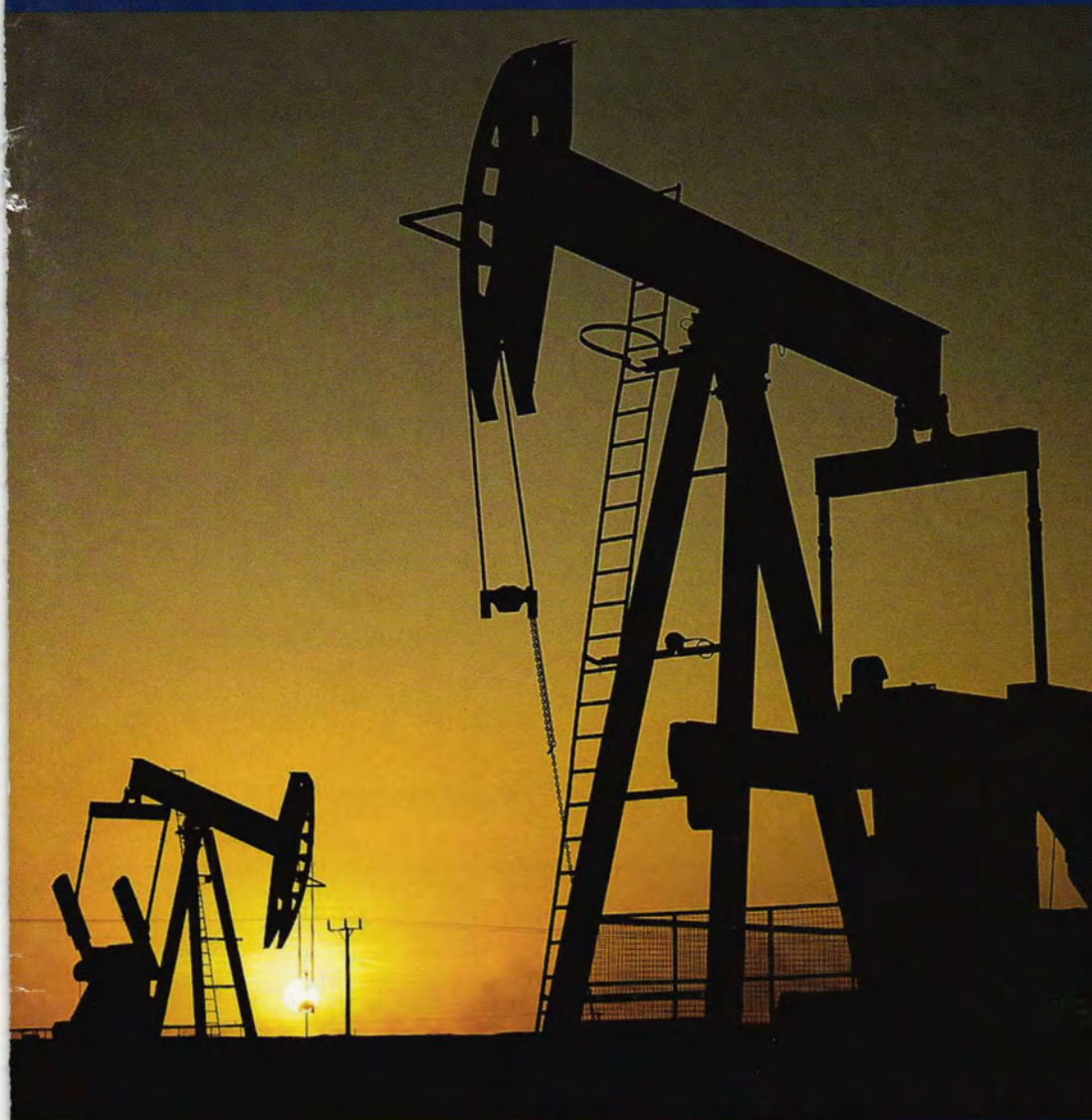


Petroleum *review*



IP WEEK 2005

- Conference retrospective

E & P

- Megaprojects to 2012 – tabulating future supplies

CLASSIFICATION/FABRICATION

- Class societies keep an eye on the future
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MIDDLE EAST

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Those working in the LNG industry in production, liquefaction, transportation and receiving, including those reliant upon LNG supply or the financing of LNG projects; analysts, planners and commercial staff, personnel operating in the gas, electricity and related energy industries and markets, regulators, advisors and policy makers, financiers, legal advisors and risk managers.

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Who should attend?

This course is particularly appropriate for those with experience in the oil, gas and energy industries wishing to widen their understanding and knowledge of the natural gas business. It is also suitable for those who are concerned with natural gas and work in other sectors such as banking or government where they need an understanding of the industry.

For more information please contact Nick Wilkinson

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ABBREVIATIONS

The following are used throughout *Petroleum Review*:
mn = million (10⁶) kW = kilowatts (10³)
bn = billion (10⁹) MW = megawatts (10⁶)
tn = trillion (10¹²) GW = gigawatts (10⁹)
cf = cubic feet kWh = kilowatt hour
cm = cubic metres km = kilometre
boe = barrels of oil sq km = square kilometres
equivalent
b/d = barrels/day
t/y = tonnes/year t/d = tonnes/day
No single letter abbreviations are used.
Abbreviations go together eg. 100mn cf/y = 100 million

Front cover picture:
Nodding donkeys, Oman
Photo: Petroleum Development Oman (PDO)

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The Energy Institute as a body is not responsible either for the statements made or opinions expressed in these pages. Those readers wishing to attend future events advertised are advised to check with the contacts in the organisation listed closer to the date, in case of late changes or cancellations.

Oil prices back to record levels

At the time of writing the price of Brent is over \$55/b and WTI above \$57/b – the highest ever oil prices in notional terms and the highest in inflation adjusted terms since the 1979–1985 price spike triggered by the Iranian revolution.

In response to record prices and strong US pressure, Opec has just raised its production quota by 0.5mn b/d to 27.5mn b/d. Saudi Arabia was the main advocate of the higher quota. However, the Opec-10 were already producing around 27.5mn b/d. Opec has scheduled a meeting to consider raising output, although it is unclear how this could be achieved.

Opec, in fact, has become a somewhat strange sort of cartel. One member – Indonesia – is now not even a net oil exporter. In February, Algeria, Iran, Kuwait, Libya, Nigeria and Qatar were all producing at all-time or recent year record output levels, according to the International Energy Agency's (IEA) March edition of the *Oil Market Report*. Venezuelan and Indonesian production continued to decline. The UAE was not at record output levels, reportedly because of work in the Murban field. This leaves only Saudi Arabia, with spare capacity estimated by the IEA at 0.80–1.30mn b/d, and Iraq (not subject to quotas), which produces as much as the insurgents will let it.

In short, the system is under real pressure. In this context, it is not surprising that, when the IEA revised its 2005 demand estimate up by 330,000 b/d to 84.3mn b/d for a 1.8mn b/d gain on the year, prices moved to record levels. The fact that Opec now anticipates oil demand growth of an even higher 1.9mn b/d in 2005, further wracked up prices. Opec output in February was 33.7mn b/d (including NGLs and non-conventionals) – just 480,000 b/d below its all-time record of 34.18mn b/d in October 2004.

It is therefore particularly timely that this issue includes our latest listing of *Petroleum Review's* megaprojects database (p16). This lists all the larger projects (peak production of over 100,000 b/d) and some smaller ones that may form production centres. In addition, all significant discoveries likely to become megaprojects are listed. This time the listing has been divided into Opec and non-Opec producers.

Simply totalling the new production available appears to suggest that supplies should be adequate to meet even vigorous demand growth. However, the volumes notionally available have to be deflated to allow for the impact

of depletion. Outright depletion (countries producing less than in the previous year) is currently running at around 1mn b/d each year (see *Petroleum Review*, August 2004). This means 1mn b/d of new capacity must be created each year before new demand is met or normal field declines offset. As a result, in 2004, net non-Opec capacity was just under 1mn b/d according to the IEA and just over 1mn b/d according to Opec.

Opec forecasts non-Opec supply gains in 2005 at 1.08mn b/d, broadly the same figure as BP's Manzoni gave in an IP Week presentation (see p28). The IEA reduced its estimate for non-Opec to 0.9mn b/d gain in 2005, but estimated a 1mn b/d capacity gain for Opec in 2005. There is now a large and hard to predict gap between notional gross capacity gains and their net delivery. With oil companies, governments and the IEA reluctant to publicly discuss and quantify the impact of depletion, oil traders will, of necessity, be forced to speculate on the inaccuracy of supply and demand projections, particularly when rapid demand growth pressures the system.

However, it is a sad truth that whenever the world focused on one potential crisis – in this case availability of oil supplies – another crisis emerges from the left field. Could a dollar crisis be the real wild card for 2005? The US is now running major budget and trade deficits. The budget deficit is of limited significance – 37 cents on the price of gasoline would close it, even if that particular option is unlikely from a Republican President.

The real problem is the trade deficit, which surged from \$530.7bn in 2003 to \$665.9bn in 2004 and appears set to increase further in 2005. For the moment the deficit is covered by inflows of \$2bn/d from countries wishing to hold dollar assets. However, nearly 80% of recent inflows are from just three sources – the central banks of Japan, China and South Korea – all reportedly becoming nervous at the sheer size of their dollar holdings. The development that would make holding dollars more attractive is higher US interest rates (which might kill the world boom). Failure to attract funds would drive the dollar lower (and cause a panic?).

Chris Skrebowski

The opinions expressed here are entirely those of the Editor and do not necessarily reflect the view of the EI.

A new website covering the human rights conduct of some 2,000 companies was recently launched at www.business-humanrights.org. The website brings abuses to international attention – from discrimination to pesticide poisoning, child labour to contamination of drinking water, sexual abuse to the displacement of indigenous peoples. It also highlights positive steps that certain companies are taking, such as promoting diversity, increasing access to HIV/AIDS drugs, reducing harmful emissions, improving working conditions in their supply chain.

CapitalLogica Consensus has launched www.Rustocks.com – an online analytical tool that provides detailed and consensus estimates of key indicators of Russian companies' activities and stock performance by major brokers.

Now available on the Drilling Research Institute's website at www.drillers.com is a free search facility that aims to simplify the search for oilfield personnel. Whilst the previous Energy Directories allowed site visitors to search for people and companies throughout the industry, the enhanced search function can find people by first name, phone number, company or city.

Custom efuels is a website template created by CH Jones, which allows members of its dealer network to offer customers new, flexible and improved ways of managing fleet and fuel information in real-time, greatly improving efficiency and reducing administration time. The system is underpinned by the technology behind CH Jones's own efuels site, which is available to all Keyfuels customers. Six dealers are now operating branded custom efuels websites and others are under development. For more information, visit www.chjones.co.uk

A long-running project that has documented the personal stories of the North Sea oil and gas industry has launched a website at www.abdn.ac.uk/oillives in the run up to the project's completion in May 2005. 'Lives in the Oil Industry' is an oral history project initiated by the University of Aberdeen and the British Library Sound Archive. The project currently comprises over 700 hours of archival recordings and is one of the biggest collections of its kind in the world. The website showcases many aspects of the project, its content and development. It also contains links to other relevant information on the UK North Sea industry.

Gas Matters has launched its second daily gas e-news service – 'Gas Matters Today Asia' – focusing on Asian gas market developments. For more information, visit www.GasMattersOnline.com

UK

For the first time since 1998 the whole of the North Sea will be open for oil and gas exploration with a record breaking 1,329 blocks on offer in the UK's 23rd Offshore Oil and Gas Licensing Round announced on 10 March 2005. More than 50 previously fallow blocks will be on offer that were not available in the previous round.

Ian Hewitt, Vice President-UK Upstream at BG Group, is to take over as the new President of the UK Offshore Operators Association (UKOOA).

Amec has been awarded a contract for the hook-up and commissioning support of the Buzzard oil and gas production platform in the central North Sea. The work will be undertaken in 2005 and 2006. Buzzard is operated by Nexen Petroleum and is being developed with co-venturers Petro-Canada, BG Group and Edinburgh Oil & Gas.

The BP-operated (28.6%) Clair oil field in blocks 206/7a, 206/12, 206/8, 206/13a and 206/9 recently came onstream. Production is expected to peak at 60,000 b/d of oil and 15mn cfd of gas in the first stage of field development. Recoverable reserves from the initial phase of development are put at 250mn barrels of oil. The Clair development comprises a conventional platform with production and process topside facilities, supported by a fixed steel jacket. Oil will be exported to the Sullom Voe terminal in Shetland. Gas will be exported to the Magnus enhanced oil recovery trunkline.

EUROPE

The Norwegian Ministry of Petroleum and Energy has received nominations from 19 companies for blocks for the 19th licensing round on the Norwegian Continental Shelf. These companies are: Amerada Hess, BG, BP, ChevronTexaco, ConocoPhillips, DNO,

Errata

Please note that the text within the first paragraph in the box piece on page 17 of the March issue contained an error. It should have read: 'In this regard, Libya is in a better position than Algeria, Egypt and Nigeria as it is free from the political violence and civil unrest that grips the other three countries.'

PDO's first full-scale EOR project

The shareholders of Petroleum Development Oman (PDO) have taken the final decision to invest in the company's first full-scale enhanced oil recovery (EOR) project as part of the development of a cluster of oil fields near Harweel, in south Oman. The \$600mn field development, known as Harweel Phase 2A/B, builds on the earlier Harweel Phase 1 pilot project that resulted in four oil fields coming onstream in 2004, beginning with the Zalzal field in March. It is this field that has now been earmarked for a full-scale EOR project. The other oil fields to be developed in Harweel Phase 2A/B – Sakhiya and Dafaq – will, for the time being, be developed by means of conventional recovery techniques.

The principle of the EOR technique being applied at Zalzal – miscible-gas injection – is based on the blending of the gas with the oil in the reservoir rock, to form essentially one fluid. The single-fluid nature of the mixture makes it move much more easily through the reservoir and into the producing wells. In essence, the injected gas acts as an oil solvent that 'cleans' the reservoir of its oil. Without the miscible-gas injection, only about 10% of the oil originally in place in the Harweel-cluster reservoirs could be expected to be recovered. But with the application of miscible-gas injection, the percentage of oil recovered can be increased to 33% or more.

Part of the gas to be injected into the

Zalzal reservoir will be produced from the nearby government-owned Rabab gas field and transported by pipeline to the oil production facilities, where it will be compressed into deep injector wells. The hydrocarbons flowing from the producing wells will be separated into oil and gas components. The oil will then be shipped by pipeline to the coast, but the gas will be re-compressed and re-injected again and again until as much oil as economically possible has been produced from the fields in the cluster. 'This EOR process is applied elsewhere in the world, but it had never before been done in Oman,' points out Harweel Project Manager Steven van Rossem.

The Harweel Phase 2A/B development will constitute one of the largest oil-field projects that PDO has undertaken in many years. By adopting a phased approach to the development of all the Harweel-cluster fields (the first of which was discovered in 1997), PDO has minimised the overall investment risk. Phase 1 confirmed the viability of miscible-gas injection at Zalzal whilst delivering some 15,000 b/d by the end of this year. Phase 2A/B will confirm the viability of miscible-gas injection at Sakhiya whilst delivering 50,000 b/d by the end of 2007. Investment proposals for further follow-up projects are currently being prepared that, if approved, could boost oil production from Harweel to some 100,000 b/d in 2010.

China unveils plans for Dina gas field

PetroChina is reportedly planning to start up the large Dina gas field in China's Tarim Basin in the remote Xinjiang Uighur Autonomous Region by the end of 2006. The field is expected to produce 5.1bn cm³/y of gas, which will be fed in to China's flagship 4,000-km West-East pipeline. It will also produce some 300,000 t/y of condensate.

China is keen to develop its gas sector as it faces declining domestic oil reserves and surging demand. The country aims to raise natural gas to 8% of its energy mix by 2010, up from the current 3%. The country's main producing gas field at present is Jingbian, in north-west Shaanxi province, followed by the Kela-2 field, which is also in Xinjiang and lies adjacent to the new Dina field. Both fields are currently feeding in to the \$8.5bn West-East pipeline. Gas sales via the pipeline are expected to rise to 4bn cm³ in 2005 – about one-tenth of China's total gas production. PetroChina was reported to have said in December 2004 that it aimed to raise sales to the full designed capacity of 12bn cm³ by 2007 – a year ahead of schedule.

Petro-Canada takes stake in Fort Hills oil sands

Petro-Canada has taken a 60% stake in, and will act as operator of, UTS Energy's C\$1bn (\$810mn) Fort Hills oil sands project in north-east Alberta. To pay for its stake, Petro-Canada will fund 75% of UTS' share of the next \$1bn of development capital, or \$300mn.

UTS is currently the owner of a block of oil sands leases north of Fort McMurray and has a plan to develop

2.8bn barrels of bitumen resource. The resource is a long-life asset that has no exploration risk and significant development potential with further investment. Current plans call for an initial mining development producing 50,000 b/d and corresponding upgrader. Subsequent development phases would expand production up to 190,000 b/d of bitumen integrated with upgrading.

Eni, Gaz de France, Norsk Hydro, Idemitsu, Lundin, Marathon, RWE Dea, Shell, Statoil, Svenska, Talisman, Total and Wintershall. The 19th licensing round will give access to frontier acreage in the Norwegian Sea and the Barents Sea.

The Tofte discovery made by Statoil (41.6%) in the Norwegian Sea during January 2004 is to be tied back to the group's nearby Kristin platform at a cost of Nkr655mn. Recoverable reserves in Tofte are estimated to be 5bn cm of gas and 18mn barrels of condensate.

NORTH AMERICA

ExxonMobil has announced that additions to its worldwide proved oil and gas reserves totalled 1.8bn boe in 2004. According to Chairman Lee Raymond, this is 'the eleventh consecutive year of greater than 100% reserve replacement'. Proved reserve additions in Qatar totalled 1.7bn boe, with proved additions also made in West Africa from developments in Nigeria, Equatorial Guinea and Angola and from new developments and established operations in Europe and the Caspian region. With 22.2bn barrels of proved oil and gas reserves at year-end 2004, ExxonMobil's reserve life at current production rates is approximately 14 years. Approximately 63% of the company's proved reserves are already developed.

ABS is to class the ChevronTexaco 'Tahiti' truss spar, destined for the deepwater Gulf of Mexico. Targeted for 4,200 ft of water in Green Canyon blocks 640, 541 and 596, the Tahiti unit demonstrates the industry's latest innovations – including the first spar with no drilling capability, no surface wellheads – and is among the first spar projects to utilise ABS' industry-first guide for building and classing these specialised deepwater floating production units, reports Dick Vukin, ABS Project Manager.

MIDDLE EAST

PTT Exploration and Production Public (PTTEP) is understood to have signed a heads of agreement covering 50mn cfd of gas sales from the Shams field in Omani block 44, beginning in 4Q2005. PTTEP plans to invest approximately \$50mn to develop the Shams gas field in 2005.

The Syrian government has cancelled Petro-Canada and its partners' Syrian

Northern Producer contract extension



Sea Production has extended its contract with Petrofac Facilities Management for the provision of operations services on board the Northern Producer to July 2006. The Northern Producer, the floating production installation located on the Talisman-operated Galley field, is managed by Petrofac on behalf of Sea Production. The field is located in block 15/23a in the UKCS.

The Northern Producer is one of the North Sea's success stories. When the project started in 1998, it was forecast to have a lifespan of approximately four years and was regarded as a relatively short-term proposition. Seven years from first production, the field has produced nearly 55mn barrels of oil.

Latest UK offshore H&S statistics unveiled

The UK Health and Safety Executive (HSE) has published its full offshore health and safety statistics for 2003/2004. The report contains provisional injury and incident figures for the year 1 April 2003 to 31 March 2004, as well as finalised data for 2002/2003.

The figures show there were three fatal accidents during 2003/2004 compared to none in 2002/2003 and 48 'major' injury incidents, a decrease of 25% on last year's figures. In addition, the statistics show a continued downward trend in the number of over-three-day injuries, with 102 incidents reported during 2003/2004 compared to 120 in 2002/2003. The combined

fatal and major injury rate per 100,000 workers decreased to 271.4 in 2003/2004 from 310.4 in 2002/2003.

The Inland Revenue's annual population survey found the offshore workforce has decreased from 20,619 in 2002/2003 to 18,793 in 2003/2004.

Meanwhile, the HSE report also reveals a reduction in the number of dangerous occurrences, with 543 during 2003/2004 compared to 635 in 2002/2003. There were also 13 cases of work-related diseases reported during 2003/2004, a decrease of six on the previous year.

The HSE report can be downloaded from www.hse.gov.uk/offshore/statistics/hsr0304

Late-life development on Statfjord

The Statfjord licences have sanctioned the implementation of a late-life development on the North Sea field at a cost of Nkr14.5bn, plus Nkr1.5bn in the associated Tampen Link gas pipeline. These plans will ensure that the Statoil-operated field remains onstream until 2020. The plan is to convert installations on the field from producing oil with associated gas to recovering gas with associated oil. This involves changing the drainage strategy to low-pressure production in order to recover the remaining gas in the reservoir.

Additional recoverable volumes associated with Statfjord late life are estimated at 32bn cm of gas, 25mn barrels of oil and 60mn barrels of condensate. It is anticipated that, with the late life project, Statfjord will reach a recovery factor of close to 70% for oil and 75% for gas. Gas recovery without the project would be only 53%.

The field has already yielded 4bn barrels of oil in 25 years.

Middle Area Gas Project, stating that it does not want foreign-owned companies involved in developing the resource, reports Stella Zenkovich. The project would have produced 300mn cfd of gas.

Iranian Oil Minister Bijan Namdar Zanganeh is reported to have announced that two new oil and gas fields have been discovered in the south-western province of Khuzestan and the South Pars gas field respectively.

RUSSIA/CENTRAL ASIA

Gazprom is to drill two exploration wells at gas fields in eastern Siberia, writes Stella Zenkovich. The company plans to start work in April, under a five-year exploration licence for the Yuzhno-Kovykta acreage. The area may hold about 100bn cm of natural gas, a fifth of Europe's annual consumption.

Russian gas production is forecast to rise to 640bn cm in 2005, up from 625bn cm in 2004, reports Stella Zenkovich. Independent producers will account for 93 bn cm of 2005 production, up from 80bn cm in 2004.

A consortium of five Korean companies – the Korean National Oil Corporation (KNOC), Samsung Corporation, LG International, Daesung Industrial and SK – are reported to have signed an agreement with KazMunaiGas (KMG) of Kazakhstan to explore for oil in the Caspian Sea. The two countries are also to develop a field in the Zhambyl area of Kazakhstan.

ASIA-PACIFIC

Kerr-McGee has received approval from the China National Offshore Oil Corporation (CNOOC) for the development of the CFD 11-3 and CFD 11-5 fields on block 04/36 in Bohai Bay, China. First production from the development is expected in 2H2005.

Shell is divesting its non-operated stakes in the Laminaria (22.5%) and Corallina (25%) oil fields in the Timor Sea, together with associated infrastructure (Northern Endeavour FPSO) and contiguous exploration acreage (ACIP8; 15%). The properties are being sold to Woodside Energy and Paladin Oil & Gas under separate sales purchase agreements for a total of \$140.2mn.

A total of 11 new offshore petroleum exploration permits in the western Australian and Tasmanian adjacent areas have recently been granted. The

Year-on-year decline in UK oil and gas

UK oil production in December 2004 increased 4.8% on the month, rising to 1,817,724 b/d, according to the latest Royal Bank of Scotland Oil and Gas Index. However, December production

was down 11.6% on year earlier levels. Gas production was up 2.5% on the month, at 11,093mn cf/d, but decreased 12.2% on the year, partly as a result of mild weather in December.

Year Month	Oil production (av. b/d)	Gas production (av. mn cf/d)	Av. oil price (\$/b)
Dec 2003	2,056,469	12,642	29.84
Jan 2004	2,014,906	12,689	31.12
Feb	1,972,891	11,220	30.89
Mar	2,006,160	11,787	33.72
Apr	1,964,905	12,181	33.36
May	1,778,979	9,218	37.72
Jun	1,776,246	10,192	35.21
Jul	1,758,312	10,292	38.15
Aug	1,621,582	8,585	42.99
Sep	1,526,692	8,726	42.92
Oct	1,630,230	9,921	49.66
Nov	1,734,630	10,395	42.88
Dec	1,817,724	11,093	39.55

Source: The Royal Bank of Scotland Oil and Gas Index

North Sea oil and gas production

Global subsea market forecast

Quest Offshore's latest 2004 statistical review of the global subsea production market reveals a robust year-to-year increase of 60% compared with 2003, 362 subsea trees versus 226 subsea trees, respectively. West Africa orders represented a 32% share followed by the North Sea with 28%, Brazil/Latin America with approximately 17%, and North America with a 17% share. Asia-Pacific represented just less than 6% of total market activity.

The company forecasts a \$15.3bn market for subsea hardware (installed base) comprising subsea wellheads, trees, controls and manifolds from 2005–2010e, with the Golden Triangle (Gulf of Mexico, Africa and Brazil) representing a full two-thirds of this activity. Over \$4.5bn is expected to be earmarked for the growing West Africa and North Africa (Mediterranean) sectors. Market projections for global subsea tree orders in 2005 are 360 trees with an upside of 400-plus. Active areas identified for 2005 subsea contract awards are West Africa, with approximately 34% of subsea tree orders; followed by the North Sea 21%; Brazil/Latin America 17%; Gulf of Mexico 14%; and Asia-Pacific 14%. Petrobras, ChevronTexaco, Total and ExxonMobil are expected to be the leaders in terms of subsea tree demand for 2005. It is expected that these four operators will award in excess of 150 trees in 2005.

Opec output up 290,000 b/d in February

Opec took advantage of continuing high oil prices in February to boost crude production, ignoring a December 2004 pledge to remove 1mn b/d of overproduction beyond the official 27mn b/d output ceiling, according to a recent Platts survey of Opec and oil industry officials. Total Opec output averaged 29.58mn b/d in February, an increase of 290,000 b/d from January's 29.29mn b/d. Excluding Iraq (whose output was unchanged from January at 1.85mn b/d), the ten remaining members of the oil cartel pumped an average 27.73mn b/d in February, up 290,000 b/d from

January's 27.44mn b/d.

The biggest single increase came from Saudi Arabia, which increased production by 150,000 b/d to 9.25mn b/d despite having previously announced that it was producing around 9mn b/d in line with its December pledge. Other smaller increases totalling 160,000 b/d came from Iran, Kuwait, Nigeria and the UAE. Only one country reduced output, Venezuelan production slipping to 2.68mn b/d in February from 2.7mn b/d in January.

The latest estimates leave the so-called Opec-10 overproducing their current 27mn b/d ceiling by 730,000 b/d.

successful applicants included Apache, BHP Billiton, Kufpec, OMV, Galveston Mining, Benaris Petroleum, Nippon Oil, Tap Oil, Cue Exploration, Exoil and Gascorp Australia.

Woodside Energy, operator of the North West Shelf Venture, has awarded a front-end engineering contract for the development of the Angel gas field offshore western Australia to Eos, a joint venture between WorleyParsons Services and Kellogg Brown & Root (KBR). Start-up is expected in 4Q2008. Development will be via a remotely operated processing platform with three subsea wells. The single processing train will be capable of producing 800mn cfd of gas and 50,000 b/d of condensate.

OMV is to sell for an undisclosed sum its Basin Oil subsidiary – which holds its Cooper Basin and Gippsland Basin gas assets in eastern and southern Australia – to joint venture partner Santos as part of an E&P portfolio rationalisation programme.

LATIN AMERICA

Mexico's state-owned oil monopoly Pemex is reported to have said that it expects production at Cantarell – its largest oil field, accounting for more than 60% of the company's total oil output in 2004 – to decline to 2.02mn b/d in 2005, down from 2.11mn b/d in 2004. The company plans to increase investment in other field by more than \$1bn from 2004 in a bid to make up the shortfall – it is expected to invest some \$11.5bn this year.

AFRICA

Some 60 blocks are to be soon put out to tender by the Nigerian government under its 2005 licensing round. It is understood that at least 12 of the blocks are in a water depth of between 2,000 and 3,000 metres. The remaining blocks are located in the Chad Basin, Benue Trough, Anambra Basin, with at least 19 of the blocks recently withdrawn from Shell, ChevronTexaco and Elf Petroleum.

Taiwan's state-owned Chinese Petroleum Corporation (CPC) may pay \$100m to the Chad government for rights to explore for oil and gas in the landlocked African country, writes Stella Zenkovich. The company and the Chad government have reached a preliminary agreement for CPC to own 20% of rights to blocks covering 440,000 sq km.

Breakthrough in tidal technology

A revolutionary breakthrough in tidal technology, with a system that uses the tidal stream in conjunction with the natural rise and fall of the tide to create electricity, has been developed by a research and development company based in Cornwall.

The offshore Ocean Hydro Electricity Generator (OHEG) power plant allows electricity to be generated from the sea, around the clock. Based on the use of tidal and chamber turbines, combined with energy accumulators, energy is created through the natural tidal stream and the rise and fall of the tide – a more reliable energy source than wind or solar technologies. The idea is the brainchild of engineers at Hi-Spec Research and Developments of Fowey, and a small team is currently producing a comprehensive report on the mechanical, design and economic viability of the project.

To date the company has been solely funding this project, but a grant application has now been submitted to the

DTI, under its Technology Programme, to help finance a full-scale feasibility study for a plant capable of producing at least 20% of Cornwall's 650–700 MW energy requirements.

The offshore OHEG structure would consist of three rows of chambers and two outer walls, creating four channels, with the tidal stream then diverted through these channels. Within the chambers are groups of energy accumulators which create power from the rise and fall of the tide. Between the rows of chambers and the outer walls are banks of tidal turbines, with four banks per channel. The OHEG plant holds back over 6mn tonnes of water every six and a half hours and, in doing so, creates power through the chamber turbines. The plant also makes a suitable foundation for offshore wind turbines, although they are not essential for its operation, and the OHEG system is claimed to be six times more powerful than the wind farm it supports.

Largest FPSO built in China to date

CNOOC and ConocoPhillips have signed a contract with Shanghai Waigaoqiao Shipbuilding (SWS), a subsidiary of China State Shipbuilding Corporation (CSSC), for the 280,000 dwt FPSO vessel hull for the Peng Lai (PL) oil fields. It is the biggest FPSO hull ever to be built in China. The contract covers the design, partial procurement and construction of the FPSO at an estimated cost of over \$200mn. The hull is scheduled for delivery from SWS in May 2007.

The topside modules of the FPSO are currently being fabricated in Singapore. Weighing approximately 35,000 tonnes, they will have a processing capacity of 190,000 b/d of oil, with 510,000 barrels of fluid handled per day. The FPSO vessel is designed to have an onboard storage capacity of approximately 2mn

barrels of crude oil.

Once completed, the FPSO is bound for block 11/05 in Bohai Bay, where ConocoPhillips (49%) and CNOOC (51%) are carrying out the development of China's largest offshore oil field – PL19-3. Production from the first phase development of the PL 19-3 oil field began in December 2002, utilising one wellhead platform and a leased FPSO. Detailed design engineering, procurement and construction are in progress on the second phase of development of the PL oil field, which is planned to include five wellhead platforms, central processing facilities and the new FPSO. The first wellhead platform of Phase II will be put into production during 1H2007. Production through the new FPSO is expected by the end of 2008.

KBR secures Bapetco gas contract in Egypt

KBR Production Services has been awarded a contract to provide engineering and support services to the Badr Petroleum Company (Bapetco) for three new, but related, projects for the Obaiyed gas plant in Egypt. Bapetco is jointly owned by the Egyptian General Petroleum Corporation (EGPC) and Shell Egypt.

Under the scope of the multi-million pound, two-year contract, the first stage of overall modifications includes the tie-in of the third party Qasr field to the Obaiyed gas plant. A related and important part of the Qasr project will be to debottleneck and upgrade the existing gas plant to increase and improve overall performance, such that a total production capacity of 420mn cfd sales gas can be achieved with high availability of at least 95%.

KBR will also implement a new pre-compression scheme to sustain Obaiyed production – this will involve significant modification and upgrade to the gas plant.

UK

BP is moving from reporting under UK Generally Accepted Accounting Principles (UK GAAP) to the new International Financial Reporting Standards (IFRS) and, as a consequence, will also discontinue supplemental disclosure of results on a pro forma basis. The company is also reorganising how it reports its businesses, primarily as a result of its plans to divest its olefins and derivatives business.

EUROPE

The European Commission (EC) has approved Repsol YPF's purchase of LPG assets in Portugal held by both Shell Gas (LPG) and its subsidiaries Spelta, in Madeira (fully-owned), and Saaga, in Azores (25% stake). Also included in the purchase are two bottling plants. Repsol YPF is now the third-largest operator in Portugal, with a 21% market share.

Shell and ERG Power & Gas have signed an agreement for the development of a regasification terminal for LNG in Italy. The envisaged site for the terminal is the industrial area of Priolo/Augusta/Melilli in the province of Syracuse in Sicily. The 8bn cmly capacity terminal will require an investment of approximately 400mn. Subject to the permitting process, construction is envisaged to begin in 2007, with the terminal expected to be commissioned in 2010.

NORTH AMERICA

ABS has given its approval in principle (AIP) to ConocoPhillips for its new proprietary Prism/Pyramid tank concept for large LNG carriers, whose new shape is claimed to reduce free surface area.

ConocoPhillips is expected to increase its current 30.3% ownership in Duke Energy Field Services (DEFS) to 50% through a series of transactions, including the transfer of ConocoPhillips' Empress natural gas plant and related marketing business in Canada to Duke Energy Gas Transmission (DEGT), as well as the contribution of certain other ConocoPhillips US midstream gas assets to DEFS.

There is market speculation that ChevronTexaco might buy smaller rival Unocal.

Eni has signed a preliminary agreement with US company Sempra LNG for the acquisition of a 4-6bn cmly share of regasification capacity at the

UK Budget highlights

In the latest UK Budget, the Chancellor of the Exchequer, Gordon Brown, announced a range of economic instruments to address the challenges posed by sustainable development, to tackle local environmental threats and to control and reduce emissions of the gases responsible for climate change and poor air quality. These include:

- New eligibility criteria for climate change agreements, which will increase the number of businesses that can participate in the scheme, and a freeze in the rates of the climate change levy.
- A package of measures to promote household energy-efficiency, including incentives for the private rented sector to invest in energy-efficiency.
- Duty rates for sulphur-free fuels raised in line with inflation from 1 September 2004, the duty for ultra-low sulphur fuels set at 0.5 p/l above this level from the same date.
- Three-year certainty for the duty treatment on alternative fuels – providing a 20 p/l duty differential in favour of bioethanol and biodiesel, guaranteed until at least 2007; reducing the duty differential in favour of LPG by the equivalent of 1 p/l for each of the next three years to 2007; and freezing the duty differential in favour of natural gas at its current level (equivalent to 41 p/l) to 2007.
- The duty on rebated gas oil (red diesel) and fuel oil will be increased by 2.42 p/l, reducing the differential between rebated oils and the main road fuels by 1 p/l to underpin the strategic approach to tackling oils fraud.
- The level of carbon dioxide emissions qualifying for the minimum percentage charge for a petrol car (15%) will be frozen at 140 g/km for 2006–2007. The fuel benefit tax charge applies the same percentage as the company car charge against a set figure. The 2003–2004 figure of £14,400 will be frozen for 2004–2005.
- VED rates for all vehicles are frozen for this year.

Looking upstream, effective from 16 March 2005 two measures will be introduced to protect Petroleum Revenue Tax (PRT) revenues – one to prevent the generation of artificial costs through the trading of assets with low market value at artificially high prices between connected companies; the other to prevent the creation of a loss, which can be set against the PRT liability in another field as a result of the successive transfer of a field interest towards the end of field life. The potential revenue loss from these loopholes is over £1bn in the long term, with at least £200mn at risk now.

Russia – time to step on the gas

The call on Russian gas is growing and the demand for Russian and Central Asian gas from Europe will grow from around 145bn cm today to 330bn cm in 2020, according to analyst Wood Mackenzie's latest study *Time to Step on the Gas: Will Russia Realise its Potential?* 'Fundamentally, Russia's supply potential is not in doubt, in fact it has ample reserves to sustain production at current levels for approximately 85 years and significant exploration upside,' explains Tim Lambert, Vice President Consulting for Wood Mackenzie. 'The bigger issue is that increasing exports to the level required by Europe implies huge investments. We estimate a total capital expenditure requirement in Russian gas fields and pipelines of around \$240bn (2004 real) over the 2004–2020 period to ensure that Europe's demand for gas will be met.'

Although expected increases in domestic and export gas prices will almost triple Gazprom's revenues to \$77bn by 2020, they will still need to raise up to \$65bn in debt to finance the required investment spend estimated by Wood Mackenzie at around \$240bn (2004 real). More worrying for European consumers is that Gazprom does not currently intend to undertake anything approaching this level of investment, states the analyst. The Russian government's energy strategy – a key determinant of Gazprom's plans – envisages much lower levels of exports to Europe, and at the same time additional priorities for the company. 'Gazprom has significant aspirations in sectors other than European gas,' says Lambert. 'The most recent illustration of these ambitions has been the move to build a major oil business by acquiring Rosneft and other entities in the Russian oil sector. Gazprom is also building a position in LNG, entering gas markets in the US and Asia, and developing Russia's Far East. This is a programme that would daunt even a supermajor.'

This makes for a potentially awkward future for European gas customers facing increasing reliance – perhaps up to 38% of the market – on Russia and Gazprom. And the alternative scenario, in which Gazprom does not meet the increased call from Europe, is even less comfortable, indicates the report. Security and diversity of supply, demand side measures, and diversification of power generation fuels will all need to be high on the policy agenda.

Cameron terminal which Semptra LNG is to build on the banks of the Calcasieu River in Louisiana. The Cameron terminal will be completed during 2008 and will have an initial processing capacity of 15bn cmy.

MIDDLE EAST

Qatar Petroleum (70%) and Shell (30%) have signed a heads of agreement (HoA) for the development of the large-scale Qatargas 4 LNG project located in Ras Laffan City, Qatar. The Qatargas 4 project comprises the integrated development of upstream gas production facilities to produce 1.4bn cfd of gas and substantial quantities of associated liquids from Qatar's North field, a single LNG train yielding approximately 7.8mn t/y of LNG for a period of 25 years, and shipping of the LNG to the intended markets in North America and Europe. LNG deliveries are expected to commence around 2010-2012.

J P Kenny, a subsidiary of Wood Group, has been awarded a contract by Zadc for the design of the potential replacement Zakum Main Oil Line (MOL) in Abu Dhabi, UAE. The existing MOL transports Upper Zakum production through a 60-km long, 42-inch diameter pipeline from the Zakum central complex to Zirku Island. The pipeline has been in continuous service since 1982 and the fields have a significant production life remaining.

Qatar Petroleum and Sasol Chevron are understood to have signed a preliminary agreement for a gas-to-liquids (GTL) base oils project in Qatar, according to Sasol. The Oryx GTL project will produce a range of high quality base oils, the primary feedstock for high quality lubricants. The technology for the plant will be supplied by ChevronTexaco.

RUSSIA/CENTRAL ASIA

The merger of Russian gas monopoly Gazprom and state-owned oil company Rosneft is reported to have been sanctioned by the Russian government. However, Yuganskneftegas, the main production unit of Yukos bought by Rosneft last year, will remain a separate company, headed by current Rosneft CEO Sergei Bogdanchikov.

Transneft has announced that the expansion of the Baltic Pipeline System (BPS) from the current 1.1mn b/d to 1.2mn b/d has been postponed until 1H2006.

Terminal plans

Russia is reported to have approved plans to build three new oil terminals on the Gulf of Finland, which could help increase Russia's oil export capacity to north-west Europe by 600,000 b/d by 2008. TNK-BP is understood to be planning to build a \$175mn terminal in Ust-Luga to export up to 150,000 b/d of oil, while Oiltanking is reported to have proposed spending \$135mn to build a terminal that will export 150,000 b/d of oil and products. The Severo-Zapadny Alliance is also planning to build a \$340mn terminal with a designed capacity to export around 200,000 b/d.

The Russian section of the Gulf of Finland has at least a dozen new oil export projects proposed – if they all come to fruition, total annual oil shipments on the Baltic could rise beyond 3.4mn b/d. Russia has been pushing hard for new terminals in the north to avoid traditional routes through the Black Sea that pass via the congested Turkish straits.

LNG delivery first

Petronas, BG International and Egyptian General Petroleum Corporation (EGPC) have delivered their first LNG cargo to Asean LNG Trading Company (ALTCO), a subsidiary of Petronas. The delivery is the partners' first cargo commitment under a five-year sale and purchase agreement signed with ALTCO and BG Gas Marketing (BGGM).

Under the agreement, ALTCO and BGGM will, on a 50:50 basis, lift 1.45mn tonnes of LNG annually from the Damietta LNG Complex in Egypt, which is owned by Spanish Egyptian Gas Company (SEGAS). The plant receives its feed gas from the West Delta Deep Marine (WDDM) concession area under a separate five-year processing agreement it reached with Egyptian Natural Gas Company Holding (EGAS).

Petronas has a 50% working interest in the WDDM concession area, located about 140 km away from the LNG Complex.

Total takes interest in Qatargas 2 LNG

Total is to take a 16.7% interest in Train II of Qatargas 2 and purchase 5.2mn t/y LNG from Qatari project for a period of 25 years. Qatargas 2 is an integrated project covering the development of two new LNG trains, each with an annual capacity of 7.8mn tonnes, with the feed gas coming from Qatar's giant North field. The LNG trains will be built at the Ras Laffan Industrial City in Qatar. Start-up of Train II is presently targeted for end-2008. Partners are Qatar Petroleum and ExxonMobil.

Latest developments in the EU

The European Commission (EC) will stage a wide-ranging competition inquiry into the energy sector, with officials to 'identify obstacles to competition – be it regulation, state aid, private barriers', then 'propose solutions, working closely with national administrations, regulatory bodies and competition authorities', reports Keith Nuthall. Brussels' competition directorate general has highlighted energy as one of two priority sectors, the other being financial services. Work should start this summer.

In other EU news:

- Austrian gas company OMZ will no longer be prevented from re-exporting gas it buys from Gazprom, with the Russian company being free to sell to other customers in Austria without first offering gas to OMV. This liberalisation follows EC pressure. The Austrians will also help boost pipeline capacity transporting Russian gas, through Austria, to Italy.
- Tanker owners and operators who carelessly pollute the seas off the European Union (EU) may be fined heavily, or even imprisoned, under a new ship source pollution directive approved by the European Parliament and EU Council of Ministers. The new directive states: 'ship source discharges of polluting substances... are regarded as criminal offences if committed with intent, recklessly or by gross negligence'.
- The European Bank for Reconstruction and Development (EBRD) is setting up a Multilateral Carbon Credit Fund, purchasing emission reductions under the Kyoto Protocol's clean development mechanism. The fund will operate in eastern Europe and central Asia.
- The EBRD and Japan will spend \$1mn helping Kazakhstan's State Agency for the Regulation of Natural Monopolies reform its market organisation and regulations for energy, oil and gas pipelines and other utilities.
- Increased compensation will be available for oil tanker accident pollution victims off Europe with the entry into force of the 2003 International Maritime Organisation (IMO) Protocol establishing an International Oil Pollution Compensation Supplementary Fund. More than \$1.14bn would be available for one incident off signatory countries, largely European.

UK

Companies covered by the European Union Emission Trading Scheme (EU-ETS) face higher costs, not just from compliance with emission reduction targets, but also from higher energy prices. A new report from Price-waterhouseCoopers – Responding to a changing environment: Applying emissions trading strategy to industrial companies – also warns that industrial companies covered by the scheme are generally less well prepared than energy and utility companies in the EU. Copies of the report can be downloaded at www.pwc.com/ipemissions

EUROPE

A new non-toxic product that turns oil into a hard, non-volatile, foam-like substance, can, it is claimed, be used for emergency storage of oil without tanks, although initially it was developed for oil spill recovery at sea, writes Brian Warshaw. HARDOIL is sprayed on the oil by a high-pressure jet to form a 50:50 mixture, which hardens, floats on water, and can be lifted with mechanical diggers. The materials to manufacture HARDOIL are readily available, and total production costs are between \$20 and \$27 per barrel. It is claimed that 95% of the oil and 85% of the HARDOIL are recoverable by a simple process. A powdered form of HARDOIL is also available to clean the fur and feathers of contaminated animals and birds. Contaminated soil, when mixed with the product, can be moulded into briquettes for use in building and road foundations.

Energia, the Viridian-owned power supply company, is reported to have secured a contract to supply power to hundreds of Dublin government-owned operations – including government departments, the Customs House, Garda headquarters, the Revenue Commissioners, prisons and hospitals across the Republic – in a deal valued at 18mn annually.

EASTERN EUROPE

Aral of Germany has announced plans to leave the Czech fuel retailing market by the end of the year, writes Stella Zenkovich. There are some 2,150 service stations in the Czech Republic, of which 550 are operated by foreign

Record fuel sales in UK

Petroleum Review's 2005 UK Retail Marketing Survey shows that in 2004 UK forecourt sales of motor fuels totalled 28.2mn tonnes – the largest volume ever sold. The total, however, conceals the fact that petrol sales continued their long slow decline while diesel sales continue their strong growth.

In the last ten years retail petrol sales have declined by 15%, while retail diesel sales have more than doubled. Taking into account the total road fuel market – both forecourt and commercial consumers – 2004 was the first year when almost equal volumes of diesel and petrol were sold in the UK. Forecourt rationalisation continued in 2004 with 184 closures, averaging 15 a month. This represents a considerable slowdown, being the lowest closure rate since 1999 and well below the 2003 total of 890 sites, or 74 sites per month. Closures in 2004 were, however, effectively confined to the oil company operated sites.

The survey is published annually by the Energy Institute and provides a comprehensive, statistical overview of the UK forecourt market. Data is broken down by company, region and forecourt facilities. The survey is based on statistics relating to the end of 2004 and does not reflect changes since that date.

The key findings of the survey are:

- There were 10,351 operational filling stations in the UK and Northern Ireland at 2004 year end.
- The number of sites declined by 184 in 2004 – a closure rate of 15 a month, well down from the 74 a month seen in 2003.
- Different sectors showed very different responses in 2004:
 - oil company sites declined by 325 to 6,307 (down 541 to 6,941 in 2003),
 - main retailer sites increased by 51 to 1,591 (down 78 to 1,231 in 2003),
 - supermarket sites increased by 16 to 1,142 (up 59 to 1,126 in 2003),
 - smaller retailer sites increased by 5 to 165 (down 43 to 168 in 2003),
 - other unbranded sites increased by 77 to 1,146 (down 12 to 1,069 in 2003).
- There were 580 quick-serve restaurants attached to forecourts (Little Chef, McDonalds etc) and 270 in-forecourt (Wild Bean Café, Bake N Bite etc).
- Average site throughput, at 2.457mn l/y, was a new record level.
- There are currently 8,916 self-service forecourts in the UK.
- 764 sites now retail auto-LPG (176 more than in 2003); the largest operators are BP with 207, up 40 on 2003, and Shell, with 197, unchanged from 2003.
- 92 sites were retailing biodiesel and this figure is expected to rise to 165 by 2008.
- 1,948 sites retailed super-unleaded petrol, 551 less than 2003.
- The four largest oil company operations by number of branded forecourts were (2003 figures in brackets):
 - BP 1,301 (1,262) – up 39
 - Esso 1,080 (1,215) – down 135
 - Texaco 1,073 (1,163) – down 90
 - Shell 1,034 (1,098) – down 64

The 2005 Retail Marketing Survey is available, priced £20, from the Energy Institute, t: +44 (0)20 7467 7114; t: +44 (0)20 7255 1472.

Scotland plugs into new GB electricity market

A new electricity market in Great Britain, bringing together Scotland's transmission networks and the grid in England and Wales will push prices down for Scottish consumers and open up lucrative new markets for Scottish generators, UK Energy Minister Mike O'Brien said on announcing the 1 April 'go-live' date for the new BETTA arrangements. The Minister also outlined plans to limit the charges renewable generators on the Scottish Islands, and potentially in the far North of the Scottish mainland, will have to pay to the National Grid to transmit electricity to customers across Britain.

Speaking at a meeting in early March with Ofgem and the companies involved in the project at Scottish Power's Glasgow control centre, O'Brien said: 'Scottish generators are set to benefit from the new single transmission system because, for the first time, they'll have real access to the wider British market, without the added complexity of negotiating and paying for the use of the existing interconnector between the two networks. For Scottish consumers, opening up competition will provide greater choice and see the sort of downward pressure on prices previously enjoyed by consumers in England and Wales. And we're putting in place additional measures to ensure that those in certain remote, rural parts of North Scotland are not hit by disproportionate energy prices.'

companies. Aral operates 69 of these outlets. Local fuel retailer Benzina, which has a network of 300 service stations in the country, has expressed an interest in acquiring the Aral sites.

Total and Lubriffin, a major producer and distributor of lubricants and greases in the Romanian market, have reached an agreement to create a joint venture – Total Lubriffin. Owned 51% by Total and 49% by Lubriffin, Total Lubriffin will begin operations in 1H2005, marketing a complete range of lubricants and greases in Romania for the automotive and industrial markets from 1H2005 under the trademarks of both partners. The venture will also build a grease unit next to the lubricant plant recently built near Brasov.

NORTH AMERICA

ConocoPhillips has launched its new tri-branded proprietary personal and commercial gasoline credit cards. ConocoPhillips' proprietary cardholders now have the ability to use one card at nearly 13,000 Phillips 66®, Conoco® and 76™ branded stations across the US. The new tri-branded cards will continue to offer the conveniences available with current cards, including pay-at-the-pump, no annual fee, multiple payment options, and online account management. Additionally, the personal card allows cardholders to access thousands of ATMs nationwide.

MIDDLE EAST

Bahrain Petroleum Company (BAPCO) has signed a financing package worth \$1.011bn with banks for the upgrading of the country's sole oil refinery, writes Stella Zenkovich. The package includes \$370mn from the commercial facility, \$330mn from the Islamic lease facility and \$311 mm of tranche guaranteed by the Japan Bank for International Cooperation and Nippon Export Credit Agency. The upgrade project is expected to complete in early 2007.

Qatar Petroleum (QP) and Shell Chemicals have signed a letter of intent for the development of a world-scale ethane based cracker and derivatives complex in Ras Laffan Industrial City, Qatar. The complex will produce cost competitive petrochemicals products to be marketed into primarily Asian growth markets, with a start-up date early in the next decade.

Fuel card providers in Europe

Unlike many industries, customer churn and competitor attrition are not necessarily the key issues for providers of fleet, oil and fuel cards. In fact, new research from independent market analyst Datamonitor reveals that seven in ten managers of fleets in the small business sector don't intend to leave their current card provider, thus giving issuers greater scope to capitalise on new business opportunities.

Markets such as Ireland, Portugal and

Italy still hold opportunities to convert non-subscribers of fuel cards across all commercial vehicle sectors, and even mature Western European fuel cards markets such as the Netherlands, France and Germany boast untapped potential at the smaller end, with many company car fleets still using credit cards and cash to pay for their fuel. Here the oil card per vehicle number ranges from 0.2 to 0.4, compared to 0.8 in the more saturated markets such as Austria and Sweden.

European consumption of motor fuels

The European Commission (EC) has released a report detailing sales trends and environment improvements in European Union-consumed motor fuels, reports *Keith Nuthall*. It shows, for instance, that the average sulphur content in petrol and diesel roughly halved between 2001 and 2003. In 2003, 30.3% of diesel sold had less than 50 ppm of sulphur, with 24.9% less than 10 ppm – Germany and Sweden dominated consumption of this cleanest diesel, while regular diesel was most common in Austria, Greece, Italy, Portugal and Spain.

The report also provides more detailed breakdowns on unleaded petrol sales by grade and national comparisons of fuel sales. These show that while Italy buys more diesel than petrol, the reverse is true in Germany and Britain, for instance. Another table shows the variation in fuel grade numbers across the EU, with Britain having three petrol grades, while Germany has four, Finland two and Italy one.

The full report and tables can be found at www.europa.eu.int/eur-lex/lex/LexUriServ/site/en/com/2005/com2005_0069en01.doc

ChevronTexaco standardises software

Wincor Nixdorf and its affiliates are to supply electronic point-of-sale (PoS) software to ChevronTexaco's branded service stations through a new global agreement which saw ChevronTexaco purchase an enterprise licence agreement (ELA) for the NAMOS compact software. The NAMOS compact software solution is made up of three main components – the PoS application, the Manager's Workstation back-store component and the Wet Data Manager (an IFSF-compliant application which integrates and controls the entire forecourt). NAMOS compact's open interface architecture enables customers to connect new back-office and also legacy systems via NACS XML standard interfaces. According to ChevronTexaco, the agreement 'will deliver a standards-based software solution as well as greater efficiency and cost-savings across our worldwide downstream business units'.

ChevronTexaco service stations operate under the Chevron or Texaco brands in the US and Canada; the Texaco brand in Europe, Latin America, and West Africa; and the Caltex brand in Asia, the Middle East and East Africa, Central Africa and South Africa.

DNV approval for engine lube metal detector

The AMOT MPD metal detector, which prevents engine failures by spotting metal particles in lubricating fluids due to bearing wear or other problems, has received a DNV Type Approval certificate. It covers application Class B for operating temperatures from 5°C to 70°C and up to 100% humidity, with 'on-engine' vibration and IP44 enclosure.

Claimed to avoid unnecessary costly repairs while minimising downtime, this recently introduced device is easily installed in a bypass pipe of the system on reciprocating equipment such as gas or diesel engines and reciprocating or

rotating compressors, pumps, turbines, transmissions and gearboxes. Compact yet robust and only needing minimal maintenance, the unit has no moving parts and a corrosion-resistant anodised aluminium body, with stainless steel available for use in other environments. Its 'unique' grid sensing technology detects all conductive materials, including non-metallic particles, in non-conductive fluid lubrication systems.

Used either with AMOT's MPD controller or an appropriate alternative controller, it converts maintenance into a continuously predictive rather than reactive process, states the manufacturer.

RUSSIA/CENTRAL ASIA

Georgian Minister of State Kakha Bendukidze has announced that the country's regional electricity distribution company and small hydroelectric power stations are to be privatised, according to reports from Imedi TV. He has also been quoted as saying that these assets will not be sold to Unified Energy System of Russia, which already owns the Tbilisi power grid and a large power station near the capital.

ASIA-PACIFIC

BP and Sinopec have signed a 50:50 joint venture contract to build a 500,000 t/yr acetic acid plant in Nanjing, Jiangsu province, China. Located in Nanjing, at the heart of the Yangtzi Delta – one of the most dynamic regions in economic development in China – this world-scale joint venture is expected to be onstream in 2H2007.

BP and Kuwait Petroleum International (the international refining and marketing arm of state-owned Kuwait Petroleum Corporation) have signed a memorandum of understanding (MoU) to investigate and develop opportunities for future joint investment in areas such as supply, refining, distribution and marketing to China and elsewhere in Asia.

ExxonMobil has sold its 3.7% stake in Sinopec, China's largest oil refiner, for \$1.37bn. The move follows Shell's divestment of its stake in the company for \$747mn in March 2004 and BP's sale for \$727mn in February 2004.

AFRICA

The Nigerian Bureau of Public Enterprises (BPE) has commenced the process of privatising the Kaduna and Warri refineries, calling for the submission of expressions of interests (EoIs) from would-be privatisation advisers. According to the Bureau, only consortia of advisers led by an investment bank would be considered, reports Stella Zenkovich.

Arabian Gulf Oil is understood to be planning to build a new 200,000 b/d refinery in Takoradi, Ghana. It is expected to be commissioned in 2009.

Technip has been awarded by NAFTEC, Algeria's national oil refining company, an engineering consultancy contract for the revamping and expansion of the Arzew refinery.

UK to introduce 'green' car labelling

A new colour-coded environment label for all new cars will appear in UK car showrooms from July. The consumer-friendly label will help car buyers assess the climate change impacts of different cars. It will also emphasise that better environmental performance means lower road tax and lower running costs. The new label – to be introduced years ahead of likely EU legislation – is the result of a voluntary agreement by car makers following discussions with environment groups and other road transport stakeholders under the auspices of the Low Carbon Vehicle Partnership (LowCVP). The LowCVP was established in 2003 with funding from the UK Department for Transport (DfT) and the Department of Trade and Industry (DTI) to help forge consensus-based solutions to the problem of carbon emissions from road transport.

The new fuel economy label is intended to be familiar to consumers as it mirrors important aspects of the design and colour-coding of the energy efficiency labels that now appear on most 'white goods', such as refrigerators. The gradations on the label are also consistent with the CO₂ (carbon dioxide) bandings used for vehicle excise duty (road tax) to ensure that the environmental message is backed up by a clear fiscal signal – lower carbon emissions equal lower road tax. The label also provides clear running cost information showing that lower carbon, 'climate-friendlier' vehicles are cheaper to run.

Fuel Economy		Toyota Prius 1.5 VVT-i Hybrid
CO₂ emission figure (g/km) 		B 104 g/km
Fuel cost (estimated) for 12,000 miles <small>A fuel cost figure indicates to the consumer a guide fuel price for comparison purposes. This figure is calculated by using the combined drive cycle (town centre and motorway) and average fuel price. Re-calculated annually, the current cost per litre is as follows – petrol 76p, diesel 78p and LPG 38p (VCA May 2004).</small>		£632
VED for 12 months <small>Vehicle excise duty (VED) or road tax varies according to the CO₂ emissions and fuel type of the vehicle.</small>		£65
Environmental Information		
<small>A guide on fuel economy and CO₂ emissions which contains data for all new passenger car models is available at any point of sale free of charge. In addition to the fuel efficiency of a car, driving behaviour as well as other non-technical factors play a role in determining a car's fuel consumption and CO₂ emissions. CO₂ is the main greenhouse gas responsible for global warming.</small>		
Make/Model: Toyota Prius 1.5 VVT-i Fuel Type: Petrol Hybrid		Engine Capacity (cc): 1497 Transmission: E-CVT
Fuel Consumption:		
Drive cycle	Litres/100km	Mpg
Urban	5.0	56.5
Extra-urban	4.2	67.3
Combined	4.3	65.7
Carbon dioxide emissions (g/km): 104 g/km Important note: Some specifications of this make/model may have lower CO ₂ emissions than this. Check with your dealer.		

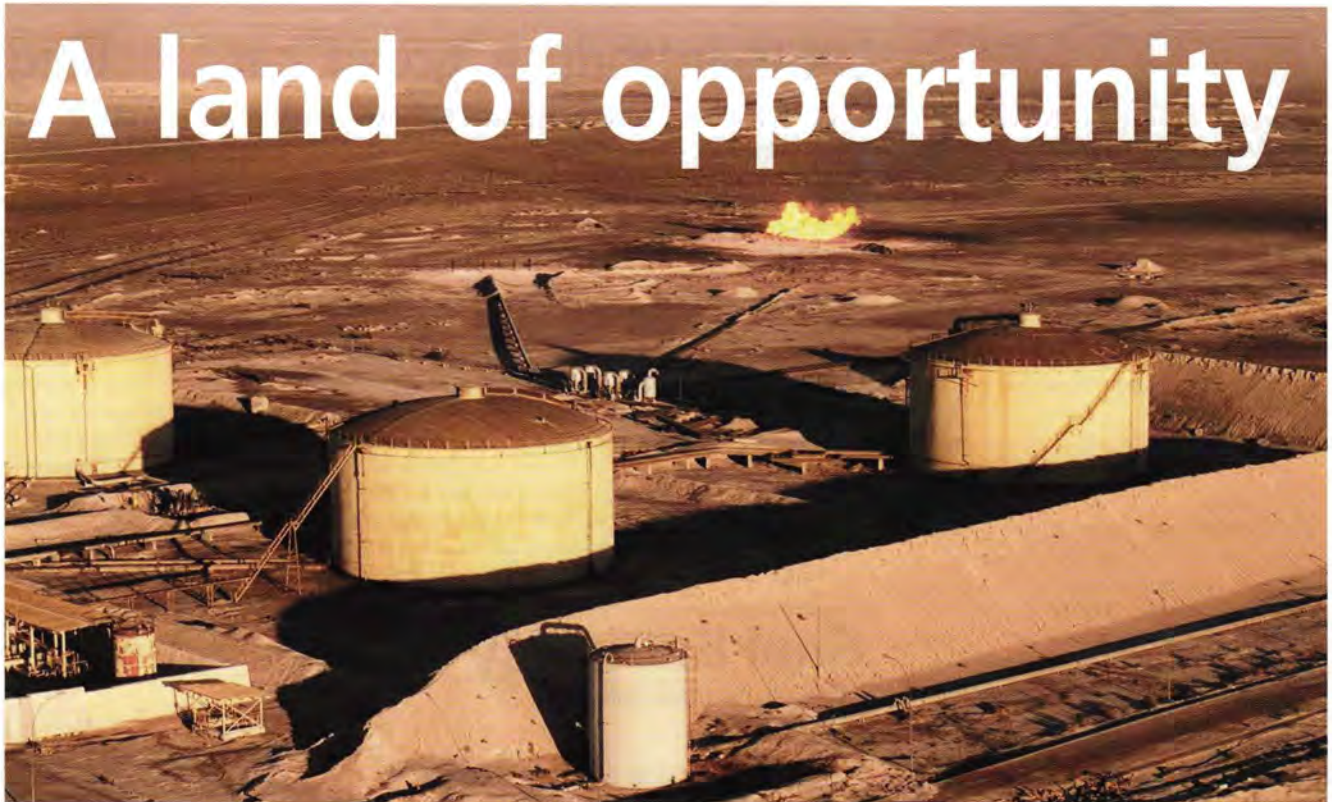


Photo: Tom Everett-Heath

A land of opportunity

The Middle East is once again the land of opportunity for oil and gas companies. Tom Everett-Heath, a Director at Kroll's Middle East Practice, reports.

The early February 2005 announcement from Indonesia's Prime Minister Purnomo Yusgiantoro that he was considering pulling out of Opec came as little surprise to the industry. Jakarta has seen its production levels plummet by some 70% over the last ten years and in recent months it has breached one of the more obvious prerequisites for Opec membership – being a net oil exporter. If the 11 members of the oil cartel become ten, it will merely serve to reinforce the predominance of Middle East and North African (MENA) oil – Nigeria and Venezuela will be the only non-MENA Opec members.

The Indonesian predicament is also symptomatic of problems facing many of the non-Opec producers. Production

rates have been falling at an average rate of 5%/y over the last decade, the result of declining yields from ageing oil fields, a lack of new investment in deepsea exploration and regulatory problems that have deterred much-needed fresh investment.

The International Energy Agency (IEA) forecasts that world oil demand will continue rising at an average rate of about 1.6% over the next quarter of a century – by 2010, global demand will rise to 90mn b/d, up from 77mn b/d in 2004, and to 120mn b/d by 2030. Faced with this, the supply-side is increasingly becoming a one-way bet. Non-Opec output is close to its peak – some capacity increases will come onstream over the next five years but, from 2010 onwards, production will gradually and inexorably decline. No surprise, then, that the IEA is predicting Opec's market share will rise from 37% to 53% – and this is 53% of a far bigger market. Put simply, of the 31mn b/d of new capacity needed between 2010 and 2030, 29mn b/d will have to come from the MENA members of Opec.

Investment required

However, for the prize to be collected, substantial investment and development is needed as most MENA producers are currently pumping either at, or close to, full capacity. The realisation has not been missed and upstream initiatives are gaining momentum across the region.

First, aggressive exploration is back on

Above: Oil tanks, Iraq

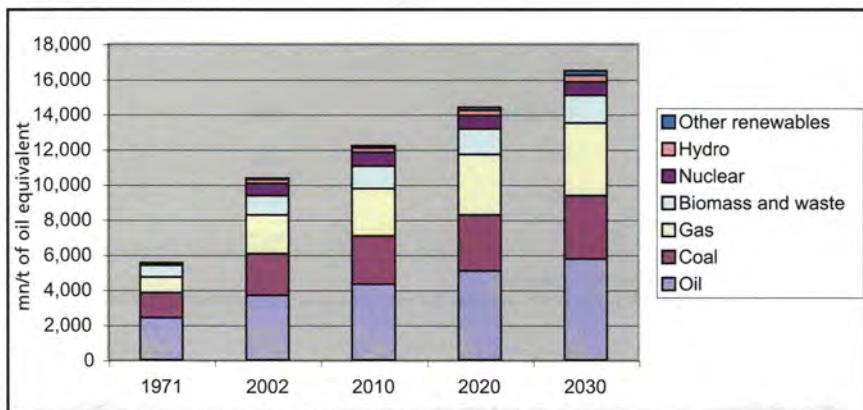


Figure 1: World primary energy demand (in mn toe)

Source: IEA

the agenda. Libya regularly tops the list of the world's most attractive exploration territories and the raising of sanctions was – comparatively – quickly followed by the EPSA IV awards, dominated by Occidental and other US companies. Tripoli has found itself in the unfamiliar position of being praised for running a transparent process. It was to launch its next round, in which a further 10 concessions will be offered, as *Petroleum Review* went to press.

Meanwhile, Algeria is in the middle of a licensing round and has two more planned by year-end. In the Gulf, Saudi Aramco has reportedly raised its exploration budget for 2005 by 17% to \$2.7bn and is aiming to increase the number of active exploration rigs in the country to over 70 from the current level of 34.

More uncertain, although potentially full of promise, are the prospects for exploration in Iraq. Little meaningful work has been done for almost a quarter of a century and the widely held view is that serious seismic work will bring a considerable increase in reserves.

The massive revenues generated by the current double whammy of sustained high oil prices and high production levels in recent years have also eased the decision making on the next wave of capital investment. For example, Saudi oil exports were worth about \$106bn in 2004, some \$20bn more than 2003, which was itself a particularly strong year. The predictable result was a budget surplus of \$26bn, despite an almost 30% overspend during the fiscal year. About half of the \$17bn of extra spending in 2003 was focused on debt reduction – Saudi Arabia has no external debt but domestic debt now stands at a manageable 66% of GDP. The other half was targeted on capital expenditure. The expansionist medicine will continue to be taken – the 2005 budget sees expenditure raised 22% on the previous year's budget and, in reality, will almost certainly go higher. In short, the oil windfall is being used to stabilise the state's finances and stimulate the economy – there is also substantial reinvestment in the oil sector.

After a period of conservatism, heavy expenditure on genuine capacity expansion is back in fashion. Petroleum & Mineral Resources Minister Ali Naimi has repeatedly been talking of Saudi plans to raise production capacity to 12.5mn b/d in the short term and to 15mn b/d in the medium term. The full commissioning in late December of the Qatif producing plants brought online the world's first single project capable of producing 800,000 b/d of crude. Further megaprojects are advancing such as the \$1.5bn Abu Hadriyah, Al-Fadhli and Khursaniya

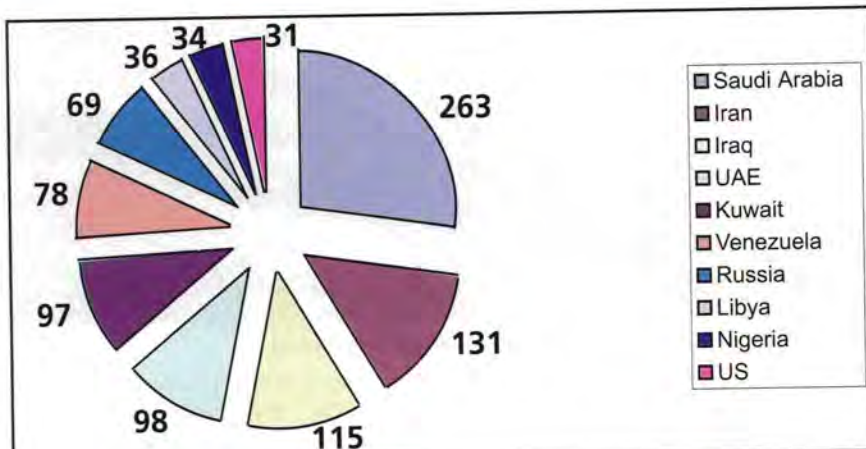


Figure 2: Top 10 countries by proven reserves, end-2003 (bn barrels)

Source: BP

field development programmes. There is also growing speculation that a second crude increment at the onshore Khurais field is being mulled, which could add some 1mn b/d of new capacity.

The story is similar elsewhere. Even before new exploration work gets underway, massive capital expenditure in Iraq should bring substantial increases in production capacity. Security problems and political instability have hindered plans so far, but southern projects such as the Hamrin and Subba-Luhais field work and the Khurmala dome developments are progressing.

Gas is the new oil

The Middle East investment surge is not limited to oil. Globally, gas is the new oil and, even more so than with oil, the MENA producers are dominant. For example, around the world, LNG liquefaction plants either under construction, proposed or planned to come onstream

within the next five years will add just over 350bn cm of annual production capacity. More than 54% of this will be built in the MENA region and – demonstrating both its ambition and capacity – 26% of this new global capacity will be delivered by Qatar alone, through its RasGas and Qatargas expansion programmes.

In fact, Qatar's broad hydrocarbon projects stand as arguably the most concentrated and intensive capital investment programmes in the world. The eight-year scheme in Ras Laffan will see \$50bn pumped into the tripling of LNG capacity and a broad array of other initiatives. Doha is leading the world in developing gas-to-liquids (GTL) plants. The pioneering Oryx GTL plant will start production by the end of the year, ExxonMobil and Shell are committed to two further facilities that will require \$12bn of investment and two more large-scale GTL projects are under discussion.

A host of other gas-related projects



Photo: Nexen Petroleum

Masila, Yemen – where more upstream investment is being sought



Photo: Tom Everett-Heath

Southern Iraq – where supply disruption remains a problem

are at various stages of the planning or tendering process, including the 140,000-b/d Ras Laffan refinery, which will process rising volumes of condensate produced from the North field; the ethane pipeline from Ras Laffan to Mesaieed; and a major sulphur recovery facility at Ras Laffan. Equally, the second phase of the Al-Khaleej gas project is moving forward, which involves the development of more upstream acreage in the North field to meet rising demand at Ras Laffan and possibly in neighbouring Bahrain.

Saudi Arabia is also investing heavily in its gas infrastructure, with projects such as the Hawiyah gas plant expansion

and massive neighbouring green-field NGL plant. But perhaps the greatest international interest was attracted by the failure of the much-touted Gas Initiative and its evolution into the gas exploration and development agreements signed with Shell, Sinopec, Lukoil, Eni and Repsol for work in the Rub al-Khali.

The headline-grabbing element is that Saudi Arabia has unlocked its upstream for the first time in a generation. And this issue of upstream access – in both the oil and gas sectors – is dominating the strategic agenda for most international oil companies (IOCs). The hunger to book reserves – to invest in equity oil – is rap-

acious and opportunities outside the region are growing ever more limited.

Rethinking attitudes

While Saudi Arabia has no intention of opening its upstream oil sector, the desire to rapidly expand capacity through the attraction of investment capital and new technology is seemingly encouraging a rethink in the attitudes of many of the regional national oil companies (NOCs).

Perhaps the most important shift can be seen in Iran. Controversy has long reigned over the terms of exploration contracts awarded to IOCs which, by delinking oil discoveries from a share of production, were often described as inflated service agreements. However, last year saw Iran tendering blocks for the first time that tied together exploration and production rights. Unfortunately, the IOCs initial excitement was tempered by the perceived unattractiveness of most of the specific blocks offered and, with the strengthening of the conservative factions' grip on power, there were concerns over the friendliness of the business environment. While not directly related, the seeming volte face over massive foreign investment programmes in the telecoms sector and the new international airport has brought little comfort.

Neighbouring Kuwait is also flirting with the IOCs. Project Kuwait, a proposal to double production from four northern oil fields to 900,000 b/d, has been in circulation for the best part of a decade – but the political infighting has been reactivated this year with a revised draft law submitted to the National Assembly's Economy and Finance Committee. The recent personnel shake up across Kuwait's oil and gas industry may see some acceleration of the programme, which is a key early component in the government's 2020 vision to raise production capacity to 4mn b/d from current levels of about 2.6mn b/d through investment of up to \$40bn. The role the IOCs will play in the programme remains a moot point – the need for technology and management expertise is imperative, but the political cost of the perceived infringement of sovereignty through the concessionary award of equity oil is high.

Legislative reform is also being proposed in Algeria, although here too there is a sense of *déjà vu*. The draft Hydrocarbons Law failed in 2002 when confronted by trade union opposition. However, Chawki Rahal, Sonatrach's Director General is expecting the new proposal to be passed by the end of the year. If so, it will remove the requirement for Sonatrach's participation in all oil and gas projects in the country, but would

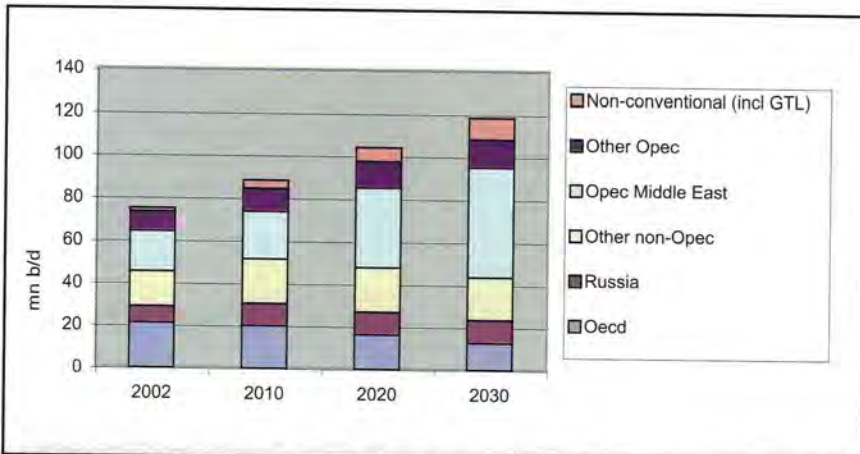


Figure 3: World oil supply projections (in mn b/d)

Source: IEA

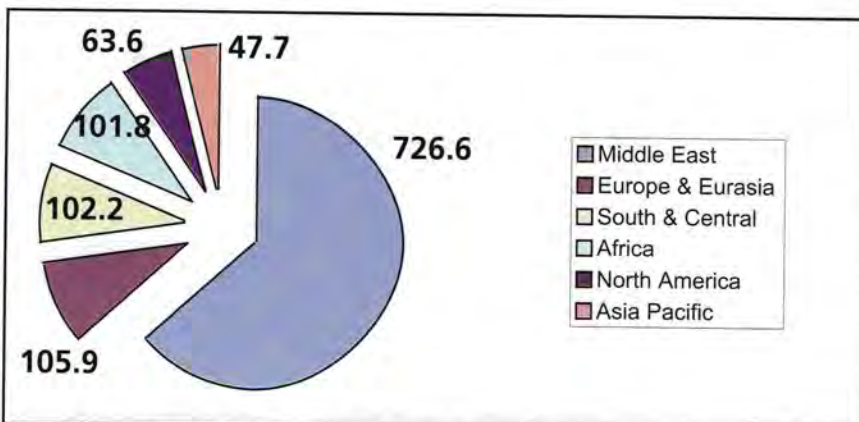


Figure 4: Global proven oil reserves, end-2003 (bn barrels)

Source: BP

offer the state-owned company the right to take a 25% stake in projects after execution. One potential difference is that the proposal to privatise Sonatrach seems to have been sidelined.

The MENA region's non-Opec producers are also in a rush to develop resources. Oman has recently extended Shell's concession agreement from 2012 to 2044, giving it the security needed to support the massive investment needed in enhanced oil recovery (EOR) projects at Harweel, Mukhaizna and Qarn Alam. The aim of stabilising PDO's dwindling production looks attainable, but the prospects for capacity expansion seem limited.

In bordering Yemen the problem is similar if, perhaps, more extreme. Crude production fell to 400,000 b/d in 2004, down from a peak of 471,000 b/d in 2001. The response has been an acceleration of exploration activity and a greater emphasis on offering the IOCs what they want – the process is transparent, the concessionary terms are good and, although security problems abound, small oil companies continue to see Yemen as an opportunity-rich territory. And fresh acreage is up for grabs – the latest bid round was launched at the beginning of February. Even the majors occasionally get excited. Total is as a 43% shareholder in what will be Yemen's first LNG facility, which has finally found offtakers supplying the Korean and US markets.

Also in the face of declining output, Egypt is encouraging fresh exploration work – it has recently awarded nine blocks and more are to come. Syria is preparing for a fifth licensing round to be launched by May, and even Jordan is reforming its near-non-existent sector in the hope that sky-high oil prices will encourage someone to view the exploitation of its oil-shale deposits as economically viable.

Substantial prize

While some MENA oil and gas projects and proposals are based more on optimism than strong economics, the extent of the base load of robust big ticket initiatives is unprecedented. The region is enjoying the opposite of a perfect storm.

The coincidence of benign long-term market fundamentals, IOC strategic interest, domestic political appetite and the budgetary capacity – fuelled by the current oil revenue windfall – to invest aggressively has stimulated a boom. While security issues and political instability across the region remain important, the tools of mitigation are available and the prize is substantial.

Project	Scope (Cost, in \$mn)
Algeria	
Gassi Touil LNG	3.8mn t/y LNG liquefaction plant and gas field development (2,100)
Skikda LNG	4mn t/y LNG train to replace three trains destroyed in January 2004 (700)
Medgaz pipeline	200-km subsea pipeline to transport 8,000–16,000mn cm ³ of gas to Spain (na)
Skikda & Algiers refineries upgrades	Rehabilitation and upgrade to control systems and atmospheric distillation units (na)
Bahrain	
Bapco refinery upgrade	40,000 b/d expansion and conversion of the existing 45,000-b/d mild hydrocracker to a diesel desulphuriser (660)
Egypt	
Second LNG train at Damietta	4.9mn t/y train (1,400)
Third LNG train at Idku	3.6mn t/y train (800)
Iran	
Bangestan oil field development	Capacity increase to 600,000 b/d from 250,000 b/d (3,000)
Azadegan oil field development	260,000 b/d new field development (2,000)
South Pars phases 15–16	2,000 cf/d of natural gas, 1mn t/y LPG, 80,000 b/d condensates, 1mn t/y ethane (2,000)
South Pars phases 17–18	2,000 cf/d of natural gas, 1mn t/y LPG, 80,000 b/d condensates, 1mn t/y ethane (2,000)
Arak refinery upgrade	Capacity increase to 250,000 b/d from 150,000 b/d (1,000)
Iraq	
Hamrin and Subba-Luhais oil field developments	Two contracts to raise the fields' combined capacity to 240,000 b/d (300)
Khurmala dome development	Raise output to 100,000 b/d from 6,000 b/d of oil (140)
Kormor gas field development	220mn cf/d of gas (na)
Zubair field upgrade	Supply and installation of five compression units (na)
Daura refinery upgrade	10,000 b/d light naphtha isomerisation unit (na)
Kuwait	
Project Kuwait	Doubling of oil production from five northern fields to 900,000 b/d (7,000)
Facilities upgrade and flowlines replacement	Replacement of underground crude oil and gas pipelines in the south and south-east and the upgrade and rehabilitation of 17 GCs (1,900)
KNPC's fourth refinery	450,000-b/d grassroots refinery at Shuaiba (1,000)
Crude storage and export facilities at Ahmadi	11.4mn barrels of crude storage capacity (850)
Mina al-Ahmadi refinery ethane recovery unit	Supply and installation of ethane recovery unit (400)
Libya	
Renovation and upgrade of Azzawiya refinery	Installation of a new catalytic reformer unit, hydrotreaters and an isomerisation unit (280)
Khoms-Melihat and Tripoli-Melihat gas pipelines	Construction of pipelines to the Khoms and Tripoli power plants (270)
Faregh field development	Construction of a 180mn-cf/d gas processing plant (100)
Oman	
Mukhaizna EOR	Boost production to 60,000-80,000 b/d (2,000)
Qarn Alam EOR	Steam-assisted gas/oil gravity drainage to achieve capacity of about 60,000 b/d (700)
Al-Kawther gas gathering	Installation of gas gathering and treatment facilities and a cathodic protection system (350)
Harweel phase 2 EOR	Use of miscible gas injection to raise production to 100,000 b/d (350)
Qatar	
RasGas II – trains 6 and 7	15.6 mn t/y of LNG (12,000)
Qatargas III – train 6	7.8 mn t/y of LNG (5,000)
Integrated Pearl GTL (Shell)	140,000 b/d of GTL (5,000)
Integrated GTL (ExxonMobil)	154,000 b/d of GTL (7,000)
Ras Laffan condensate refinery	140,000 b/d (450)
Saudi Arabia	
Abu Hadriyah, Al-Fadhli and Khursaniya field development	500,000 b/d of oil (1,500)
Hawiyah NGL plant	800 mn cf/d straddle plant (1,200)
Juaymah gas fractionation plant fourth train	270,000 b/d of ethane and NGL, and 100,000 b/d of propane (200)
Hawiyah gas plant expansion	Increasing capacity by 800,000 cf/d (200)
Rabigh refinery upgrade (and petrochemicals complex)	80,000-b/d expansion at the hydroskimming export refinery (4,300)
UAE	
OGD-3/AGD-2	Gas gathering network, plant facilities and pipelines NGL recovery facilities and a new NGL train (3,000)
Inter-refinery pipeline	500-km products pipeline in Abu Dhabi (400)
Green diesel	37,000-b/d mild hydrocracker, 42,000-b/d sulphur-handling unit (na)
Umm Shaif gas injection	600 mn cf/d of gas in offshore Abu Dhabi (400)
Jebel Ali condensate refinery expansion	70,000-b/d hydrotreater, continuous catalytic reformer, associated works and upgrade of existing facilities (350)
Yemen	
Yemen LNG at Bel Haf	Two LNG trains with total capacity of 6.2 mn t/y (2,000)
Safir-Marib-Aden/Hodeidah gas pipeline	565-km natural gas pipeline (500)
Ras Issa refinery	30,000 b/d (250)
Hadamout refinery	40,000 b/d (300)

Source: MEED

Table 1: Selected MENA oil and gas projects on which major contract awards are awaited

New projects to 2012

The latest update of Petroleum Review's megaprojects database has been presented with Opec and non-Opec projects separated, reports Chris Skrebowski, Editor.

The basis of this month's listing is that it records all those oil projects with peak flows exceeding 100,000 b/d, which usually means reserves in the 400–500mn barrel range. Where reserves are significantly smaller than this, it usually means either that the field is to be depleted very rapidly or, more likely, that nearby discoveries will be produced through the field facilities as production from the named field starts to decline. A good example of this is the Exeter-Mutineer field offshore Australia, where field reserves are small but a number of not yet fully delineated discoveries have been made in the area.

The tabulation also includes several fields that have peak flows of under 100,000 b/d. These have been included because later phases of development may take them over this level. This group comprises Corocoro, Angostura, Clair South, Bozhong, Darkhovin, Nowrouz, Jubarte, Mad Dog and Chinguetti. The Long Lake tar sands project has been included because of its expansion potential, while the two Qatar GTL plants have been listed as they represent the first large-scale units converting gas to petroleum products.

With the inclusion of these smaller projects and some recent additions, the listing now comprises 73 projects – 24 in Opec countries and 49 in non-Opec countries – all due onstream in the next seven years, ie by 2012. Developments printed in bold are already onstream.

The principal change from the version

printed in *Petroleum Review's* August 2004 issue is the number of projects where start-up times have slipped. Four projects due onstream in 2004 have slipped in to 2005. However, of these, Clair South has already come onstream and the Nowrouz and Soroush expansions are due onstream imminently. The Roncador II project has been delayed to 2006. Project slippage is a recurrent theme that is tending to smear out the forward production profile. Nevertheless, it remains true that few projects are listed beyond 2007/2008.

Analysis of the database shows that the average time delay between discovery and first oil is nearly six years. Onshore projects are rather faster – a major redevelopment of known and existing onshore fields such as the Abu Hadriya, Khursaniyah, Fadhili (AKF) fields project in Saudi Arabia taking two-and-a-half to three years, while a major onshore development requiring infrastructure and field delineation, such as the El Merk fields in block 208 in Algeria will take at least four years from the start of the project to first oil.

Notably long delays are occurring in West Africa, particularly offshore Nigeria with project times up to seven years (Erha) or even nine (Agbami), while start-up of the ill-starred Bonga project has been delayed again to September/October 2005 – some nine years after its discovery.

A few projects in the database have come in early, but usually only by a few months. The one truly dramatic acceler-

ation is Kizomba B, now due onstream in 3Q2005 rather than in 2006. This is seen as a vindication of ExxonMobil's 'design one, build two' philosophy for this project.

The conclusion, however, is that with most projects taking at least five years to come onstream, likely developments and production flows are unlikely to change much in the period to 2010 and additional projects are unlikely to come onstream before that date.

The listing of 14 possible developments in Opec countries and 28 possible developments in non-Opec countries shows the potential for future production – however, the long project lead times means virtually all of these projects and potential developments will only come onstream after 2010, and most probably after 2012. Projects that are virtually certain to materialise include two, possibly three, deepwater projects offshore Angola in blocks 31 and 32; several deepwater Gulf of Mexico projects; and further large-scale development of Canadian tar sands. Similarly, a second phase of Orinoco heavy oil developments may be about to start, with Sincor II being close to sanction. The projects that have a realistic chance of coming onstream before 2010/2012 are those that will utilise some existing infrastructure offshore Vietnam, Brazil and Australia.

All Russian projects have become somewhat problematic as Russian policy towards inward investment and the speed of development appears to be under review. Only once a clearer idea of the Russia government's objectives emerge will it be possible to gauge the likely speed of new developments in that country, despite its obvious potential. ●

Project	Location	Operator	Oil peak flows (kb/d)	Gas peak flows (mn cf/d)	Reserves (mn/b)	Partners and shareholdings
Onstream 2004						
<i>Opec countries</i>						
Abu Sa'fah (expansion)	Saudi offshore	Saudi Aramco	+150 (by Oct)		6,100	Saudi Aramco 100%
Elephant NC-174	Libya onshore	Eni	150 (2006)		760	Libya NOC 50%, Eni 33.34%, Korean consort'm 16.66%
Hamaca (Orinoco hvy oil)	Venezuela	Petrolera Ameriven	+70 (end-year)			ChevronTexaco 60%, ConocoPhillips 40%
Qatuf field expansion	Saudi onshore	Saudi Aramco	+500 (by Oct)		8,000	Saudi Aramco 100%
<i>Non-Opec countries</i>						
Barracuda	Brazil	Petrobras	150 (mid-2005)		867	Petrobras 100%
Bayu-Undan	PHI (liqs)	ConocoPhillips	115	(950 injct)	400 (cond)	ConocoPhillips 56.72%, Eni 12.04%, Santos 10.64%, Inpex 10.53%, Tokyo Elect/Gas 10.08%
Bozhong 25-15 (hvy oil)	China Bohai Gulf	CNOOC	80 (2008)			
Caofedian	China Bohai Gulf	Kerr-McGee	100			Kerr-McGee
Holstein	Gulf of Mexico	BP	100	290	500–1,000 boe	BP 50%, Shell 50%
Karachaganak	Kazakhstan onshore	Eni, BG	+100 (2004)	1,400	2,400 (liqs)	Eni 32.5%, British Gas 32.5%, ChevronTexaco 20%, Lukoil 15%

Future oilfield projects with a peak production capacity of over 100,000 b/d

Project	Location	Operator	Oil peak flows (kb/d)	Gas peak flows (mn cf/d)	Reserves (mn/b)	Partners and shareholdings
Kizomba A (HungoCrocchal)	Angola	ExxonMobil	250		1,000 boe	ExxonMobil 40%, BP 26.66%, Eni 20%, Statoil 13.33%
Marco Polo	Gulf of Mexico	Anadarko	100		180	Anadarko
Marlim Sul II	Brazil	Petrobras	100 (2005)	80	1,700 (total)	Petrobras 100%
Priobskoye	Russia Siberia	Yukos	+350		4,000	Yukos 100%?
Onstream 2005						
<i>Opec countries</i>						
Bab North East	Abu Dhabi onshore	ADCO	+100 (2005)			ADCO 100%
Bonga	Nigeria OML 118	Shell	225	170	600	Shell 55%, ExxonMobil 20%, Total 12.5%, Agip 12.5%
Darkhovin Ph I	Iran	Eni, Naftiran	50			
NEAD project	NE Abu Dhabi	Adnoc	+100			ADNOC 100%?
North fields expansion	Kuwait	KOC	+300			
Nowrouz expansion	Iran	Shell	+90			Shell buy-back from NIOC
Soroush expansion	Iran	Shell	+100			Shell buy-back from NIOC
<i>Non-Opec countries</i>						
ACG megastructure Ph I	Azerbaijan	BP	400 (2006)		6,000+	BP 34.14%, Unocal 10.28%, Socar 10%, Inpex 10%, Statoil 8.56%, ExxonMobil 8% TPAO 6.75%, Devon 5.62%, Itochu 3.92%, Delta Hess 2.72% Petrobras 90%, Repsol 10% BHP Billiton 45%, Total 30%, Talisman Energy 25%
(Azeri-Chirag-Guneshli) Central Azerbaijan						
Albacora Leste	Brazil	Petrobras	180 (2006)		700mn boe	
Angostura Ph I	Trinidad	BHP Billiton	60 (2005)		300	
Caratinga	Brazil	Petrobras	150 (2005)		362	
Clair South	UKCS, W. of Shet'l'd	BP	60 (2006)	15	250	BP 28.6%, ConocoPhillips 24%, ChevronTexaco 19.4%, Shell 18.7%, Amerada 9.3% Petrobras 100%?
Jubarte	Brazil (B60 Santos)	Petrobras	60 (2008)		600	ExxonMobil 40%, BP 26.66%, Eni 20%, Statoil 13.33%
Kizomba B (KissanyeDikanza)	Angola	ExxonMobil	250		1,000	ExxonMobil 11%?
Kristin	Norway	Statoil	126 (cond)	530	220 (cond)	
Mad Dog	Gulf of Mexico	BP	80	40	250 boe	BP 60.5%, BHP Billiton 23.9%, Unocal 15.6% Santos 33.3977%, Kufpec 33.4023%, Nippon Oil 25.0%, Woodside 8.20%
Mutineer-Exeter	NW Australia	Santos	85 (2006)	361		Gazprom?, Rosneft? Exxon NG 30%, Sakhalin O&G 30%, ONGC Videsh 20%, Sakh MNG 11.5%, RB-Astra 8.5% Salyem Petroleum Development NV (SPD) 50% Shell 50% QAO Evikhon Sonangol 41%, ChevronTexaco 39.2%, Total 10%, Eni 9.8%
Pirrazlomnoye	Russia Siberia	Gazprom, Statoil	155 (2010)		610	
Sakhalin I (Chayvo field)	Russian Far East	ExxonMobil	250	1,000	2,300	BP 75%, ExxonMobil 25% Husky Oil 72.5%, PetroCanada 27.5%
Salyem fields -W, Upp, Vadelep	Khanty-Mansiisk	Shell, Evikhon	120 boe (2009)		800	
Sanha (cond), Bomboco(crude)	Angola	ChevronTexaco	100 boe (2007)			
Thunder Horse (inc North)	Gulf of Mexico	BP	150**	200	1,500 boe	
White Rose	Eastern Canada	Husky Oil	100 (2006)		230	
Onstream 2006						
<i>Opec countries</i>						
Banyu Urip (Cepu block)	Indonesia offshore	ExxonMobil	165	20	700 in block	Under negotiation
Bu Hasa development proj	Abu Dhabi	Adco	180			ADCO 100%
Darkhovin Ph II	Iran	Eni, Naftiran	160			
Erha	Nigeria (OPL 209)	ExxonMobil	165		500	ExxonMobil 56.25%, Shell 43.75%
Ghawar Haradh Ph III	Saudi onshore	Saudi Aramco	+300			Saudi Aramco 100% Non-Opec countries
ACG megastructure Ph II	Azerbaijan	BP	+500 (2007)		6,000+	See under Ph I in 2005
Atlantis	Gulf of Mexico	BP	150		675 boe	BP 56%, BHP 44%
Benguela-Belize (BBLT1)	Angola	ChevronTexaco	100		400	ChevronTexaco 31%, Agip 20%, Total 20%, Sonangol 20%, Galp 9% Encana 43%, Intrepid Energy 30%, BG Group 22%, Edinburgh Oil & Gas 5% Woodside 53.85%, Hardman Res 21.6%, Roc Oil 3.69, Premier 9.23%, BG 11.63% Total 40%, BP 16.67%, Statoil 13.33%, ExxonMobil 20%
Buzzard	UKCS	Nexen	200 (2007/2008)		550	Woodside Petroleum 60%, Mitsui 40% ChevronTexaco 42.5%, Petrobras, Nissho Iwai Petrobras 100% Petrobras 100% ConocoPhillips 43.5%, Total 43.5%, Devon 13% Canadian Oil Sands Ltd 32%, Imperial Oil 25%, Petro-Canada 12%, Nexen 7%, others?% ChevronTexaco 50%, ExxonMobil 25%, KazMunaiGaz 20%, LukArco 5%
Chinguetti Ph I	Mauritania offshore	Woodside	75	120		
Dalia	Angola	Total	240		1,600	
Enfield (+Laverda/Vincent)	Australia NW Shelf	Woodside	100		363	
Frade	Brazil	ChevronTexaco	110 (2007)		300	
Golfinho Module I	Brazil (Espirito Santo)	Petrobras	100 (2007)	450		
Roncador II	Brazil	Petrobras	145 (2008)		2,700 (total)	
Surmont (heavy oil)	Canada, N Alberta	ConocoPhillips	100 (2012?)			
Syncrude Ph III	Athabasca, Canada	Canadian Oil Sands	100			
Tengiz/Kololev exp'n*	Kazakhstan	ChevronTexaco	285 to 450+	100	7,000	
Onstream 2007						
<i>Opec countries</i>						
Abu Hadriya/Khursariyah/Fadhili	Saudi onshore	Saudi Aramco	+500	250	4,500/500/950	Saudi Aramco 100%
Akpo	Nigeria OPL 246	Elf Nigeria (Total)	100		590	Total
Azadegan (southern part)	onshore Iran	Inspex	260 (2012)		2,500-3,000	Pedco 25%, Japanese interests 75% (Inspex, Japex, JNOC, Tomen)
Bonga South + Aparo?	Nigeria (OML 118)	Shell, ChevronTex	250		500+	Shell 55%, ExxonMobil 20%, Total 12.5%, Eni 12.5%
Corocoro Phase I	Venezuela offshore	ConocoPhillips	75		450	ConocoPhillips 50%, PdVSA 24%, Eni 26%
<i>Non-Opec countries</i>						
Golfinho Module II	Brazil (Espirito Santo)	Petrobras	100 (2007/2008)		450	Petrobras 100%
Greater Plutonio (6 fields)	Angola block 18	BP	220	800		BP 50%, Shell 50%
Kikeh	Malaysia offshore	Sabah	Murphy Oil	120 (09)	400	Murphy 80%, Petronas Carigali 20%
Lobito-Tombuco (BBLT 2)	Angola	ChevronTexaco	100 (2008)	400+		ChevronTexaco 31%, Agip 20%, Total 20%, Sonangol 20%, Galp 9%
Long Lake (tar sands)	Canada Northern Alberta	Nexen	60		4,000	Nexen 50%
Mangala and Aishwariya	India onshore Rajasthan	Cairn Energy	80-100		600	Cairn Energy 70%, ONGC 30%
Marlim Leste	Brazil	Petrobras	150 (2008)		150	Petrobras 100%
Peng Lai Ph II	China Bohai Bay	ConocoPhillips	190 (2009)	750		CNOOC 51%, ConocoPhillips 49%
Roncador III	Brazil	Petrobras	145 (2008)		2,700 (total)	Petrobras 100%
Rosa (tieback to Girassol)	Angola block 17	Total	250, net+40		300	Total 40%, Esso 20%, BP 16.67%, Statoil 13.33%, Norsk Hydro 10% ChevronTexaco 58%, Encana 25%, Shell 17%
Tahiti	Gulf of Mexico	ChevronTexaco	150?		500mn boe	
Vankorskoye 2 fields	Russia Siberia	Shell/TFE PSA	216		900	
Onstream 2008						
<i>Opec countries</i>						
Agbami	Nigeria OPL 216/217	ChevronTexaco	250 (2008)		800	ChevronTexaco 68.15%, Petrobras 13%, Statoil 18.85%

Future oilfield projects with a peak production capacity of over 100,000 b/d

Project	Location	Operator	Oil peak flows (kb/d)	Gas peak flows (mn cf/d)	Reserves (mn/b)	Partners and shareholdings
Block 208 El Merk fields	Algeria	Anadarko	100			
Usan/Ukot/Tongo	Nigeria (OPL 222)	Elf Nigeria (Total)	150-230		480+	Elf Nigeria, ChevronTexaco, ExxonMobil 30%, Nexen
Non-Opec countries						
ACG megastructure Ph III	Azerbaijan	BP	+400 (2009)		5,400	See under Ph I in 2005
Horizon Ph I (tar sand)	Canada	CNR	110		3,300	CNR?
Kashagan Ph I	Kazakh Caspian	Agip (Eni)	450 (2009)	1,500	10,000 (total)	Agip/Total/ ExxonMobil/Shell 20.37%, ConocoPhillips 10.19%, Inspec 8.33%
Kizomba C (Mondo,Saki,Batur)	Angola	ExxonMobil	250		1,000	ExxonMobil 40%, BP 26.66%, Eni 20%, Statoil 13.33%
Marlim Sul III	Brazil	Petrobras	100		2,679 boe (tot)	Petrobras 100%
Su Tu Trang (White Lion) 15-1	Vietnam Cuu Long Bas	ConocoPhillips	100?		220	Petrovietnam 50%, ConocoPhillips 23.25%, KNOG 14.25%, SK Corp 9%, Geopetrol 3.5%
Onstream 2009						
Opec countries						
Al Shaheen expansion	Qatar offshore	Maersk Oil	+210			
Qatar GTL (Ph I)	Qatar	Qatar Shell Gas	70 (cond)	800		Qatar Petroleum, Shell
Non-Opec countries						
Corocoro Phase II	Venezuela offshore	ConocoPhillips	+45		450	ConocoPhillips 50%, PdVSA 24%, Eni 26%
Karachaganak Ph III/IV	Kazakhstan	Eni, BG	+200?			Eni 32.5%, British Gas 32.5%, ChevronTexaco 20%, Lukoil 15%
New Canadian tar pit	Athabasca, Canada	Imperial Oil	100			Imperial Oil, ExxonMobil
Onstream 2010						
Non-Opec countries						
Kashagan Ph II	Kazakh Caspian	Agip (Eni)	900 (2012)	1,500	16,000	Agip/Total/ ExxonMobil/Shell 20.37%, ConocoPhillips 10.19%, Inspec 8.33%
Uvatskoye	Russia Siberia	TNK-BP	200			
Onstream 2011						
Opec countries						
Qatar GTL Ph2 II	Qatar	Qatar Shell Gas	70 (cond)			Qatar Petroleum, Shell
Onstream 2012						
Non-Opec countries						
Horizon Ph III (tar sand)	Canada	CNR	+132		3,300	CNR?
Kashagan Ph III	Kazakh Caspian	Agip (Eni)	1, 200(2015)	1,500	10,000 (total)	Agip/Total/ ExxonMobil/Shell 20.37%, ConocoPhillips 10.19%, Inspec 8.33%
Potential Projects						
Opec countries						
Ahwaz Bangestan Devs	onshore Iran	Pedco?	+150			
Arash	Iran in Gulf	NIOC			683 boe	
Azadegan (Northern part)	onshore Iran	NIOC?	400		2,500-3,000	
Hamrin	Iraq onshore (south)	SOC				
Khurais	Saudi onshore	Saudi Aramco	1,200	3,000		Saudi Aramco 100%
Manifa (Arab Heavy)	Saudi offshore	Saudi Aramco	300			Saudi Aramco 100%
Majnoon	Iraq onshore	SOC	360		12,100	
Nuayyim (Arab Super Light)	Saudi onshore	Saudi Aramco	75	250		Saudi Aramco 100%
Northern Fields 'Project Kuwait'	Kuwait	KOC?	+450			
Ramin	Iran near Ahwaz	NIOC			1,500	
Shaybah expansion	Saudi onshore	Saudi Aramco	+500			
Subbah-Luhais	Iraq onshore (s'th)	SOC				
Yadavaran	Iran onshore	NIOC/Chinese	300	1,000 boe+h	1,500+	NIOC 80%, ONGC 20%
West Qurna Ph II	Iraq onshore	SOC	650		11,300	
Non-Opec countries						
BM-C-8	Brazil (Campos)	Devon Energy	80			Devon Energy 60%, SK Corporation 40%
Block 09-03	Vietnam (Cuu Long)	Petrovietnam	100+?	300-400		
Block 31	Angola block 31	BP	5 discoveries			BP 26.67%, ExxonMobil 25%, Sonangol 20%, Statoil 13.33%, Marathon 10%, Total 5%
Block 32	Angola block 32	Total	3 discoveries			Total 30%, Marathon 30%, Sonangol 20%, ExxonMobil 15% and Petrogal 5%
Fort Hills oilsands	Canada, N Alberta	PetroCanada	50-190?	2,800		Shell?
Great White	Gulf of Mexico	Shell			500-1,000 boe	Sampang PSC: Santos 45%, Singapore Petroleum Co (SPC) 40%, Cue Energy 15%
Jeruk	Indonesia, off Java	Santos	170 boe			
Jubarte	Brazil	Petrobras			350	
Kebabangan	Malaysia, off Sabah	ConocoPhillips		200-300		Block J: Petronas Carigali 20%, ConocoPhillips 40%, Shell 40%
Kharyaga	Russia Siberia	Total PSA			5200	
Khvalynskoye	Russian Caspian	Lukoil/KazMgaz			627 boe	
Kirkuk Khurmala Dome Dev	Iraq onshore	NOC	100			Rosneft 25%, Other Russian 25%, KazMunaiGaz 25%, Total 25%
Kurmangazy	N Caspian	Rosneft/KMG				
Lungu	China Tarim Basin	Petrochina			500	
Northern Territories 4111a	Russia Timan-Pech	Lukoil, ConPhil	990			
Shenzi	Gulf of Mexico	BHP Billiton	50-100			
Sincor II	Venezuela	Total	180			
Stybarrow	Australia (Exmouth)	BHP Billiton	100		90	BHP Billiton 50%, Woodside Petroleum 50%
Su Tu Vang (Golden Lion) 15-1	Vietnam (Cuu Long)	ConocoPhillips	100?		400?	Petrovietnam 50%, ConocoPhillips 23.25%, KNOG 14.25%, SK Corp 9%, Geopetrol 3.5%
Suncor (tarsands) expansion						
Talanskoye	Canada		100			
Tiof	Russia Siberia	Surgutneftegas			832	
Tsentralnoye block	Mauretania	Woodside			287	
	Rus/Kaz Caspian	Lukoil/Kazakhoil			3,800	TsentrKasneftegas JV : Kazakhoil 50%, Lukoil and Gazprom 50%
Val Gamburtsev	Russia Siberia	Yukos/Sibneft			600	
Verkhnechonsknoye	Eastern Siberia	TNK-BP?			1,500	
Yalamo-Samur	Rus/Azer Caspian	Lukoil			3,750 boe	
Yuri Korchagin	Russian Caspian	Lukoil			879 boe	
Yuzhno-Shapinskoye	Russia, Siberia	SeverTek			500	Lukoil, Fortum

*limited production from 12/2004

** 200,000 b/d 2007-2009

Future oilfield projects with a peak production capacity of over 100,000 b/d

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All EI Awards 2004 photos: Jim Four.

Top: EI Awards statues

Middle: EI Awards 2004 Guest speaker and presenter, Matthew Pinsent, CBE

Bottom: EI Awards 2004 winners on stage with Matthew Pinsent (centre).

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Class societies keep an eye on the future

Classification societies have an integral role to play in advancing the novel concepts that continue to push the frontiers of oil and gas development. William J Sember, Vice President, Energy Development, ABS, explains.

The ABS-classed *Belanak* FPSO under construction at Dalian New Shipyard for ConocoPhillips is destined for the Belanak field, South Natuna, Indonesia

Innovation along with technological advances in offshore production, storage and transportation methods have made possible the commercial recovery of oil and gas from deepwater offshore locations. From the development of new designs for specific floating production unit (FPU) types to new approaches toward field developments that maximise recovery, the offshore industry continues to display remarkable ingenuity in meeting the challenge of producing oil and gas from the most demanding environments.

Class societies have become an integral part of this offshore development process – providing the independent third-party review and approval of these novel concepts that continue to push the frontiers of development. By addressing technical challenges at the earliest stages of a project, working in close collaboration with the designers and the operators, class is able to facilitate innovative approaches to the extraction, storage and onward shipment of the energy resources.

The tools available to the class society that allow us to play such a vital and inter-

active role have been developing as rapidly as the design concepts themselves. For example, there was no means available to industry to effectively evaluate residual and expected fatigue in an FPSO conversion when the first of these units were being modified from their former role of trading tankers. Today, sophisticated dynamic load approach (DLA) and spectral fatigue analysis (FSA) tools have been developed by class societies, such as ABS, that allow us to accurately predict a converted FPSO's expected fatigue life for a specific site. Rational evaluation of dynamic load components, hull strength (both as-built and in existing state) and site-specific fatigue assessment is essential in the development of appropriate design criteria for FPSOs, both newbuildings and conversions.

At ABS the evaluation process will initially use the advanced ABS SafeHull system that has been specifically developed to consider FPSO configurations. Using a three-hold, midships model, SafeHull assesses the strength based on a rational approach to evaluating the dynamic loads and environmental severity factors to which the vessel has been and will be subject. For a conversion of an existing vessel, this analysis draws on the extensive ABS global wave database to consider the past trading history of the tanker to calculate the cumulative fatigue that the structure has experienced. Using the wave data for the projected service location, SafeHull then calculates the remaining fatigue life at the time of the conversion so that appropriate steel repair or replacement can be undertaken prior to the vessel entering service, thereby minimising the risk of costly future downtime.

Other tools such as DLA and SFA can be used to consider the whole ship should the owner or charterer require a more detailed analysis of the structure. These analyses are particularly recommended for the larger units that are projected to maintain a busy working life of constant loading and discharge, since these operations can contribute significantly to the build-up of fatigue within the structure.

No matter what advanced analysis tools are used, the importance of strength and fatigue assessment cannot be overstated. As FPUs become larger, more technically sophisticated and subject to more complex loading patterns, accurate assessment of these factors is needed by the operator and can be undertaken by the classification society. This degree of precision allows an owner and the charterer of a vessel to undertake the conversion of an ageing tanker for an extended and uninterrupted 15- or 20-year on-site service life as an FPSO with a great deal of confidence.

New classification standards

The development of new classification standards for the design and construction of alternative production units such as tension leg platforms (TLPs) and spars has similarly spurred greater innovation in developing these concepts. Mini-TLPs are now in-service and spar designs have already developed to fourth generation concepts. The classic, or caisson, spar has evolved through the truss configuration to the current cell structures, with new concepts on the designers' tables.

Each new generation design has enhanced the spar concept by reducing steel weight, increasing deck loadings and improving stability. Classification society involvement in this rapid developmental process has helped enhance the opportunities for more efficient and cost-effective development of the deep-water fields that are so important to the future supply of global energy.

The next generation

Looking ahead, what is the next advancement for FPU's? As an organisation responsible for setting technical standards and verifying regulatory compliance we continuously explore that question. For example, the more traditional converted FPSO is still in demand to meet the needs of fast-track development projects, but topside production equipment has grown exponentially to increase production capability from a modest 25,000–50,000 b/d to more than 200,000 b/d. This raises detailed questions on aspects as diverse as strength of the hull structure to maintenance of the intricate complex of piping and equipment that is exposed to the corrosive maritime atmosphere.

Where an operator has the luxury of time when developing a new field, the preference is for purpose-built tonnage such as the recently ordered *Agbami* FPSO, ordered from Daewoo in South Korea by ChevronTexaco for service off West Africa. Increasingly, designers are looking at newbuild structures in which the hull form may differ radically from the ship shape of the units converted from tankers.

An associated development stems from the burgeoning global market demand for gas, coupled with increased environmental restrictions on the flaring of gas from FPSOs, for example in Nigerian waters. Recently delivered from Japanese builders is the world's first FPSO designed to handle liquefied petroleum gas (LPG). The *Sanha* LPG FPSO newbuild for ChevronTexaco is for operation offshore Angola. ABS provided classification services that

reviewed and approved the design of the vessel, surveyed the construction and will continue to survey the vessel throughout its operational life.

Operators are now looking to offer dual capability to accommodate both LPG and liquefied natural gas (LNG) onboard an FPSO. This LNG/LPG FPSO newbuild concept will allow for the extraction and transport of heavier gases, propane and butane, as well as lighter natural gas, methane.

Pure LNG FPSOs are already on the drawing board. A classification society's experience with the design and construction of large LNG carriers that have been trading for many years gives them a unique understanding of the strength, stability and containment challenges that such designs pose, particularly when in a partially filled condition. ABS, for example, brought together its 50 years of LNG experience to draw up the industry's first guidelines for appropriate standards for building and classing offshore floating LNG terminals – installations that may, depending upon the complexity of their gas handling installations, bear close similarities to the projected LNG FPSOs.

A key issue for a floating gas terminal or FPSO is the design of the system to be used for the cryogenic transfer, particularly the manner in which it addresses the relative motions likely to occur during loading and offloading operations. ABS has been working closely with the designers of these systems to develop appropriate standards.

A class society perspective provides a comprehensive look at concepts like this which call for the integration of marine and typically shore-based gas processing facilities on a floating concept. A significant part of that process includes cross-referencing classification rules with other relevant industry documents such as API, NFPA, ASME and the IMO Gas Code.

The structure, as well as associated mooring systems, containment systems, process facilities, offloading systems and possible terminal structure must all be examined, as well as the initial installation, hook-up and commissioning. Class societies provide this oversight for surveys from the construction of a unit and on throughout its life cycle operation.

Evolution process

Faced with such rapid innovation, the question has become: 'How can class societies properly evaluate a novel design for offshore service that does not fit traditional prescriptive rules or for which there is no in-service history?' The answer is the selective application of various sophisticated risk assessment methodologies.



The ABS-classed *Sanha*, the world's first newbuild LPG FPSO slated for operations offshore Angola, has a daily production capacity of 6,000cm and storage capacity of 135,000cm. ABS experience with IHI's self-supporting, prismatic-dhape, IMO type-B tank system (or SPB) was key for classification society selection. The SPB containment system is recognised by industry as particularly effective for liquid gas storage on an FPSO or FSO because of its internal tank stiffening structure and suitability for partial loading.

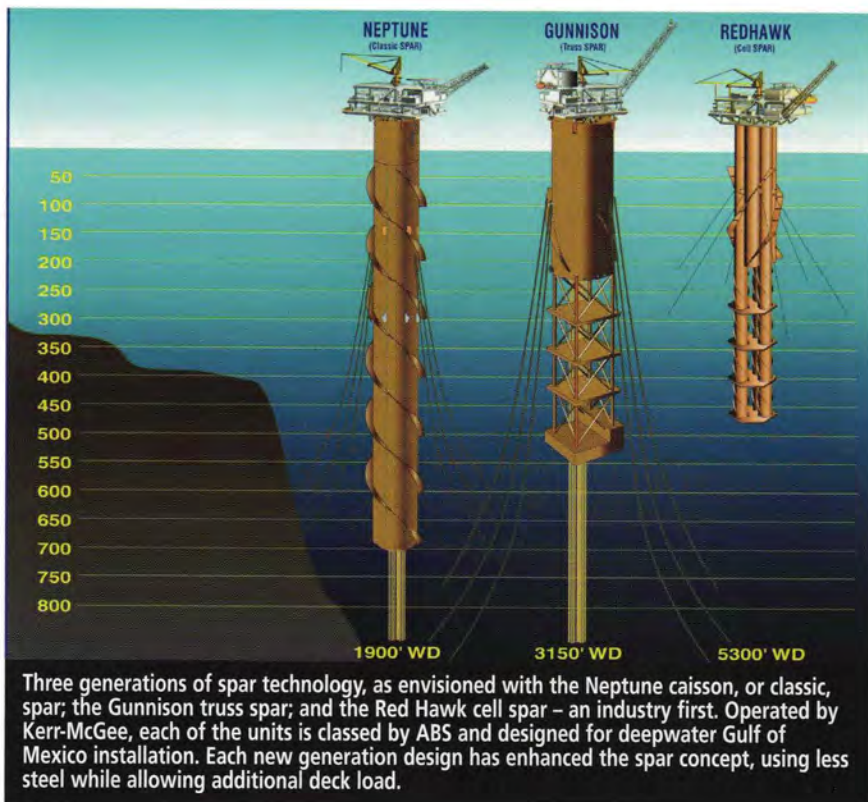
New frontiers of design and operation require case-specific understanding of the risks to which a unit will be exposed when placed into deeper water, a remote location or a harsh environment.

The evolution of classification standards to include the rational and scientific assessment of the hazards that an offshore unit will face and the development of appropriate risk-based mitigation techniques is perhaps the most significant recent contribution of the class sector to innovation in the offshore industry.

Traditional class rules relied upon empirical experience and extrapolated prescriptive standards. By understanding the risks associated with the operation of proposed offshore structures, class is able to determine if a proposed design adequately meets accepted levels of safety, thereby spurring continuing innovation. Guides such as the recently released *ABS Risk Evaluations for the Classification of Marine-Related Facilities* and the *ABS Guide for Surveys Using Risk-Based Inspection Techniques* draw upon risk-based methodologies and assessment to establish classification requirements that meet this equivalency test. The risk-based *ABS Guidance Notes for Novel Concepts* addresses technologies or approaches for which no precedent exists.

The advantages of this approach include an increased ability to review innovative designs; an increased confidence that alternative designs can provide levels of safety equivalent to those of traditional designs; and a better understanding of the hazards, mitigation measures and risks of proposed designs.

For existing units already in service, the ABS standards for risk-based inspection (RBI) have been developed in a joint project with one of the leading operators of FPSOs. The approach



elements of risk, but with the availability of RBI in the offshore industry, both consequence and frequency are considered in conjunction within a holistic framework.

RBI survey and inspection programmes focus resources and activities upon systems and components associated with the highest risk. By targeting predictable failure that could affect the safety of an installation, RBI encourages the timely identification of potential damage and repair needs.

This example illustrates classification working in tandem with industry to create new standards, new ways to review new designs and new approaches to lifecycle maintenance through more effective inspections. Given the high investment costs for today's offshore field developments, the reliance on class for technical guidance and mitigation of operational risk has raised the profile of class societies.

By working collaboratively with industry, class continues to support innovative concepts that adequately meet accepted technical and regulatory standards. And this very active involvement of class gives rise to new research into emerging technologies and advancement of existing rules and criteria for the next generation of floating production units.

allows for the determination of potential consequences and the likely frequency of damage or undesirable

events measurable by one or more inspection techniques. Inspection schemes have always considered some



High oil price – the impact on UKCS business

9 June 2005

Aberdeen Exhibition and Conference Centre, Aberdeen, UK



The 7th Logic Conference, organised for the first time by Logical Advantage in partnership with the Energy Institute, will aim to address just how well the UKCS is positioned in a number of key areas including:

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Inputs from the workshops will be drawn together during the day to allow analysis of industry concerns to be presented in the conference's final sessions.

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To register please complete the registration form at www.logic-events.com

Or contact: Kelly Newlands t: +44 (0)1224 853430 e: kelly.newlands@logic-oil.com or Arabella Dick on t: +44 (0)20 7467 7106 e: arabella@energyinst.org.uk for further information.

Workload, organisational change and stress – practical application of human factors tools to major hazard operations

Tuesday, 26 April, Royal Society of Medicine, London

Of particular interest to SHE professionals and operators of major hazard installations in the offshore petroleum industry and onshore petroleum, chemical and allied industries, this seminar intends to communicate how best to manage the key human factors issues of workload, organisational change and stress. Featuring presentations and case studies from HSE, industry and consultancies, delegates will be informed of regulatory thinking and how to secure compliance by applying recently developed practical tools.

Focusing on a practical tool or guidance, sessions will concentrate on managing:

- Workload
- Staffing arrangements
- Organisational change
- Stress in the workplace

The seminar will be of interest to:

- Health, Safety and Environmental Managers
- Major Hazard Installation Operations Managers
- Human Factors specialists

Confirmed speakers:

- Dr Andy Brazier, Entec
- W Ian Hamilton, Human Engineering
- John Wilkinson, HSE
- Graham Reeves, BP
- Rob Miles, HSE
- Ronny Lardner, Keil Centre
- Angela Whitehead, BP
- Dr Michael Vaughan, Shell International E&P



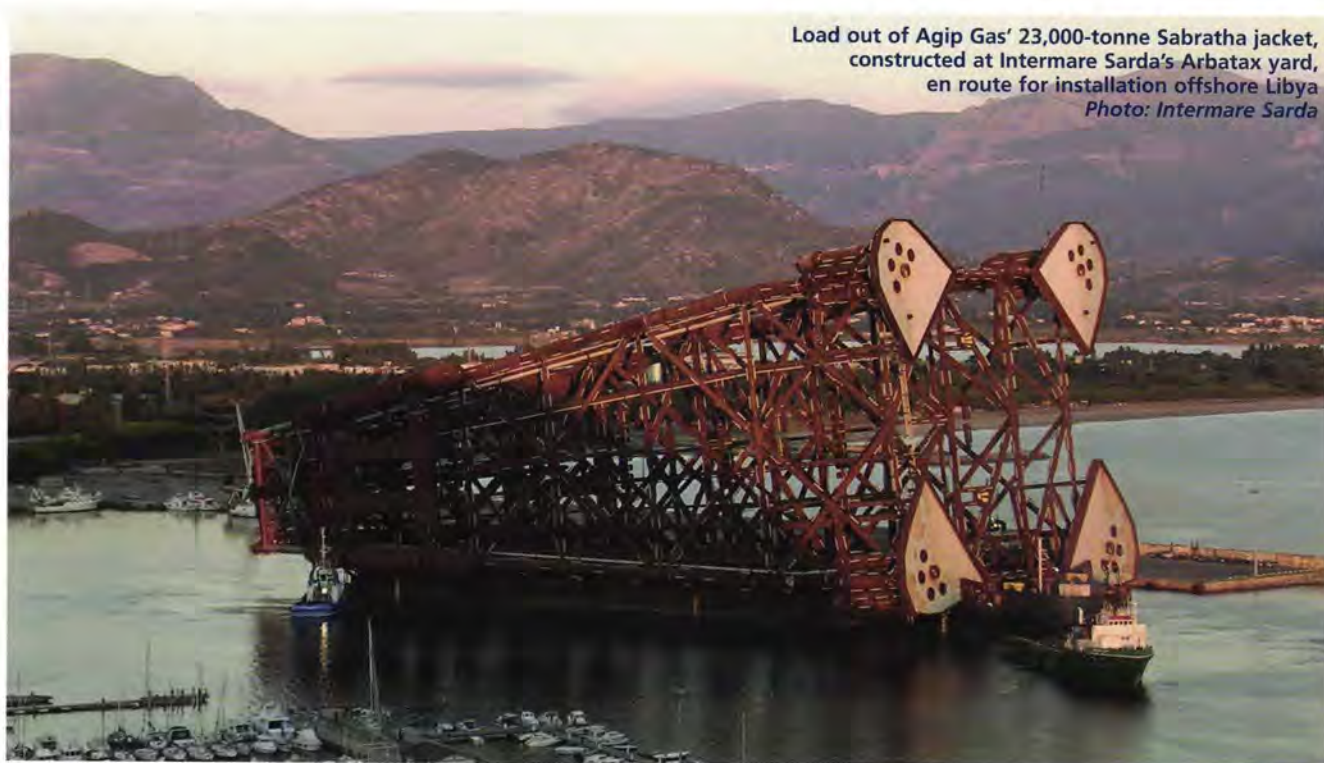
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Load out of Agip Gas' 23,000-tonne Sabratha jacket, constructed at Intermare Sarda's Arbatax yard, en route for installation offshore Libya
Photo: Intermare Sarda

Fabrication for sale

The European fabrication sector continues to struggle with excess capacity and a lack of large platform construction contracts as offshore operators are increasingly bringing new projects onstream via subsea completions. Fighting against competition from the Far East market, which can offer lower cost bases for projects, and feeling the pinch of the euro/\$ exchange rate, many yards are having to diversify their operations, target new markets and embrace new contracting strategies in order to stay in business. Some are losing the battle, however, with KBR's Nigg yard in the UK being the latest casualty. Kim Jackson reports.

Having remained on inspection, repair and maintenance (IRM) for a number of years, Kellogg Brown & Root's (KBR) Nigg yard on the Cromarty Firth is finally to be sold off. Selling agent DTZ is to handle the sale and has launched an aggressive marketing campaign aimed at highlighting the 'world class' facilities at the site to a cross-section of potential purchasers and industries, including the oil and gas sector. According to DTZ Director James Thomson: 'Nigg possesses approxi-

mately 25% of UK major yard capacity and also boasts the largest dry dock facility in Europe. The yard is suitable for a wide range of uses, either in its current format or redeveloped.'

As well as an excellent strategic location on the Cromarty Firth, DTZ also highlights other features of the yard that it believes will attract interest throughout the oil and gas industry, including:

- 45,570 sq metres of covered workshop facilities with integral craneage, one

of the largest covered offshore fabrication areas in Europe;

- yard space totalling 28.61 ha, with heavy-duty loading capacity;
- one of Europe's largest dry docks, with 9.5-metre draughts, covering 4.35 ha;
- quaysides of 725 metres, for draughts from 4.5 metres to 9.5 metres;
- deepwater access to North Sea strategic shipping routes;
- fabrications shops, paint and blast workshops and pipe shops;
- adjacent oil terminal facility.

Meanwhile, in Europe, it had been earlier reported that Grenland Group and Heerema Fabrication Group had signed a letter of intent for Grenland to acquire Heerema Tonsberg and all its assets.

A brighter note

With few large fabrication projects in the offing, the Buzzard field – the largest discovery on the UK Continental Shelf in the past decade – has provided a much needed boost to order books, both in the UK and elsewhere in Europe. Burntisland Fabrications has secured the contract for the management, fabrication and provision of assistance with commissioning of Buzzard's 3,650-tonne wellhead deck, while Heerema Group is to undertake fabrication of the 9,500-tonne utilities deck at

Operator/Contractor Field [®]		Work	Delivery
UNITED KINGDOM			
Burntisland Fabrications			
Agip	Bouri, Libya	EPC subsea manifold	Jan 2005
Nexen Saipem	Buzzard	3,650-tonne wellhead deck Manifolds and tie-in spools	May 2005 May 2005
Heerema Nexen	Buzzard	9,500-tonne utilities deck	2005
SLP Engineering			
ConocoPhillips Nexen	Saturn Buzzard	Wellhead platform – 400-tonnes topsides 700-tonne accommodation module and helideck	May 2005 Jun 2005
NORWAY			
ABB			
Norsk Hydro	Visund	\$80mn contract for 670-tonne and 300-tonne modules – one contains equipment to boost gas injection rate and increase oil production; the other will allow gas export from platform	2005
Sakhalin Energy Investment	Sakhalin, Sakhalin Island	Two modules and supporting equipment for Molikpaq oil platform	–
Aker Kvaerner			
Statoil Agip KCO	Kristin Kashagan, Caspian	NKr5bn contract; floating production platform fabrication, outfitting and testing of seven barges for oil production. Barge hulls to be fabricated at Aker Tulcea and Braila yards in Romania. Six hulls will be towed to Kvaerner Egersund for outfitting/testing; the seventh towed to Astrakhan Korabel yard in Astrakhan for completion	2005 2005
ITALY			
Intermare Sarda			
ExxonMobil	East Area, Nigeria	1,000-tonne topsides	Feb 2005
Canadian Natural Resources ExxonMobil	West Espoir, Ivory Coast Sable tier II, Canada	WHT platform comprising 1,400-tonne jacket, 960 tonnes of piles and 600-tonne deck 3,000-tonne jacket	Aug 2005 Feb 2006
THE NETHERLANDS			
Heerema			
Petro-Canada	De Ruyter	4,300-tonne integrated production deck and 12,500-tonne (dry weight) gravity based structure	–
ConocoPhillips	Britannia satellites	6,100-tonne platform jacket	June 2006
SPAIN			
Dragados Offshore			
Statoil	Snøhvit	LNG terminal (Melkøya Island), comprising 25,500-tonne plant constructed on barge measuring 9 metres in height, 154 metres long, 54 metres wide	July 2005
Nexen	Buzzard	10,500-tonne production deck	March 2006
SWEDEN			
Emtunga			
AIOC/BP	Chirag FFD Ph2, Caspian	Azeri West 1,200-tonne living quarters for between 130 and 190 men	2005
BP	Schiehallion FPSO	Extra living quarters for 28 men, plus new lifeboat installation	2005
Agip KCO	Kashagan, Caspian	Upgrading of LQ barge <i>Shapagat</i>	2005
AIOC/BP	Chirag FFD Ph2, Caspian	Azeri East 1,200-tonne living quarters for between 130 and 190 men	2006
AIOC/BP	Chirag FFD Ph3, Caspian	1,200-tonne living quarters for between 130 and 190 men	2007

Current orders for some European fabricators (North Sea projects unless otherwise indicated)

its Hartlepool yard. Dragados of Spain will construct the 10,500-tonne production deck at its Cadiz facility. Saipem UK has been awarded the contracts for pipelay on the project, as well as the transport and installation of the jackets and topsides.

The Norwegian sector, too, is being bolstered in the short-term by large projects such as Norsk Hydro's Ormen Lange development and Statoil's Snøhvit project. The Spanish fabricator Dragados Offshore, for example, has secured the contract for the Snøhvit LNG terminal – Europe's first LNG export facility – that

will be located on Melkøya Island, offshore Hammerfest, Norway.

Looking at the alternatives

The renewables energy sector is increasingly emerging as a potentially lucrative new sector for UK fabricators to target – SLP being just one company to have made moves into this arena. However, UK fabricators will face tough challenges in securing work from established players in the European market, who have secured high-profile contracts in the wind-rich Scandinavian countries.

Many of the UK's fabricators are also looking to diversify from their traditional central and northern North Sea market, focusing attention on smaller southern sector projects and developments in the Gulf of Mexico, the Caspian and West Africa. This trend is being followed across Europe, with a number of fabricators looking to secure onshore oil and gas construction work as well as civil engineering projects. Others are looking at decommissioning, upgrade and refurbishment programmes, and platform injection modules to boost tail-end production in maturing fields, as well as the mainstay contracts for subsea templates and manifolds, tie-in spools, piles and inspection/repair/maintenance (IRM) work.

Among other recent developments, Intermare Sarda is supporting its parent company, Saipem, as a technical partner in the establishing of a new fabrication yard in the Kuryk area of Kazakhstan. Aker Kvaerner, too, has its sights set on the Caspian market, recently acquiring from ST Holding a 26% stake in the Finnish contractor RR Offshore, which is the majority owner of the Astrakhan Korabel yard in Russia.

Rental market

A number of fabricators are now offering modules under rental agreements. Duffy and McGovern, for example, claimed in 2003 to have become the first offshore accommodation company to provide rental engineering cabins in the Gulf of Mexico. The financial benefits of such agreements are quite compelling – according to Duffy and McGovern Commercial Director Craig Russell, a cabin that might cost \$130,000 to buy outright can typically be leased for as little as \$80/d subject to a minimal rental period. More recently, the company claimed to be the first to bring a fully-compliant 12-man offshore sleeper cabin onto the market. The new unit is said to be the first of its size to comply with SOLAS (Safety of Life at Sea), IMO (International Maritime Organisation) and fire-test procedure (FTP) requirements. It has been designed with the Americas and West Africa region in mind and is now available for rental or lease/purchase.

Meanwhile, Aberdeen-based Labtech reports that increasing demand for its modules had led to it investing £180,000 to create three specially designed cabins – increasing its hire fleet to more than 40 units. Built to the latest Norwegian design and safety standards (reportedly the highest standards in the world), the cabins are suitable for use in any international location and are on long-term hire with clients in West Africa and the Danish sector of the North Sea.

The yellow brick road block

Overproduction of sulphur may lead to headaches for the oil and gas industry. Petroleum Review investigates.

Sulphur (brimstone) is a wondrous thing. Blend it with phosphorous and it helps to make the majority of the world's commercial crops grow. Mix it with a little oxygen and hydrogen and it will eat through the strongest steel. Combine it with hydrogen and it produces a gas more deadly than Sarin.

As one could imagine, such a versatile element has a myriad of uses – from fertiliser production and manufacturing chemicals to herbicides, food preservation and medicines. However, the pace of its production means that the world has faced a glut of sulphur over the last decade – and the ramifications of this surplus are starting to make the petroleum industry very nervous.

According to The Sulphur Institute, an international non-profit organisation that promotes the use of sulphur, the majority of worldwide production arises from two sources – sulphuric acid from smelters (around 23mn t/y) and elemental sulphur from gas and oil refining (around 42mn t/y). Most of the former is either recycled within the industry, or marketed to industrial users. However, it is the latter that causes headaches – virtually all of it is involuntary production, removed from oil and gas as an unwanted by-product in order to avoid acid gas pollution. While the Middle East, Former Soviet Union (FSU) and West Asia are all significant producers, almost half of all elemental sulphur comes from two countries, Canada and the US. Canada produces around 8mn t/y, most of it from natural gas. In the US, most sulphur comes from refineries, approximately 6.9mn t/y out of a total of 9.6mn t/y from all sources. In comparison, UK production is relatively modest – British refineries create about 130,000 t/y.

Fortunately, uses abound. Demand for elemental sulphur falls into two categories – phosphate fertilisers, and everything else. 'Over 50% goes into phosphate fertilisers, but there are over 250 different uses, from metallurgical processes to pigments,' says Bob Morris, President of The Sulphur Institute. Much of it is consumed in the US, but a growing amount is shipped abroad to China, Africa and South America. In the

UK, demand is for 350,000 t/y, primarily for pulp, pigment and agricultural uses (for example, according to The Sulphur Institute, British farmers spray sulphuric acid on potato vines in order to dissolve them prior to harvesting the tubers).

The price for sulphur is governed by a complex interaction of factors that sometimes turn the economic rules of supply and demand on its head. For instance, in 2003, consumption was 62mn tonnes and production was 65mn tonnes, a surplus that would normally depress the commodity price – but, in fact, it rose. 'The market right now is very strong,' comments Bill Kennedy, Shell Canada's Vice President for Sulphur Business. 'It's the best it's been in the last 15 years.' Terry Draycott, President and CEO of Prism Sulphur Corporation – a marketer of sulphur for several major producers in Canada – agrees. 'Vancouver price is \$55–\$60/t, fob [free on board]. Back in 2001 and first quarter 2002, it was \$15–\$20.'

The reason for the paradox, in one word, is China. The Asian country's demand for sulphur, primarily for its fertiliser industry, has been growing immensely. As recently as 1995, it produced most of its sulphur needs by burning pyrites. That was before The Sulphur Institute explained the value of imports, however. 'We did an economic study in conjunction with the Chinese government, comparing pyrites versus elemental sulphur to make sulphuric acid,' explains Morris. 'It illustrated that sulphur could be imported economically as compared to the domestic source.' Since then, imports have grown from virtually nothing to 6mn tonnes in 2004. 'Imports are expected to expand at a rate exceeding 1mn t/y for the next several years, until it stabilises in the region of 10–11mn t/y,' continues Morris.

While China has been soaking up ever increasing amounts of sulphur, transportation bottlenecks have sidelined the rest of the surplus. Each year, several million tonnes of sulphur are produced in remote regions such as the oil sands in Alberta. 'Sulphur produced at Syncrude doesn't see the light of day,' says Draycott of Prism Sulphur. 'The logistics and costs are prohib-

itive. It goes into the inventory.' The result is that supply and demand are in such close proximity that Shell Canada, which produces 2.6mn t/y, is re-melting part of its 1.5mn tonnes of inventory. 'We're selling everything we have right now,' says Shell Canada's Kennedy. 'I wish we had more.'

Brimming stone

With sulphur taking on such a rosy hue, it is hard to imagine difficulties ahead. However, The Sulphur Institute sees a large problem – while consumption is growing at 2% annually, production is growing by 3%.

The fact that production is inexorably outpacing demand is due to a number of factors. First, the amount of natural gas being consumed is increasing. The Energy Information Administration (EIA) estimates that consumption in North America alone, currently at approximately 22tn cf/y, could rise to 35tn cf/y by 2025. Oil is on a similar growth curve – transportation demand in the US will drive consumption from current levels of 22mn b/d to 29mn b/d in 2025.

The developing world faces similar growth. China's march to modernisation, for instance, is propelling its energy consumption at rates far exceeding Western ones. The International Energy Agency (IEA) notes that China consumed 5.49mn b/d in 2003 and 6.24mn b/d in 2004, or 13% growth. The transport sector is expanding at almost 20% per year, with private cars alone expected to exceed 100mn units by 2020, doubling current consumption.

In order to meet the growing energy demands, natural gas will be increasingly imported in the form of LNG from isolated deposits, such as the North field located between Qatar and Iran. Unfortunately, the North field is laden with sour gas. 'It will exceed North America as the primary exporter of sulphur in the next 10 years,' says Morris. Oil production is following a similar trend towards higher-sulphur deposits. In Canada, the oil sands are expected to expand from current production of 1mn b/d to 2.2mn b/d in 2015. Sulphur production, now at 1.5mn t/y, will grow apace.

Secondly, legislation in North America and Europe continues to restrict sulphur content in transportation fuels. Laws limiting its content in petrol to 30 ppm have come into effect in Canada and the US, and by 2006 diesel will have a limit of 15 ppm. The EU is even more strict – it has mandated 10 ppm by 2009. The Sulphur Institute estimates that all this will cause the annual sulphur surplus to expand from the current rate of 2.2mn tonnes to 5.4mn tonnes in 2006, and 5.9mn tonnes by 2011. When developing countries are added in, the situation gets worse. The



Photos: www.sultran.com

surplus could be 8.5mn tonnes by 2006. Furthermore, if, as the EU is debating, limits are extended to marine bunker fuels, the surplus could bulge to 12.1mn tonnes per year.

Finally, traditional Frasch mines (which inject hot fluids into sulphur veins to dissolve the material and carry it to the surface) have largely been shut down. This has removed any swing production, and thus the ability to moderate price fluctuations.

Enormous implications

The implications are enormous. The phosphate fertilizer is notoriously cyclical – a combination of a downturn in demand and an upswing in involuntary production could create huge surpluses. In the past, producers simply stockpiled sulphur in the form of immense blocks – Canada has some 14mn tonnes sitting in isolated fields. Governments, however, are already placing pressure on producers to curtail such behaviour. For example, the Kazakh authorities fined Tengizchevroil (a joint venture led by ChevronTexaco) \$7mn for polluting the region around the Tengiz field with its stockpile.

Refineries in North America face worse restrictions. 'In the US, there's very little stockpiling capacity,' says Morris. 'Most is moved out, sold to create sulphuric acid.' There have been forewarnings of trouble already. 'There was a reduction in the phosphate market in 2000, and in 2001 demand for sulphur slowed, and [refiners] had to store it in railway cars because there was no place for them to send it.' If the market for sulphur becomes glutted to the point where prices collapse, it would accumulate around US refineries at the rate of 140,000 tonnes per week. 'As a consequence, the only option may be to shut down a refinery if they have no place to send it,' concludes Morris.

Paving the way

Apparently, there's nothing like the prospect of a closure in a fortnight to

focus the mind. Because sulphur production is almost completely involuntary, solutions must focus on either not producing it in the first place, or finding new uses. In the case of the former, various proposals are being made to re-inject the stuff as new fields are developed. Unfortunately, the technology is still uncertain. 'Theoretically, it can work, you have to liquefy acid gas and then pump it down,' explains Shell Canada's Kennedy. 'At the Kashagan field [a new Caspian Sea field in Kazakhstan] the pressure is at 850 bars, and today's re-injection technology is at 690 bars. There's some proving to do.'

New uses hold more prospects. Shell Canada, for instance, is spending \$3m/ly on R&D into sulphur fertilizer. Ironically, the success at reducing sulphur dioxide (SO₂) emissions from vehicles and industry has created a situation in which soils that were formerly enriched by acid rain are now showing signs of sulphur depletion. Studies have shown that yields for a wide variety of crops increase by an average of 12% when sulphur-rich fertilisers are applied to fields. 'The big numbers are in India and China where they are cropping so often,' says Kennedy. 'We see it as a 1–2mn t/y market for sulphur.'

Shell and other companies are also investigating Sulphur Enhanced Asphalt (SEA). Initially developed in the 1970s, modern versions of SEA are created by mixing around 3% pellet sulphur into the road mix prior to application. The advantages of SEA over regular asphalt include resistance to cracking at lower temperatures, higher resilience and longer replacement cycle. 'The big thing about sulphur asphalt is that it is rut resistant,' comments Kennedy. 'Asphalt begins to flow at 25°C, but sulphur is solid to 130°C. We see it as a 1–2mn t/y market.'

Sulphur also has potential as an additive to concrete. Elemental sulphur and polymers are mixed into concrete to create a concoction that shows very high resistance to corrosion, high strength, low water permeability and fast curing time. Sulphur concrete also has an eco-

logical advantage over Portland cement; the production of the latter requires the emission of approximately one tonne of carbon dioxide (CO₂) for every tonne of cement produced.

Recent worldwide demand for base metals has created another new use for sulphur as the mining industry seeks to exploit lower-concentration deposits. Nickel and cobalt occur widely as laterites, or oxides. The most economical method of concentrating the laterites is through sulphuric acid leaching. This extraction method could consume as much as 7mn t/y of sulphur.

While many factors could quickly alter sulphur's fortunes, most industry participants agree on a general outlook. 'In the short term, we foresee continuation of much of what we've got today,' says Draycott. 'Pricing will be relatively stable.'

In the longer-term, however, the outlook is less benign. 'The market should begin to tip around 2007–2008,' predicts Draycott. 'The Sulphur Institute thinks we'll be significantly oversupplied. We acknowledge the oversupply, but not their magnitude.' Draycott's optimism is based on a mix of factors. 'Some major FSU projects are exploring the feasibility of re-injecting acid gas. Two [nickel] acid leaching projects currently under construction for 2006–2007 will create 1mn t/y of new demand. There is no major drop-off for phosphate – it will grow modestly. My hope will be that it will remain in fairly good balance.'

Whether sulphur retains its current good fortunes or becomes an anvil around the neck of the oil and gas sector depends a lot on how stakeholders address the issue. 'We'd like to see industry engage in more activities to develop demand and help address transportation and regulatory issues in the future,' says Morris. 'Everyone needs to work on a solution together.'

Major producers are heeding the call. 'We've got recognition that the issue has to be dealt with,' says Shell Canada's Bill Kennedy. 'We're quite encouraged.' ●

IP Week retrospective



Petroleum Review's Chris Skrebowski and Kim Jackson review some of the highlights during IP Week 2005.

IP Week 2005 started with the Peter Ellis Jones memorial conference at One Great George Street, entitled 'Fighting for energy: Geopolitics of oil and gas'. Following a warm welcome by Sir John Collins, the EI's President-Elect and Chairman of the DTI/Defra Sustainable Energy Policy Advisory Board, John Manzoni, Group Managing Director and Chief Executive, Refining and Marketing, BP, gave the keynote address on the global outlook for resources and demand. He started by noting that ensuring supplies had nothing to do with fighting and everything to do with investment and technology. He did not think that companies were striving to get hold of energy sources, but rather were seeking to provide affordable, clean and secure supplies.

Although peak oil is expected to occur at some point, the world had 40 years' supply of oil and 60 years of gas supply, he said, while proved resources were still increasing. Opec needed to increase spare capacity, but it had lots of resources that could be developed. Advances in technology were continuing, with wells being drilled in 2,000 metres of water in the Gulf of Mexico and offshore Angola. Heavy oil development had now reached the point

where it is increasingly economic. So, in Manzoni's view, future supplies were all about terms and conditions.

His view was that there would not be a repeat of 2004, when the strength of demand produced a 24-year record of nearly 3mn b/d of incremental demand compared with 2mn b/d in 2003 and 1-2mn b/d of demand growth in earlier years. The perception of shortage had come about because the exceptional demand growth in 2004 had reduced spare capacity to just 1mn b/d. However, he expected demand growth in 2005 to be around 1.5mn b/d.

Manzoni's view was that the best estimate of incremental non-Opec oil supply was an additional 1mn b/d in each of the next three years. This would be enough, along with Opec capacity expansions, to take the pressure off the system and start to rebuild spare capacity - although he saw oil prices being supported around \$30/b. In terms of gas supplies, he also saw additional LNG supplies into North America easing the supply pressure and high prices. In Europe, he felt that deregulation would achieve the same easing of supply and prices.

He also believed that the environment needed clean energy for sustainable economic development. He noted

that in terms of cleaning up the environment, decisive steps had been taken to improve local air quality, citing the dramatic reductions in NO_x (nitrous oxides) emissions that had been achieved by applying known technology. In terms of greenhouse gas emissions, some progress had been made, but more needed to be done. The current emissions of 25 Gt (giga tonnes) of greenhouse gases would rise to 50 Gt by 2050, he predicted, but needed to be stabilised at 25 Gt. The two largest incremental sources of greenhouse gas emissions would be power generation, accounting for 35% of emissions, and transport, which would account for 20%.

The simplest route to reducing greenhouse gas emissions was to substitute gas for coal in generation and under boiler applications. The capture and storage of CO₂ (carbon dioxide) was already becoming a practical reality, as demonstrated by the Sleipner field in the North Sea and BP's In Salah gas project in Algeria. Manzoni also saw a role for renewables and nuclear. In the transport sector, the move from gasoline to diesel could reduce greenhouse gas emissions by 15%, while hybrids, biofuels and hydrogen offered even greater reductions. His view was that the application of already visible technology could halve greenhouse gas emissions by 2050.

Turning to the security of future



Left: The Peter Ellis Jones Memorial conference kick-starts IP Week 2005. Right: Lord Colin Moynihan, FEI
Photos this page: Jim Four

energy supplies, he stressed that markets must be allowed to work, but that secure energy didn't require ownership. 'The world will always need Opec oil,' he stated, but added that Opec needed markets as much as consumers needed security of supply. In his view there were no resource constraints, although maintaining access and the return on investment were important considerations.

Citing the success of new areas such as the Caspian and Angola, Manzoni suggested there were at least 20 years to run before supply constraints were of concern. He noted that strong non-Opec growth was already assured over the next three to four years, coming from Russia (where TNK-BP recorded 10% growth in 2004), West Africa, the deep-water Gulf of Mexico and the Caspian.

The next speaker, Thomas Ahlbrandt, USGS World Energy Project Chief, continued the theme of reassurance about future supply and resources. He described the methodology and outcomes of the USGS 2000 World Energy Project, noting that for the first time this had been an estimate of world oil and gas resources on a 30-year timeframe (1995–2025) rather than one attempting to estimate ultimate resources. Noting the difficulty of summarising a 32,000-page report, he explained the material is widely available having been issued on CD-Rom and backed up by the website www.USGS.com. He showed the potential resources the USGS had identified in Iraq, with the mapping of the present day generation and migration of oil and the promising structural trends in the Western Desert and the Zagros fold belt regions – features which helped to show that the very large additional resources identified by the USGS in the Middle East were based on detailed and sophisticated analysis.

Ahlbrandt noted that the real 'wild card' had been reserves growth, where conservative initial estimates had then expanded as technology (exploration,

drilling and production) enabled more resources to be identified and produced. In the case of the US, 85% of all reserve additions over the last 15 years came from reserve growth.

The presentation provided a detailed assessment of all aspects of oil and gas reserves, as well as alternative views and analysis. Reviewing the results of the first seven years of the 30-year forecast period, the conclusion was that the reality was broadly on track with the predictions – oil having slightly underperformed and gas having overperformed on a strictly pro-rata basis. This, according to Ahlbrandt, confirmed the validity and basis of USGS analysis. A detailed study of Arctic provinces had established that its 21 new provinces are the next frontier.

Other key conclusions were that reserve growth was three times as important as new discovery in adding to reserves. That non-Opec oil production would peak in the 2015–2020 period. That most of Opec countries' undiscovered oil would be onshore, while OECD future resources would be mostly offshore.

Leonardo Bartolini of Technip, then described the potential and current status of gas-to-liquids (GTL). He started by noting the size, potential and rapid growth of the natural gas market. In particular, he noted the 2,500tn cf of stranded gas already known around the world and the 3.8tn cf/y of gas that was still being flared in 2003. The worldwide trend to non-flaring could produce an additional 607bn cf/y from Nigeria, 406bn cf/y from Russia and 371bn cf/y from Iran, he said. These three countries account between them for 37% of the world's flared gas. He then went on to show that GTL represents a viable route to market, particularly for smaller accumulations where pipelines or LNG plants are not viable options.

Bartolini then reviewed the various technologies and the status of the current GTL projects. He noted that plants

could be built to maximise diesel production, in which up to 80% of the output could be high cetane, no sulphur diesel, probably for use as a blendstock. He also noted that there were speciality applications such as producing normal paraffins for the economical production of detergent surfactants and also for high quality synthetic lube blendstocks. He outlined the impact high quality GTL blendstocks could have for refiners in meeting quality challenges, both in terms of sulphur levels and cetane levels. He then looked at the various projects based around North field gas in Qatar, noting the country was set to become the GTL capital of the world. He finished by examining the increasingly attractive economics of GTL, noting that while most operations were looking to economies of scale to produce the required returns, relatively small floating GTL units could be attractive to monetise stranded offshore gas assets in the 1–3tn cf range.

Mike Bowyer, the UK Managing Director of Halliburton's Energy Services Group, then spoke to the title 'Making resources available – looking beyond'. He started by noting that global spending on E&P did not match the distribution of global reserves of oil and gas. Nearly three-quarters of the world's reserves were held by national oil companies (NOCs), but two-thirds of the development expenditure came from private companies. The world was globalising and needed annual energy investment of around \$500bn, he said. Of this, oil and gas would account for \$200bn, with over \$100bn/y being spent in the oil and gas service sector.

He then looked at various challenges facing the industry, concluding that technology and innovation allowed investment to be leveraged to secure the greatest gains. Also, in a world in which many influences on the industry were outside its control, this was an area in which it had total control. The key



Left: Carl Hughes speaking at Monday's drinks reception, sponsored by Deloitte. Right: IP Week also offers opportunities to network with senior industry figures as well as draw from a wealth of knowledge in the conference sessions.
All photos this page: Jim Four

resource challenges Bowyer saw were: stewardship of mature assets, marginal and stranded reserves, challenging reservoirs and new frontiers, capacity and utilisation, knowledge management and the 'ageing' workforce, and the funding of technology. His conclusion was that success lay in collaboration between operators, suppliers and national governments to apply resources in a sustainable way to maximise recovery from global basins. He suggested that critical success factors would be sustainable contracting practices, eliminating waste and duplication in the supply chain, reducing the impact of boom and bust cycles, investing in people to attract and retain the right people, and investing in maturing reservoirs.

Peter Cook, General Manager, New Ventures for SasolChevron, described the Oryx GTL project, which is now under construction in Qatar. He explained that the unit would be tailored to maximise diesel output, where GTL diesel with no aromatic or sulphur is highly attractive as a blendstock to meeting tightening specifications raising cetane requirements. The 34,000 b/d Oryx plant is due to start-up in early 2006. He noted that the 572,000 b/d of GTL diesel that could be produced from all the currently planned GTL plants could easily be absorbed into the 3.2mn b/d European diesel market.

An Opec perspective was then given by Adnan A Shihab-Eldin, the Director of the Research Division of Opec. He started by noting that from stability in 2000–2003, the last year had been a dramatic discontinuity as demand had surged. For the 30 years to 2002 oil demand growth had averaged 1.4%, or

1mn b/d. In contrast, the 2003–2005 period looks set for 2.6% growth, or 1.9mn b/d. In 2004, supply increased by 3mn b/d – 1mn b/d from non-Opec and 2mn b/d from Opec. This had reduced Opec's spare capacity to 8% at one point, although this had rebuilt to 10% by year-end. The slowdown of Russian production growth to 350,000 b/d had also tightened the market. Opec's expectation was that 2005 demand growth would slow to 1.5%, or 1.4mn b/d, and the market would start to rebalance – although demand growth for light products and tightening refinery capacity had produced a structural change in which the price differential between light sweet crude and heavy sour crude had widened considerably.

Opec saw demand growth of 32mn b/d between 2005 and 2025, with three-quarters of the growth coming from developing countries. He concluded by noting that Opec had the oil, it simply needed to make the investments. While non-Opec producers had been investing \$100bn/y, Opec had only been investing \$20bn/y. However, there were huge uncertainties to be overcome if Opec was to make the huge investments required.

His Excellency the Ambassador of the Republic of Kazakhstan, Erlan Idrissof, started his address by noting the way that energy production in his country was transforming and modernising the state very rapidly, and was proud to report that Kazakhstan now had investor grade status. Some \$28bn of foreign debt investment had been made in Kazakhstan since 1994. The economy had grown at 9.7% in 2004, with inflation down to 7% – an impressive reduction from the 3,000% of the

mid-1990s. More importantly still, he claimed that the country now operated to European financial standards and was confident of 6%–8% economic growth going forward. Oil reserves of 50–100bn barrels meant that plans to raise production from 1.1mn b/d in 2004 to 2mn b/d in 2010 and 3mn b/d in 2015 would be realised.

Explaining that Kazakhstan was keen to export in all directions, he reported plans to expand capacity of the pipeline to Samara, the CPC line to Novorossiysk and the building of the pipeline to China (to be completed in autumn 2005 with a parallel gas pipeline likely to follow). He confirmed that Kazakhstan is also keen to be involved in the Baku-Ceyhan pipeline. He also noted that Kazakhstan has concluded a median line demarcation of its Caspian border with Russia, the two countries jointly pursuing a number of oil and gas field development that cross the median line border.

Jean Jacques Mosconi, Senior Vice President, Strategy and Development in the Downstream Division of Total, addressed the conference on north-west European demand projections. He started by noting world oil product demand was being driven by growth in North America and China. The average growth rate in the 1995–2004 period had been 2%, with Asia now accounting for 45% of the growth (half from China alone), followed by North America and the Middle East. In contrast, the European market was mature. Heating oil and fuel oil demand was in gentle decline as competition, particularly from gas, eroded the market. Limited increases in the transportation market concealed a steady growth in diesel and a steady erosion of gasoline.

In 2000 the European motor fuel was 263mn tonnes, split 55% diesel/45% gasoline. By 2010 the market is expected to have grown to 295mn tonnes, but with a 68% diesel/32% gasoline split.

The drivers for diesel growth are lower taxes on diesel in all European countries, apart from the UK, its lower carbon dioxide emissions/km and its higher fuel efficiency. However, with the pressure for a 140 grammes CO₂/km standard in 2008, diesels are favoured as the only engine type that can currently meet the standard. Technological developments are also favouring diesel, with further developments underway, notably very high pressure injection systems (2,000–2,400 bar). This is expected to lead to diesel dominating the motor fuel market by 2010.

Heating oil demand is eroding in the face of competition from gas and more efficient space heating units. Jet kerosene, which is a product in long-term expansion has seen a demand setback over the last three years, with cutbacks caused by 9/11, SARS and the Iraq war. The growth trend now seems to have been reestablished and is expected to continue. Heavy fuel oil demand continues to fall largely on reduced generation demand. However, bunker demand continues to grow slowly, with a move from high sulphur to low sulphur grades now starting.

For the foreseeable future, transport will be the main driver of oil products demand in Europe, with an increasing focus on the environment driving fuel quality and emissions standards. Curbing greenhouse gas emissions will become an increasing priority.

A structural imbalance is developing in Europe, in which increasing volumes of diesel are being imported from Russia and the Middle East, while increasing volumes of gasoline are being exported to the US. Mosconi suggested that what the European refining industry needed was more hydrocrackers to start to address the imbalance.

Peter Newman, Global Managing Partner, Oil & Gas, for Deloitte, then examined future demand scenarios to test the realism of the 'official' world view. He started by noting that the IEA in its *World Investment Outlook 2003* saw, over the 2001–2030 period, natural gas growing at 2.5%/y from 2.5tn cm/y to 5.3tn cm/y; electricity growing at 2.4%/y from 3,498 GW to 7,157 GW; crude oil demand expanding at 1.6%/y from 75mn b/d to 120mn b/d; and coal demand growing at 1.4%/y from 4,595mn t/y to 6,954mn t/y. The main drivers would be growth in electricity demand for homes and for transportation fuels. The challenge was that nat-

ural depletion would require 200mn b/d of new oil production capacity and 9tn cm/y of new gas production capacity.

To meet the foreseen demands, some \$16tn would have to be invested over the period, he said, made up of \$9.8tn electricity investment, \$3.1tn in the oil industry, \$3.1tn in the gas sector and \$0.4tn in the coal industry.

Newman then examined the make-up of demand by country and sector, and questioned if the underlying assumptions, particularly about price, were realistic. He queried whether there would be sufficient oil available at prices low enough to support the demand projections and examined a range of scenarios.

His summing up was that the official world view might prove to be optimistically 'comfortable', particularly about future availability and moderate prices. Noting higher price signals and a growing belief in an imminent real physical supply peak, he suggested that this would lead to faster fuel substitution, slower overall economic growth and less regional convergence of economic developments.

Gao Shixian, Director of the Centre for Energy Economics and Development Strategy of the Energy Research Institute, National Development and Reform Commission, People's Republic of China, gave a very detailed presentation to the title 'China – meeting the demand challenge'. After observing that just over 40% of China's 1,292mn population now live in urban centres, he presented a graph of China's energy consumption, showing rapid growth from 1980 to 1995, little change from 1995 to 2001, and rapid growth since 2001. He noted that China's 1,678mn tonnes coal equivalent (tce) of energy consumption in 2003 was second only to the US and accounted for 12.1% of the global total. In 2003 the growth in primary energy demand was 13.2%, made up of coal 13.6%, oil 12% and electricity 15.29%. Energy use per capita, however, at 0.91 toe, was just 58.6% of the world average. He went on to show the way that oil consumption had exceeded production in 1995, with the gap widening steadily since.

The energy outlook was that overall energy demand would grow from 1,397mn tce in 2000 to 2,471–2,663mn tce in 2010, and 3,179–3,580mn tce in 2020. Oil demand would grow from 230mn tonnes in 2000 to 350–380mn tonnes in 2010 and 420–500mn tonnes in 2020, while gas demand would grow from 24bn cm in 2000 to 100–125bn cm in 2010, and 180–250bn cm in 2020. This would lead to net imports of 240–300mn tonnes of oil in 2020 and

50–100bn cm in the same year, accompanied by a marked increase in dependence on oil and gas.

He concluded by tackling the charge that China is a threat to world energy supplies. He pointed out that China, although a large consumer is also a large producer. So, as China only takes 6% of world supplies as net imports, it cannot really drive prices. He also noted that China's per capita oil consumption is only 37% of the world average.

The final speaker on the first day was Adam Sieminski, Global Oil Strategist for Deutsche Bank, who was clear and emphatic that current concerns over oil prices and oil supplies were misplaced. His view was that prices would ease back to the \$30–\$35/b range later in the year as economic growth slowed, notably in China. He pointed out that non-Opec production was still growing and that Opec had incremental capacity coming onstream. In other words, that economics would work well, with high prices slowing demand and boosting supplies.

That left the problem of what happened in 2004 to produce a price spike. According to Sieminski, a number of factors came together – extra demand from China to build strategic stocks and large diesel imports to generate electricity; Iraqi production continuing a decline that started in 2000 and now amounts to almost 1mn b/d lost; hurricane Ivan took out 0.5mn b/d of Gulf of Mexico production in the run up to winter, which reduced Opec spare capacity to 2mn b/d, around 1mn b/d of which was unavailable as it is heavy oil. As with any commodity, once utilisation rates exceed 95% prices rise. He believed the situation would now start to correct itself, with demand down and non-Opec supply up. Money was now moving back into mature asset plays. Higher prices increased production by around 0.5mn b/d for every \$10/b increase.

There were, however, good reasons for thinking oil prices would move to the \$30–\$35/b range, even with increased supplies. The strength of demand allied to weak non-Opec production growth, rising upstream costs and the depreciation of the dollar would all underpin higher prices. Russian output growth was trending lower and no more than 0.5mn b/d growth was likely in 2005. Among the Opec producers, access was limited in the UAE and Kuwait, and blocked in Saudi Arabia. Iran had very tough terms, Venezuela was very difficult and Iraq would be later. So, prices would rise from the \$28/b range to the \$32/b range, even with balanced supply and demand, according to Sieminski.

African and Middle East potential

The Tuesday 15 February morning session at the Dorchester focused on 'Future opportunities in the Middle East and North Africa' – sponsored by Ashurst, the international law firm, and chaired by Tim Reid, Partner, Global Energy Team.

His Royal Highness Prince Turki Al Faisal, Ambassador of the Kingdom of Saudi Arabia to the United Kingdom, provided the keynote address, outlining Saudi Arabia's policy towards energy affairs. He spoke of Saudi Arabia's unparalleled reserve base and the immense potential for new discoveries to be harnessed that would help meet the world's energy demands and the country's global supply commitments. According to His Royal Highness, current proven oil reserves stand at 260bn barrels in 85 fields, of which less than two dozen are currently in production, with a further 200mn barrels of estimated in-place reserves. Proven gas reserves are put at 235bn cf, of which 40% is non-associated, and the country is reportedly confident of adding some 5bn cf annually to this reserves base.

He stated that Saudi Arabia was committed to 'reliability, market stability, and reasonable and affordable prices'. Security and a stable infrastructure were key priorities and, with advances in technology and operations, Saudi Arabia was not only confident that it could continue to maintain future supplies without disruption, but could also expand its contribution to world energy supply. According to His Royal Highness, the Kingdom has the capacity to produce 11mn b/d in 2004 – some 12% of total world crude oil output – a level that could be sustained for the next 50 years. This means there was a 1mn b/d 'supply cushion' over recent production levels and there were plans to increase production capacity to 12bn b/d in the short term, rising to 15mn b/d once market conditions permitted.

His Royal Highness said that the Saudi government recognised that substantial investment was needed to allow the industry to prosper and grow, and stated that developing partnerships with international companies and governments would be instrumental in achieving this. He stressed that 'sincerity, transparency and integrity' were key priorities in such partnerships – as, without these, formal contracting relationships would not stand the test of time.

Next to speak was Fuad Krekshi, Chairman of the Management Committee, Eni Gas Libyan Branch, who outlined the new upstream opportunities to be found in Libya – a country

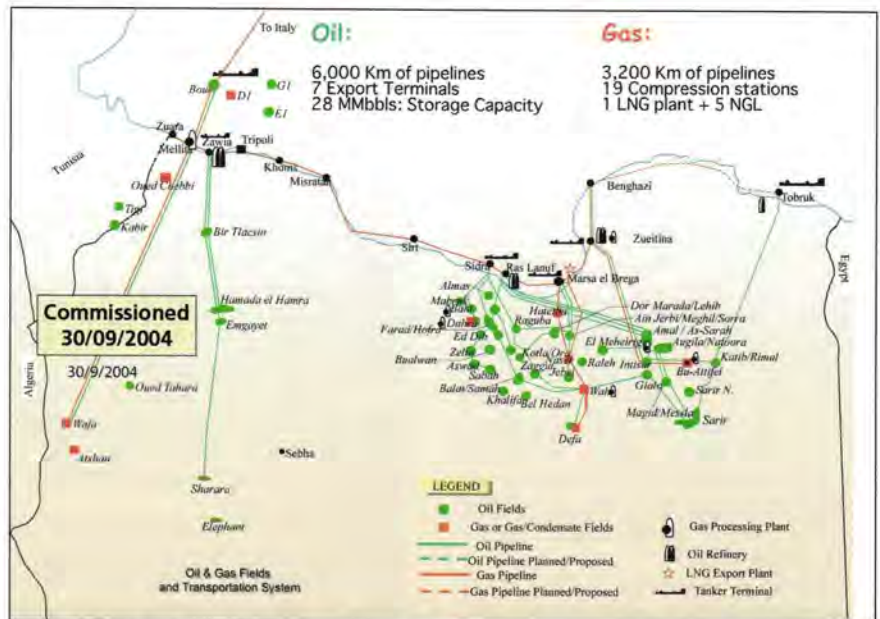


Figure 1: Oil and gas infrastructure, Libya

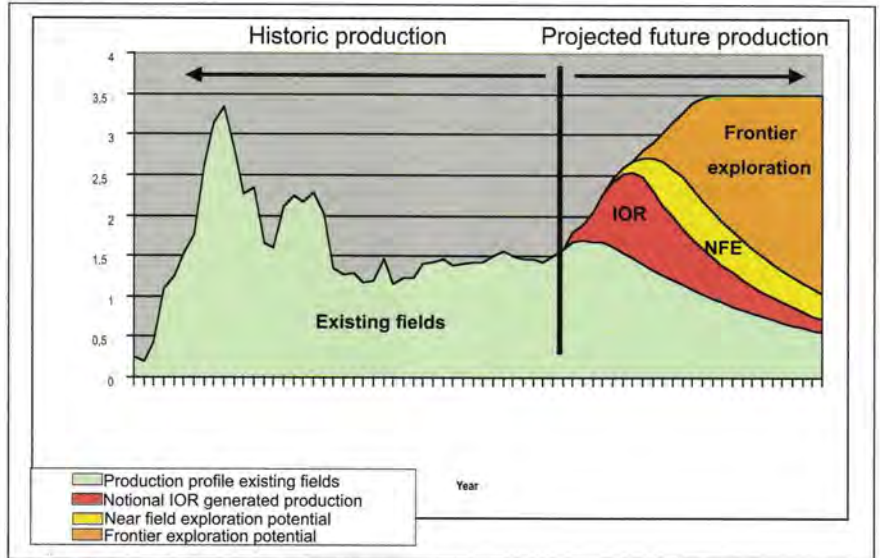


Figure 2: Libya oil production profile/capacity

that had 'significant remaining potential'. Key upstream objectives were to increase oil and gas reserves and production, partly through new joint ventures with foreign companies but also through the application of improved oil recovery (IOR) techniques, which had the potential to 'double production' from existing fields. Indeed, it is predicted that IOR techniques will enable Libya to boost oil production to 2mn b/d in the next five years, with plans to further increase this to 3mn b/d in the future. There are also plans to improve and upgrade the country's existing infrastructure (see Figures 1 and 2).

Libya is seeking huge levels of foreign investment following the lifting of US sanctions against the country. Its latest, recently completed first licensing round

under EPSA IV made available 58 blocks in 15 areas. Krekshi went on to explain that the new EPSA IV contracting model was designed to 'offer flexibility, continuously reflecting the market conditions without the need to review and adjust the initial terms'. US companies are reported to have won most of the contracts on offer, with three US firms – including Occidental – winning 11 of the 15 oil exploration and production sharing agreements. The second licensing round under EPSA IV is expected to be announced shortly.

Krekshi also provided some detail on new gas projects in Libya, including the recently onstream Western Libya gas project (1,000mn cf/d), the Attahady project (270mn cf/d) that is currently being commissioned, Faregh (30mn cf/d

under the already commissioned Phase 1, 250mn cf/d under Phase 2 in 2006), NC98 (350mn cf/d, due onstream in 2007) and Atshan (200mn cf/d in 2008). He also mentioned the upgrade at the Marsa Brega LNG plant, through which Libya exports most of its gas.

Phil Hunt, Vice President, Global Head of Downstream Consulting, Nexant, was the last speaker before the coffee break, addressing the issue of meeting capacity requirements in the refining and petrochemicals sector. Looking at net oil trade, he stressed the continued key role of the Middle East, which currently exports some 25mn b/d. He painted a similar picture for gas, a market in which the Middle East will retain dominance, having a natural gas reserve/production ratio of some 278 years – compared with 98 years for the Africa region as a whole, 76 years for the Former Soviet Union, 60 years for South and Central America, 43 years for the Asia-Pacific region, 10 years in North America and 18 years in Europe.

He went on to explain that the newly industrialised nations of China and India were the key emerging demand markets in the Asia-Pacific region, where energy consumption was closely related to burgeoning GDP growth. The Middle East was well placed to meet much of this rising demand for oil products, he said, as this was where the resources were and where much of the region's refining capacity was already export oriented. Furthermore, Saudi Arabia and Kuwait were already investing in expanding refining capacity and some 23mn t/y of new petrochemical capacity was planned in the Middle East over the next five years. Hunt also stated that the focus on gas-to-liquids (GTL) would continue to accelerate. However, he stressed that project finance would be key for all this to happen – as the scale of the projects required major funding, while politics would remain a key factor, as would the availability of competent, skilled people.

Raed Kanaan, Executive Director, Middle East and Africa, ABN Amro, focused more closely on the topic of project finance. He explained that project finance has 'played a central role in the development of the economic base' of many countries in the Middle East and Africa, 'allowing many governments to implement their plans for economic liberalisation, industrial diversification away from crude exports, and overall expansion of their infrastructure.'

The growth and popularity of project finance has been fuelled by increasing liquidity in the region – higher oil prices and a low interest environment; improved credit rating and growing familiarity with



Ashurst sponsored the morning seminar on the Middle East and North Africa

the limited-recourse structures,' he said. It is estimated that around \$30bn was raised from commercial institutions between 2000 and 2004, of which some \$16bn was raised for oil, gas and petrochemical projects and \$10.4bn for power and utilities projects. The main players have been large international and regional banks, with the latter upgrading their role and lending more regionally. There has also been a sharp rise in the number of 'club deals' in which a dozen or more banks are involved, while the market widened in 2001 with the entry of Islamic (*sukuk*) financing for the Qalhat LNG project in Oman.

According to Kanaan, the landmark deal of 2004 was the £12bn Qatargas II project. Being developed by Qatar Petroleum (70%) and ExxonMobil (30%), the project comprises two 2.7mn t/y LNG trains in Qatar with production destined for the UK market via a new regasification terminal in Milford Haven, Wales. The initial plan was to finance the trains in sequence – the first in 2004 and the second in 2005. However, in the end some \$7.6bn was raised in debt and the level of commitments meant that both trains could go ahead simultaneously. The debt package has a multi-tranche structure consisting of (i) bank tranche, (ii) Islamic tranche, (iii) SACE tranche and (iv) US Exim tranche. The regasification terminal was financed separately with a GBP bank loan. Kanaan explained that the bank tranche 'demonstrated a shift in the project finance scene'. The total commitments received amounted to \$3.6bn, versus the \$1.5bn requested; 36 banks were involved, out of which only eight are Middle Eastern banks; banks never/rarely seen before in the regional market participated in the loan; and the structure of the loan is such that lenders are taking UK gas market price risk, whereas previous LNG deals have been tied to oil prices.

Looking to the future, Kanaan stated that project financing would remain the favoured way to raise funding for large oil, gas and energy projects, and expected to see 'more active private sector participation'. Some \$34bn in new project debt is expected in the coming

two years. He expects some constraints will set in with reduced limit availability from the bank market and general liquidity in the market. He also predicts that debt pricing will rise as the interest rate increases, with sponsors becoming more pro-active in managing interest rates. He also expects to see more innovative, multi-tranche structures, with a larger contribution from the bond market.

Next on the agenda was Algeria, whose prospects were covered by a presentation from Dr Chawki Mohamed Rahal, Director General, Sonatrach. He explained that although Algeria has been relatively under-explored in the past, the authorities were striving to attract foreign investment and partnerships by an ongoing restructuring of the legal framework to improve efficiency of the process as well as transparency and speed.

Oil and gas are of fundamental importance to Algeria. The industry accounts for around 36% of Algeria's GDP, with the proceeds from exports accounting for between 90% and 95% of the country's hard currency resources. More than half (60%) of the state budget is funded by oil and gas tax revenues. According to Dr Rahal, in-place gas reserves are put at 300tn cf, with the potential to add a further 200tn cf. Oil reserves in place are put at 80bn barrels, with the prospect of adding a further 40bn barrels. The country also has an extensive infrastructure in place (see Figure 3) and has much experience in partnering foreign companies – having signed 68 contracts with 33 companies to date. Some 132 discoveries have been made between 1986 and 2003, with a 40% success ratio, commented Dr Rahal.

Dr Rahal went on to outline Algeria's legal framework, stating that open bids have improved the transparency of the licensing process, while negotiation time has been reduced and better, competitive economic terms have been introduced. Another recent development is the fact that the involvement of state-owned Sonatrach is no longer a legal requirement – 'it is now a partner of choice', commented Dr Rahal. Algeria's sixth licensing round, comprising 10 projects, was launched at the

these imbalances cannot be expected to be resolved through industry restructuring or investment, meaning that inter-regional trade is likely to play an increasingly important role.

Highlighting some of the more specific issues addressed in the seminar, David Waring of Deutsche Bank looked at the merger and acquisitions (M&A) dynamics in the European refining and marketing (R&M) sector. He commented that rationalisation/consolidation of this sector had been largely hindered by the lack of a US-style independent sector and weak profitability, with the result that the supermajor mergers (Conoco/Phillips, Chevron/Texaco, BP/Amoco/Arco, Exxon/Mobil, Total/Fina/Elf) had had relatively limited impact on this sector. However, he did point to 'significant consolidation' in Germany (Veba/DEA) and, to a lesser extent in Central and Eastern Europe (Slovnaft/Ina).

Waring said that he believed the industry was on 'the cusp of change' and went on to outline the potential drivers of increased M&A activity in the European R&M sector: a strong outlook for refining margins, declining mandatory environmental capex requirements, stable competitive dynamics in most key retail markets, an ongoing corporate focus on reducing downstream capital employed by integrated oils; equity markets have rewarded R&M stocks with strong outperformance, and an extremely 'hot' leverage loan market with increased risk appetite to fund buyers. According to Waring, up to 18 European refineries could see corporate change in 2005/2006 through IPO spin-offs, planned sales and potential non-core disposals.

Ferenc Horvath, Managing Director Downstream Division, provided an in-depth overview of Mol's activities in the changing Central European downstream environment, arguing that the Hungarian oil and gas company was well-placed – both in assets and in location – to meeting the demands of the market place. Among the 'competitive advantages' he cited, were the fact that Mol had the capability to process Urals crude purchased by pipeline; its excellent refinery configuration meant that the company had a favourable product slate; its logistics system provided quick and efficient supply for the covered market (including its own retail network) and cost-efficient arrival of crude oil; inland markets provided a favourable sale mark-up; the company had a favourable share of regional markets in Hungary and Slovakia; and last, but not least, Mol had a 'quality advantage' compared to most regional refineries in that it is capable of producing fuels with a sulphur content of less by 10 ppm from 2005.

Horvath also injected a lighter note



Wood Mackenzie sponsored an afternoon seminar on global refining

into the afternoon's proceedings, inviting delegates to take part in a quiz to predict the average price in \$/b for Brent DTD (dated) and Brent DTD-Ural spread in 4Q2005. Participants were to fill in their answers on a form, and the winners would be announced at IP Week 2006. The winners will be able to partake in one of Hungary's finest exports – Tokaji Aszu – a sweet dessert wine with intense floral, honey, caramel and burned marmalade balanced by piquant acidity, with a very long finish (to quote Oddbins!).

Wood Mackenzie's Sat Roopra closed the day's proceedings by drawing heavily on the analyst's recently completed multi-client study covering the refining market in the Asia-Pacific – entitled *Will the Tiger Roar Again? Refining in Asia Pacific*. The key messages from his presentation were that oil demand is expected to grow by over 3.5% per annum to reach 1.6bn tonnes by 2015, with China and India accounting for some 64% of incremental growth during this period. Refinery supply will increase by 300mn tonnes over the same period due to increased utilisation rates, capacity creep and an additional 150mn tonnes of planned capacity additions. The crude slate in the region is forecast to change from 55% sour/45% sweet today to around 68% sour/32% sweet in 2015.

Roopra also predicted 'significant deficits of all products' developing in the period, particularly gas/diesel oil and naphtha. Strong fundamentals will underpin a significant recovery in refining margins in the region, while location remains the 'single biggest driver of refinery competitive position'. He concluded by stating that Reliance and S-Oil are the top ranking companies in terms of net cash margin.

Pricing in the medium term

The morning of Wednesday 16 February featured a conference at One Great George Street held in association with Argus Media – entitled '18th energy price conference: Pricing in the medium term' – chaired by Richard Ward, Chief Executive, International Petroleum Exchange (IPE).

Jim Nicholson, Head of Business

Development, Argus Media, started the proceedings with a look at the EU gas market, under the slightly inflammatory title of 'What went wrong?!' He began outlining the conditions required for a successful spot market – the commodity must be in oversupply, there must be many sellers and buyers, there must be available transportation, there must be a standard contract, there must be a desire to trade, there must be liquidity, and there must be transparency. Citing the UK as a 'successful' case study and the 'most open gas market', he pointed to the several UK spot gas markets currently trading – APX-Gas, OCM (on the day commodity) market, the over-the-counter (OTC) market, the IPE futures market and various capacity trading and derivatives markets.

Moving on to continental Europe, Nicholson explained that there was 'unlikely to be surplus gas' in this market because 'the system is managed', with any surplus being absorbed by companies within the existing structure. He also commented that gas-on-gas pricing was also unlikely to occur in the short term (typically priced on formulae linked to crude oil or products such as fuel oil that compete with gas). As a result, 'Europe lags as a trading market', he said. However, on a slightly more positive note, he said that 'liquidity is improving, but is still poor' and hubs are developing, albeit slowly. Nicholson stated that restricted access to pipeline capacity was one of the main barriers to cross-border gas trade and a significant reason for the slow development of a competitive EU gas market. He called for more political action, probably at the EU Commission level, noting that regulatory action was needed on non-discriminatory third-party access and regulatory support was needed for pro-competitive requirements on new transit lines.

Nicholson then went on to look at the lessons that could be learnt from America, which had 'nearly destroyed its gas market' during 2002/2003 following market abuse and an archaic pricing system that led to pricing anomalies.

Mark Lewis of Energy Market Consultants then took the podium to discuss 'Oil pricing in the medium term:



Figure 4: Main new infrastructure projects in Europe (pipelines and regas terminals)

Stability or rollercoaster?' He pointed to the word 'rollercoaster' on the screen, stating: 'There's your answer! ... luckily, he then went on to present the argument in more depth! He began by presenting a brief history of oil prices, noting the recent substantial upwards shift, driven by rapid global oil demand growth of 2.7mn b/d in 2004 (+3.4%; the biggest percentage growth since 1988 and the biggest absolute increase since 1976), which, in turn, was linked to growth in global GDP (5% in 2004; the fastest since 1976). He saw China as the 'wild card' for future oil demand growth. Noting China's apparent oil demand growth accelerated to 16%–17% in 2004, up from 12% in 2003 and accounting for 40% of total world oil demand growth, he suggested that this was unsustainable and would slow down in 2005.

Lewis then took a closer look at Opec, noting that the organisation's price basket hit a record \$46.61/b in late

October 2004 and was currently at near \$40/b. He reminded delegates that Opec had 'temporarily suspended' its price band of \$22–28/b at its recent meeting on 30 January 2005, stating that while there was no clear price target at present, analysts believed Opec would be willing to 'defend' a basket price in the region of \$35/b. As a result, he argued that Opec has lost its structural framework and is currently in a 'price vacuum' – allowing big potential upside and intense volatility. 'Opec is waiting for price "stability",' he commented, 'but is its own behaviour adding to instability?'

He then went on to explain that the situation was being complicated by wide crude differentials, mainly due to rising demand for light sweet crude at a time of squeeze on refinery upgrading and increasing supplies of Arab Gulf heavy sour grades.

Sylvie Cornot-Gandolphe, Principal Administrator Gas Expert, International

Energy Agency (IEA), then tackled the topic of energy supply – looking at the routes of supply into the EU and UK and their associated security of supply issues, and how new sources of supply such as LNG imports could affect pricing. She began by predicting an increase in EU gas demand from 500bn cm to 780bn cm by 2030, driven primarily (70%) by rising demand from the power sector. Stating that gas production in the region was set to fall from 240bn cm in 2003 to 150bn cm in 2030, she said the EU would need to be importing some 600bn cm of gas by 2030.

She stressed that imports do not necessarily mean less secure gas, pointing out that even the break-up of the Former Soviet Union did not impact supplies. She also noted out that LNG – which currently accounts for only 9% of European gas demand – would play an increasing role, predicting a 200bn cm market potential by 2030 (40bn cm market today).

Cornot-Gandolphe then went on to outline some of the main new infrastructure projects in Europe (pipelines and regasification terminals) – see Figure 4 – and the UK (see Table 1).

She concluded by stating that European/UK gas supply and demand were at a 'turning point', with new infrastructure/investment required in order to facilitate increased levels of gas imports. She stated that security of supply was high on the agenda, with diversification being key and dialogue required between producing, transit and consuming countries. As Europe becomes more interconnected and the UK is 'no longer an island', she predicted that the gas price may come down in the UK. However, she expected the gas price to retain a strong link with the oil price and for trans-Atlantic arbitrage to continue.

Next up was Tim Longstaff, Managing Director, Atkins Power, who presented what he called a 'micro-perspective' on energy prices in a world with sustainable growth, arguing that industry could 'usefully consider existing technologies in the renewables sector as the price determining ceiling for prices going forward'. He began by outlining the 'sweeping assumptions' he had made in order to present his UK electricity generation model – these were a continuation of historical demand patterns and zero impact of energy efficiency, price elasticity and demand management.

He stated that the price of UK electricity could be characterised as having six constituents: fuel cost, plant depreciation, plant operating costs, corporate profitability, 'shadow cost' pollution taxes and general taxation – all of which were likely to rise in the medium term, leading to an overall increase in

Mode	Project	Capacity bcm/year	Start-up date
Pipe	Langeled	25	2007/08
Pipe	Staffjord Late Life	5	2007/08
Pipe	Interconnector	+8 and +7	End 2005/06
Pipe	BBL	17	2006/07
Pipe	Northtransgas	> 5-10*	?
LNG	Isle of Grain	4.4-14	2005-2008
LNG	Milford Haven (Petroplus)	6	End 2007
LNG	Milford Haven (ExxonMobil)	10 (first phase)	2007/08

* For the UK market

Table 1: Planned UK gas import projects

the price of UK electricity.

He then presented a number of graphs, overlaying the 'simple laws of supply and demand' onto these drivers. Looking at how far the supply curve would shift upwards with each single cost component, he argued that the key drivers would be fuel cost and plant depreciation. 'Now we get on to the contentious bit,' he said. 'For UK electricity, we can model this ceiling by looking at renewables... Renewables have no fuel cost, so one of the two degrees of freedom are removed. The supply constraints for renewables are well understood (assuming planning obstacles can be overcome). Renewables could provide for the full electricity demand of the UK if money and aesthetics were no object and intermittency could be accommodated. If fuel price (gas and oil, and nuclear) rise to infinity, and we assume zero net electricity import, then the upper limit of UK electricity prices is provided by renewables,' he explained. 'This simple approach suggests that 6-7p/kWh is the top limit for UK wholesale electricity prices.'

Nigel Lang, Managing Director, Catalyst, then presented an overview of the motor fuel market, pricing and demand at the forecourt – a topic addressed in detail by *Petroleum Review's* annual *Retail Marketing Supplement* published in March, whose statistical information is produced with the help of Catalyst's comprehensive database. He began by outlining the general oil price/fuel retail pricing relationship, where the price at the forecourt lags the international oil price. He then went on to look at some of the national variations in this trend. Belgium, for example, had experienced a small increase (+1) in gross margin (measured in euro cents/litre) in 2004 as government intervention set the maximum price, meaning that retail prices tended to follow the international oil price more quickly. In contrast, Denmark experienced a fairly noticeable decrease (-4) as an ongoing price war was keeping prices low. Other 'micro-factors' leading to a decrease in gross margin were the high number of unmanned sites in Norway and the Netherlands (-1) and the entry of Tesco (three supermarkets selling 50mn litres of fuel) into Ireland (-2).

Lang then presented analysis of the key performance drivers, which varied between European countries. For example, in the UK market, position and price are key, whereas in Italy, price is a less significant factor. He then went on to explain that price reporting had a key role to play in setting fuel retail prices, stressing the importance of the micro-market as well as the corporate pricing strategy. He outlined Catalyst's role in pro-

viding such detailed information, reiterating the point that capturing the micro-market dynamics enabled the forecourt operator to select the best price to optimise profits.

Ted Keen, Tax Partner, KPMG closed the day's proceedings with a look at EU energy taxes and their effect on pricing. He pointed out that while taxes are known to distort markets, they can be effective as a policy tool to reduce/increase production and consumption of the taxed goods or to increase tax revenue.

However, he warned that unintended consequences could result. For example, adherence to the Kyoto Protocol, which is intended to reduce greenhouse gas emissions, could increase the cost to energy-intensive EU producers, thereby increasing the competitiveness of non-EU, non-Kyoto producers, leading to an increase in greenhouse gas emissions! In another example, he said governments seeking to increase revenues may raise taxes on producers with little flexibility. In the short-run producers would bear much of the burden, in the long-run they may reduce investment and target other markets. In addition, producers who might otherwise invest are wary of rent-extraction taxes. This could lead to dramatic shortages in the future and tax revenue may actually shrink! Keen concluded by stressing the importance of applying economic analysis to tax policy in order to anticipate such effects.

Climate change consultation

The Energy Institute (EI) had organised a consultation event on climate change for the afternoon of Wednesday 16 – the day on which the Kyoto Protocol came into force – bringing together over 100 experts from across the energy sector and Defra/DTI officials to discuss how the industry can support government in meeting targets set in the Kyoto Protocol and the Energy White Paper.

The meeting, chaired by Professor John Cheshire OBE FEI, was divided into two breakout sessions covering energy supply and energy efficiency respectively. The energy supply workshop focused on how the UK energy system can deliver carbon reduction over the long term and the signals that the government should be giving about the development of the EU emissions trading system (EU-ETS). Meanwhile, a lively energy efficiency workshop was taking place in an adjacent room to establish what further measures the government might introduce to drive energy efficiency savings to 2010 and 2020.

Transcripts of the debate are to be edited and submitted to Defra for inclusion in the Climate Change Review documentation, which will be published on the Defra website in due course. These transcripts will also be made available to all participants and upon request to the Energy Institute.

LETTER TO THE EDITOR

Dear Sir

Dr Mamdouh G Salameh's article on Saudi Arabia's reserves in the February 2005 issue of *Petroleum Review* misquotes me as 'insisting' that Saudi Arabia's proven reserves are only 130bn barrels. This was based on a dubious second-hand report from a Hong Kong online news service which misquotes an article that I wrote in the 17 May 2004 issue of *Oil and Gas Journal*.

My article states that Saudi Aramco's proven reserves were 260bn barrels as of year-end 2004. Approximately 130bn barrels were 'proven undeveloped', while the other 50% were 'proven undeveloped'. Because 'proven undeveloped' reserves are based on much lower recovery factors than 'proven developed' reserves, the article indicated room to add more 'proven developed' reserves by the eventual development of the untapped fields.

As to the increases in proven reserves, my article reported Saudi Aramco's were based on hundreds of millions of dollars of confirmation work in terms of intense delineation drilling, reservoir modelling and seismic surveys. This was a highly professional multi-year programme that has been confirmed by subsequent sustained oil production capabilities.

As a matter of interest, the whole issue of defining proven reserves for giant accumulations remains an area in need of detailed and wide ranging attention. For example, in the last few years, the proven Canadian reserves were variously reported to have jumped from 4bn to over 154bn barrels in one year. These are mainly extra heavy crudes that cannot substitute for conventional crudes and are as land-locked as many Central Asian 'proven' reserves. On the face of it, they apparently conform to the current Canadian definition of proven reserves. Is this definition relevant, however, to the realities of timely access and availability to the energy markets?

Sadad Husseini

Going digital – more process than technology driven

Digital oilfield developments come by all sorts of names, ranging from 'e-fields' and 'i-fields' to 'Smartfields'. Whatever the name, the goal is the same – to create better and faster decision-making in real time with more integrated processes.

'The i-field programme will have a big impact on the bottom line, creating value for all parties concerned, reducing costs by being more proactive and increasing understanding through access and incorporation of continuous down-hole models,' maintains ChevronTexaco's Upstream Information Technology Manager, Derek Magness.

ChevronTexaco's i-field programme has been underway for about two and a half years. The programme is being deployed globally on a project-to-project basis on assets in US west coast operations, mid-US, Gulf of Mexico, the North Sea, mid and southern Africa, Tengiz (Kazakhstan), Saudi Arabia, Indonesia and Australasia. The programme is a key strategic focus to bridge the gap and get better alignment between strategic research and tactical day-to-day expenditure (see Figure 1). 'We aim that i-field should set the foundation and governance of projects, as an integrated approach that looks at real-time control of assets. This is not just from the technology standpoint, but for both cultural and process change – in terms of strategic research, technology development and day-to-day operations,' comments Magness.

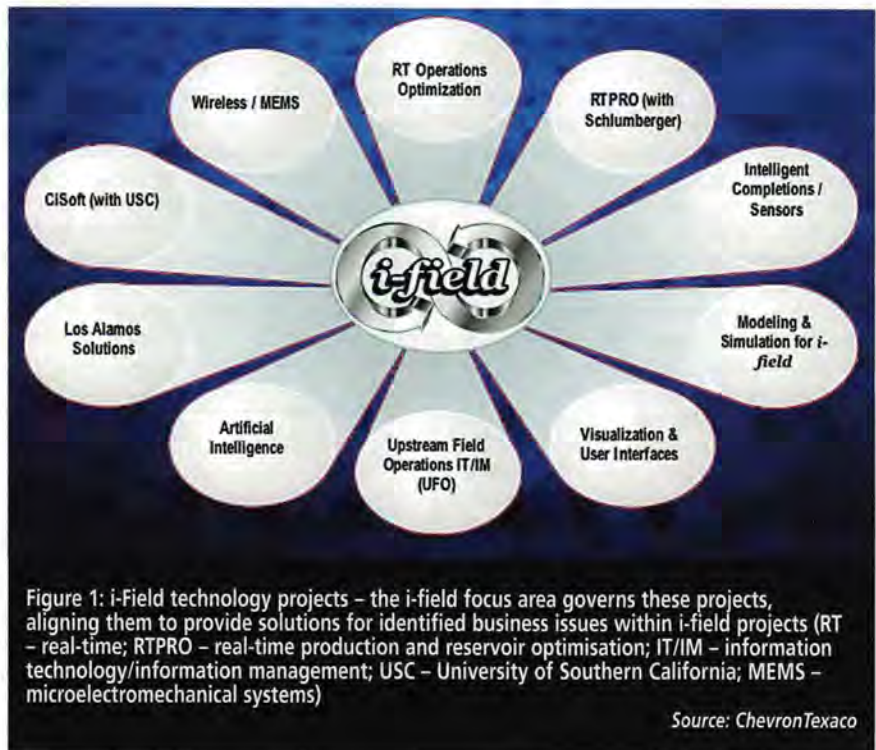
New i-field initiatives promise opex benefits from improved field recovery, acceleration of production, reduction in downtime, better efficiency and reduction in regulatory events. On the capex side, the company is looking for significant drilling cost reduction.

Big benefits

ChevronTexaco is not simply trying to introduce new technology for i-field. 'Change management is a priority to maximise return on investment, by ensuring stakeholder involvement through careful management of change, formal training or documented work-flow change,' remarks Magness.

The group runs the gamut of i-field technology from real-time measure-

The rationale behind 'digital business' both upstream and downstream is on business process optimisation throughout the supply chain rather than technology drive. As two of the oil majors explain, the real benefits of e-business and real-time data management come from a more focused approach to long-term strategy, with improved tactics day-to-day. Brian Davis reports.



ment log drilling through to mechanical borehole completions and surface plant for process flow, volumetric, pressure and temperature analysis. The main priority for the i-field programme is to create integrated processes for better decision-making in real time, at all levels (see Figure 1).

In practice this mean targeting individual operator optimisation in seconds rather than a day or more by having the right information in front of the right people; at the next level cutting down production optimisation from months to days; field optimisation from years to

months; and reservoir optimisation from multiple years to a single year.

ChevronTexaco believes it will be possible to reduce the decline in the production recovery curve in fields by 3.5% to 12%, by a combination of integrated processes and faster decision-making based on continuous data with related information and modelling in real-time. 'One of the key aspects of an i-field architected project is to understand what pieces of data are critical,' explains Magness, 'and to manage them from an "exception" basis, reflecting deviation trends or abnormalities.'

He suggests i-fields will help bring new fields onstream faster. 'They will allow us to shift the value curve back in time. With enhanced workflows we can integrate existing and new technology solutions a lot quicker, using a compatible data infrastructure, change management and organisational capability.'

The success of i-field developments is currently being evaluated on a scale of 0 to 4. Needless to say, few are yet at level 4. Cost-wise, the i-field programme is not considered to be a large add-on cost, but is aligned with planned expenditures both tactical and strategic, for both short-loop operations and long-term developments.

'Real-time data capture using i-field will ensure we have complete integration of what we do, ensuring we enable both ourselves and the vendors to get the most out of the supply chain,' says Magness. 'Within i-field we are focused on many sub-divisions and the aim is to supercharge the supply chain.'

ChevronTexaco has also established strategic partnerships with universities and a laboratory to progress i-field development. Its partners include the University of Southern California's Center for Interactive Smart Oilfield Technologies (CiSoft) and Los Alamos National Laboratory to address advanced energy solutions, data transmission and compositional sensor research, and the University of Bergen's Center of Integration Petroleum Research.

Upstream e-business initiatives

Although ChevronTexaco abandoned its Petrocosm e-marketplace initiative, it continues to use Ariba software as the backbone for spend management optimisation throughout the supply chain.

Steve Foster, ChevronTexaco Upstream Europe's e-Procurement Deployment Manager, explains that the Ariba buyer module has now been deployed worldwide, handling procure-to-pay (P2P) processes for 70% of the group's spend on services and 30% on materials. ChevronTexaco's main back office system is SAP, which handles accounts as well as offering modules for logistics, inventory and plant maintenance transactions. However, Foster claims there are problems interfacing the Ariba P2P system with the latter three SAP modules.

ChevronTexaco recently began using Ariba's sourcing module for reverse auctions in Europe. 'But our policy is to concentrate on the total cost of ownership and efficiency improvement, not just the first cost,' remarks Foster. 'Considering there is an initial bid price

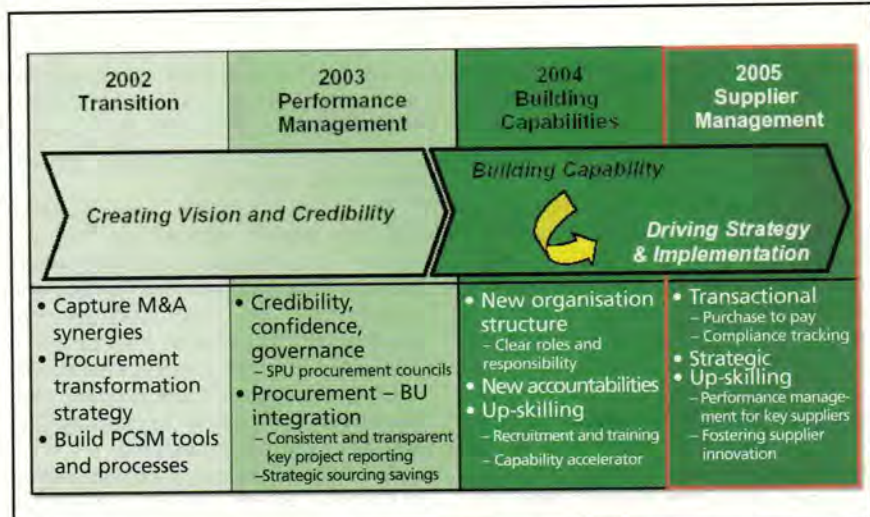


Figure 2: BP's procurement transformation journey from 2002 to 2005

Source: BP

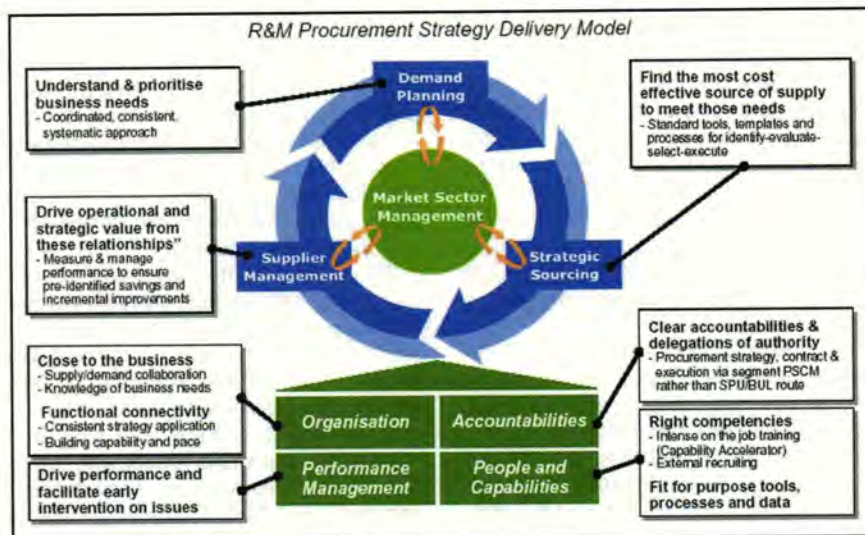


Figure 3: BP's refining and marketing division's procurement value delivery model

Source: BP

[the first cost] for a product or service, we are more interested in minimising the total cost of ownership during the life of a contract.' Supplier engagement is still a challenge, and the group is intent on convincing suppliers of the benefits of improved efficiency using electronic bids and the promise of faster payment - although it also expects a small discount in return!

About 10% of contracts are currently e-enabled, and the aim is to handle 80% of the group's upstream spend by year-end. Foster suggests there are four main areas of benefit - internal productivity improvements, as invoices are processed faster, freeing up people for value added activities; ensuring the spend goes to preferred suppliers; early payment discounts; more accurate pricing and catalogue compliance.

Ariba's online analysis module is also being introduced to gain better understanding of the group's spending patterns. The results will subsequently feed into a category management module to optimise the supply chain for world class performance.

standing of the group's spending patterns. The results will subsequently feed into a category management module to optimise the supply chain for world class performance.

BP's e-procurement strategy

'BP is on a procurement transformation journey,' explained Bill Knittle, Global Procurement Director, Refining and Marketing BP, at a recent Ariba Live conference in London and later to *Petroleum Review* (see Figure 2). As a highly decentralised organisation BP is driving towards significant business unit optimisation. Better procurement is viewed as a key objective, given that about \$40mn is spent annually on non-hydrocarbon related products and services.

Despite the mergers, BP still has six regional procurement teams. Chairman

Lord Browne set very ambitious targets for e-procurement during the dot.com boom. However, the group failed to get the early returns expected on e-business investment, as it was so wrapped up in integrating different business segments with dozens of legacy systems.

'When we started the purchase-to-pay project last year, it wasn't simply a system initiative but business process management optimisation,' explains Knittle. 'Technology was an enabler but certainly not the driver. That was a significant shift.'

Today there are six distinct business models for supplier performance management (SPM) from refining to marketing – including retail space, fast moving goods and process manufacturing. In 2004, the BP R&M team targeted putting a pilot SPM scheme in place, driving change around the behaviours of individuals and what controls needed to be set up, using limited technology and legacy systems for implementation.

BP pulled out of using the TradeRanger marketplace when it came back to BP for a second round of funding. 'We were dissatisfied with what we were getting,' admits Knittle. 'We found that low-cost technical solutions, like Procard, were better for dealing with many suppliers. Although we lost out on internal software integration and required middleware.'

For example, BP often has to integrate two types of catalogue (which it owns) with one that a supplier manages. This is not cost effective considering that BP spends less than £2,000 on average with 80,000 suppliers. About 4,000 suppliers account for 80% of BP's R&M spend. 'As we tighten visibility and redefine the preferred supplier base, our goal is to reduce the supplier base by 30% to 40%. The goal with Procard is to handle at least 40% of suppliers by e-invoicing and consolidate to monthly invoices.'

Improving supplier performance management

Since 2002, BP has focused on strategic sourcing and more proactive SPM. First, the company carried out extensive benchmarking in order to identify best practice in every area along the value chain. 'Demand and supply was very reactive downstream and we wanted to become more proactive with coordinated key supplier management,' says Knittle.

A more integrated procurement strategy was set up in 2003, with more consistent and transparent key project reporting and strategic sourcing savings. Last year, sourcing and procurement capabilities were built up, with a

new organisation structure, new accountabilities and upskilling. In 2005, BP's focus is targeted at supplier management, improving transactional electronic purchase-to-pay, compliance tracking and strategic performance management.

BP initially created a new 'value delivery model', focused on four key areas – organisation, accommodation, performance management, people and capabilities. A new 'procurement strategy delivery model' aims to prioritise business needs, driving operational and strategic value from supplier relationships, with clear accountabilities and the right competencies.

The R&M team identified the need to rationalise systems and add more sophistication to analyse their spend data. They discovered over 85 different legacy systems in place, handling data on \$16mn of spend. 'We knew we had to analyse suppliers in more detail and by commodity, business and geography, using common tools and processes,' says Knittle. Consequently the team sought to determine best procurement practice internally and externally. As a result they developed a new spend management tool and managed to unify the approach. (See Figure 3.)

BP improved its 'take to market' approach with an integrated strategic sourcing process and a sound rationale for the supplier market. 'We also began more proactive management of key preferred agreements,' says Knittle.

The biggest change was to put a consistent reporting system in place for the performance management reporting pipeline. Procurement became a strategic part of the business, where previously BP didn't even have a defined 'procurement' section. New competence models were introduced, with multiple dimensions. Then the BP team undertook an assessment of staff against these performance models and identified gaps. Authority and accountability were shifted to people who faced the market in market sector teams.

During 2004 the R&M team focused on building people capabilities and introduced a SWAT team, which procured bright students from US universities, and put 50 people through an Accelerator programme at a cost of \$30,000 per person.

Current strategic focus

The strategic sector management objective for e-procurement and e-sourcing is set at around 85% of the company's spend. Knittle anticipates it will take three years to get the full cycle of strategic sourcing in place.

This year the focus is on beginning to 'operationalise' the market sector strategies in a five-year plan. Recruitment and sector performance benchmarking continues, while reviewing the performance management approach and knowledge management. A common 'purchase-to-pay' process is being implemented, with a common technical architecture around all key operations. The team is also creating a common planning and target selling process; building up supplier performance measurements and management capabilities across top strategic suppliers to drive innovation and value.

'Considering that BP is not a process-driven company, we'll need to be very innovative to encourage and install common working practices for e-procurement,' admits Knittle. 'Our aim is to build long-lasting supplier relationships. If you don't manage the supplier relationship management properly, you'll lose out in the long run. It's also vital to have the right measurements in place – not simply a dozen or so KPIs [key performance indicators].'

BP currently deals with over 100,000 suppliers, and intends to rationalise the supplier base significantly over the next three years. Only 1% of these suppliers are strategic partners (SPM level 1), 10% are at level 2, and 89% use some form of purchase-to-pay system. 'Generally we've met or exceeded our targets for e-procurement and SPM over the last two years, but the real challenge is to take it to the next level of spend management excellence,' he says.

Knittle recognises that it'll take more than electronic P2P systems to deliver base value for complex agreements, although incremental value is available throughout the SPM journey. Measurement is vital. BP is currently working with 20 select suppliers to determine a better model for measuring supplier performance around three key metrics – the service relationship, quality/health and safety, and assurance of supply. The group is also applying Six Sigma quality rules to measure process fitness, as well as defining the total cost of ownership of new solutions and the degree of innovation involved.

'We've a lot to learn from the automotive industry,' he suggests. 'They are much further along the way to good supplier relationship management than the oil sector. Building a better supplier relationship is vital for better collaboration and demands significant change management in order to have a uniform approach in all three BP businesses.'

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New publication



Design, construction, modification, maintenance and decommissioning of filling stations (2nd edition)

This new edition of the 'Blue Book' is essential reading for all those involved in the design, construction, modification, maintenance and decommissioning of facilities for the storage and dispensing of vehicle fuels at either retail or commercial premises, as well as those involved in the enforcement of regulations applicable to such sites. This new publication has been produced jointly by the Association for Petroleum and Explosives Administration (APEA) and the Service Station Panel of the Energy Institute (EI). Considerable technical input has also been provided by the Health and Safety Executive (HSE) and other industry stakeholders in the UK. The publication:

- provides technical information on the storage and dispensing of petroleum products used as fuels for motor vehicles including petrol, diesel and auto gas (also known as LPG), primarily at filling stations to which the general public has access;
- covers civil, mechanical, hydraulic and electrical installation issues for the planning, design, construction, commissioning, modification, maintenance and decommissioning of filling stations;
- provides information aimed at minimizing the risks from fire and explosion, to health and to the environment;

- describes good practice and certain legal requirements, particularly those applicable in Europe and the UK;
- is intended to be applicable to both new sites and existing sites that are modified/refurbished.



The HSE has provided considerable technical input to the publication's development. This second edition replaces that published by APEA/IP in 1999, which in turn was a replacement for the HSE's HS(G)41 *Petrol filling stations: Construction and operation*. Although the information is largely based on experience from the UK, making frequent reference to legislation applicable in the UK, it is anticipated that the general principles will be applicable in most regions internationally. HSE supports the publication of this guidance and believes it represents current good practice. In HSE's view it provides useful and authoritative advice that will help the industry fulfill their legal obligations to minimise fire and explosion risks at filling stations.

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An independent strategy

Continuing with our series of articles analysing some of the smaller and intermediate oil and gas companies from around the world – based on information supplied by Oilvoice.com* – we take a closer look at the activities of Occidental Petroleum.

Occidental Petroleum is one of the world's largest independent oil and natural gas exploration and production companies, with operations concentrated in the US, the Middle East and Latin America (see Figure 1).

In the US, the company produces crude oil and natural gas, principally in California, the Permian Basin of Texas and New Mexico and the Hugoton area encompassing parts of Kansas, Oklahoma and Texas. It also has an interest in the Horn Mountain field in the deepwater Gulf of Mexico. The US accounts for more than 70% of Occidental's proven worldwide oil and gas reserves and 60% of current worldwide production.

In the Middle East, Occidental has assets in Oman, Qatar and Yemen, and is a partner in the transborder Dolphin project that will supply natural gas from Qatar to markets in the United Arab Emirates (UAE). The company's Latin American operations include producing assets in Colombia

and Ecuador. It also has producing assets in Russia and Pakistan.

Occidental's exploration success includes the discovery of five of the world's 50 largest oil fields discovered in the past 35 years, each of which exceeds 1bn barrels in resources. Within the past decade, the company has also discovered three major natural gas fields, each containing more than 3tn cf of natural gas.

Proved reserves

Occidental recently reported that 2004 year-end worldwide proved reserves, on a consolidated basis, totalled 2.49bn boe compared to 2.42bn boe at the end of 2003. Proved developed reserves make up 78% of the company's total proved reserves. Crude oil and condensate account for 80% of proved reserves.

A breakdown by category of the 2004 consolidated proved reserve additions shows improved recovery added 120mn boe (45%), extensions and discoveries added 61mn boe (23%), revisions to previous estimates added 45mn boe (17%), and acquisitions added 40mn boe (15%).

Middle East and North Africa focus

Occidental has established a strong position in the Middle East by partnering with the governments of Oman, Qatar, UAE and Yemen to assist in developing their energy resources. Continued growth in the Middle East is an integral part of Occidental's global strategy.

In early 2005, Occidental was awarded interests in nine exploration blocks in Libya's first licensing round since US sanctions were lifted. Among the awards were blocks 106 and 124 in the Sirte Basin, blocks 131 and 163 in the Murzuk Basin and block 59 in the Cyrenaica Basin. Occidental will act as operator, holding a 90% working interest in these blocks. Liwa Energy – owned by Mubadala Development, the investment and development company wholly owned by the government of the Emirate of Abu Dhabi – will hold the remaining 10% stake.

In addition, Occidental is a member of the consortium that was named the winning bidder in four offshore blocks – blocks 35, 36, 52 and 53 – holding a 35% interest. Woodside Petroleum, which will serve as operator, holds a 55% interest, and Liwa the remaining 10%.

In 1983, Occidental discovered the 300mn barrel Safah field in the Suneinah concession (block 9) in Oman, located in the north-western part of the country along the border with the UAE. The success at Safah was followed by the discovery of eight smaller oil fields. Occidental has produced more than 160mn gross barrels from 190 producing wells, most from the Safah field.

Occidental currently holds a 65% interest in Omani blocks 9 and 27, and is the operator under a production sharing contract. The Japanese company Mitsui holds the remaining 35%.

Occidental is also aggressively developing the Idd El Shargi North Dome (ISND) oil field, a mature field offshore

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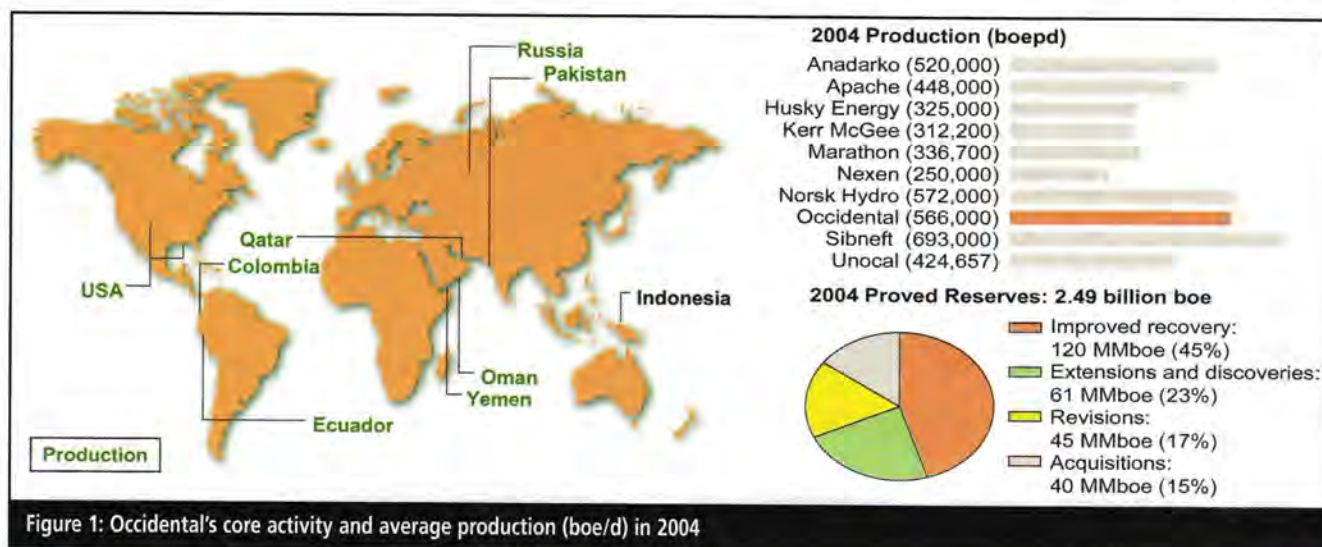


Figure 1: Occidental's core activity and average production (boe/d) in 2004



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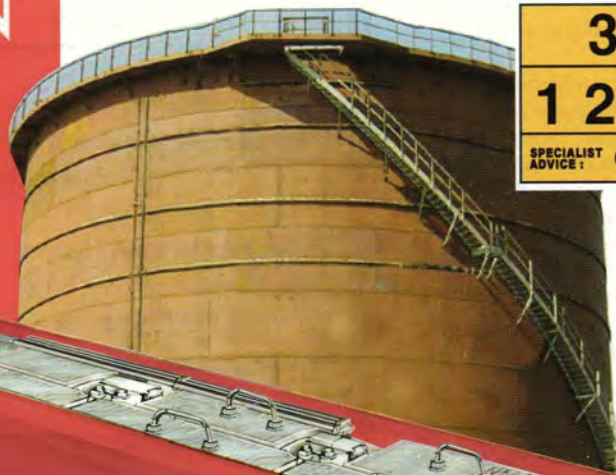
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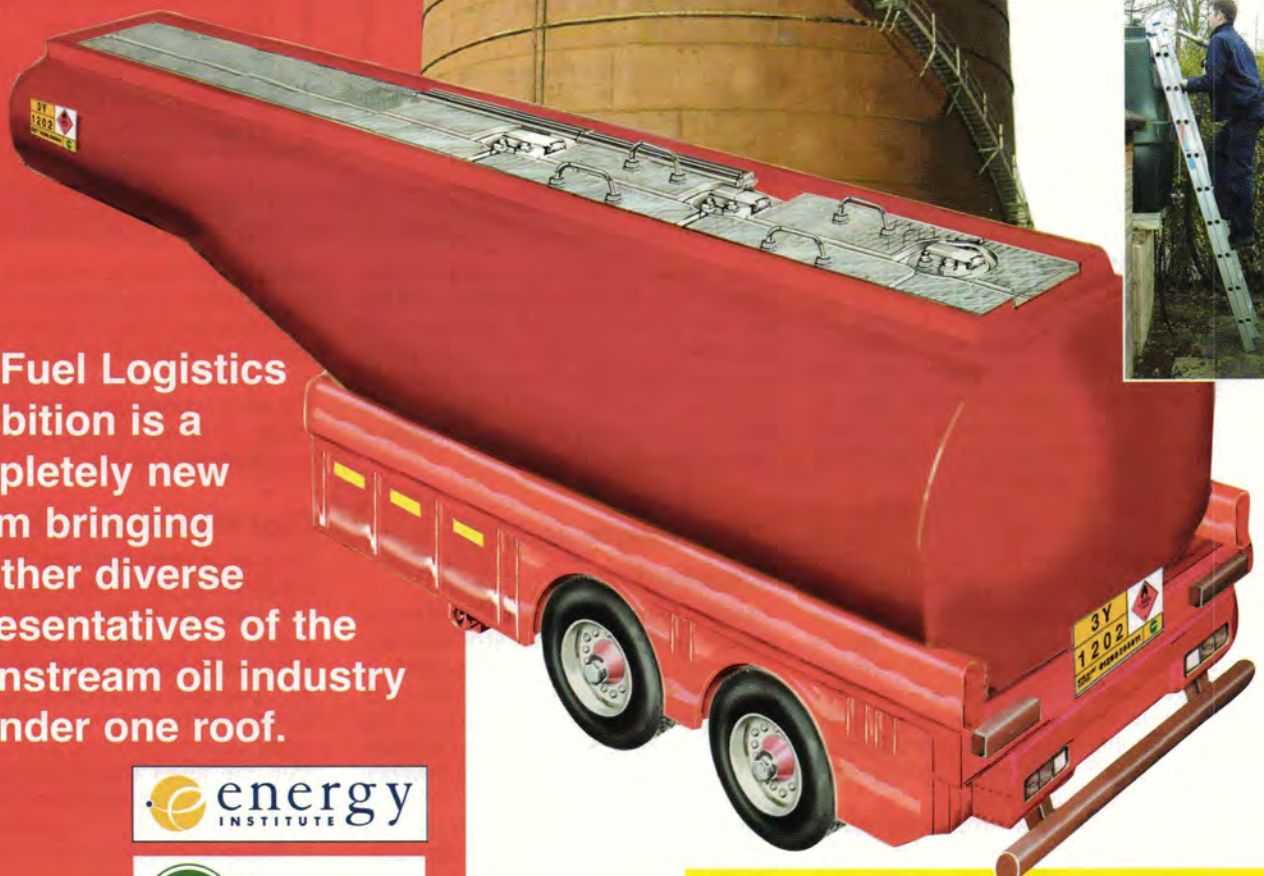
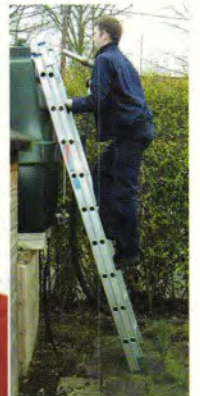
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Long-term fiscal, contractual stability proves elusive

Building upon the upstream fiscal and contractual frameworks outlined in his February article, David Wood* now looks at how their flexibility and stability could be improved in the future.

Production sharing mechanisms ideally should be simple, but need to retain sufficient flexibility to avoid leading to highly regressive systems that inhibit investment in small or marginal fields. EPSA (exploration and production phase) terms also require flexibility because prior to drilling the size and nature of potential fields is highly uncertain.

The most common method for introducing flexibility into fiscal contracts is with sliding scale terms. These yield progressively smaller shares of profit to the contractor as economic returns from a field improve. Daily production rates are the most common trigger used in PSA (production sharing agreement) sliding scales. However, some contracts tie more than one fiscal element to sliding scales and these scales may be triggered by a wide range of metrics (Figure 1).

Figure 2 shows a sliding scale for profit oil that varies from 35% to 15% to the contractor, depending upon 10,000 b/d production rate tranches. The sliding scales usually operate on increments of production. If daily oil production is 15,000 b/d then 10,000 b/d are subject to a 35% profit split and 5,000 b/d are subject to a 30% split. In Nigerian PSAs an increasing petroleum profits tax sliding scale is linked to cumulative oil produced.

In some PSAs, such as Libya, a profit/investment ratio, or R-factor, is used as the trigger for profit splits. It is also used to trigger royalty and income tax rates in Tunisian contracts. In Indian PSAs investors' rate of return (IRR) is used as the trigger, while a rate of return is used in the tax-royalty contract of Papua New Guinea to trigger additional profits tax and is also involved in contracts offshore Nova Scotia and Newfoundland (Canada).

Such mechanisms are fiscally quite progressive, but require significant administrative effort to ensure that costs are appropriately allocated and are sometimes open to manipulation by both government and contractor. In

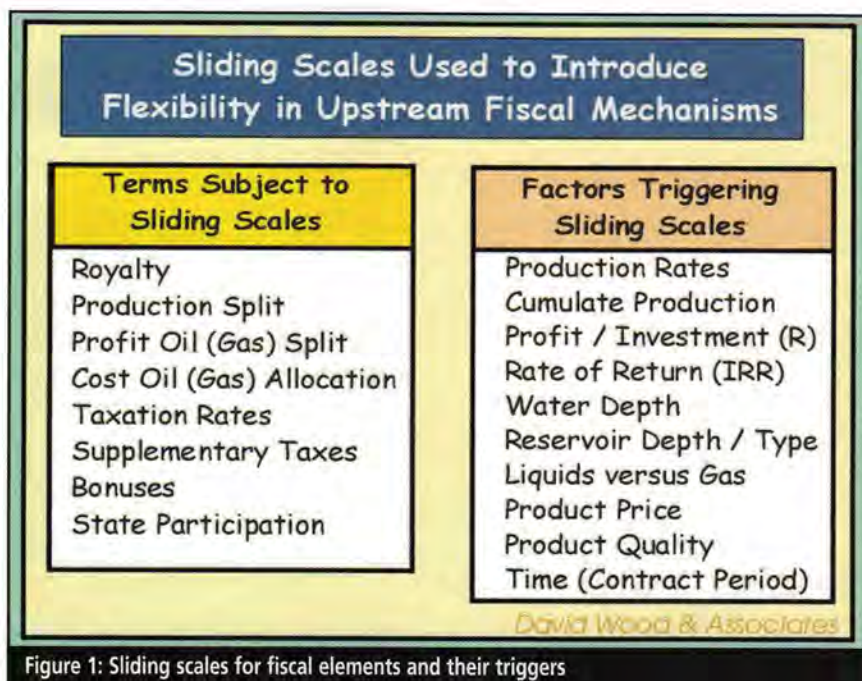


Figure 1: Sliding scales for fiscal elements and their triggers

some cases, under such contracts decisions on the timing of expenditures may be driven by the fiscal mechanism (ie avoiding a move into a lower profit tranche) rather than by sound technical practice. The economic performance and fiscal mechanism of such contracts are well documented.¹

Performance and negotiation

In order to understand how fiscal mechanisms perform from an economic and commercial context it is essential to build and evaluate a discounted cash-flow model to take into account the time value of revenue and cost streams. From a discounted perspective, revenue earned from production in 'Year 5' (Figure 2) will be worth substantially more to both contractor and state than revenue earned in Year 17 – in spite of production volumes being the same.

If the fiscal mechanisms – such as sliding scale profit oil split – are nego-

table, an economic model is essential to establish acceptable terms for the field type and environment under consideration. Figure 3 illustrates how such an evaluation might be usefully portrayed to distinguish the impact of a range of terms on discounted returns and breakeven points.

Cost recovery mechanisms

Time-value considerations are never as important as when discussed in terms of cost recovery. As the contractor is providing all the capital investment for field development (sometimes with the NOC (national oil company) as an equity partner either carried or paying its share later out of production) under a PSA, the faster that investment (sunk costs) can be recovered the higher the discounted value of the project.

The pace at which costs are recovered is determined by the cost oil (or gas) allocation and the amortisation schedules for specific types of costs (ie exploration, development or operating costs

with development costs often divided into specific categories associated with types of facilities or materials precisely defined – tangible, intangible etc). Amortisation schedules are either specified in the PSA or the national tax regulations and are quite distinct from those applied under corporate accounting procedures. The general rule is that the lower the cost oil (gas) allocation and the longer the amortisation period the slower the pace of cost recovery.

As illustrated in Figures 4 and 5 governments prefer slow contractor cost recovery mechanisms as more oil is then allocated to profit sharing in the crucial early years. This results in higher value and more cash flow in the early years of production for a government. Contractors prefer fast cost recovery mechanisms as the discounted values of projects are increased and payback times are reduced. Contracts with cost oil (gas) allocations of less than 50% (of revenue less royalty) and amortisation schedules of more than five years (for field development costs) are considered as slow cost recovery mechanisms.

The issue of how, and if, decommissioning costs are tax deductible or recoverable varies from country to country. Frequently the contract term ends while the field and facilities retain commercial life for the government. Hence field abandonment and decommissioning may be dislocated in time beyond the end of the contract period of a PSA.

Production and cost recovery for gas fields are commonly characterised by approximately flat profiles spread over many years (Figure 6), due to long-term contractual quantities and prices specified in the contracts (eg gas liquefaction-LNG project). Such projects require huge (several billion US dollars in some cases) upfront capital investments both for gas field development and liquefaction (or gas-to-liquids, GTL) plant facilities. Some PSAs deal with these developments as integrated projects with both sets of costs to be recovered from the cost gas allocation.

Achieving project pay back in a meaningful timeframe is often one of the key commercial challenges for the investors. Fiscal mechanisms that take into account the time-value issues can help the commerciality of such projects from the IOCs (international oil company) perspective. For example, at least one GTL project currently under development in Qatar has a fiscal mechanism (associated with a DPSA) involving a high cost gas allocation and a forward weighted component to the contractor's profit gas entitlement.²

Such a mechanism (Figure 6) will enhance the discounted value to the contractor and at the same time gradu-

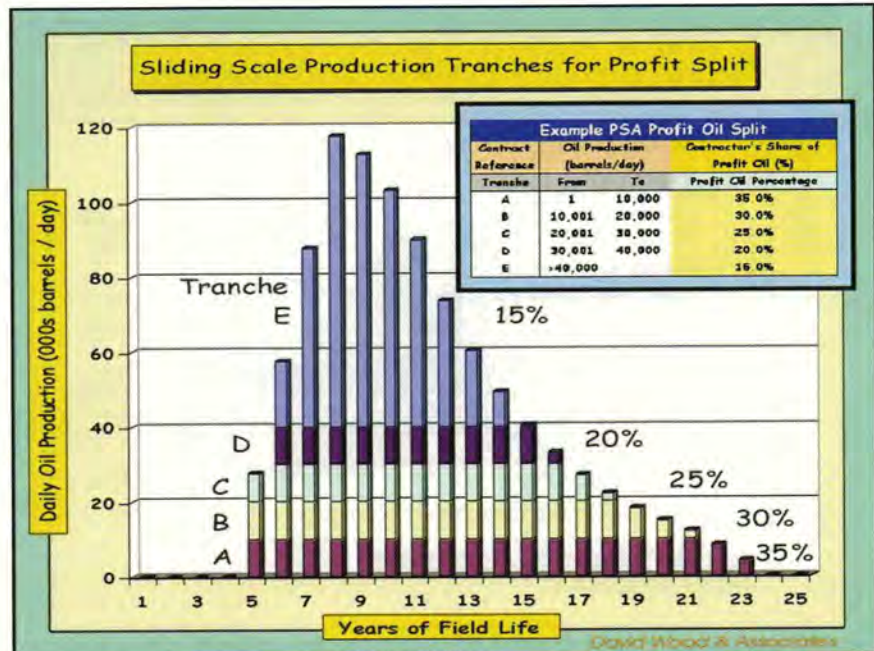


Figure 2: An oil field production profile illustrating how tranches of production are subjected to different splits contractually defined within a PSA

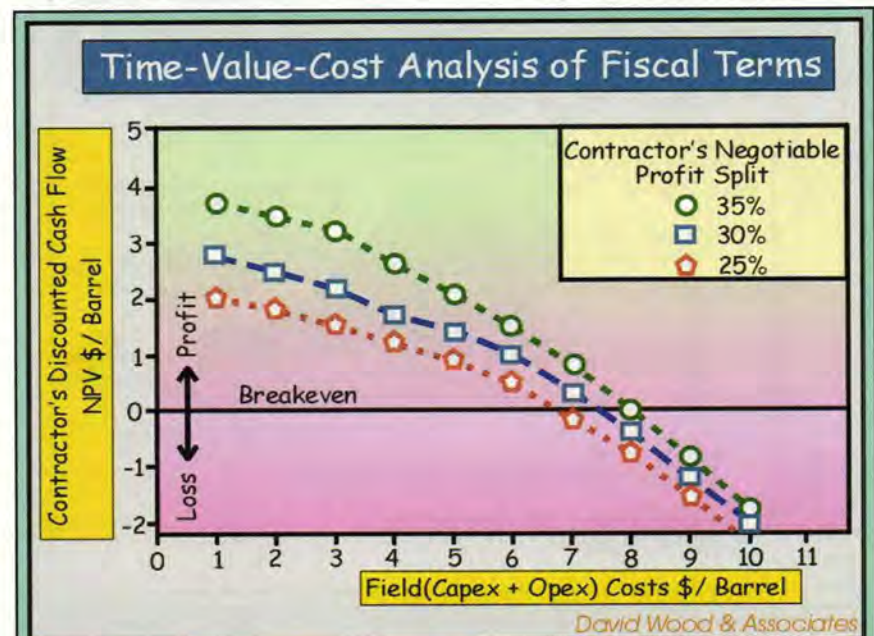


Figure 3: Cross plot, on a per barrel basis, of discounted contractor cash flow (NPV) and full project costs can reveal much about the economic performance of specific fields and contract terms

ally passes the major share of profit to the state. At the end of the contract period (usually some 25 years or more) the facilities pass to the state and have many years of production life left from which the state can benefit on a 100% basis if it so wishes.

Reserves allocation issues

Reserves that can be allocated under specific contract types can be of significant importance to companies regis-

tered or listed on US stock exchanges and therefore subject to US GAAP and SEC reporting rules. Under concessionary contracts all of an IOC's working interest share in the proved reserves of a field may be booked as reserves. Under PSAs only the profit and cost oil (gas) entitlements allocated to the IOC, plus the tax component paid (if any) from the government's production share (on the IOC's behalf – referred to a tax gross-up), may be booked as reserves. This will be substantially less

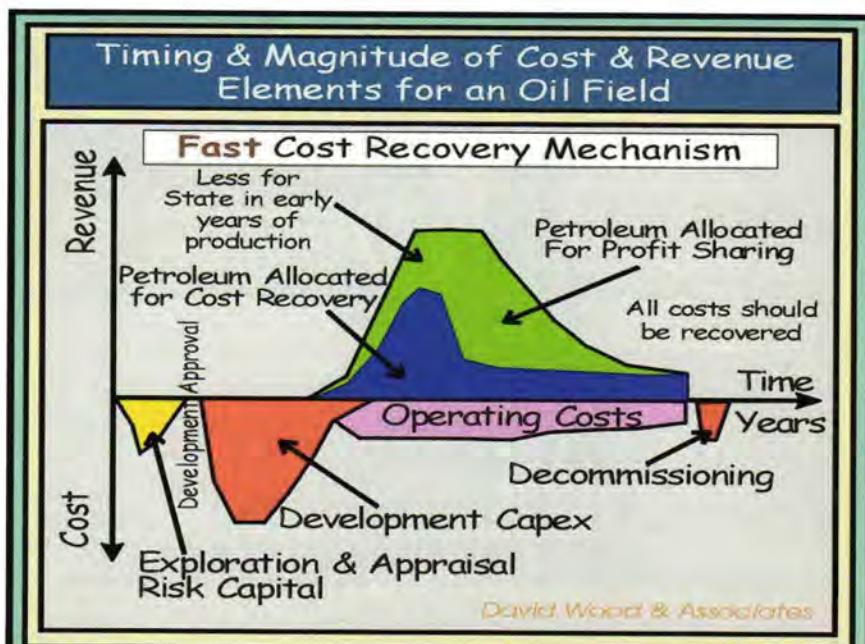


Figure 4: Example of fast cost recovery mechanism for an oil field

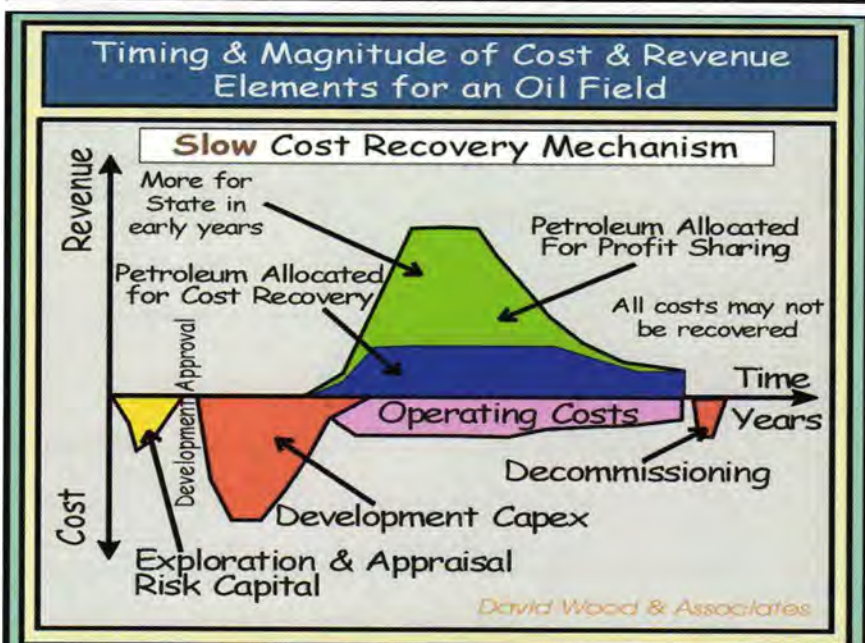


Figure 5: Example of slow cost recovery mechanism for an oil field

than equivalent reserves booked under a concessionary contract.

Booking reserves under service or hybrid contracts is usually not possible as the fee paid to the contractor for the investment and work provided is not related to reserves, but is either financial or linked to production revenues. This impact on reserves booking due to agreement type can be significant for IOCs pressured by reporting standards to demonstrate sustainable growth in their reserves base. It is one of several reasons that make service and buy-back type agreements unattractive to them.

Capitalising on fiscal flexibility

Fiscal mechanisms in international upstream contracts are complex and varied. Many countries operate contracts with progressive and flexible fiscal elements or offer the opportunity to build in additional flexibility to suit the requirements of specific projects. It is important for a clear, unambiguous definition of the fiscal mechanism to be defined in the PSA and for an economic model (ideally ratified by both parties (contractor and government) to be built and used to explore the workable limits

and potential problems with the prevailing structure. The more fiscally flexible the model, ie the more it varies the contractor:government profit takes according to market and field performance variations, the more likely it is to last and not be meddled with by taxation authorities in the long-term.

Notwithstanding the above, no matter how flexible the fiscal mechanism negotiated and no matter how well it is defined in the contract, where the long-term objectives of the parties are not aligned or unstable political circumstances prevail, many governments will be tempted to increase their fiscal take as and when circumstances allow. For this reason it is important for IOCs to be aware of situations that might lead to fiscal and contractual instability.

Potential contractual instability

In several of the countries currently experiencing contractual instability (see Part 1 in February 2005 issue) some warning signs should have been picked up by astute IOCs during the negotiation period. Some of these signs are listed below.

West Africa – In the 1990s in several West African countries (Nigeria and Angola in particular) IOCs persuaded the governments to ease the fiscal terms for deepwater exploration rights compared to their terms prevailing in shallow waters. In exchange, IOCs agreed to pay substantial signature bonuses (hundreds of millions of dollars in some cases). Lures of large upfront cash payments to governments, with questionable motives in countries with track records of corruption and instability, were inevitably snapped up. When giant fields were discovered in these licences the reality for subsequent governments was that they were going to see substantially less from these because of the agreed terms. It is not surprising, therefore, that they have sought every opportunity to increase their take.

The IOC's defence that high costs, technological challenges and risks associated with deepwater operations warrants more favourable terms has been progressively diluted as more and more large fields have been discovered. Whilst honouring the PSAs in principle, any contractual irregularity on discovered fields (eg Texaco's farm-in to Famfa's licence covering most of the deepwater Agbami field, Nigeria) has been used to enable the NOC to increase its equity share. Procurement restrictions to local companies and approving assignments have offered other opportunities to exert further state influence.

Payment of high signature bonuses in

exchange for diluted fiscal terms may secure E&P contracts in the short-term (particularly with corrupt regimes) but is hardly a recipe for aligned long-term objectives. Entertaining farm-in deals with small local players that improve an IOCs fiscal position at the expense of the state company is also unlikely to survive the test of time.

Kazakhstan – Following the break-up of the Soviet Union in the early 1990s, Kazakhstan, Azerbaijan and Turkmenistan all signed PSAs with IOCs for the highly prospective, but technically challenging and remote, Caspian offshore. They saw oil and gas development as a means of securing their independence from Russia. High political risk, high technical cost of drilling and facilities development and requirements for expensive export pipelines meant that PSA fiscal terms had to reflect those realities to attract foreign investors. Although these countries had split from the Soviet Union their mindsets had retained much of the old soviet distrust for western capitalism, political paranoia, state interference in all aspects of business life and corruption.

In Kazakhstan, following spectacular technical success (Tengiz, Kashagan, Karachaganak – all world class fields) built upon western technology and large investment under PSAs, the high oil price environment of recent years has led the government to adopt a highly adversarial stance, eroding value of the IOCs at every opportunity.³ The 2004 tax code amendments have increased government take to between 65% and 85% of revenues and rates of return for IOCs in the major field developments are now reported to be less than 10%. Further disputes over import duties, pre-emption and the reluctance of KazMunaiGas (the NOC) to pay its contractual share all indicate an ongoing scenario of further dispute and fiscal/contractual instability.

In Azerbaijan, the key development investment – building of the Baku-Tbilisi-Ceyhan (BTC) pipeline – is now approaching completion. It will be interesting to see if fiscal and contractual stability can be maintained. The pressures and hostility from its neighbours (Russia, Iran), plus political alignment with the west at government level, should help to maintain stability in the medium term. The profit oil split of the PSA has several tranches linked to an R-factor that progressively increases state-owned Socar's entitlement from about 50% to 90%. Such flexibility should help both parties as projects progress through the production phase.

If a country and government retains a Soviet-style mindset it is unlikely that the capitalist principles embodied in PSAs will result in contractual and fiscal

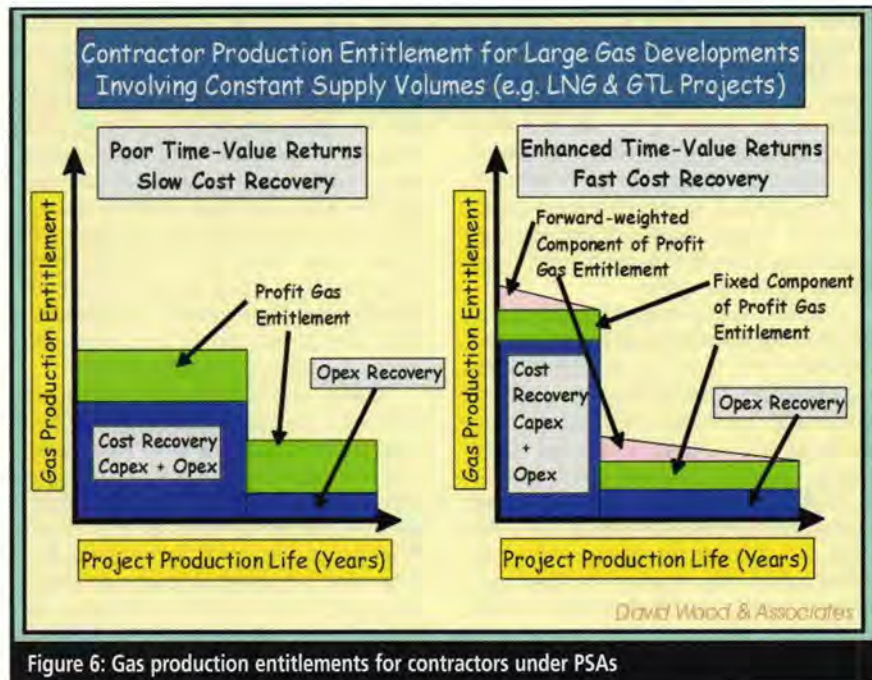


Figure 6: Gas production entitlements for contractors under PSAs

stability and non-intervention by the state. A long-term pro-western political alignment at governmental level going beyond the energy sector provides a better chance of contractual agreements being honoured.

Trinidad & Tobago (T&T) – The prolific eastern offshore oil and gas fields of T&T were discovered and developed by Amoco under tax-royalty licences signed in the 1970s. Developments focused on oil and condensate production, flaring large amounts of gas, until the late 1990s when gas monetisation projects (fertilisers, methanol and LNG) were developed. BP 'inherited' these licences in its corporate takeover of Amoco in 1998. In order to stimulate exploration in its north and north-west territorial waters extending into deep-water, the T&T government entered into PSAs with a number of IOCs in the 1990s on quite lenient fiscal terms (about 50% government take of revenue) and several very large gas fields were discovered.

Several billions dollars of investment have been made since the mid-1990s to develop the Atlantic LNG (ALNG) plant (four trains either operating or under construction) taking gas from both the older licence areas and subsequently the PSA areas. Progressively, the T&T government has extracted tougher terms for the approval of the IOCs to build each liquefaction train (without the liquefaction capacity there is no export route for the gas).

ALNG Train 4, due onstream in January 2006, is an arm's length gas processing entity (tolling plant) with no title to the gas and a fixed 8% rate of return. Title to the gas liquefied remains

with the upstream gas producers, which are subject to higher levels of taxation (55% petroleum profits tax versus 30% corporation tax for the downstream activities). A price cap of \$3.5/mn Btu Henry Hub is also applied to the LNG from the fourth train, whereby proceeds from sales above that price are passed back to the upstream gas producers (and subject to taxation). In addition, BP and its partners agreed to supply T&T with 100mn cf/d of free gas that could be used to support a new gas-fired power generation plant planned for La Brea in south-west Trinidad. They are to provide all of the 450mn cf/d for ALNG Train 4.

The T&T government announced in July 2004 that it had reached an agreement with BP and its partners regarding the payment of royalties for gas used for LNG. In October 2004 it announced plans to renegotiate its PSAs for LNG exported from ALNG because 'the conditions of the contracts have changed'. Following the sinking of billions of dollars of investment in building its LNG industry in T&T, based upon specific long-term fiscal and contractual terms, the T&T government now wishes to change and tighten the fiscal terms. Not surprisingly, the IOCs and other investors are not delighted – however, they have little choice but to agree if they wish to continue with the development of their gas reserves.

Complex contractual chains with different IOC groups operating on different contractual terms, profit interests and strategies make it easy for a government to pressurise individual IOC project groups and play them off against each other. It is difficult to maintain a relatively

lenient fiscal take over the long-term in large-scale international projects. Once one IOC group agrees to a change to more onerous fiscal terms, in exchange for future development approvals, the other project groups find it difficult to refuse. However, the T&T government might find it more difficult to secure foreign investment for future long-term development projects as a result of its short-term moves to increase its fiscal take.

In all the above cases the fiscal mechanisms in the contracts were well defined. However, the technical and commercial uncertainties surrounding the projects when the contracts were signed have evaporated following substantial investment, technical success and positive market movements. Rather than rewarding the IOCs for taking the initial risks and thereby promoting more risk-taking and inward investment leading to growth and faster development of their petroleum sectors, these governments have decided to focus on what they see, with many of the risk issues now removed, as reducing the inequitable economic returns accruing to the IOCs. These governments have used their increased power, due to the IOCs financial exposure, to adjust the terms in their favour. These examples suggest that tightly defined contracts on their own cannot secure long-term contractual and fiscal stability.

Risk evaluation and mitigation

IOCs should analyse and evaluate the detailed components of fiscal and political risks associated with each country and region and reflect upon them, and the country's track record with respect to the oil industry, before negotiating and concluding an upstream contract.⁴ It is not sufficient to just take a general political risk ranking factor for a country, produced by independent industry consultants, compare it with other country rankings or adjust it for offsets.⁵

Recognising that a country is high risk, but then assuming that such risks can be either offset by prospectivity, diversified or removed through contractual arrangements, is probably a mistake in almost all cases. What is required is the development of a risk mitigation strategy that not only focuses on optimising fiscal terms but also attempts to achieve long-term alignment of goals, contracts and sustainable benefits for all stakeholders (contractor, government, local communities, local industry etc) that can act together to cement stability and jointly seek out opportunities within a unified vision for growth. If such a strategy is not a credible reality or cannot be realistically developed it is probably sensible to look elsewhere.

In the UK, an increasingly short-term approach seems to be the only credible explanation for the government choosing to impose windfall profits taxes on an already ailing and contracting industry. A collective industry (operators, suppliers and service providers including the financial and legal sectors) risk-mitigation strategy is required to educate the government and other industry stakeholders about the long-term damage to investment, development and growth in the petroleum sector and dependent industries that such actions cause.

To date, the collective UK industry has failed to persuade the UK government that greater fiscal incentives for re-investment of profits in E&P and marginal field developments would ultimately yield a greater taxation return to the government than the short-term gains from increased tax rates. Until such persuasion succeeds, the risk of fiscal instability associated with small, high-cost field developments in the UK remain higher than they should be and will undoubtedly deter or delay substantial investment capital. Moreover, such actions have damaged an aligned approach between government and industry that is crucial for sustained growth. ●

Footnotes

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3 Christopher Pala, 'Kazakh government discourages Caspian exploration', *Petroleum Review*, November 2004, p12-13. Martin Clark, 'Call the lawyers', *Petroleum Economist*, September 2004, p22-26.

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Qatar with significant oil reserves. The company is working closely with state-owned partner Qatar Petroleum (QP) to evaluate and implement new technologies to further increase the recovery rate. As a result of a 2002 agreement with the government of Qatar, Occidental expanded the ISND development programme, which is expected to result in the recovery of approximately 145mn additional gross barrels of oil. Phase II of the development project is currently underway.

Occidental's successful redevelopment of ISND resulted in the Qatari government awarding the company a production sharing contract for the undeveloped Idd El Shargi South Dome (ISSD) field, 15 miles south of ISND. Occidental first began production from ISSD in October 1999 and has begun full field development under a separate agreement.

The Dolphin gas project is one of the largest transborder energy projects in the Middle East. It is the flagship venture of Dolphin Energy, in which Occidental has a 24.5% interest. The \$4bn, 2-phase initiative will bring natural gas from Qatar via pipeline to meet the growing energy needs of the UAE. In the first phase, the consortium will develop and produce natural gas and condensate in Qatar's giant North field. The second phase – a 48-inch diameter, 260-mile long subsea pipeline – is scheduled to complete in 2006.

The Dolphin project will carry up to 2bn cf/d of Qatari gas to the UAE for 25 years. The pipeline has the capacity to transport up to 3.2bn cf/d and the consortium is pursuing new opportunities to fill the line with additional purchase commitments.

Occidental also holds a 38% interest in the 900mn-barrel Masila field in Yemen's block 14. Masila was one of the world's largest oil discoveries in the 1990s and accounts for more than half of Yemen's total oil production. Occidental also holds a 40% stake in the adjacent East Shabwa field in block 10. Both of these fields are outside-operated. In central Yemen, Occidental is the operator of block 20, where it plans to drill several exploration wells and has significant potential to expand operations. ●

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