based upon the oil and gas resource base/growth outlook and sector maturity (Industry) and the broader industry competitive environment (Country). The ‘Risks’ rating comprises Industry Risks and Country Risks which have a 65% and 35% weighting respectively and are based on a subjective evaluation of licensing terms and liberalisation (Industry) and the industry’s broader Country Risks exposure (Country), which is based on BMI’s proprietary Country Risk Ratings. The ratings structure is aligned across the 14 Industries for which BMI provides Business Environment Ratings methodology, and is designed to enable clients to consider each rating individually or as a composite, with the choice depending on their exposure to the industry in each particular state. For a list of the data/indicators used, please consult the appendix. Source: BMI

Libya Upstream Rating – Overview

Libya continues to occupy first place in our updated upstream Business Environment ratings. The country's score benefits from its proven oil reserves and a region-topping oil reserves-to-production ratio (RPR). The competitive landscape features numerous non-state companies, and licensing terms are generally good. However, country risk factors undermine some of the hydrocarbons-specific strength.

Libya Upstream Rating – Rewards

Industry Rewards: On the basis of upstream data alone, Libya ranks second behind Nigeria in the Africa region. The country ranks first in terms of its oil reserves position, with gas reserves placed fourth. Oil and gas RPRs are first and fifth respectively.

Country Rewards: Influencing Libya's first place in the Rewards section is the joint second-placed country rewards rating, alongside South Africa and Egypt. Libya ranks second by the number of non-state operators in the upstream sector and seventh in terms of state ownership of assets.

Libya Upstream Rating – Risks

Industry Risks: Libya is ranked seventh in the Risks section of our ratings. Its joint seventh position alongside Angola and Sudan for industry risks is attributable to a mid-table licensing environment.

Country Risks: Its broader country risks environment is reasonably attractive, ranking Libya fourth, just ahead of Egypt. The best, but far from optimum, score is for physical infrastructure. Would-be investors are faced with a relatively low score for long-term policy continuity, while corruption and rule of law are the weakest elements.

Downstream Scores

South Africa and Congo are in the top and bottom places respectively in the downstream ratings, with the former driven by the size of the fuels market, privatisation moves and the competitive landscape, plus a reasonable country risk rating. Egypt still holds second place, but is at some risk from Algeria. Both are currently well clear of Nigeria, which is itself being hunted down by Libya. Sudan has remained ahead of Gabon, with Equatorial Guinea and Cameroon squabbling near the foot of the ladder.

Table: Regional Downstream Business Environment Ratings

	Rewards			Risks				
	Industry Rewards	**Country Rewards**	**Rewards**	**Industry Risks**	**Country Risks**	**Risks**	**Downstream Rating**	**Rank**
South Africa	46	86	56	100	47	79	63	1
Egypt	68	58	65	45	53	48	60	2
Algeria	63	52	61	40	55	46	56	3
Nigeria	57	72	61	20	45	30	51	4
Libya	**59**	**44**	**55**	**30**	**54**	**39**	**50**	**5**
Angola	56	52	55	15	46	27	46	6
Sudan	38	52	41	55	39	49	44	7
Gabon	32	40	34	70	40	58	41	8=
Cameroon	43	28	40	45	45	45	41	8=
Equatorial Guinea	38	26	35	60	49	55	41	8=
Rep of Congo	40	36	39	65	7	42	40	11

Scores are out of 100 for all categories, with 100 the highest. The Downstream BE Rating comprises two sub-ratings 'Rewards' and 'Risks', which have a 70% and 30% weighting respectively. In turn, the 'Rewards' Rating comprises Industry Rewards and Country Rewards, which have a 75% and 25% weighting respectively. They are based upon the downstream refining capacity/product growth outlook/import dependence (Industry) and the broader socio-demographic and economic context (Country). The 'Risks' rating comprises Industry Risks and Country Risks which have a 60% and 40% weighting respectively and are based on a subjective evaluation of regulation and liberalisation (Industry) and the industry's broader Country Risks exposure (Country), which is based on BMI's proprietary Country Risk Ratings. The ratings structure is aligned across the 14 Industries for which BMI provides Business Environment Ratings methodology, and is designed to enable clients to consider each rating individually or as a composite, with the choice depending on their exposure to the industry in each particular state. For a list of the data/indicators used, please consult the appendix. Source: BMI

Libya Downstream Rating – Overview

Libya is in the middle of the league table in **BMI**'s downstream Business Environment ratings, with a few high scores but near-term progress up the rankings unlikely. It is ranked fifth thanks to poor country risk factors, a largely state-controlled industry and reasonable oil and gas demand growth prospects.

Libya Downstream Rating – Rewards

Industry Rewards: On the basis of downstream data alone, Libya ranks third among the region's 11 countries. This score reflects the region's sixth-highest refining capacity, fourth-highest gas consumption, fifth-placed oil demand, eighth-highest oil and ninth-highest gas demand growth.

Country Rewards: Libya ranks equal fifth with Angola in terms of the Rewards section, although its country rewards rating takes seventh place in the region, above Gabon. Population and nominal GDP rank the country seventh and sixth respectively, while growth in GDP per capita is the lowest in the region.

Libya Downstream Rating – Risks

Industry Risks: In the Risks section of our ratings, Libya is ranked ninth, behind RoC. Its ninth position for the industry risks section reflects the current regulatory regime and its limited progress in terms of privatisation of government-held assets.

Country Risks: Its broader country risks environment is relatively attractive, ranked second behind Algeria. The best, and optimum, score is for short-term economic external risk, followed by physical infrastructure and short-term economic growth risk. Operational risks for private companies are increased by the state's rule of law and legal framework.

Risk Summary

Political

The Libyan Authority for Ports and Maritime Transport has signed a contract with Irish company Transas Marine in Tripoli to purchase a coastal monitoring system for around US$28mn. The radar system will help Libya monitor its vast coastline of almost 2,000km for illegal migrants as well as shipping in its waters and pollution. Transas Marine is expected to install the system, which comprises 15 monitoring stations, in 16 months. This will come as a welcome announcement for southern European states that have often accused Tripoli of not doing enough to fight illegal immigration.

Economic

The International Finance Corporation, the private sector arm of the World Bank, together with the Islamic Development Bank will establish a new fund targeted at reducing the infrastructure deficit in the Middle East North Africa region. The fund hopes to level the playing field across the region, by attracting investors from some of the best performing countries to finance infrastructure improvements in some of the worst performing. We expect Libya to be a key beneficiary of this new fund, which chimes well with our positive outlook on the country's infrastructure sector.

Business Environment

Four IOCs, including Chevron and Occidental Petroleum, have decided not to renew their five-year exploration leases in Libya, effectively ending their involvement in the country. The decision to leave appears to have been largely due to a lack of discoveries, although changes to the production sharing contract (PSC) in 2007 are likely to have played a role as well. Given ongoing concerns surrounding the possibility that Tripoli would seek to nationalise the industry, we expect major IOCs to exercise greater caution in their dealings with the country.

Industry Forecast Scenario

Oil And Gas Reserves

About 80% of Libya’s proven oil reserves are located in the Sirte Basin, which is responsible for 90% of the country’s oil output. The remainder of the country is considered unexplored and has the potential to hold substantially higher reserves. Much of the acreage has yet to be licensed so, longer term, Libya offers exceptional scope for reserves and production growth. The June 2010 BP Statistical Review of World Energy puts end-2009 proven oil reserves at 44.3bn bbl. We see scope for further gains to an estimated 45.0bn bbl by 2012. Gas reserves of 1,540bcm are forecast to reach 1,600bcm during the forecast period.

Libya's top energy official has claimed a 1.26bn bbl rise in proven oil reserves and a 50bcm increase in proven gas reserves, on the back of successes at new exploratory wells drilled in the country in 2009 and H110. In an interview with Dow Jones republished by news agencies on July 30 2010, the chairman of NOC, Shokri Ghanem, said that Libya's oil and gas reserves increased respectively by 653mn bbl and 22bcm in 2009, and 612mn bbl and 28bcm in H110. Ghanem claimed that NOC and international companies operating in Libya recorded a 51% success rate at the 65 new wells drilled in 2009, but did not specify the drilling success rate for H110. Ghanem also said that Libya has identified 20 new highly prospective areas to be drilled in 2010.

The government is to spend LYD12.1bn (US$9.86bn) on a programme to upgrade 24 of its oil fields, including field rehabilitation and drilling projects, as it seeks to boost reserves and production. According to a report in September 2009 by the state news agency, the programme will be financed by local banks, with NOC acting with state-owned and foreign companies to undertake the planned investment programme. Importantly, the news agency made clear that this would occur ‘without the entrance of new parties’, which presents significant opportunities for established players.

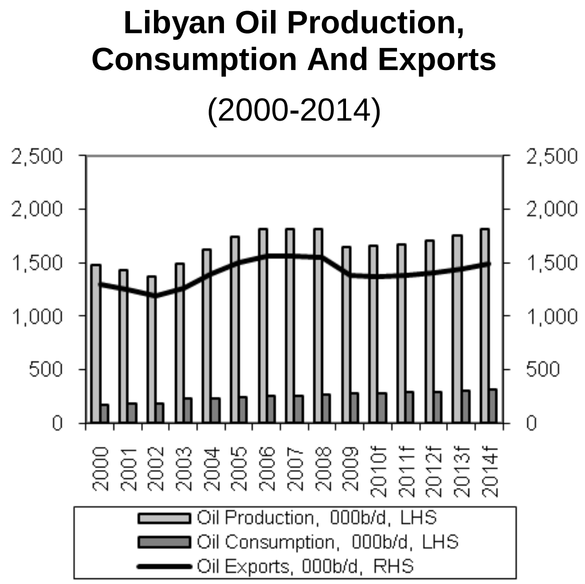
BP has now delayed plans to begin deepwater drilling in Libya. A spokesperson for the company had, in August 2010, told reporters that it expected drilling to begin by the end of the year.

In May 2007, BP signed an agreement with NOC and government vehicle Libya Investment Corporation (LIC), in which it committed US$900mn to secure an exploration and production-sharing agreement (EPSA) that gave it access to the western Ghadames Basin and the offshore Sirte Basin. The latter is believed to be a geological extension of the onshore Sirte Basin, which, according to BP, had produced 20bn barrels of oil equivalent (boe) as of 2007.

BP completed seismic surveys of its offshore and onshore acreage in 2009 and on July 1 2010 announced that it expected to begin drilling operation in the Gulf of Sirte in 'the coming weeks'. That announcement, however, quickly came under fire from Italy's foreign minister Franco Frattini, who told British newspaper the Financial Times that it was inappropriate for BP to drill in the Mediterranean before the Macondo oil spill investigations were completed. He proposed putting the issue before the Union of the Mediterranean (UoM), a group of the EU's 27 member nations plus non-EU states that border the sea including Libya, which is scheduled to meet in November 2010. Pushing its plans back to the end of the year may allow BP to strike a mutually agreeable solution with Italy and other concerned states.

Oil Supply And Demand

During September 2010, Libyan crude-only production averaged an estimated 1.55mn b/d, which is well below most estimates of productive capacity, which is put at 1.70mn b/d. Libyan production should have fallen below 1.5mn b/d under the new post-January OPEC quota. The **BMI** liquids output assumption is 1.88mn b/d by 2015. Libyan oil consumption is expected to increase to 333,000b/d by the end of the forecast period, implying net exports of 1.55mn b/d.



f = forecast; Source: Historical data - BP Statistical Review of World Energy June 2010, EIA; Forecasts - BMI

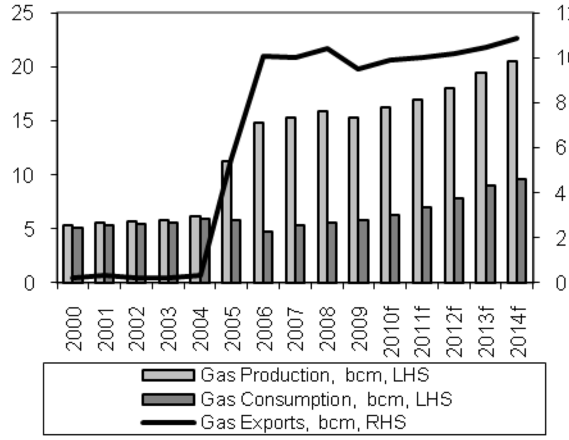
Libya has delayed its oil production capacity target of 3mn b/d from 2012 to 2015/2016, according to Shokri Ghanem, CEO of NOC. Speaking to Reuters at a conference in Cairo on December 5 2009, Ghanem said that the delay was due to ‘changes in the market and budget constraints’. Other news sources, such as AFP, quoted the CEO as saying that under the new timeline, 3mn b/d of capacity would be reached by 2016/2017 as long as more investment was secured. In June 2009, NOC slashed its production forecast to 2013 by nearly 25% to 2.3mn b/d.

Medco has forecast that the Area 47 block is expected to pump 50,000-100,000b/d of crude oil and is due to start production in 2014.

Gas Supply And Demand

Libyan Gas Production, Consumption And Exports

(2000-2014)



f = forecast; Source: Historical data - BP Statistical Review of World Energy June 2010, EIA; Forecasts - BMI

In terms of gas, the country has vast untapped potential and a desire to become a much bigger gas exporter. The WLGP venture with **Eni** meant an extra 8bcm of gas a year exported to Italy and France. A lack of firm projects over the medium term suggests only slow progress in boosting pipeline and LNG sales, and we now expect Libyan gas production to rise from an estimated 16.2bcm to 25.0bcm by 2015. Given that domestic gas consumption is also on the rise, and set to reach 10.0bcm by 2015, export potential is likely to be around 15.0bcm.

LNG

In 1971, Libya became the second country in the world (after Algeria in 1964) to export LNG. Volumes have been held back by technical limitations. Libya's LNG plant, at Marsa El Brega, was built in the late-1960s by **ExxonMobil** and has a nominal capacity of about 3.5bcm per year. However, US sanctions prevented Libya from obtaining the equipment it needed, thereby limiting the plant's output to about 15% of nameplate capacity, all of which is exported to Spain. Since sanctions were lifted, companies have been looking into Libya's LNG potential. In May 2005, **Royal Dutch Shell** agreed to a final deal with NOC to develop Libyan oil and gas resources, including LNG export facilities. Reportedly, Shell is aiming to upgrade and expand Marsa El Brega and possibly build a new LNG export facility as well, at a cost of US$105-450mn. In addition to Shell, other companies such as **Repsol YPF** and Eni are apparently interested in developing Libya's LNG export potential.

Refining And Oil Products Trade

Domestic oil refining capacity of around 378,000b/d is set to rise still further in order to permit higher export volumes. Extra capacity is expected to be online by the end of 2010, taking the country's capability to a minimum of 450,000b/d of refined products. Oil demand in Libya stands at around 274,000b/d, but could climb towards 320,000b/d by 2014. This would leave Libya with substantial and rising volumes of refined products exports.

UK banking group **HSBC Holdings**, which acts as a financial advisor to Libya's **Zwara Refining Company** (ZORCO), intends to attract an IOC partner for the planned Zwara refinery, the Middle East Economic Digest (MEED) reported on July 16 2010.

An HSBC project finance executive was quoted by MEED as saying that the company had drawn up a shortlist of potential IOC strategic partners, and that one would be secured by end-2010. Zwara, located near Libya's border with Tunisia, is to be the site of a 200,000b/d refinery. The planned facility's holding company, ZORCO, is held by Tamoil, an arm of NOC.

Revenues/Import Costs

For crude, the estimated 1.38mn b/d of 2010 exports could reach 1.55mn b/d by 2015 – bringing in US$50.82bn of revenues at our forecast OPEC basket oil price of US$90.00/bbl. The value of gas exports by 2015 is an estimated US$5.39bn. Combined crude oil and gas export revenues in 2015 are put at US$56.20bn, with the potential for an additional US$14.00bn of products income.

Table: Libya Oil And Gas – Historical Data And Forecasts

	2008	2009	2010f	2011f	2012f	2013f	2014f	2015f
Proven Reserves, bn barrels	44.3	44.3	44.3	44.0	45.0	44.4	43.7	43.0
Oil Production, 000b/d	1,820	1,652	1,655	1,670	1,705	1,750	1,815	1,880
Oil Consumption, 000b/d	268	274	279	287	296	308	320	333
Oil Refinery Capacity, 000b/d (EIA/BMI)	378	378	378	378	578	578	578	725
Oil Exports, 000b/d (BMI)	1,552	1,378	1,376	1,383	1,409	1,442	1,495	1,547
Oil Price, US$/bbl, OPEC basket	94.1	60.9	77.0	80.0	85.0	90.0	90.0	90.0
Value of Oil Exports, US$mn (BMI base case)	53,283	30,620	38,668	40,370	43,711	47,372	49,102	50,817
Value of Petroleum Exports, US$mn (BMI base case)	56,954	32,897	41,669	43,519	47,124	51,091	52,963	56,203
Value of Oil Exports at constant US$50/bbl – US$mn	28,319	25,155	25,110	25,231	25,712	26,318	27,279	28,231
Value of Oil Exports at constant US$100/bbl – US$mn	56,638	50,310	50,220	50,462	51,425	52,635	54,558	56,463
Value of Petroleum Exports at constant US$50/bbl – US$mn	30,196	26,937	27,059	27,200	27,720	28,384	29,424	31,224
Value of Petroleum Exports at constant US$100/bbl – US$mn	60,393	53,875	54,118	54,399	55,440	56,768	58,848	62,448
Refined Petroleum Products Exports, 000b/d (BMI)	106	101	95	87	276	264	252	385
Gas: Proven reserves, tcm	1.54	1.54	1.55	1.55	1.60	1.60	1.60	1.60
Gas Production, bcm	15.9	15.3	16.2	17.0	18.0	19.5	20.5	25.0
Gas Consumption, bcm	5.5	5.8	6.3	7.0	7.8	9.0	9.6	10.0
Gas Exports, bcm (BMI)	10.4	9.5	9.9	10.0	10.2	10.5	10.9	15.0
Value of Gas Exports, US$mn (BMI base case)	3,671	2,277	3,001	3,150	3,413	3,720	3,861	5,387
Value of Gas Exports at constant US$50/bbl – US$mn	1,877	1,782	1,949	1,969	2,008	2,067	2,145	2,993
Value of Gas Exports at constant US$100/bbl – US$mn	3,755	3,564	3,898	3,937	4,015	4,133	4,290	5,985
LNG Exports, bcm	0.5	0.7	0.7	0.7	0.7	0.7	0.7	4.0
LNG Price, US$/mn btu	12.55	9.06	11.46	11.91	12.65	13.40	13.40	13.40
LNG Revenues, US$mn (BMI)	186	183	225	233	248	263	263	1,501

f = forecast. Source: Historical data, BP Statistical Review of World Energy June 2010, Forecasts, BMI.

Other Energy

Libya has power generating capacity of about 6GW. It generates around 29 terawatt hours (TWh) per annum. Most of Libya's existing power stations are being converted from oil to gas, and new power plants are being built to run on gas to maximise the volume of oil available for export purposes. Libya is also looking at potential wind and solar projects, particularly in remote regions where it is impractical to extend the power grid. Libya's state-owned **General Electricity Company** (GECOL) is building several new power plants. One factor leading to rapid power demand growth is the fact that electricity is heavily subsidised, at perhaps one-third of the market cost.

Table: Libya Other Energy – Historical Data And Forecasts

	2008	2009	2010f	2011f	2012f	2013f	2014f	2015f
Coal Reserves, mn tonnes	na	na	na	na	na	na	na	na
Coal Production, mn tonnes	na	na	na	na	na	na	na	na
Coal Consumption, mn toe	na	na	na	na	na	na	na	na
Electricity Generation, TWh	25.7	27.5	29.4	31.5	33.7	36.0	38.5	41.2
Thermal Power Generation, TWh	25.7	27.5	29.4	31.5	33.7	36.0	38.5	41.2
Hydro-electric Power Generation, TWh	na	na	na	na	na	na	na	na
Consumption of Hydro-electric Power, TWh	na	na	na	na	na	na	na	na
Consumption of Nuclear Energy, TWh	na	na	na	na	na	na	na	na
Primary Energy Consumption, mn toe	na	na	na	na	na	na	na	na

f = forecast; na = not applicable. Source: Historical data, BP Statistical Review of World Energy June 2010, Forecast, BMI.

Key Risks To BMI's Forecast Scenario

There are clear risks to these projections. First, Libya is dependent on foreign investment and OPEC policy to deliver its crude export growth. The increase in refining capacity is also subject to investment slippage, thus reducing products export potential. There could be delays in reaching the desired level of gas production and exports. Finally, the level of oil prices has a dramatic impact on Libyan revenues. Assuming our volume projections prove correct, oil prices have the potential to make a big difference to revenue generation. At a flat US$50/bbl oil price, Libya would generate revenues of US$31.22bn in 2015 from crude oil and gas exports, which, with refined products income, would mean a total of around US$39.00bn. Using a US$100/bbl oil price boosts the total for crude oil and gas to US$62.45bn, with products exports inflating this total to a minimum of US$78.00bn.

Long-Term Oil And Gas Outlook

Details of **BMI**'s 10-year forecasts can be found in the appendix to this report. Between 2010 and 2020, we are forecasting an increase in Libyan oil and gas liquids production of 36.0%, with volumes rising steadily to 2.25mn b/d by the end of the 10-year forecast period. Oil consumption between 2010 and 2020 is set to increase by 45.2%, with growth slowing to an assumed 4.0% per annum towards the end of the period and the country using 405,000b/d by 2020. Gas production is expected to rise to 27bcm by the end of the period. With demand rising by 92.8% between 2010 and 2020, there should be export potential increasing to around 15bcm, via pipeline and in the form of LNG.

Oil And Gas Infrastructure

Oil Refineries

As of 2010, Libya has five refineries, of which only two have substantial capacity. All refineries are owned by NOC, although they are held through a variety of subsidiaries. According to the Oil & Gas Journal World Refining Survey, January 2010, Libya's refining capacity reached 378,000b/d during 2009. **BMI** forecasts this to increase to 650,000b/d by 2014. NOC's overseas branch **Tamoil** also owns three refineries in Italy, Switzerland and Germany, which are supplied with crude oil from Libya.

Table: Refineries In Libya

Refinery	Capacity (b/d)	Owner (Contractor)	Completed	Details
Ras Lanuf	220,000	NOC	1984	Export refinery
Zawiya	120,000	NOC	1974	
Tobruk	20,000	NOC	1985	
Sarir	10,000	NOC	1986	
Marsah El Brega	8,000	NOC	na	
Total Capacity	**378,000**			
Planned Additional Capacity				
Zwara	200,000	NOC		

na = not available. Source: Company data

Ras Lanuf (Active)

Ras Lanuf, completed in 1984, is Libya's biggest refinery by nameplate capacity. The export refinery is located in the town of Ras Lanuf in the Gulf of Sidra and is linked to a petrochemicals plant and an oil terminal. Crude feedstock is provided by oil piped from fields in the Sirte Basin, immediately to the south of the refinery. Ras Lanuf is operated by NOC subsidiary **Ras Lanuf Oil and Gas Processing Company**, which also owns the petrochemicals facility.

In July 2008, NOC signed a US$2.5bn deal with companies from the UAE to upgrade the Ras Lanuf refinery. NOC signed a 50:50 JV for the project with the **Star Consortium**, which includes **TransAsia Gas International** and **Star Petro Energy**. The deal is based on an MoU that was signed between the two companies on January 7 2008. According to officials, the upgrade of the refinery will take three years to complete.

Zawiya Refinery (Active)

The head of NOC, Shokri Ghanem, has announced that the company is seeking a JV partner for the expansion of the Zawiya refinery. Ghanem told Zawya Dow Jones on April 16 2010 that Libya was willing to sell a 50% stake in the refinery and that increased capacity was required to sate domestic gasoline demand.

In 2007, two Indian companies won a bid to expand capacity from 100,000b/d to a Libyan government target of 122,800b/d. The refinery's current capacity is 120,000b/d.

Zwara (Planned)

UK banking group **HSBC Holdings**, which acts as a financial advisor to Libya's ZORCO, intends to attract an IOC partner for the planned Zwara refinery, MEED reported on July 16 2010.

An HSBC project finance executive was quoted by MEED as saying that the company had drawn up a shortlist of potential IOC strategic partners, and that one would be secured by end-2010. Zwara, located near Libya's border with Tunisia, is to be the site of a 200,000b/d refinery. The planned facility's holding company, ZORCO, is held by Tamoil, an arm of NOC.

ZORCO designated HSBC as its financial advisor in December 2008. Two months earlier, it selected the Italian subsidiary of engineers **Foster Wheeler** as Zwara's project management consultant, responsible for the preparation of EPC tenders, and the selection of licensors and front-end engineering and design (FEED) contractors. Foster Wheeler and ZORCO envisioned a total investment of US$4bn and the start of refinery operations in 2014.

Oil Terminals/Ports

In 2007 Libya had five oil terminals, according to the Petroleum Economist. The terminals are located at the sites of the country’s three largest refineries at Az Zawiyah, Ras Lanuf and Tobruk. In addition there are oil export terminals in the ports of Sidra and Zuetina, both in the Gulf of Sidra.

Oil Pipelines

Libya’s oil pipeline network is based on transporting crude oil from inland fields to the coast for export, rather than for exporting oil by land. All of Libya’s seven major pipeline systems therefore terminate at ports. The densest concentration of oil pipelines is located in the Sidra Basin, where four separate pipeline networks link onshore fields to refineries and export terminals.

LNG Terminals

In 1971, Libya became the second country in the world (after Algeria in 1964) to export LNG. Volumes have been held back by technical limitations. Libya’s LNG plant, at Marsa El Brega, was built in the late-1960s by Exxon and has a nominal capacity of about 3.5bcm a year. However, US sanctions prevented

Libya from obtaining equipment it needed, thereby limiting the plant's output to about 15% of nameplate capacity, all of which is exported to Spain. The terminal is operated by **Sirte Oil**, a JV of Shell and NOC. A Libyan official said in June 2010 that Sirte will be looking for bidders in Q410 to upgrade the terminal. Libya has been hoping to upgrade the terminal ever since the signing of the Shell JV deal. Modernisation efforts at the LNG plant will cost Shell US$105-450mn.

Table: LNG Terminals In Libya

Terminal	Trains	Capacity, mn tpa	Capacity, bcm	Completed	Ownership
Marsa El Brega	3	2.5	3.5	1971	Sirte Oil Company
Planned Expansion					
Marsa El Brega*	1	3.2	4.4	na	Sirte Oil Company

na = not available. Source: Company data, BMI

Gas Pipelines

Most of Libya's gas exports are by pipeline. Exports to Europe have slowed following the period of rapid expansion set off by the completion of the Greenstream pipeline in 2004. Previously, the only customer for Libyan gas was Spain's Enagás, via the Marsa El Brega LNG terminal. However, Greenstream has now expanded these exports to Italy and beyond.

Greenstream Pipeline

The 10bcm Greenstream gas pipeline, part of the Western Libyan Gas Project (WLGP), came onstream in October 2004. The US$6.6bn, 32-inch diameter pipeline transports dry sweet natural gas from the Mellitah Gas Compressor Station (MGCS) on Libya's northern coast near the border with Tunisia to Gela on the coast of Sicily, where it links to the Trans-Mediterranean pipeline linking Algeria and mainland Italy. The subsea section of the pipeline runs for 516km and reaches a maximum depth of 1,150m. Greenstream is a 50:50 JV between Eni and NOC.

Other Pipeline Projects

Libya and Tunisia announced in January 2007 that they were planning a joint project to build oil and gas pipelines between the two countries and to construct a new refinery in Tunisia's al-Skira region. The project will require the assistance of international investors, according to Libya's trade and investment minister.

Macroeconomic Outlook

Multilateral Development Plans To Sustain GDP Growth

BMI View: *Libya's prospects for real GDP growth to recover to pre-crisis levels are positive – we project the economy to expand 3.2% in 2010 before continuing on an upward trend in the long run to average 4.6% over 2011-2015. The economy will remain dependent on hydrocarbon exports for the foreseeable future but we believe that the government's plans to expand its investments in infrastructure projects and an eventual rise in private consumption will improve its diversification picture.*

Our projection for real GDP growth in 2010 is 3.2%, rising only slightly to 3.3% in 2011. In the medium term, we see real GDP recovering to figures more akin to pre-crisis growth levels, with the economy forecast to expand 5.7% in 2015. The oil price rebound will be a major driver behind growth heading into 2011, and hydrocarbon exports will continue to form the biggest single sector of the economy in the long run. We see export growth rising from 1.5% in 2010 to 1.7% in 2011.

During 2009 private consumption growth was a respectable 8%, and we believe this rate can be sustained in 2010, with household spending maintaining its momentum. We also expect this to account for a greater portion of real GDP growth, at 3.0pp compared with 2.7pp in 2009. Given that private spending was able to achieve 8% growth during a more challenging financial climate, we see strong growth prospects for 2010 (when global conditions are much better) as a distinct possibility. The government's aforementioned plans to proceed with much-needed infrastructure investments will eventually filter through to higher household spending by helping to spur job creation.

Inflation conditions also support a strong consumption outlook, with the latest consumer price inflation data released by the central bank showing CPI coming in at only 3.2% y-o-y in July 2010, a marginal drop from 3.4% in June 2010. Inflation for food and beverages slowed modestly from 4.6% y-o-y in June to 4.0% y-o-y in July. Monthly data point to housing and transportation prices experiencing mild deflation on the back of low demand. We project that consumer price inflation will reach 2.5% in 2010 before rising slightly to 3.0% by 2011, an impressive reduction given that the consumer price index was scaling the heights of 13.4% in February 2008.

Banking On it

The currently underdeveloped banking sector is also undergoing extensive reform, with plenty of opportunities for new banks that offer modern services and access via mobile phone or the internet. Italian lender **UniCredit** was granted a banking licence by the Libyan authorities in Q310, following years of slow progress on foreign banks entering Libya after the government decided to reform the banking sector and give the central bank more independence back in 2005.

Private banks in Libya can operate under more streamlined conditions without undergoing lengthy bureaucratic processes by the government. With foreign banks likely to increase their presence in the country with the upside of bringing experience and expertise, we expect consumers to be able to spend more – if through the expansion of credit card and bank credit extension. This could have a dramatic impact on private consumption and push up liquidity, demand and therefore prices.

That said, there are downsides that still need to be addressed by the banking sector – few ATMs and limited facilities by retailers to accept credit/debit cards obliges the ordinary consumer to pay for products upfront in cash. As a result, they may avoid large or expensive purchases all together. In our view, making cash more freely available through modern banking services should go some way to driving growth in private sector consumption.

Risk To Outlook

Our positive outlook for real GDP growth in Libya depends also on whether the Libyan government continues its liberalisation path and expands the private banking sector to this effect. The fact that cash still dominates day-to-day transactions underlines the immense potential of banking expansion in products including credit cards, internet banking and other affiliated services. We also note that financial regulation and transparency needs to accompany the banking sector reform in order to support growth, particularly since the state needs to attract FDI to sustain its national development plans.

On the downside, political interference still has the potential to undermine or deter further business deals. We believe that FDI, as well as increased government expenditure is crucial to the economic development of the country. That said, the government's ambitious spending plans, the historic nature of the nation's modernisation, economic reform and the fact that our OPEC oil basket price forecast is bullish to the tune of US$83/bbl for 2010 and US$85/bbl for 2011, we believe that political meddling will be unlikely to tip the scales significantly in the near term.

Table: Libya – Economic Activity

	2006	2007	2008	2009e	2010f	2011f	2012f	2013f	2014f	2015f
Nominal GDP, LYDbn [1]	78.9	92.8	116.5	86.1	91.6	97.5	104.2	113.5	122.8	133.6
Nominal GDP, US$bn [1]	61.6	75.9	89.7	71.5	73.2	78.0	83.4	90.8	98.2	106.9
Real GDP growth, % change y-o-y [1]	5.7	4.9	2.7	-0.9	3.2	3.3	3.9	5.7	5.1	5.7
GDP per capita, US$ [1]	10178	12300	14254	11137	11190	11684	12272	13122	13963	14952
Population, mn [2]	6.0	6.2	6.3	6.4	6.5	6.7	6.8	6.9	7.0	7.2

e/f = estimate/forecast. Sources: [1] IMF/BMI. [2] World Bank/BMI calculation/BMI.

Competitive Landscape

Executive Summary

- State-controlled oil and gas sector. The main government vehicle is NOC, which accounts for about half of the country's oil and gas production and 100% of the country's refining capacity.

- IOC involvement is extensive, but in partnership with the state using the PSA approach. US companies, which withdrew at the time of sanctions against Libya, have now returned to the upstream segment. Major established non-US partners are Eni, OMV, Repsol YPF and Total.

- Eni is Libya's biggest foreign producer with 108,000b/d of oil and 8.1bcm of gas in 2009. It is the operator and joint owner of the Greenstream pipeline, which came onstream in 2004, as well as related gas processing infrastructure.

- In early-2010 Libyan Investment Authority (LIA) bought Canadian oil company **Verenex** in a friendly takeover for CAD357mn. Medco has become the operator of the Area 47 block, replacing Verenex. The project is expected to produce 50,000-100,000b/d of crude oil and is due to start production in 2014.

- Repsol YPF produces around 45,000b/d, mostly from block NC 186 in the Murzuq Basin.

- Total pumped 60,000b/d of oil in 2009 through its operated Mabruk field and the start-up of the Al Jurf field.

- Shell and NOC have established a long-term strategic partnership targeting major integrated upstream projects to enhance LNG export capacity.

- BP has delayed its deepwater drilling in the Gulf of Sirte but plans to start in early 2011.

- Oxy was awarded interests in nine exploration blocks in May 2005. It also became a partner in four offshore blocks (35, 36, 52 and 53), with additional acreage grants in subsequent licensing rounds. The US group has now announced its intention to relinquish its exploration interests.

- Russia's **Tatneft** holds four licences in Libya following its entry into the country in the second licensing round in 2005. Several small discoveries were made in 2009-2010.

- **ConocoPhillips** and co-venturers **Marathon** and **Hess** in December 2005 returned to their former E&P interests in the Waha concession. ConocoPhillips' net 2009 petroleum production amounted to 47,000b/d.

- Woodside won the operatorship of offshore blocks 35, 36, 52 and 53 in the Sirte Basin in May 2005. It intends to quit Libyan exploration.

- **Chevron** was made operator of Block 177 with 100% of the equity in 2005. The US group has now announced its intention to relinquish its exploration interests.

- Britain's **BG Group** is in the process of dissolving its remaining token presence in Libya after failing to discover oil at the blocks it won in the country's second licensing round. It had attempted to increase its acreage in the 2007 round but was outbid.

Table: Key Players – Libyan Oil And Gas Sector

Company	2008 Sales (US$mn)	% share of total sales	No. of employees	Year established	2007 Total assets (US$mn)	Ownership
NOC	na	na	na	1970	na	100% state
Eni Libya	na	na	na	1959	5,827	100% Eni
Total Libya	na	na	na	1959	na	100% Total
OMV Libya	na	na	na	1985	na	100% OMV
Conoco Libya	na	na	na	2005	na	100% ConocoPhillips
Repsol Libya	na	na	na	na	na	100% Repsol YPF

e = estimate; na = not available/applicable. Source: BMI

Overview/State Role

Libya's oil industry is run by NOC, along with smaller subsidiary companies that combined account for around half of the country's oil output. Several IOCs are partners in E&P agreements with NOC, with the leading foreign producer being Italy's Eni. Domestic refining capacity is controlled by the government, with the state downstream arm, Tamoil, developing an international presence.

Licensing And Regulation

Libya's governmental structure tends to change frequently, with the body that was formerly nominally in charge of oil and gas, the Supreme Council of Oil and Gas Affairs (SCOGA), being replaced in October 2009 by the Supreme Council of Energy Affairs (SCEA). In reality, most of the functions of the SCOGA were carried out by NOC, with the government body meeting only rarely. Theoretically, the new SCEA will be responsible for production targets, contract negotiations and regulation. The name change also demonstrates a wider remit, with the body becoming responsible for the development of alternative energy. It is less clear how much influence the new SCEA will wield in reality. In December 2009 the head of NOC, Shokri Ghanem, said that NOC and not SCEA was in charge of decisions about oil.

Tax Law

Libya operates under a PSC regime and currently uses the fourth version of the contract, EPSA IV. Although IOCs have to submit royalty and tax returns, for legal purposes all taxes are deemed to have been paid by NOC. Tax computation is notional.

Income tax in the oil and gas sector is made up of four elements. CIT, the main element, consists of a progressive levy on all income earned in Libya. On income of between LYD0.2mn (US$0.54mn) and LYD2.0mn (US$1.55mn) income tax is levied at between 15% and 35%, while income of over this amount is taxed at a flat rate of 40%. The second element, known as the Jihad Tax, was initiated in the 1970s for the purposes of national defence and international Islamic activism and currently stands at 4% for corporations. The third element, surface rent, varies from concession to concession but according to Ernst & Young never exceeds 21% of taxable income. The fourth element is a surtax to ensure that the total tax paid is no less than 65%.

Government Policy

In January 2009 Libyan leader Muammar Qadhafi called for the nationalisation of the country's oil industry. Although full-scale nationalisation is unlikely, in our view, we expect to see further revisions of contracts with foreign oil companies as Libya attempts to boost the state's take from oil projects. NOC has indicated that it will seek to reduce foreign companies' shares in fields to around 10-15%. According to a report published in early February 2009 by NOC, the Libyan government earned an additional US$5.4bn in oil revenues during 2008 as a result of contract alterations with foreign companies operating in the country, including **Petro-Canada**, Eni, Repsol, OMV, Oxy and **Wintershall**. Should further contract revisions be enforced or full-scale nationalisation be imposed, the deterioration in Libya's business environment would suggest significant downside risks to oil output targets.

In early-March 2009, Libya's people's congress voted to delay Qadhafi's plan to disband the government and hand out revenues from the oil sector directly to the people.

The head of NOC, Shokri Ghanem has stated that Tamoil, the state's oil refining and marketing arm, is looking for strategic investors. The comments, made while Ghanem was attending the International Energy Forum in Rome in April 2008, came after the sale of a 65% stake in Tamoil to US investment firm **Colony Capital** failed in March. It was thought the deal was cancelled because Tamoil failed to disclose company information. Colony Capital had bid US$6.3bn for Tamoil.

In May 2010 Ghanem reiterated the government's desire to draft a new hydrocarbons law regulating foreign investment. Ghanem emphasised that the law, which he expected to be enacted in H210, would establish a transparent bidding process for companies seeking to gain access to exploration blocks, and that natural gas and downstream activities would be covered as well. However, attempts to entice greater foreign investment may be hampered by the outcome of the current dispute between Libya and Switzerland, which began following the arrest by Swiss authorities of Qadhafi's son. Comments made by

Ghanem indicate that Libya might be contemplating replacing Swiss-registered companies such as **Transocean** and **Noble**, with other firms, as retaliation against Switzerland.

Licensing Rounds

In 2003 the UN Security Council voted to lift sanctions against Libya, allowing international players to take part in Libya's oil and gas licensing rounds. The first licensing round was held in August 2004, with a second following soon afterwards in May 2005. A third round was held in December 2006, and the fourth was held in December 2007. Since the fourth round, however, Libya has moved away from large licensing rounds towards signing bilateral contracts with international companies. In December 2009 the head of NOC, Shokri Ghanem, said that the fifth licensing round would not take place in the immediate future as the country wished to focus on developing existing fields rather than attempting to discover new ones.

Fourth Licensing Round (First Gas Licensing Round)

In December 2007, Libya auctioned exploration permits in the central, western and southern desert, as part of its first licensing round focused on gas. **Gazprom**, Shell, **Sonatrach** and **Polskie Gornictwo Naftowe i Gazownictwo** (PGNiG) of Poland won four of 12 licences on offer. Six licences, five of which were offshore and one in southern Libya, did not attract any bidders. Oxy and Germany's **RWE** were the sole bidders for the other two.

In the auction, Gazprom beat off competition from **GDF Suez**, BG Group and fellow Russian company **Lukoil** for a licence to explore in western Libya. Shell fended off rival bids from Paris-based Total and Petro-Canada to search for gas in central Libya. Sonatrach teamed up with India's **Oil India Ltd** (OIL) and **India Oil Corporation** (IOC) for its winning bid. PGNiG saw off GDF for exploration rights in south-west Libya.

Third Licensing Round

In Libya's third licensing round, which opened in August 2006, the country offered 12 offshore and 29 onshore areas. The total area of the concessions on offer was 99,437sq km. In October 2006 NOC announced that 47 companies had qualified to take part in the round. The big winner was Russia's **Tafneft**, which won three of the 14 contracts on offer. Gazprom, Taiwan's **CPC**, Petro-Canada, Repsol and Wintershall each won one. Offshore areas 20 and 43 and Area 113 (Murzuq) were withdrawn as they attracted only one bid each.

Second Licensing Round

In May 2005, NOC announced a second licensing round. The results in October 2005 saw BG Group and ExxonMobil among the leading IOCs to secure acreage, while Japanese interests were particularly successful. ExxonMobil won Cyrenaica Basin Contract Area 44, along with **Nippon Oil** of Japan and **Pertamina** of Indonesia. ExxonMobil was the only US oil company named as a high bidder in the round.

Other winners in the first 2005 licensing round include Verenex, Algeria's Sonatrach, Medco of Indonesia, Brazil's **Petrobras**, **Liwa** of the UAE and India's OIL and IOC.

The second bidding round attracted 48 IOCs, which submitted a total of 99 bids for 26 blocks. Block 146-1, which was the most contested block in the Murzuq Basin, attracted eight bids. Some big names, such as **BP**, failed to score. Successful bidders included ExxonMobil, BG Group, **Statoil**, Eni, Total, Norsk Hydro, Pertamina, **Inpex** and Nippon Oil.

First Licensing Round

In January 2005 Libya awarded 15 new exploration blocks in the country's first bidding round since the lifting of sanctions, including nine onshore blocks and six offshore. The blocks, which covered a total of 127,000sq km, provided Libya with US$150mn of bids from 60 companies. US companies won 11 of the 15 blocks that were awarded. Occidental Petroleum was the major winner with nine licences awarded, including as a member of the Woodside-led consortium which was awarded four offshore blocks. Chevron and Hess were each awarded one block.

International Energy Relations

In May 2006, the US government announced the last stage of the reconciliation and a complete normalisation of relations with Libya. The move saw Libya removed from Washington's state sponsors of terrorism list, paving the way for substantial FDI inflows from the US into the Libyan oil sector.

Italy is a prime target for Libyan sovereign funds, with LIA seeking to acquire stakes in a variety of business sectors, including energy firms **Enel** and Eni. The Libyan ambassador to Rome, Hafed Gaddur, has told Italian media that Libya was looking at buying a stake of between 5% and 10% in Eni. In early 2008, Italy's foreign minister Franco Frattini that Libya's decision to acquire a substantial stake in Eni was unlikely to face any political obstacles.

The Libyan government made several announcements in May 2009 indicating its desire to boost investment in strategic foreign ventures, predominantly in the energy sector. Low levels of public investment have allowed Libya to accumulate large volumes of foreign currency reserves, which Qadhafi appears keen to use in bolstering the country's regional influence.

In February 2010, the Libyan government briefly stopped issuing visas to European citizens from the Schengen border-free zone. The move was seen as retaliation against the Swiss government's decision to blacklist 188 Libyans, including Qadhafi and his family, from travelling to the country. The decision affected European nationals from 25 states although British nationals were still able to obtain visas. The situation was resolved on March 27 when Libya lifted the ban in response to Switzerland's decision to cancel the blacklist.

Four IOCs including Chevron and Occidental Petroleum have decided not to renew their five-year exploration leases in Libya, effectively ending their involvement in the country. The four entered Libya in

2005 in the country's first licensing round following the end of international sanctions. The decision to leave appears to have been largely due to a lack of discoveries, although changes to the PSC in 2007 are likely to have played a role as well.

In a Reuters article on October 2 2010, Fitouri said that four of the winners from the first licensing round had decided not to extend their Libyan licences. Fitouri said that the companies – Chevron, Occidental, Woodside Petroleum and the UAE's Liwa Energy – were now on their way to leaving Libya. He said that five companies had decided to renew their licences at a total cost of US$133mn, namely US independent Hess, Oil India, Brazil's Petrobras, Indonesia's Medco Energi and Algeria's Sonatrach.

BG Group has announced plans to exit Libya, following a lack of exploratory success. The company is in the process of relinquishing its two Libyan licences and will formally leave the country pending approval from Libya's state-run National Oil Corporation (NOC), a BG company spokesperson said on August 20 2010. The spokesperson also indicated that BG intends to transfer its 50% interest in its exploration licence in the onshore Kufra Basin to Norway's Statoil.

Table: Key Upstream Players

Company	Oil production (000b/d)	Market share (%)	Gas production (bcm)	Market share (%)
NOC	840e	50.8	8e	40e
Eni Libya	108	6.5	9.4	56
Repsol Libya	45e	2.7	0	na
Total Libya	60	3.6	0	0
OMV Libya	29.4	2	na	na
ConocoPhillips	47	3	na	na
Marathon	46	3	0.04	na
Hess	22	1.3	na	na
Occidental	7	0.5	na	na

e = estimate; na = not available/applicable; Source: Company data, 2009.

Table: Key Downstream Player

Company	Refining capacity (000b/d)	Market share (%)	Retail outlets	Market share (%)
NOC	378	100	na	na

na = not available/applicable; Source: BMI.

Company Monitor

National Oil Corporation (NOC)

Company Analysis

State-owned NOC is charged with increasing Libya's productive capacity, oil output, LNG sales and refined products volumes. It operates closely with predominantly European IOCs in the upstream segment, although it has gradually increased cooperation with US partners following the lifting of international sanctions. The outlook is one of steady revenue growth as numerous new fields enter production under the guidance of Eni, Total and Repsol from Europe and Conoco, Marathon and Hess from the US.

SWOT Analysis

Strengths:	Biggest domestic oil and gas producer
	Unrivalled access to exploration acreage
	Operates the national refining system
	Well established partnerships with IOCs
Weaknesses:	Limited financial or operational freedom
	Cost and efficiency disadvantages
	Rising investment requirement
Opportunities:	Substantial production growth potential
	Considerable untapped gas export potential
	Rising domestic energy consumption
	Large areas of unexplored territory
Threats:	Risk of renewed sanctions
	OPEC influence over oil volumes
	Changes in national energy policy

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Operating Statistics

- Year established: 1970
- Oil production: 790,000b/d (estimated)
- Gas production: 8bcm (estimated)
- Refining capacity: 343,000b/d

Market Position

State-owned NOC is responsible for all segments of the energy chain. The company accounts for around half of Libyan oil and gas output. Key subsidiaries include **Waha Oil Company**, which was established in 1986 to take over the interests of the departing **US Oasis Group**. The **Arabian Gulf Oil Company** operates the Sarir, Nafoora/Augila and Messla oil fields, while the **Zueitina Oil Company** operates the Intisar oil fields in the Sirte Basin. **Sirte Oil Company** operates the Raguba oil field and the Attahadi and Assumud gas fields, all located in the Sirte Basin, as well as the country's sole LNG plant at Marsa el-Brega.

Downstream assets include the 120,000b/d Az Zawiya, 220,000b/d Ras Lanuf and 8,400b/d Brega refineries. South Korea's **LG Petrochemicals** is currently upgrading the Az Zawiya facility under a US$280mn contract, and the Ras Lanuf plant is also due to be upgraded. The Ras Lanuf petrochemicals complex uses naphtha feedstock to produce a variety of basic petrochemical products.

The NOC's international investment arm, **Oilinvest**, which is connected to the Libyan Investment Authority (LIA), operates through the Tamoil subsidiary. **Tamoil Italia** operates the 96,000b/d Cremona refinery and a network of around 2,200 service stations, holding over 5% of the Italian market. Additional refineries are located in 105,000b/d Hamburg (Germany), 50,000b/d Collombey (Switzerland), and retail networks in Germany, Switzerland, the Netherlands, Spain and Egypt. Tamoil also operates petrol stations and related storage and distribution assets across Africa. **Tamoil East Africa** is constructing a pipeline between Kenya and Uganda.

In June 2007, US-based property buyout company **Colony Capital** tried to buy Tamoil for US$5.4bn. Although the deal collapsed in March 2008, in April NOC head Shokri Ghanem said that Tamoil was looking for strategic investors.

Strategy

Libya is planning to increase its oil exploration levels with a US$7bn programme that it hopes will boost reserves by as much as 50% over the next decade. NOC will necessarily be at the forefront of such expansion. The latest (third) oil and gas licensing round attracted a number of IOCs willing and able to develop Libya's substantial oil and gas wealth.

Libya's five-year upstream development plan calls for US$300mn of seismic survey work and the drilling of 100 exploration and 686 development wells, with a further US$10bn in investment needed in the event of oil and gas discoveries.

According to the International Crude Oil Market Handbook, NOC would like to raise oil production to 3.0mn b/d by 2010-2013 – requiring up to US$30bn of foreign capital. We consider this target highly ambitious, both in terms of expanding production capacity to this target and with regards to OPEC quotas.

Latest Developments

In July 2010 NOC announced a discovery with the N1-47/02 well in Area 47 in Libya. The well was drilled to a depth of 3,284m and flowed oil at a rate of 1,790b/d and gas at a rate of 60 thousand cubic metres per day (mcm/d) from the Memoniat formation. The well also hit oil at a rate of 1,494b/d and gas at a rate of 23.2mcm/d from the Lower Acacus formation.

NOC signed a multimillion-dollar deal with **Ukrainian Petroleum** in March 2009 that includes the production and distribution of oil and gas. According to media reports, Ukrainian Petroleum will invest US$60mn in four selected gas wells in the first stage, before commercial operations are due to start. The wells are expected to produce 110mn tonnes of oil and 30bcm of gas over the entire length of the contract. The agreement covers 25 years of oil production (88,405b/d) and 30 years of gas production (10bcm per year).

In December 2008, NOC and the AGOCO announced the discovery of oil and gas with wildcat well D1-NC7A in the Ghadames Basin. The well hit multiple oil and gas shows in three levels of reservoir formations – the Upper, Middle and Lower Acacus Sandstone. The well, which is located some 500km south of Tripoli and 70km west of the Hamada oil field, has produced positive flow tests at different intervals. According to NOC's website, the discovery is estimated to hold recoverable gas reserves of 48.1bcm and 19mn bbl of recoverable oil, with oil and gas in place (OGIP) put at 56.7bcm and oil and condensate in place (OCIP) put at 62mn bbl. The oil at the discovery measured 64.4° API, making it extremely light and valuable.

In August 2008, NOC and AGOCO announced a new discovery with exploration well D1-NC129 in the Sloug Depression Basin, which is located about 100km south of Benghazi City in Libya. D1-NC129 was drilled to a total depth of about 2,590m, hitting a Palaeocene Dolomite formation at a depth of 2,287m. According to the company, tests confirmed flow rates of 2,780b/d of oil and 9,231cm/d of gas, using a 32/64-inch choke. The oil has a gravity of 46.1° API.

NOC signed a PSA with Gazprom in March 2007 for the exploration and development of offshore Block 19. Gazprom said that it would invest around US$200mn in the exploration of the 10,288sq km block. Gazprom's Deputy Chairman Alexander Medvedev and the NOC's head Shokri Ghanem also discussed possible future cooperation through JVs in oil and gas production and in upgrading Libya's LNG sector.

Eni North Africa

Company Analysis

Eni is already Libya's biggest foreign oil producer and looks set to increase substantially its share of output over the next year or two. Eni also has a role in developing Libya's gas exports to Italy through the Greenstream pipeline, plus a share of the oil services segment. The country therefore forms a key part of the group's international portfolio and should make a growing contribution to revenues and earnings over the medium term.

SWOT Analysis

Strengths:	Strong presence in producing projects
	Major share of development upside
	Rapid near- to medium-term output growth
	Involvement in gas export infrastructure
	Good relationship with state
Weaknesses:	Substantial and rising investment requirement
	Competition from returning US companies
Opportunities:	Substantial production growth potential
	Considerable untapped gas export potential
	Rising domestic energy consumption
	Large areas of unexplored territory
Threats:	Risk of renewed sanctions
	OPEC influence over oil volumes
	Changes in national energy policy

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Financial Statistics (Group)

Net sales:

- EUR87.2bn (2009)
- EUR108.1bn (2008)
- EUR87.3bn (2007)
- EUR86.1bn (2006)
- EUR73.7bn (2005)

Net profit:

- EUR10.0bn (2009)
- EUR8.8bn (2008)
- EUR10.0bn (2007)
- EUR9.2bn (2006)
- EUR8.8bn (2005)

Operating Statistics

- Year established: 1959

Oil production:

- 108,000b/d (2009)
- 147,000b/d (2008)

Gas production:

- 8.1bcm (2009)
- 9.4bcm (2008)

Market Position

Eni is the largest foreign oil and gas producer in Libya, accounting for approximately 12% of total crude output. Key operated assets include the Bu-Attifel oil field (50%) in the central-eastern desert, the offshore Bouri field (30%) on Block NC 41 and the US$5.6bn Western Libyan Gas Project (WLGP), which involves the development of the onshore Wafa oil, gas and condensates reserves in Block NC 169 A (50%) and offshore Block NC-41 in the in the Gulf of Gabes. Eni's share of the recoverable reserves amount to over 1bn boe, with the Wafa field reaching its production plateau of 132,000 barrels of oil equivalent per day (boe/d) in 2007.

WLGP involved the construction of treatment plants at Wafa and Mellitah on the Libyan coast, the construction of onshore and offshore infrastructure, the laying of pipelines to transport both gas and condensates to the Mellitah plant and the laying of the540km Greenstream underwater pipeline connecting Mellitah to Sicily. The Mellitah plant has an annual treatment capacity of 10bcm, with around 8bcm of output to be exported to Italy.

Strategy

Eni was very successful in securing fresh acreage under the second Libyan licensing round. However, the group now faces a much more competitive environment with the restoration of normal relations between Libya and the US. Even so, this development should not hinder Eni's development plans for its existing portfolio.

Eni has proposed an ambitious plan to link Egypt's and Libya's gas grids by a pipeline network. In 2001, the NOC signed a JV agreement with Egypt's **General Petroleum Corporation** for construction of a pipeline to carry Egyptian gas to Libya and for another link that would pipe Libyan crude oil to Egypt. However, little progress has been made since.

In October 2007, Eni announced plans to invest US$28bn jointly with NOC in order to expand significantly crude and natural gas production in Libya. The 10-year programme will see each partner contribute equally, although Eni has also agreed to extend existing supply contracts to receive oil from Libya through to 2042 and natural gas through to 2047. Eni plans to double capacity at the Mellitah gas export hub to 16bcm. The company will also increase pipeline capacity by 3bcm and said in 2007 that it was considering building a new gas liquefaction plant. As part of the programme, the Italian group will invest an additional US$800mn over the next seven years on seismic data acquisition and exploration.

Latest Developments

In May 2010 Eni sold 25% of its stake in the company that manages the Greenstream pipeline to the government, resulting in the pipeline now being equally owned.

In April 2010 **Gazprom Neft** announced that it had agreed terms to acquire a stake in Libya's Elephant oil field. Under the deal Gazprom Neft will take half of Eni's stake in the field, or 33% of the total interest. In return Eni will farm into some of Gazprom Neft's interests in Russia.

Eni and NOC in June 2008 signed six EPSAs that revised earlier contracts and extended them by 25 years as of January 2008. The EPSA IV is based on a strategic agreement that the companies signed in October 2007. The new expiry date for oil production is 2042, while for gas production it is 2047.

In March 2008, Libya's NOC ordered Eni to reduce its stake in the El Feel (Elephant) oil field from 33.33% to 14%. Eni operates the field, which produces 138,000b/d, alongside a South Korean consortium comprising **SK Energy** and **Korea National Oil Corporation** (KNOC). The consortium will reduce its stake from 11.67% to 7%. NOC will now raise its stake to 79% from 65%. Following NOC's order action, Eni agreed to divest its entire 33% stake in Elephant field to state-run **Gazprom Neft**, as part of an asset swap with the Russian company. In April 2010, Gazprom Neft and Eni agreed the terms of the asset swap and said they planned to finalise the deal by the end of that year.

In October 2007, Eni announced plans to invest US$28bn jointly with NOC in order to significantly expand crude and natural gas production in Libya. The 10-year programme will see each partner contribute equally, although Eni has also agreed to extend existing supply contracts to receive oil from Libya through to 2042 and natural gas through to 2047. Eni plans to double capacity at the Mellitah gas export hub to 16bcm. The company will also increase pipeline capacity by 3bcm and is considering building a new gas liquefaction plant. As part of the programme, Eni will invest a further US$800mn over the next seven years in seismic data surveys and exploration. Libya wants to increase crude output capacity to 3mn b/d by 2013, through new field developments and EOR from existing fields.

In April 2007, large foreign companies operating in Libya's oil industry were required to change their names to reflect the culture and geography of the country. Eni has become **Mellita Gas**. The new name, a reference to the region west of Tripoli where Eni operates, will be used in all contracts.

Total Libya

Company Analysis

Like the other European oil groups, Total profited from the absence of US companies and established a strong position in the upstream sector, benefiting from rising output and an extensive exploration portfolio. Near-term production trends are favourable and Total remains committed to its Libyan business. It may find it harder to get the highest quality exploration and development opportunities now that US firms have returned, although it did pick up new acreage in the second licensing round.

SWOT Analysis

Strengths:	Strong presence in producing projects
	Major share of development upside
	Rapid near-term output growth
	Broad exploration portfolio
	Good relationship with state
Weaknesses:	Competition from returning US companies
Opportunities:	Substantial production growth potential
	Considerable untapped gas export potential
	Rising domestic energy consumption
	Large areas of unexplored territory
Threats:	Risk of renewed sanctions
	OPEC influence over oil volumes
	Changes in national energy policy

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Operating Statistics

- Year established: 1959

Oil production:

- 60,000b/d (2009)
- 74,000b/d (2008)

Market Position

Total has stakes in two oil developments in Libya. It holds a 37.5% stake in and the operatorship of the Mabruk field in the Sirte Basin as well as the offshore Al Jurf field in Block C 137. The latter field came onstream in September 2003 with production due to plateau at 40,000b/d. Crude is being produced via 10 production wells connected to the Farwah FPSO, which has 900,000bbl of storage capacity.

Total has a 37.5% interest in Al Jurf oil field, with Wintershall (12.5%) and NOC (50%). In addition, Total holds a 7.5% interest in the Repsol YPF-operated El Sharara field on Block NC 115, which is producing around 170,000b/d. The 'A' structure of El Sharara on Block NC 186 began production in October 2003, with an average output of 8,000b/d. Total has a 24% interest in the concession. The French company is also carrying out exploration work in the Murzuk Basin (blocks NC 186, 187, 190 and 191) and the Sirte Basin (Block NC 192). Total drilled two wells on its 100%-owned Block NC 191 in 2004.

Strategy

Now that US firms have returned to Libyan upstream projects, with Occidental leading the charge, Total may find it more difficult to expand its existing Libyan footprint. However, for the moment the firm has good growth prospects from its existing concessions and picked up some useful assets in the country's second licensing round. Libya is attractive to Total not only because of its impressive reserves of 39.2bn bbl of easily processed low sulphur sweet crude, but also because of its close location to important European refining centres on the Mediterranean, such as its La Mède refinery.

Latest Developments

In February 2010 Total renewed its blocks C17 and C137 with NOC. The blocks were converted into the new EPSA-4 format that reduced Total's share in output from the Mabruk field on Block C 17 and the Al-Jurf field on Block C 137. Total now holds 37.5% of each of the blocks. The new contract was backdated to January 2008. In addition, the French company agreed to pay a US$500mn signature bonus.

According to Total's 2007 annual report, the company already owns a 37.5% stake in the offshore Al-Jurf field, together with Wintershall (12.5%) and NOC (50%). Its stake in Al-Jurf, which produces around 45,000b/d, will therefore remain the same. Total held a 75% stake in the 40,000b/d onshore Mabruk field, however, and that will now fall to 37.5%. However, it was reported in May 2009 that Total agreed on May 21 to reduce its interest in the two oil blocks from 50% to 27%. Under the revised contract, the foreign partners have also agreed to have their share of gas production cut from 50% to 40% and further to 30% at a later stage. No details over whether Total had paid a US$500mn signature bonus for the renewal of the contract have been released.

In April 2007, large foreign companies operating in Libya's oil industry were required to change their names to reflect the culture and geography of the country. Total became **Mabruk Oil**, which means 'congratulations' in Arabic, and this name will be used in all of its contracts.

OMV of Libya

Company Analysis

OMV is a major buyer of Libyan crude, which represents the major feedstock for one of its European refinery sites. It is also a well established oil producer in the country, with significant near-term upside potential. With Repsol YPF, OMV has signed up for a major new exploration initiative over six years, so there is clear commitment from the Austrian company. Libya represents a key component of the group's E&P strategy and will shortly be making a sizeable contribution to OMV's earnings.

SWOT Analysis

Strengths:	Strong presence in producing projects
	Major share of development upside
	Rapid near-term output growth
	Broad spread of exploration interests
	Good relationship with state
Weaknesses:	Rising investment requirement
	Competition from returning US companies
Opportunities:	Substantial production growth potential
	Considerable untapped gas export potential
	Rising domestic energy consumption
	Large areas of unexplored territory
Threats:	Risk of renewed sanctions
	OPEC influence over oil volumes
	Changes in national energy policy

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Operating Statistics

- Year established: 1985

- Net oil production:
- 29,400b/d (2009)
- 34,000b/d (2008)

Market Position

Austrian OMV entered Libya in 1985 (its second international upstream venture after Tunisia) with the purchase of 25% of Oxy's producing assets. The group's current assets include 24% stakes in Blocks NC 186, NC 187 and NC 190, all of which are operated by Repsol YPF (32%). Total and Statoil hold the remaining 24% and 20% stakes respectively. OMV also holds a 7.5% interest in the Repsol YPF-operated El Sharara field on Block NC-115, which is producing 170,000b/d of crude.

The Austrian firm and its partners have drilled four successful exploration wells on Block NC 186, reporting the discovery of 140-300mn bbl of recoverable reserves. Having invested US$155mn in the development of Field A at the block, the company announced first oil production in October 2003. Output is expected to peak at 40,000b/d gross.

Strategy

The firm appears comfortable taking a back seat to Repsol on its recent concessions in Libya, a strategy that should yield respectable returns from minimal outlay. However, as the group's ambitious foreign E&P expansion plans begin to take off we should see OMV taking more operatorship roles within Libya.

The majority of OMV's assets in the country are mature and therefore demand advanced and costly oil-recovery techniques to extend their producing life.

OMV's original focus in North Africa was on oil rather than gas, with its interests in Libya and Tunisia providing feedstock for its European refineries. In recent years this strategy appears to have shifted with its moves into Egypt and the Kurdistan Region of Iraq, which have focused more on gas. In 2007 the group said that it was also looking into producing natural gas in Libya and was actively seeking suitable sites for this end, outlining plans to invest in some 30 exploration blocks over the following three years.

Latest Developments

In April 2009 OMV announced that it had made an offshore oil discovery in the Sirte Basin Block NC202. The discovery, made with the A1-NC202 exploration well, was drilled to a total depth of 4,820m and produced a flow rate of up to 1,264b/d. The discovery was OMV's first to be made offshore Libya.

In 2008 OMV and Repsol YPF extended their agreements for blocks NC115 and NC186 until 2032, effective from January 2008. The companies also announced a new drilling programme at the blocks.

November 2007 saw OMV sign a revised deal with NOC, which allows the Austrian group a reduced share of the oil produced from its Libyan acreage.

Repsol YPF Libya

Company Analysis

Like its European rivals, Repsol YPF has targeted Libya as a source of low-cost upstream production and reserves growth. It has an extensive spread of exploration acreage and strong near-term production growth. Recent drilling success and the new commitment with OMV to increase exploration spending makes Libya one of the key priorities outside Repsol YPF's core areas of Spain and Latin America.

SWOT Analysis

Strengths:	Strong presence in producing projects
	Major share of development upside
	Rapid near- to medium-term output growth
	Extensive exploration portfolio
Weaknesses:	Rising investment requirement
	Competition from returning US companies
Opportunities:	Substantial production growth potential
	Considerable untapped gas export potential
	Rising domestic energy consumption
	Large areas of unexplored territory
Threats:	Risk of renewed sanctions
	OPEC influence over oil volumes
	Changes in national energy policy

Address

- Repsol Exploración Murzuq SA
- http://www.repsol.com

Financial Statistics (Akabus Oil):

Net profit

- EUR0.3mn (2008)

Operating Statistics

Net oil production

- 43,000b/d (2009e)
- 50,000b/d (2008)
- 52,631b/d (2007)

Market Position

Spain's Repsol YPF holds a 10% stake in the 170,000b/d El Sharara oil field in Block NC 115 in partnership with the NOC (75%), Total (7.5%) and OMV (7.5%). The company also operates and holds an 8% interest in Blocks NC 186, NC 187 and NC 190. Field A on Block NC 186 started production in October 2003, with output to peak at 40,000b/d. The 35,000b/d field D on NC 186 came onstream in Q304. It also holds a 50% stake in Block 137. Repsol YPF's net production derives mainly from the El Sharara field.

Strategy

Repsol's Libya projects will be crucial to buttressing the company's declining oil and gas reserves position during 2007 and beyond. The country will therefore receive renewed investment to build upon recent discovery successes, with reports indicating that the group could be interested in forthcoming Libyan LNG projects.

The Murzuq Basin is looking increasingly promising and when brought fully onstream should enhance the firm's existing production capability.

Latest Developments

Repsol YPF announced in mid-April 2009 that it had made an oil and gas discovery on the NC202 Block in the Sirte Basin offshore Libya. The A1-NC202 well, which is located in water depths of 50m, was drilled to a depth of 4,820m and hit oil and gas in the Demah formation at an interval of 1,354-1,367m. The well produced test flows of 1,264b/d of 26° API crude and 16.4Mcm/d of gas from a 32/64-inch choke. This is the first discovery on Block NC202, which is operated by Repsol with a 21% stake alongside NOC with 65% and Austria's OMV with the remaining 14% interest.

In 2008 OMV and Repsol YPF extended their agreements for blocks NC115 and NC186 until 2032, effective from January 2008. The companies also announced a new drilling programme at the blocks. At the end of 2008, Libya approved development for block NC186.

In April 2007, large foreign companies operating in Libya's oil industry were required to change their names to reflect the culture and geography of the country. Repsol has become **Akakoss Petroleum Operations**. The new name, a reference to the Akakoss Mountains in southern Libya, will be used in all contracts.

Marathon Oil

Company Analysis

Marathon enthusiastically returned to Libya at end-2005 after a long absence during the period of US trade sanctions. Currently operational alongside fellow US producers ConocoPhillips and Hess, Marathon hopes to boost its current net oil output by over 75% by 2017. Achieving these goals will require high levels of investment, for which other company projects will compete. However, consortium support helps to ameliorate these concerns.

SWOT Analysis

Strengths: One of only three US independents in Libya

Significant acreage position

Weaknesses: Stagnant production since 2007

Opportunities: Substantial production growth potential

High upstream environment ranking

Threats: Changes in national energy policy

Address

- Waha Oil Company
  Airport Road,
  P.O. Box 395, Tripoli
- Tel: +218-21-3331116
- Fax: +218-21-3337169
- www.marathon.com
- www.wahaoil.net

Financial Statistics (Group)

Revenues:

- US$53.5bn (2009)
- US$76.7bn (2008)
- US$64.1bn (2007)

Net Income:

- US$1.5bn (2009)
- US$3.5bn (2008)
- US$3.9bn (2007)

Oil Production (Libya):

- 46,000b/d (2009)
- 46,000b/d (2008)
- 45,000b/d (2007)

Gas Sales Volumes (Libya):

- 0.04bcm (2009)
- 0.04bcm (2008)
- 0.04bcm (2007)

Market Position

Between 1958 and 1961, Marathon discovered fields at Bahi, Dahra, Waha, Defa and Gialo. First oil flowed in 1962 via pipeline to the Es Sider Terminal on the Mediterranean coast. Eight additional fields were discovered and subsequently developed. The group ceased active participation in the Waha concessions in 1986 following the imposition of trade sanctions by the US government. From 1986 to 2005, the Waha concessions were operated by the Waha Oil Company, a wholly owned subsidiary of the Libyan NOC.

In April 2004, the US government lifted sanctions, allowing Marathon and its partners to advance plans to return to production operations in Libya. In late 2005, Marathon reached agreement with the Libyan NOC on the terms under which the companies would return to their former oil and gas exploration and production operations in the Waha Concessions.

Marathon operates in Libya as a consortium member of the Waha Oil Company, which acquired exploration and production rights in Libya in the mid-1950s. Marathon holds a 16.33% working interest in the Waha Concessions, which in 2009 produced a gross average of 340,000boe/d. The Waha Concessions encompass almost 53,000sq km in the Sirte Basin – one of the most prolific oil and gas producing areas of Libya, containing sizeable undeveloped oil and gas resources. Marathon's remaining proven reserves in Libya are estimated at 231mn boe net. Marathon's end-2009 Libyan output represented 19% of the company's international liquid hydrocarbon sales.

Strategy

In 2007, Marathon envisioned a goal of 500,000-600,000boe/d gross production by 2017. This would require a minimum increase of about 75% on end-2009 production levels.

The Faregh Phase II Gas Plant project is expected to deliver a gross output of 1.86bcm of natural gas and 15,000b/d of liquids into the Libyan domestic market. Commissioning will begin in 2010, with start-up planned for first quarter of 2011.

The Waha Group is also planning for the development of two oil and gas fields in the Waha-operated concessions – the North Gialo Field development and the NC-98 Field development. These projects are located in the southeastern section of Libya's Sirte Basin. The planned development for the North Gialo gas recycle project is expected to generate gross peak rates of 1.86bcm and 100,000b/d in 2019. The NC-98 field, a gas condensate reservoir, is expected to produce gross output of 4.13bcm of gas and 80,000b/d at its peak in 2019.

Latest Developments

In August 2010, Libya's top energy official, Shokri Ghanem, claimed a 1.26bn bbl rise in Libya’s proven oil reserves and a 50bcm rise in proven gas reserves, on the back of successes at new exploratory wells drilled in the country in 2009 and H110. According to Ghanem, in 2009, the Oasis Oil consortium (Waha), comprising NOC, Marathon, ConocoPhillips and Hess, made six discoveries.

Marathon’s exploration program in 2009 included the drilling of four wells. At end-2009, one well was reported as waiting on completion, one was dry and abandoned, and two were currently drilling. Marathon also drilled 5 development wells in Libya during the year.

ConocoPhillips

Company Analysis

ConocoPhillips returned to Libya at end-2005 after a long absence during the period of US trade sanctions. Currently operational alongside fellow US producers Marathon and Hess, ConocoPhillips hopes to boost its current net oil output by over 75% by 2017. Achieving these goals will require high levels of investment, for which other company projects will compete. However, consortium support helps to ameliorate these concerns.

SWOT Analysis

Strengths:	One of only three US IOCs in Libya
	Significant acreage position
Weaknesses:	Stagnant production since 2007
Opportunities:	Substantial production growth potential
	High upstream environment ranking
Threats:	Changes in national energy policy

Address

- Waha Oil Company
  Airport Road,
  P.O. Box 395, Tripoli
- Tel: +218-21-3331116
- Fax: +218-21-3337169
- www.conocophillips.com
- www.wahaoil.net

Financial Statistics (Group)

Revenues:

- US$149.3bn (2009)
- US$240.8bn (2008)
- US$187.4bn (2007)

Net Income:

- US$4.8bn (2009)
- (US$16.9bn) (2008)
- US$11.9bn (2007)

Oil Production (Libya):

- 46,000b/d (2009)
- 46,000b/d (2008)
- 45,000b/d (2007)

Gas Sales Volumes (Libya):

- 0.04bcm (2009)
- 0.04bcm (2008)
- 0.04bcm (2007)

Market Position

ConocoPhillips, Marathon and Hess ceased active participation in the Waha concessions in 1986 following the imposition of trade sanctions by the US government. From 1986 to 2005, the Waha concessions were operated by the Waha Oil Company, a wholly owned subsidiary of the Libyan NOC. In April 2004, the US government lifted sanctions, allowing Conoco and its partners to advance plans to return to production operations in Libya.

The re-entry terms include a 25-year extension of the concessions to 2031-34. The consortium agreed on a US$1.3bn payment to Libya's NOC (US$520mn net from Conoco) for re-entry and the concessions' extension, in addition to a contribution of US$530mn (US$212mn net to Conoco) for unamortised investments made since 1986.

ConocoPhillips operates in Libya as a consortium member of the Waha Oil Company, which acquired exploration and production rights in Libya in the mid-1950s. Conoco holds a 16.33% working interest in the Waha Concessions, which in 2009 produced a gross average of 340,000boe/d. The Waha Concessions encompass almost 53,000sq km in the Sirte Basin – one of the most prolific oil and gas producing areas of Libya, containing sizable undeveloped oil and gas resources. ConocoPhillips' end-2009 Libyan output represented 4.75% of the company's international liquids production that year.

Strategy

In 2007, Conoco's Waha partner, Marathon, envisioned a goal of 500,000-600,000boe/d gross production by 2017. This would require a minimum increase of about 75% on end-2009 production levels.

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Latest Developments

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BP – Summary

After withdrawing from Libya following the nationalisation of the oil industry in 1974, the British major re-entered the country in May 2007, signing a US$900mn exploration deal for the two contract areas: the northern part of the Ghadames Basin and the offshore extension of the Sirte Basin. Exploration will take place in cooperation with Libya Investment Corporation. According to a BP spokesperson quoted by British newspaper the Independent in 2009, the company could invest as much as US$20bn in Libya over the next two decades. The director of the company's local unit, however, speaking in October 2009, said BP had earmarked US$1bn of investment in the country between 2009 and 2016.

BP's activities in Libya have drawn criticism from outside the country for two reasons. First, the company has come under scrutiny owing to allegations of the British government's involvement in the company's Libyan deal, particularly in relation to the August 2009 release from a Scottish prison of Abdelbaset Mohmed Ali al-Megrahi, the man convicted of the Lockerbie bombing in 1988. Second, following the Macondo oil leak in the Gulf of Mexico, the company has also come under fire from some European countries concerned about the effects of a potential spill in the Mediterranean.

BP completed seismic surveys of its offshore and onshore acreage in 2009 and on July 1 2010 announced that it expected to begin drilling operations in the Gulf of Sirte in 'the coming weeks'. That announcement, however, was quickly attacked by Italy's foreign minister Franco Frattini who said that it was inappropriate for BP to drill in the Mediterranean before the Macondo oil spill investigations were completed.

Shortly afterwards, in August 2010, BP announced that it had delayed its drilling plans, although it still expected to start drilling by year-end. In December 2010, however, the company said that it had further delayed plans to drill a well in the Gulf of Sirte, partly because of a legal dispute over the drilling rig to have been used.

Originally BP had contracted **Noble Corporation**'s *Noble Ferrington* drilling rig for its planned Libyan deepwater well but decided against it 'for operational reasons', a spokesperson said. The Financial Times reported on December 9 that Noble had initiated arbitration proceedings against BP and ExxonMobil after the latter transferred the rig to BP, after having drilled two dusters offshore Libya in 2009 and 2010. Consequently, BP abandoned plans to use the Noble rig, which is now idle.

On December 14, BP said it would move US drilling contractor **Pride International**'s *Deep Ocean Ascension* rig from the US Gulf of Mexico (GoM) to offshore Libya for its exploration programme to be carried out in the country in 2011. The company also wanted to examine the results of the Macondo oil spill in the GoM before starting drilling operations, said Toby Odone, a BP spokesperson .

ExxonMobil – Summary

US major ExxonMobil in February 2007 said that it had signed an EPSA with NOC to initiate exploration activity offshore Libya in the Sirte Basin. The deal includes four blocks in Contract Area (CA) 20, about 160km off the Libyan coast, which were awarded under the third round of EPSA IV licensing in December. The contract area comprises 10,117sq km and is situated in water depths of 1,219-1,981m. In October, Exxon announced plans to establish a 'significant' position in Libya. The company aims to boost its output in Africa by 50% by 2010 and sees Libya as one of its most promising new markets on the continent.

June 2008 saw Exxon finalise another agreement with NOC to explore for oil at CA 21 in the Sirte Basin offshore area. The latest acquisition, CA21, lies 177km off the Libyan coast and covers a total area of 10,000sq km in water depths of around 2,000m. Under the agreement, Exxon will explore the area for five years, NOC said. NOC has also agreed that the US group pays a fee for the permit and implements a training programme for Libyan technicians and engineers. It will also provide funds for educational facilities in the country.

ExxonMobil announced that it spudded the A1-20/3 well in CA 20, also located in offshore section of the Sirte Basin, in mid-July 2009. Meanwhile, Exxon has also announced that it has completed two 3D seismic studies in offshore CA 20 and CA 21 and three 2D seismic studies in offshore CA 44, CA2 0 and CA 21.

Tatneft – Summary

Russia's **Tatneft** entered Libya in October 2005 when it was awarded Area 82 (Block 4) in the second Libyan licensing round. Three additional licences were awarded to Tatneft in March 2007, when it was one of the biggest winners in the country's third licensing round. Tatneft received Area 82 (Block 1) and Area 98 (blocks 2 and 4) in the Ghadames Basin as well as Area 69 (blocks 1-4) slightly to the north-east in the Sirte Basin. In December 2009 Tatneft announced that it was planning capex above its usual level of US$500mn for Libya in 2010.

Tatneft's most advanced licence in Libya is the 2,145sq km Area 82 (Block 4), in which it is the operator with a 10.5% stake, alongside NOC with the remaining 89.5% interest. Both 2D and 3D seismic data were acquired in 2007 and drilling at the site began in July 2008 with the A1-82/04 wildcat. The well hit water, which was sent for testing to the Libyan Petroleum Institute. Following testing, Tatneft appears to have re-drilled the well, discovering oil in August 2009. The well produced test flow rates of 400b/d of 40° API oil.

More discoveries were announced in 2010. In January 2010 oil was found with wildcat B1-82/04. The well was drilled to a total depth of 2,667m and hit 3.4m of pay in the Ouen Kasa layer. The well flowed 829b/d of 37° API oil through a 32/64-inch choke. Tatneft holds a 10.5% interest in the well, with NOC holding the remaining 89.5%. In April 2010 Tatneft announced the discovery of crude oil with the A1-82/01 in Area 82. The A1-82/01 well, which was drilled to a depth of 2,499.36m, discovered hydrocarbons in the Ouan Kasa formation. The well tested at 415b/d.

Tatneft's remaining three concessions are at an earlier stage of exploration, with 2D seismic surveys being carried out at the areas in 2008. Tatneft is also planning to spend US$1bn in 2010 on a processing facility being built by subsidiary **Taneko**.

Occidental Petroleum – Summary

In October 2010, NOC Exploration Director Hadj Fitouri told Reuters that four IOCs, including US independent Occidental Petroleum (Oxy), had decided not to renew their five-year exploration licences in Libya. The decision to leave appears to have been largely due to a lack of discoveries, although changes to the PSC in 2007 are likely to have played a role as well.

Oxy re-entered Libya in 2005 after a near two-decade absence prompted by the US embargo. The company immediately committed to a 30-well drilling programme through to 2009 across a sizeable area, including several producing assets. In January 2007, Oxy confirmed that it had won stakes in nine exploration blocks. At five of them (blocks 106 and 124 in the Sirte Basin, 131 and 163 in the Murzuk Basin and 59 in the Cyrenaica Basin) Oxy took a 90% operating interest, working alongside the UAE's Liwa Energy with the remaining 10%. It won the other four offshore blocks (35, 36, 52 and 53) as a member of a consortium, in which Oxy has a 35% interest. The nine blocks awarded to Occidental and its partners cover an area in excess of 76,000sq km.

The production sharing contract (PSC) was re-negotiated in 2007 and finalised in mid-2008. Under the new contract compatible with the ESPA IV framework, Oxy agreed to pay a US$1bn signature bonus and to receive 10-12% of gross production at the fields after tax. The contracts call for large capex aimed at significantly boosting output at the fields, with Oxy liable for 35% of the total development costs. As a result of the new contract, Oxy's output fell from 15,000b/d in 2008 to 5,000b/d by Q309. Average production net to Oxy in 2009 was 9,000boe/d.

In February 2008, NOC signed EPSAs with Shell and Oxy, both of which had won gas exploration permits in December 2007. Occidental was awarded Block 103, located in the Sirte Basin. Occidental, alongside partner Liwa, agreed to undertake 3D seismic surveys over a 2,000sq km area and 3D seismic surveys on 1,000sq km, as well as drilling three wells. The companies agreed to pay a US$10mn signature bonus and committed to invest a minimum of US$70mn.

BG Group – Summary

BG Group won exploration licences in Area 123 (blocks 1 and 2), and Area 171 (blocks 1, 2, 3 and 4) in Libya's second licensing round in 2005. It assumed 100% ownership and operatorship of the E&P sharing agreements (EPSAs) for Area 123 (blocks 1 and 2) and a 50% interest in the EPSA for Area 171 (blocks 1, 2, 3 and 4) in partnership with Statoil (operator). A number of 3D seismic surveys were carried out in 2007, with three wells drilled at the areas in 2008, but all were dry. BG Group also bid in Libya's fourth bidding round but was not awarded any blocks.

In August 2010 BG Group confirmed that it intends to exit Libya, citing a lack of exploratory success. The company is in the process of relinquishing its two Libyan licences and will formally leave the country pending approval from NOC. A company spokesperson also indicated that BG intends to transfer its 50% interest in its exploration licence in the Kufra Basin to Statoil.

Hess – Summary

In December 2005, US-based Hess reached agreement with NOC on the terms under which it returned to its former oil and gas production operations in Libya. Under the agreement, Hess and partners Marathon and ConocoPhillips have returned to their former E&P interests in the Waha concessions. Hess holds an 8.16% stake. In 2008, it produced 22,000b/d of oil.

Hess also owns a 100% interest in Area 54 in the offshore Sirte Basin, where it has been involved in exploration drilling. In December 2009 Hess released drilling test results from its wholly owned A1-54/01 discovery well in the area. The company said the well at the Arous Al-Bahar prospect produced 533b/d of condensate and 0.76Mcm/d of gas on a 52/64-inch choke. The well was drilled in water depths of 856m. The company encountered several intervals of hydrocarbons with a combined gross section of around 152m. The company has an EPSA for the well with NOC.

Woodside Petroleum – Summary

Woodside is exiting Libya after deciding against renewing its contracts. The Australian producer had two major contracts in the country, signed after international sanctions were lifted in 2004. The first, EPSA III, was for exploration and appraisal of onshore acreage, with Woodside the operator with 45%. In 2009, Woodside completed the last two wells required under EPSA III. Both wells were unsuccessful and on the expiry of the contract in December 2009 the assets were sold to GDF Suez.

Under the second contract, EPSA IV, Woodside operated four offshore licences (blocks 35, 36, 52 and 53) covering a total 37,300sq km, with a 55% share of the equity alongside partners Occidental (35%) and Liwa (10%). No seismic or drilling activity was undertaken in 2009 and the contract expired in Q110.

Chevron – Summary

Through its JV company **Amoseas Libya**, Chevron was one of the largest acreage holders in Libya in the early 1970s. Following nationalisation, the company relinquished all holdings. It re-entered the country in 2005, taking 100% ownership and operatorship of Block 177 in the Murzuq Basin. After failing to encounter hydrocarbons, however, Chevron quit the block in 2009 and chose not to renew its five-year exploration lease, effectively ending its involvement in the country, although it maintains a representative office in Tripoli and apparently continues to monitor investment opportunities.

Statoil – Summary

Following the merger with Norsk Hydro in October 2007, Norwegian state-run Statoil holds stakes in four exploration contract areas, 94 (Cyrenaica, 100%), 146 (Murzuk, 100%), 171 (Kufra, 50%) and 186 (20%).

Royal Dutch Shell – Summary

In March 2004, Shell Libya Petroleum Development signed a heads of agreement with NOC, establishing a long-term strategic partnership that could lead to the development of major integrated upstream projects to enhance LNG export capacity. During May 2006, NOC and Shell announced an oil and gas exploration and development deal covering the existing Marsa al-Brega LNG plant and five concessions in the Sirte Basin. Modernisation efforts at the LNG plant will cost Shell US$105-450mn on top of a minimum commitment cost of US$187mn for the Sirte Basin concessions, covering an area of around 20,000sq km.

December 2007 saw Shell win a permit to explore in potentially gas-rich acreage in the Libyan gas licensing round. February 2008 saw NOC sign EPSAs with Shell for Block 89. Under the EPSA, Shell has committed to invest at least US$95mn. The company will carry out 3D seismic surveys over a 1,750sq km area and drill six wells, according to the contract. Shell will also pay NOC a US$103mn signature bonus.

Suncor – Summary

Through its newly acquired arm, Petro-Canada, Canadian producer **Suncor** has been involved in Libya for over 40 years and is exploring and producing in nine concessions in the Sirte Basin. It is one of Libya's biggest producers through its 49% stake in Veba Oil Operations – a JV with NOC with eight concessions.

June 2008 saw Petro-Canada sign six new exploration and production sharing agreements (EPSAs) with NOC. The 30-year contracts cover the redevelopment of existing producing fields by **Harouge Oil Operations**, a JV between the two companies, and an extensive exploration programme by Petro-Canada in the Sirte Basin. The finalisation of the deals follows a HoA that was signed between the two companies in December 2007. Petro-Canada estimates that there are gross contingent and prospective resources of nearly 2bn barrels of oil in the fields that are to be redeveloped, with the programme set to cost around US$7bn.

The Harouge JV is hoping to double existing output levels over the next five to seven years, with a production target of 200,000b/d. Under the terms of the EPSAs, Petro-Canada will pay 50% of development costs and will receive an initial 12% share of production. It is not clear whether the US$7bn figure includes an agreed signature bonus of US$1bn payable by Petro-Canada in three stages, of which US$100mn will be channelled into social investment projects in Libya. The production sharing terms are heavily weighted towards the state and seem on the verge of being uneconomical, a factor that illustrates Libya's pulling power. As well as the redevelopment programme, the Canadian company is to invest US$460mn in exploring the Sirte Basin. The planned programme includes the acquisition of 10,000sq km of 3D seismic data and 600km of 2D seismic plus the drilling of 50 exploration and appraisal wells. All exploration costs will be borne by Petro-Canada. In its last exploration programme, Harouge hit oil and gas in seven of the nine wells it drilled, which bodes well for the potential for further discoveries in the area and adds potential upside risk to Petro-Canada's reserves and production.

PGNiG – Summary

Poland's PGNiG was awarded a gas exploration concession in the Murzuq Basin in the December 2007 gas licensing round. PGNiG agreed to a minimum work programme that includes a 3,000km 2D seismic survey and a 3D survey covering 1,500sq km in contract area 113. The company will drill at least eight wells over a six-year period at a cost of around US$108mn.

Gazprom – Summary

In February 2008, NOC signed an agreement with Russia's Gazprom for Block 64. Under the terms of the deal, Gazprom committed to invest US$110mn in an exploration programme that will see it undertake a 3D seismic survey of a 1,750sq km area and 2D seismic of 1,500km, as well as drill six wells. Gazprom will also pay a US$10mn signature bonus for Block 64, which is located in the south-western region of Ghadames. Meanwhile, ExxonMobil has agreed to invest US$97mn in the project and pay a signature bonus of US$72mn.

Following this, Gazprom and NOC agreed to set up a JV that is to operate in all aspects of Libya's oil and gas sector in April 2008. According to Gazprom's CEO, Alexei Miller, the JV will undertake geological prospecting, E&P, transportation, sales and infrastructure developments. He said that Gazprom was interested in participating in LNG projects, as well as taking part in the construction of a gas pipeline from Libya to Italy.

In April 2010 Gazprom subsidiary Gazprom Neft announced that it had agreed terms to acquire a stake in Libya's Elephant oil field. Under the deal Gazprom Neft will take half of Eni's stake in the field, or 33% of the total interest. In return Eni will farm into some of Gazprom Neft's interests in Russia.

RWE – Summary

Germany's RWE has said that it will spend at least US$76mn on drilling two exploration wells in its newly awarded gas blocks in Libya. RWE was awarded a 30% stake in blocks 1, 2, 3 and 4 at area 58 in the Cyrenaica Basin in December 2007, in Libya's first gas licensing round since the lifting of international sanctions. The German company will explore the blocks in partnership with NOC, which will hold the remaining 70%. According to NOC, RWE's interest in the blocks will decrease once commercial production begins and will continue to decline as production grows.

Before the latest acquisition, RWE had total acreage of 30,000sq km in Libya, covering six concessions that were awarded by NOC in May 2003. The company's first discovery was announced by NOC in April 2007. At the end of September 2008, RWE made its eighth discovery in Libya on the NC193 concession in the Sirte Basin. This is the second discovery made by RWE and NOC on NC193 in September 2008. RWE has plans to drill additional appraisal wells during the remainder of 2008 to explore further a group of five discoveries made on the NC193 concession. The company will have a 32% share in each discovery, with NOC holding the remaining 68% stake.

Verenex Energy – Summary

Canadian explorer Verenex Energy entered into an agreement to be acquired by the Libyan Investment Authority (LIA) for CAD314.1mn (US$293.7mn) in November 2009, following CNPC's withdrawal of its CAD499mn bid for the company in September of that year. CNPC cancelled its bid following months of wrangling over the proposed purchase with the Libyan government. Following CNPC's withdrawal and Libya's eagerness to acquire Verenex, albeit for a lower price, the company has had little choice but to accept LIA's offer. Verenex has said that it will try to secure agreement for the deal from its management and major shareholder, **Vermilion Resources**. The agreement was approved by 99.5% of Verenex's shareholders on December 11 2009. Under the deal, LIA will acquire all of the issued and outstanding shares in Verenex for CAD7.24 per share, or a total of CAD357mn, significantly below the CAD10/share bid that CNPC offered in February 2009.

After CNPC launched its CAD10/share bid for Verenex, NOC said it would exercise its rights of first refusal to buy the company, with the contractual pre-emption clause requiring NOC to match CNPC's offer. However, although no matching offer was put forward by NOC, the sale to CNPC remained blocked, resulting in the Chinese state company eventually losing patience with the deal and deciding to pull out. The Chinese exit from the deal left Verenex alone to negotiate with Libya, which was unwilling to pay as high a price as CNPC. This stance reflects a common view among Libyan politicians that the government should not have to pay a market price for what it sees as its own land and mineral rights.

Verenex is active in Libya through its 50% share and operatorship over Area 47. The company was awarded an exploration and production sharing agreement (EPSA) for the area as part of Libya's first licensing round in 2005. Its partner and the block's operator is Indonesia's Medco, which holds the remaining 50%. According to a November 2008 independent survey of Area 47, carried out by the service group **DeGolyer and MacNaughton**, the area holds gross prospective resources of around 2.15bn boe. In addition to its interest in Libya, Verenex also holds shares in three exploration licences (two offshore and one onshore) in France and one in Canada.

Others – Summary

India's state-owned IOC and Oil India in 2006 won a licence to explore the 7,087sq km block 086 in the Sirte Basin. The Indian companies receive an 18.4% share of any future production in the block, with the remainder going to Libya's NOC. Other recent market entrants include Turkey's **TPAO** and India's **ONGC Videsh**, which are exploring blocks NC 188 and NC 189 in the Sirte and Ghadames Basin. Chilean state oil company **ENAP**'s international unit **Sipetrol** in August 2004 unveiled plans to invest in Libyan crude oil E&P.

Newly merged **GDF Suez** acquired a 20% participating interest in an E&P licence in Libya from Greece's Hellenic Petroleum in September 2008. The other partners in the licence, operator Woodside (45%) and Repsol YPF (35%), as well as NOC have already approved the acquisition, which now needs only to be ratified by the Libyan parliament. The licence covers five onshore blocks that are located in the Sirte Basin and one onshore block in the Murzuq Basin, which cover a total acreage of 20,129sq km. Under the terms of the licence, the partners also have the option to negotiate the terms of the appraisal and development of an additional block in the Murzuq Basin.

Brazil's Petrobras and Australian partner Oil Search in May 2009 spudded the A1-18/01 wildcat well in offshore Area 18. The well was drilled to a total depth of 4,700m, and was abandon after failing to encounter pay. Petrobras is the operator of the concession with 70% interest; Oil Search has the remaining 30%. The licence for the well was awarded in 2005 and expired in March 2010.

Japan's Inpex, in partnership with Total, was the winning bidder for the Area 042 blocks 2 and 4 in Libya's second bidding round. The block is located in the Cyrenaica Basin in the north-east part of the country and covers 3,419 sq km. Inpex has a 40% participating interest in the block and Total is the operator (60%).

In November 2010, Libya's Waha Oil Company announced three discoveries in the Sirte Basin. The 6R1-59 appraisal well, drilled to a total depth of 3,475m, produced 1,321b/d of crude and 33,980 cubic metres per day (mcm/d) of gas during initial testing. The second well, 6P1-59, produced oil at a rate of 637b/d. The well was drilled to a total depth of 3,795m. The third well, UU1-71, produced 765b/d of oil.

Turkey's **Türkiye Petrolleri Anonim Ortakligi**'s (TPAO) subsidiary **Turkish Petroleum Overseas Company** (TPOC) announced in December 2010 that it had discovered 35m of net hydrocarbon pay with its F1-147/03 exploration well in the Murzuq Basin. The well, drilled to a total depth of 2,507m, flowed oil at a rate of 1,032b/d during testing. The discovery is the fourth made by the company in the area. TPOC is the operator of the well with a 9.7% stake, working alongside NOC with the remaining 90.3%.

Oil And Gas Outlook: Long-Term Forecasts

Regional Oil Demand

An acceleration of the 2010-2015 oil demand trend is predicted for the 2015-2020 period, reflecting the underdeveloped nature of several key economies, plus ongoing wealth generation thanks to robust energy prices and rising export volumes. The region's oil consumption is expected to increase by 18.6% in 2015-2020, after 15.5% growth in 2010-2015. Over the extended 2010-2020 forecast period, Angola leads the way, with oil demand increasing by an estimated 343%, followed by Nigeria's impressive 97% growth. South Africa lags behind the rest of the field, as a result of greater market maturity and the lack of hydrocarbons income that stimulates economies elsewhere in the region.

Table: Africa's Oil Consumption, 2012-2019 (000b/d)

Country	2013f	2014f	2015f	2016f	2017f	2018f	2019f	2020f
Algeria	383	399	415	431	449	467	485	505
Angola	149	179	215	258	296	341	378	416
Cameroon	40	42	44	46	48	50	53	56
Republic of Congo	8	8	9	9	10	10	11	11
Egypt	810	835	860	885	912	939	968	997
Equatorial Guinea	1	1	1	2	2	2	2	2
Gabon	16	17	18	19	20	21	22	23
Libya	**308**	**320**	**333**	**346**	**360**	**375**	**390**	**405**
Nigeria	342	367	395	425	456	491	528	567
South Africa	547	555	564	572	581	598	607	616
Sudan	101	106	111	117	123	129	136	142
BMI universe	2,706	2,830	2,964	3,110	3,256	3,422	3,578	3,747
Other Africa	1,425	1,432	1,439	1,446	1,453	1,461	1,468	1,475
Regional total	4,131	4,262	4,403	4,556	4,710	4,883	5,046	5,222

f = forecast. Source: BMI

Regional Oil Supply

A 7.2% gain in African oil production during the 2015-2020 period represents a significant slowing from the rate of expansion seen in 2010-2015 (18.7%), and reflects a plateau in likely Angolan output, with no other major country expected to have substantial longer-term upside potential. Nigeria is by far the biggest contributor to growth, with output forecast to rise by 49.6% between 2010 and 2020. Its nearest rival, with 40.2% growth forecast, is Algeria. Egypt and Congo have the weakest production trends, with likely 18.2% and 11.7% declines between 2010 and 2020.

Table: Africa's Oil Production, 2013-2020 (000b/d)

Country	2013f	2014f	2015f	2016f	2017f	2018f	2019f	2020f
Algeria	1,995	2,050	2,200	2,310	2,400	2,475	2,515	2,600
Angola	2,100	2,250	2,375	2,450	2,400	2,250	2,100	2,000
Cameroon	83	95	98	96	94	92	90	89
Republic of Congo	346	339	332	325	319	313	306	300
Egypt	700	698	681	664	647	631	615	600
Equatorial Guinea	430	447	455	446	437	428	420	411
Gabon	250	245	240	235	230	226	221	217
Libya	**1,750**	**1,815**	**1,880**	**1,925**	**1,990**	**2,050**	**2,110**	**2,250**
Nigeria	2,535	2,600	2,750	2,910	3,100	3,300	3,400	3,500
South Africa	16	16	15	15	14	14	14	14
Sudan	691	735	770	755	740	725	710	696
BMI universe	10,896	11,290	11,796	12,131	12,371	12,503	12,502	12,620
Other Africa	269	277	285	293	302	311	321	330
Regional total	11,164	11,566	12,080	12,424	12,673	12,815	12,823	12,950

f = forecast. Source: BMI

Regional Refining Capacity

Africa is set for a 63.4% increase in crude distillation capacity between 2010 and 2020, contributing modestly to the expansion of the world's over-stretched refining industry. Cheap and plentiful local crude supplies should increasingly make it a region of choice for refinery investment, although government control of the downstream industry will need to be eased. Angola has particularly ambitious expansion plans, reflecting the surge in crude supply and growth in local demand. Nigeria is also expected to increase its capacity substantially, with Libya and South Africa also planning new refining sites. The region should increase in importance as a net exporter of refined products.

Table: Africa's Oil Refining Capacity, 2013-2020 (000b/d)

Country	2013f	2014f	2015f	2016f	2017f	2018f	2019f	2020f
Algeria	494	494	794	794	794	794	794	794
Angola	39	39	139	239	239	239	239	239
Cameroon	70	70	70	70	70	70	70	70
Republic of Congo	21	21	21	21	21	21	21	21
Equatorial Guinea	na	na	na	na	na	na	na	na
Egypt	726	976	976	976	976	976	976	976
Gabon	24	30	30	30	30	30	30	30
Libya	**578**	**578**	**725**	**725**	**725**	**725**	**725**	**725**
Nigeria	540	540	720	720	720	720	720	720
South Africa	485	485	485	485	885	885	885	885
Sudan	122	122	152	152	152	152	152	152
BMI universe	3,099	3,355	4,112	4,212	4,612	4,612	4,612	4,612
Other Africa	510	536	562	590	620	651	683	718
Regional total	3,609	3,891	4,674	4,802	5,232	5,263	5,295	5,330

f = forecast. na = not applicable. Source: BMI

Regional Gas Demand

Gas demand growth could decelerate somewhat between 2015 and 2020, when compared with the 42.6% rate expected for the 2010-2015 period. There is likely to be some 37.1% gas market expansion in the region in the final five years of the period. Expansion of gas consumption is expected to be at its greatest in Angola, Cameroon, Nigeria, South Africa and the Republic of Congo. Egypt and Libya are likely to lag behind the field.

Table: Africa's Gas Consumption, 2013-2020 (bcm)

Country	2013f	2014f	2015f	2016f	2017f	2018f	2019f	2020f
Algeria	32.1	33.7	35.1	36.7	38.3	39.9	42.6	45.6
Angola	8.1	9.3	10.6	12.2	14.1	16.2	18.6	21.4
Cameroon	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.4
Republic of Congo	1.5	2.0	2.0	2.4	3.0	3.0	3.0	3.0
Egypt	52.3	54.4	56.6	59.4	62.4	65.5	68.8	72.2
Equatorial Guinea	1.9	2.0	2.1	2.2	2.3	2.4	2.5	2.6
Gabon	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Libya	**9.0**	**9.6**	**10.0**	**10.4**	**10.8**	**11.2**	**11.7**	**12.1**
Nigeria	19.5	23.0	26.0	29.5	32.0	36.0	40.0	45.0
South Africa	10.5	12.0	14.0	15.0	17.0	17.0	17.0	17.0
Sudan	na	na	na	na	na	na	na	na
BMI universe	136.1	147.2	157.6	169.1	181.2	192.5	205.6	220.4
Other Africa	16.6	17.4	18.2	19.2	20.1	21.1	22.2	23.3
Regional total	152.7	164.6	175.9	188.2	201.3	213.6	227.8	243.7

f = forecast. na = not applicable. Source: BMI

Regional Gas Supply

A production increase of 23.2% is forecast for Africa in 2015-2020, representing a deceleration compared with the 47.0% predicted during the 2010-2015 period. Angola's explosive growth in the first half of the forecast period is not sustainable at the same rate, although its volumes could still rise 107% in 2015-2020, compared with 252% in 2010-2015. Nigeria is the other key player in the region. Gas production is expected to increase by 36% in 2015-2020, after 69% in 2010-2015. Cameroon could see production increase from 0.2bcm to 5.0bcm during the 10-year period.

Table: Africa's Gas Production, 2013-2020 (bcm)

Country	2013f	2014f	2015f	2016f	2017f	2018f	2019f	2020f
Algeria	111.0	116.5	122.0	125.0	130.0	132.0	135.0	140.0
Angola	15.0	16.3	17.6	24.2	26.1	28.2	33.6	36.4
Cameroon	0.2	0.2	0.3	4.8	4.8	4.9	5.0	5.0
Republic of Congo	1.5	2.0	2.0	2.4	3.0	3.0	3.0	3.0
Egypt	73.0	75.0	77.0	84.0	86.5	89.0	92.0	95.0
Equatorial Guinea	6.6	6.7	6.8	6.9	7.0	7.1	7.3	7.5
Gabon	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Libya	**19.5**	**20.5**	**25.0**	**25.5**	**26.0**	**26.0**	**27.0**	**27.0**
Nigeria	48.0	52.0	59.0	62.0	65.0	69.0	75.0	80.0
South Africa	7.0	7.0	7.0	6.0	6.0	6.0	5.0	5.0
Sudan	na	na	na	na	na	na	na	na
BMI universe	282.8	297.2	317.7	341.8	355.4	366.2	383.9	399.9
Other Africa	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
Regional total	287.8	302.2	322.6	346.8	360.4	371.2	388.9	404.9

f = forecast. na = not applicable. Source: BMI

Libya Country Overview

Between 2010 and 2020, we are forecasting an increase in Libyan oil and gas liquids production of 36.0%, with volumes rising steadily to 2.25mn b/d by the end of the 10-year forecast period. Oil consumption between 2010 and 2020 is set to increase by 45.2%, with growth slowing to an assumed 4.0% per annum towards the end of the period and the country using 405,000b/d by 2020. Gas production is expected to rise to 27bcm by the end of the period. With demand rising by 92.8% between 2010 and 2020, there should be export potential increasing to around 15bcm, via pipeline and in the form of LNG.

Methodology And Risks To Forecasts

In terms of oil and gas supply, as well as refining capacity, the projections are wherever possible based on known development projects, committed investment plans or stated government/company intentions. A significant element of risk is clearly associated with these forecasts, as project timing is critical to volume delivery. Our assumptions also take into account some third-party estimates, such as those provided by the EIA, the IEA, OPEC and certain consultants' reports that are in the public domain. Reserves projections reflect production and depletion trends, expected exploration activity and historical reserves replacement levels.

We have assumed flat oil and gas prices throughout the extended forecast period, but continue to provide sensitivity analysis based on higher and lower price scenarios. Investment levels and production/reserves trends will of course be influenced by energy prices. Oil demand has provide itself to be less sensitive to pricing than expected, but will still have some bearing on consumption trends. Otherwise, we have assumed a slowing of GDP growth for all countries beyond our core forecast period (to 2012) and a further easing of demand trends to reflect energy-saving efforts and fuels substitution away from hydrocarbons. Where available, government and third-party projections of oil and gas demand have been used to cross check our own assumptions.

Glossary Of Terms

AOR	Additional Oil Recovery
APA	Awards for Predefined Areas
API	American Petroleum Institute
bbl	barrel
bcm	billion cubic metres
b/d	barrels per day
bn	billion
boe	barrels of oil equivalent
BTC	Baku-Tbilisi-Ceyhan Pipeline
BTU	British Thermal Unit
Capex	capital expenditure
CBM	coal bed methane
CEE	Central and Eastern Europe
CPC	Caspian Pipeline Consortium
CSG	coal seam gas
DoE	US Department of Energy
EBRD	European Bank for Reconstruction &
EEZ	exclusive economic zone
e/f	estimate/forecast
EIA	US Energy Information Administration
EM	emerging markets
EOR	enhanced oil recovery
E&P	exploration and production
EPSA	exploration and production sharing
FID	final investment decision
FDI	foreign direct investment
FEED	front end engineering & design
FPSO	floating production, storage & offloading
FTA	free trade agreement
FTZ	free trade zone
GDP	gross domestic product
G&G	geological and geophysical
GoM	Gulf of Mexico
GS	geological survey
GTL	gas-to-liquids conversion
GW	gigawatts
GWh	gigawatt hours
HDPE	high density polyethylene
HoA	Heads of Agreement
IEA	International Energy Agency
IGCC	Integrated Gasification Combined Cycle
IOC	international oil company
IPI	Iran-Pakistan-India Pipeline
IPO	initial public offering
JOC	joint operating company
JPDA	Joint Petroleum Development Area
KCTS	Kazakh Caspian Transport System
km	kilometres
LAB	Linear Alkyl Benzene
LDPE	low density polypropylene
LNG	liquefied natural gas
LPG	liquefied petroleum gas
m	metres
mcm	thousand cubic metres
Mcm	mn cubic metres
MEA	Middle East and Africa
mn	million
MoU	Memorandum of Understanding
mt	metric tonne
MW	megawatts
na	not available/ applicable
NGL	natural gas liquids
NOC	national oil company
OECD	Organisation for Economic Cooperation & Development
OPEC	Organisation of the Petroleum Exporting Countries
PE	polyethylene
PP	polypropylene
PSA	production sharing agreement
PSC	production sharing contract
q-o-q	quarter-on-quarter
R&D	research and development
R/P	reserves/production
RPR	reserves to production ratio
SGI	strategic gas initiative
SoI	Statement of Intent
SPA	Sale and Purchase Agreement
SPR	Strategic Petroleum Reserve
t/d	tonnes per day
tcm	trillion cubic metres
toe	tonnes of oil equivalent
tpa	tonnes per annum
TRIPS	Trade-Related Aspects of Intellectual Property
trn	trillion
T&T	Trinidad and Tobago
TTPC	Trans-Tunisian Pipeline Company
TWh	terawatt hours
UAE	United Arab Emirates
USGS	US Geological Survey
WAGP	West African Gas Pipeline
WIPO	World Intellectual Property Organisation
WTI	West Texas Intermediate
WTO	World Trade Organisation

Oil And Gas Ratings: Revised Methodology

Introduction

BMI has revised the methodology of its Oil & Gas Business Environment Ratings. Our approach has been threefold. First, we have disaggregated the upstream (oil/gas E&P) and downstream (oil refining and marketing, gas processing and distribution), enabling us to take a more nuanced approach to analysing the potential within each segment, and the different risks along the value chain. Second, we have identified objective indicators that may serve as proxies for issues/trends that were previously evaluated on a subjective basis. Finally, we have used **BMI**'s proprietary Country Risk Ratings (CRR) in a more refined manner in order to ensure that only those risks most relevant to the industry have been included. Overall, the new ratings system – which is now integrated with those of all 16 industries covered by **BMI** – offers an industry-leading insight into the prospects/risks for companies across the globe.

Ratings Overview

Conceptually, the new ratings system is organised in a manner that enables us clearly to present the comparative strengths and weaknesses of each state. As before, the headline Oil & Gas BER is the principal rating. However, the differentiation of Upstream/Downstream and the articulation of the elements that comprise each segment enable more sophisticated conclusions to be drawn, and also facilitate the use of the ratings by clients, who will have varying levels of exposure and risk appetite for their operations.

Oil & Gas Business Environment Rating: This is the overall rating, which comprises 50% Upstream BER and 50% Downstream BER:

Upstream Oil & Gas Business Environment Rating: This is the overall Upstream rating which is composed of limits/risks (see below);

Downstream Oil & Gas Business Environment Rating: This is the overall Downstream rating which comprises limits/risks (see below).

Both the Upstream BER and Downstream BER are composed of Limits/Risks sub-ratings, which themselves comprise industry-specific and broader Country Risk components:

Limits of Potential Returns: Evaluates the sector's size and growth potential in each state, and also broader industry/state characteristics that may inhibit its development;

Risks to Realisation of those Returns: Evaluates both Industry-specific dangers and those emanating from the state's political/economic profile that call into question the likelihood of expected returns being realised over the assessed time period.

Table: BMI Oil And Gas Business Environment Ratings: Structure

Component	**Details**
Oil & Gas Business Environment Rating	**Overall rating**
- Upstream BER	50% of O&G BER
-- Limits of Potential Returns	- 70% of Upstream BER
--- Upstream Market	-- 75% of Limits
--- Country Structure	-- 25% of Limits
-- Risks to Realisation of Potential Returns	- 30% of Upstream BER
--- Industry Risks	-- 65% of Risks
--- Country Risks	-- 35% of Risks
- Downstream BER	50% of O&G BER
-- Limits of Potential Returns	- 70% of Downstream BER
--- Upstream Market	-- 75% of Limits
--- Country Structure	-- 25% of Limits
-- Risks to Realisation of Potential Returns	- 30% of Downstream BER
--- Industry Risks	-- 60% of Risks
--- Country Risks	-- 40% of Risks

Source: BMI

Indicators

The following indicators have been used. Overall, the rating uses three subjectively measured indicators, and 41 separate indicators/datasets.

Table: BMI Oil And Gas Business Environment Upstream Ratings: Methodology

Indicator	Rationale
Upstream BER: Limits to potential returns	
Upstream Market	
Resource base	
- Proven oil reserves (mn bbl)	Indicators used to denote total market potential. High values are given better scores.
- Proven gas reserves (bcm)	
Growth outlook	
- Oil production growth (2009-2014)	Indicators used as proxies for BMI's market assumptions, with strong growth accorded higher scores.
- Gas production growth (2009-2014)	
Market maturity	
- Oil reserves/ production	Indicator used to denote whether industries are frontier/emerging/developed or mature markets. Low existing exploitation in relation to potential is accorded higher scores.
- Gas reserves/ production	
- Current oil production vs. peak	
- Current gas production vs. peak	
Country structure	
State ownership of assets, %	Indicator used to denote opportunity for foreign NOCs/IOCs/Independents. Low state ownership scores higher.
Number of non-state companies	Indicator used to denote market competitiveness. Presence (and large number) of non-state companies scores higher.
Upstream BER: Risks to potential returns	
Industry Risks	
Licensing terms	Subjective evaluation of government policy towards sector against BMI-defined criteria. Protectionist states are marked down.
Privatisation trend	Subjective evaluation of government industry orientation. Protectionist states are marked down.
Country Risk	
Physical Infrastructure	Rating from BMI's CRR. It evaluates the constraints imposed by power, transport & communications infrastructure.
Long Term Policy Continuity Risk	Rating from BMI's CRR It evaluates the risk of a sharp change in the broad

Table: BMI Oil And Gas Business Environment Upstream Ratings: Methodology

Indicator	Rationale
	direction of government policy.
Rule of Law	Rating from BMI's CRR. It evaluates the government's ability to enforce its will within the state.
Corruption	Rating from BMI's CRR, to denote risk of additional illegal costs/possibility of opacity in tendering/business operations affecting companies' ability to compete.

Source: BMI

Table: BMI Oil And Gas Business Environment Downstream Ratings: Methodology

Indicator	Rationale
Downstream BER: Limits to potential returns	
Downstream Market	
Market	
- Refining capacity (000b/d)	Indicator denotes existing domestic oil processing capacity. High capacity is considered beneficial.
- Oil demand (000b/d)	Indicator denotes size of domestic oil/gas market. High values are accorded better scores.
- Gas demand (bcm)	
- Retail outlets/1,000 people	Indicator denotes fuels retail market penetration; low penetration scores highly.
Growth outlook	
- Oil demand growth (2009-2014)	Indicators used as proxies for BMI's market assumptions, with strong growth accorded higher scores.
- Gas demand growth (2009-2014)	
- Refining capacity growth (2009-2014)	
Import dependence	
- Refining capacity vs. oil demand, % (2009-2014)	Indicators denote reliance on imported oil products and natural gas. Greater self-sufficiency is accorded higher scores.
- Gas demand vs. gas supply, % (2009-2014)	
Country structure	
State ownership of assets, %	Indicator used to denote opportunity for foreign NOCs/IOCs/Independents. Low state ownership scores higher.
No. of non-state companies	Indicator used to denote market competitiveness. Presence (and large number) of non-state companies scores higher.

Table: BMI Oil And Gas Business Environment Downstream Ratings: Methodology

Indicator	Rationale
Population, mn	Data from BMI's CR team. Indicators used as proxies for overall market size and future potential.
Nominal GDP, US$bn	
GDP per capita, US$	
Downstream BER: Risks to potential returns	
Industry Risks	
Regulation	Subjective evaluation of government policy towards sector against BMI-defined criteria. Bureaucratic/intrusive states are marked down.
Privatisation trend	Subjective evaluation of government industry orientation. Protectionist states are marked down.
Country Risk	
Short Term Policy Continuity Risk	Rating from BMI's CRR. It evaluates the risk of a sharp change in the broad direction of government policy.
Short Term Economic External Risk	Rating from BMI's CRR. It evaluates the vulnerability to external economic shock, the typical trigger of recession in Emerging Markets.
Short Term Economic Growth Risk	Rating from BMI's CRR. It evaluates the current trajectory of growth and the state's position in the economic cycle.
Rule of Law	Rating from BMI's CRR. It evaluates the government's ability to enforce its will within the state.
Legal Framework	Rating from BMI's CRR, to denote risk of additional illegal costs/possibility of opacity in tendering/business operations affecting companies' ability to compete.
Physical Infrastructure	Rating from BMI's CRR. It evaluates the constraints imposed by power, transport & communications infrastructure.

Source: BMI

BMI Methodology

How We Generate Our Industry Forecasts

BMI's industry forecasts are generated using the best-practice techniques of time-series modelling. The precise form of time-series model we use varies from industry to industry, in each case being determined, as per standard practice, by the prevailing features of the industry data being examined. For example, data for some industries may be particularly prone to seasonality, meaning seasonal trends. In other industries, there may be pronounced non-linearity, whereby large recessions, for example, may occur more frequently than cyclical booms.

Our approach varies from industry to industry. Common to our analysis of every industry, however, is the use of vector autoregressions. Vector autoregressions allow us to forecast a variable using more than the variable's own history as explanatory information. For example, when forecasting oil prices, we can include information about oil consumption, supply and capacity.

When forecasting for some of our industry sub-component variables, however, using a variable's own history is often the most desirable method of analysis. Such single-variable analysis is called univariate modelling. We use the most common and versatile form of univariate models: the autoregressive moving average model (ARMA).

In some cases, ARMA techniques are inappropriate because there is insufficient historical data or data quality is poor. In such cases, we use either traditional decomposition methods or smoothing methods as a basis for analysis and forecasting.

It must be remembered that human intervention plays a necessary and desirable part of all our industry forecasting techniques. Intimate knowledge of the data and industry ensures we spot structural breaks, anomalous data, turning points and seasonal features where a purely mechanical forecasting process would not.

Energy Industry

There are a number of principal criteria that drive our forecasts for each energy indicator.

Energy supply

Supply of crude oil, natural gas, refined oil products and electrical power is determined largely by investment levels, available capacity, plant utilisation rates and national policy. We therefore examine:

- national energy policy, stated output goals and investment levels;

- company-specific capacity data, output targets and capital expenditures, using national, regional and multinational company sources;

- international quotas, guidelines and projections, such as OPEC, the IEA, and the EIA.

Energy consumption
A mixture of methods is used to generate demand forecasts, applied as appropriate to each individual country:

- underlying economic (GDP) growth for individual countries/regions, sourced from **BMI** published estimates. Historical relationships between GDP growth and energy demand growth at an individual country are analysed and used as the basis for predicting levels of consumption;

- government projections for oil, gas and electricity demand;

- third party agency projections for regional demand, such as the IEA, the EIA, and OPEC;

- extrapolation of capacity expansion forecasts, based on company- or state-specific investment levels.

Cross checks

Whenever possible, we compare government and/or third party agency projections with the declared spending and capacity expansion plans of the companies operating in each individual country. Where there are discrepancies, we use company-specific data as physical spending patterns to ultimately determine capacity and supply capability. Similarly, we compare capacity expansion plans and demand projections to check the energy balance of each country. Where the data suggest imports or exports, we check that necessary capacity exists or that the required investment in infrastructure is taking place.

Sources

Sources include those international bodies mentioned above, such as OPEC, IEA, and EIA, as well as local energy ministries, official company information, and international and national news agencies.