Petroleum review

FEBRUARY 2004

Russia and Eastern Europe

- Expanding Russian exports
- EU membership benefits for Eastern Europe
- Sakhalin launches new offshore province

Exploration and production

- Dry vs wet trees in deepwater development
- Few large wildcat discoveries in 2003

Covering the international oil and gas industry from field to forecourt – exploration, production, refining, marketing and e-business

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ABC

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ABBREVIATIONS

The following are used throughout *Petroleum Review*:

mn = million (10^6)	kW = kilowatts (10^3)
bn = billion (10^9)	MW = megawatts (10^6)
tn = trillion (10^{12})	GW = gigawatts (10^9)
cf = cubic feet	kWh = kilowatt hour
cm = cubic metres	km = kilometre
boe = barrels of oil equivalent	sq km = square kilometres
	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 cubic feet per year.

Front cover: For a full update on Russian oil and gas activities see p 16–30
Photo: www.sibneft.ru

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Time for independent audit of reserves

The near hysterical reaction of the London financial analysts to the non-appearance of the Shell's Chairman and Finance Director at a meeting to explain the recent downward revision in the company's proved reserves illustrates two truths – that reserves have now become a critical factor in valuing a company and that the analysts continue to have an enormously high opinion of their own importance. While Shell's actions appear unfortunate, it was Shell and not the analysts who identified and corrected the error. Wood Mackenzie's excellent analysis of the implications is on p14.

One option to protect shareholders and to give a reliable guide to an oil company's future prospects is to have independent reserves audits. Independent financial audits are normal and uncontroversial. Improved seismic means that accurate reserves assessments are easier to produce and more reliable than ever before. At a time when there is real concern over future production growth from large and small companies alike it seems desirable that reserves, like financial results, are independently audited.

If Shell – a company usually known for its probity and one that has not one but two independent financial auditors for its accounts – wishes to start remedying the damage done to its reputation by the recent reserves reporting debacle, the simplest and most effective move would be to appoint independent reserves auditors with a brief to report as soon as possible.

When Russia started to open up after the collapse of Communism in 1991 a number of investors were burned by wilful confusion between Russian and western reserve definitions. In reaction large discounts were applied to Russian reserve figures until a number of Russian companies decided to have independent reserves audits done so that they could be listed on western stock exchanges. Many, if not all, were able to show that they had larger reserves than most had thought. Was it the independent auditing of Russian reserves that led to the change in western perceptions about Russian oil production prospects?

Given that modern technology makes reserves assessment more accurate and less subjective than ever before, can we now look forward to company reports with independently audited reserves broken down by region and giving both SEC style proved reserves and 2P proved and probable reserves?

The consultant IHS Energy has just reported its first take on discovery in 2003 (see p46). It is little short of horrifying. At the moment it looks as though 2003 will be the first year to have recorded no large oil discoveries at all. We would probably have to go back to the early 1920s to find a year when fewer large oil discoveries were made. The situation for gas discovery appears little better. It is worth recording that exploration is driven by the prospect of finding large fields, which justify the expenditure on the infrastructure. Small fields are found as a by-product of searching for the large ones and depend on the large field infrastructure for their development, particularly offshore.

The main feature in this issue looks at Russia and Eastern Europe (see pp18–30). For the last few years expansion of Russian supplies have been the largest single component in the expansion of non-Opec supply (see table below). If non-Opec, non-FSU production is separated out it can be seen to have peaked in 1998, although it will expand in 2004–2006 as projects come onstream in Angola, the Gulf of Mexico, Brazil and the Caspian. Russian production expansion remains a vital component in meeting oil and gas demand growth.

Chris Skrebowski

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

Year	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
Russia	7,173	6,419	6,288	6,114	6,227	6,169	6,178	6,536	7,056	7,698
FSU	1,023	972	1,009	1,057	1,150	1,222	1,373	1,477	1,603	1,784
Non-Opec/ non-FSU	22,744	24,915	25,816	27,074	27,536	27,665	27,364	27,574	26,927	26,732
Total non-Opec	30,940	32,306	33,113	34,245	34,913	35,056	34,915	35,587	35,586	36,214

Russian, FSU and non-Opec oil production (in ,000 b/d), 1993–2002

Source: BP Statistical Review, June 2003

e-world

The Energy Institute's new 'STM Online' service is now live at **www.energyinstpubs.org.uk**

Users can access the latest test methods for petroleum and related products, and BS2000 Series, online by subscribing to the service and/or by purchasing individual test methods and paying online. Subscribers receive 12 months access to the site, including all updates and amendments made during that period.

PetrolWorld's new **PetrolWorld.com** website went 'live' on 26 January 2004. Apart from a new look, the main feature is an up-to-date global information service, reflecting the site's existing network reach around the world and the database of information and contacts developed since 1990. For more information, visit **www.petrolworld.com**

The **BigOil.net** web portal has been unveiled. Developed in association with Platts and Big Oil Associates, the portal provides real-time industry intelligence that will include Platts-based market data branded as 'Daily Petroleum Quotes', together with daily industry intelligence reports and news items on the downstream petroleum industry. The website also includes Platts 'Trend Analysis' that is based on weekly and monthly trends, together with a 'Pump Price Optimisation Model' to optimise margins and working capital.

Capping a two-year-long evaluation of the development impacts of the World Bank Group's support for oil, mining, and gas projects worldwide, the Extractive Industries Review (EIR) has recommended that the World Bank adopt significant reforms, including doing more to reduce poverty, immediately ceasing funding for coal projects worldwide and phasing out its support for oil production by 2008. The EIR report is available on **www.eireview.org**

ExxonMobil has launched a new website – **www.exxonmobileurope.com** – that provides information on the group's interests and activities in Europe.

The Offshore Technology Conference (OTC) has created 'OTC Papers Online', a searchable database of more than 9,000 technical papers from all OTC meetings since 1969. Papers may be downloaded from **www.OTCnet.org** at a cost of $10 each.

SBES's new safety alarm systems website at **www.sbes.co.uk** has been upgraded to include virtual demonstrations illustrating how the company's range of products can 'easily and affordably protect staff or customers located in potentially hazardous situations'.

In Brief

UK

UK independent CH4 Energy is to *acquire for an undisclosed sum Eni's 37.5% operated interest in the Markham gas field in the southern gas basin of the North Sea, its 4% non-operated stake in the J3C field in the Dutch sector and 12.5% non-operated interest in UK block 43/20d.*

Total has begun a wide-ranging stake- *holder consultation process on the decommissioning of the concrete manifold compression platform MCP-01 in North Sea block 14/9. Further information can be found at* **www.uk.total.com/activities/EP_SF-MCP01Platform**

Centrica has produced first gas from the *Rose field in southern North Sea block 47/15b. Developed as a subsea well tie-back to the BP-operated Amethyst field, Rose flowed at 120mn cf/d.*

ExxonMobil subsidiary Mobil North *Sea Limited (MNSL) (70%) has made a gas discovery in the southern sector of the North Sea, in block 53/2. Located near the MNSL-operated Camelot field, the well tested at 65mn cf/d of gas.*

Petro-Canada's Clapham field in block *21/24 in the UK central North Sea has achieved first oil. Proved plus probable reserves are put at more than 20mn barrels of oil. Peak production of 15,000 b/d is expected in 2004.*

BG Group has taken operatorship and *100% ownership of blocks 1/2, 1/5 and 1/6 in Norway's first Predefined Areas licensing round.*

Addendum

On p13 in the January 2004 edition we erroneously cited ChevronTexaco as the sponsor of the Captain virtual visit developed as part of the Discover Petroleum website at **www.energyinst.org.uk/discover** In fact, the Society of Petroleum Engineers (SPE) sponsored the visit to the ChevronTexaco-operated platform. For further details, see *Petroleum Review*, December 2003).

Enhanced UK tax relief for new North Sea entrants

The UK Chancellor of the Exchequer has announced that he intends to enhance tax relief on exploration costs for new entrants to the North Sea. While welcoming the news, UKOOA (UK Offshore Operators' Association) says that it is 'disappointed' that the Chancellor 'appears to have failed to seize the opportunity to raise exploration and appraisal activity levels across the North Sea by broadening the benefit to all companies active in the UK Continental Shelf (UKCS)'.

The Association had hoped that the Chancellor would use the autumn pre-budget statement to announce specific tax measures for all exploration and appraisal in the UKCS following consultation with industry, which ended in October 2003.

Steve Harris, UKOOA's Acting Director General, said: 'We actively seek government support with tax measures to help offset the increasing risks and high costs of exploration and appraisal in the UKCS today. We need to encourage more activity to find the oil and gas reserves that will meet current needs and sustain future production and safeguard long-term energy supplies, jobs and revenues for the UK.

'While the tax measure will allow new entrants to offset more effectively the cost of their investment capital and explore on a more equal economic footing with existing operators, we fear that it will not have any tangible impact on exploration and appraisal activity levels. The government-led vision through Pilot of maintaining production levels at 3mn boe/d in 2010 will only be met through better collaboration. Going forward we need increasingly to share the exploration, appraisal and development risks to deliver the Pilot vision. Without this we will impair our ability to assist in meeting the UK's long-term needs for security of energy supply.

'Much of the North Sea is now regarded as mature. Prospects tend to be increasingly small in size and the costs of exploration, development and operation are amongst the highest in the world. We exist and compete in a global market where competition for investment funds is intense. We have to work together to try and tip the scales in our favour. Exploration drilling today is just one-tenth of the 1990 peak of 159 wells. Sixteen exploration wells were drilled in 2002, well below the annual activity of almost all of the last 35 years. This level of exploration will not maximise recovery of the nation's natural resources.

'Yet, even after more than three decades of activity, the UKCS still has significant development potential, with just under half of the UK's total estimated reserves still to be recovered. This includes between 5bn boe and 11bn boe which are yet to find, and the potential for a further 8bn barrels in over 300 undeveloped oil and gas discoveries.

'The timing is now critical. Commercial discoveries are on average about 30mn boe, too small to support their own pipelines and production facilities. Most will rely on existing, but ageing, infrastructure. There is a sense of urgency to carry out as much exploration and appraisal now, particularly within the catchment areas of these infrastructure facilities before decommissioning plans are put in place, and the opportunity to develop outlying marginal reserves is lost, possibly for ever.'

Apache agrees Egyptian gas sales

Apache has signed a Memorandum of Understanding (MoU) for a $6bn gas sales agreement, field development plan and deepwater development lease for a minimum of 2.7tn cf of natural gas over 25 years from the deepwater portion of its Egyptian West Mediterranean Concession. Production is expected to commence in 2007.

'Principal terms include supplying approximately 400mn cf/d of gas to the Egyptian market over the first five years and 375mn cf/d for the remainder of the term,' said Apache Chief Executive Officer and President G Steven Farris. 'Upon finalisation of the agreements, we will have effectively contracted for all of the gas we have found to date in the deep water.'

Farris said Apache will begin appraisal drilling on the concession and start infrastructure construction soon after the final agreements are executed. In addition, he said: 'We have another five Pliocene-age gas exploratory prospects and eight Miocene-age prospects in the area.'

The MoU was signed with the Egyptian General Petroleum Corporation and the Egyptian Gas Holding Company.

Norway's 18th licensing round

Norway's 18th licensing round on the Norwegian Continental Shelf includes 95 blocks or parts of blocks, almost three times the number of blocks that were included in the 17th licensing round. 'The announced area contains a variety of challenges, which should provide interesting opportunities for both established and newer companies,' said Einar Steensnæs, Minister of Petroleum and Energy.

In the announcement the government has been concerned with balancing the interests of the environment, the fisheries, the aqua culture and petroleum. The conditions relating to environmental concerns and the fishery interests is therefore more extensive in this round than has previously been the case.

The deadline for submission of applications is 15 March 2004. The award of production licences is planned to take place before summer 2004.

Steensnæs also stated that the Norwegian Government had decided not to continue further petroleum activities in the area Nordland VI outside Lofoten – a fishing ground and a spawning ground for important fish stocks. The question is to be considered again when the integrated management plan for the Barents Sea is completed. However, the government had decided to allow for further all-year petroleum activity in the already opened areas in the south Barents Sea, except for certain especially 'valuable areas'. These include the coastal areas of Troms and Finnmark and the especially valuable areas of the polar front, the ice edge, Bear Island and Tromsøflaket.

Parliament approved the Snøhvit development, located partly in Tromsøflaket, in 2002. 'To improve the project economics it is important to tie in additional resources to the field. The government will therefore allow further exploration for additional gas resources that may be tied in to Snøhvit,' explained Steensnæs.

The Goliat field is located close to Tromsøflaket. Steensnæs pointed out that while the government had decided that the field's licensees may drill the necessary appraisal wells to clarify if the field can be developed, this decision will in no way prejudice a decision as to whether a development of the Goliat field will be approved. A possible development will be decided upon after the licensees submit a plan for development and operation for the Ministry's approval. In connection with such a plan it will be up to the companies involved to demonstrate that a development properly takes into account issues relating to the environment and the risks of pollution in the area, said Steensnæs.

In opening up for further petroleum activity in the south Barents Sea now, the government has made it possible for the oil companies to drill three wells, as they have indicated, in the licenced area in Lopparygen, Nordkappbassenget and Goliat in the fall of 2004 and in the spring of 2005. This will give valuable information with regard to the prospectivity of the area and at the same time will have a positive effect on the low level of activity on the Norwegian Continental Shelf.

Karachaganak production further delayed

As announced in September 2003, oil sales from the Karachaganak Phase Two facilities were delayed because product entering the export pipeline connecting the field to the CPC pipeline became contaminated with caustic soda. BG Group now reports that whilst this issue has been successfully resolved, continued testing during commissioning has identified an unrelated issue associated with small bore pipe welds within the facilities.

'This issue is confined to low pressure instrumentation and other small bore connections and has no implications for main process piping,' states the company. 'However, as operational safety is paramount, the decision has been taken to perform appropriate remedial works prior to re-starting production. Whilst the work involved is straightforward, winter conditions, which can see temperatures in the region fall as low as –40°C, extend considerably the time required.

'As a result, production into the export pipeline is expected to re-start in the second quarter of 2004, with sales at Novorossiisk later in the same period. BG's total production from Karachaganak in 2004 is now projected to be around 35mn boe. This is around 4mn less than planned and 12mn more than expected production in 2003.

'Production to Orenburg, now running at record levels, is not affected. Production at the level of 120,000 b/d of condensate and 700mn cf/d of sales gas is expected to be maintained throughout the winter period and beyond.

'This delay has no impact on the Group's 2003 production target. The Group's production target for 2006 is also unaffected,' said the company.

In Brief

Europe

A production well with a total measured length of 10,000 metres *is being planned to tap Statoil's Gulltopp discovery in the North Sea – reportedly the longest so far to be drilled by the Norwegian company. Previously known as Dolly, Gulltopp will be produced from the Gullfaks A platform. Recoverable reserves are put at just over 25mn barrels of oil and 500mn cm of gas.*

NAM is reported to have discovered a *new gas field in the Dutch sector of the North Sea, estimated to contain some 5bn cm of gas.*

Norsk Hydro and partners in the *Ormen Lange licence, together with the Langeled joint venture, have submitted the plan for development and operation (PDO) for field development, and the plan for installation and operation (PIO) for the transport system, to the Norwegian Ministry of Petroleum and Energy. Recoverable gas reserves are estimated at 397bn cm of gas and 28.5mn cm of condensate. The field is due onstream in October 2007.*

Eastern Europe

Polish fuel company PKN Orlen is *understood to be planning to buy access to oil and gas fields in 2004, working in close association with gas monopoly PGNiG via their financial involvement in Ukrainian firm Dewon.*

North America

The Princess field in Gulf of Mexico *Mississippi Canyon blocks 765 and 766, has come onstream. Peak production for this initial stage of development is estimated at 55,000 b/d of oil and 110mn cf/d of gas. Total recoverable reserves are put at 175mn boe.*

Talisman Energy plans to spend a *record $2.35bn on exploration and development in 2004.*

US Energy Secretary Spencer Abraham *has stated that the US Government will not stop topping up its strategic petroleum reserve (SPR) despite high oil prices. In early January the US was filling its SPR at a rate of about 100,000 b/d.*

Shell's Habanero field in Garden Banks *block 341 is the fourth subsea development to be tied back to the Auger hub.*

In Brief

Habanero output is forecast to peak at 22,000 b/d of oil and 75mn cf/d of gas by the end of 1Q2004.

***Eni (25%) has announced the start-up** of production from the first of six planned wells on the Medusa field in deepwater Gulf of Mexico. Medusa has reserves of 70mn boe, of which 17.5mn boe are net to Eni.*

***Following the drilling of two successful** exploration wells – Margaree and MarCoh – near the Deep Panuke natural gas field in Nova Scotia. EnCana reports that it has initiated work on a new plan for a potential offshore development at Deep Panuke.*

Middle East

***Five new upstream oil projects are** planned over the next five years, Saudi Aramco's Vice President for New Business Development, Khaled al-Falih, said at a recent industry gathering in London,* writes Stella Zenkovich. *The projects involve the onshore fields of Khursaniya, Nuayyim and Abu Hadriyah and the offshore Manifa field.*

***It is understood that the US considered** using force to seize Middle East oil fields during an oil embargo by Arab states in 1973, according to British Government documents recently made public. It was thought that US airborne troops would seize the oil installations in Saudi Arabia and Kuwait and might even ask the British to do the same in Abu Dhabi.*

***Bahrain's Oil Ministry is planning to** expand production of the Abu Safa field through a $1.2bn investment and to alter the route of the Bahrain-Saudi Arabia oil pipeline at a cost of between $37mn and $76mn, reports* Stella Zenkovich.

***Iraqi oil production was reported to** have risen from 1.9mn b/d in December 2003 to 2.3mn b/d in early January and is forecast to reach 2.5mn b/d by April.*

***Shell is reportedly planning to triple** output from its oil fields offshore Iran to 190,000 b/d by the end of March 2004 following the commissioning of the Sorush and Nowruz fields.*

***Iraq is reported to have invited bids to** drill more than 40 oil wells from international oil companies. A separate*

NEWS Upstream

Xikomba development onstream

ExxonMobil has started production at the Xikomba deepwater development offshore Angola in block 15. Xikomba employs an early production system (EPS) consisting of nine subsea wells tied back to an FPSO vessel. The project is the third deployment of ExxonMobil's EPS technology offshore West Africa and the first EPS offshore Angola.

Xikomba has estimated recoverable resources of 100mn barrels of oil, with a target production of 80,000 b/d.

In addition to Xikomba, ExxonMobil has previously announced two world-class deepwater developments on block 15 that incorporate the company's 'design one–build two' approach, which provides significant time and cost savings. Kizomba A and Kizomba B, both $3.4bn developments, together have estimated recoverable resources of approximately 2bn barrels of oil and a combined target production of 500,000 b/d. First oil from Kizomba A is scheduled for 2004; Kizomba B first oil is expected in early 2006.

First gas from Gunnison Gulf of Mexico field

The Gunnison field in the deepwater Gulf of Mexico achieved first production in early December. The remaining two subsea wells are were due onstream by year-end, with daily production from all three wells expected to reach 5,000 b/d of oil and 125mn cf/d of gas by mid-January 2004. Output is expected to ramp up to a peak daily rate of 30,000 barrels of oil and 180mn cf of gas by year-end 2004 from seven wells.

The Gunnison field covers Garden Banks blocks 667, 668 and 669, with the truss spar facility moored in 3,150 ft of water in block 668. Partners are Kerr-McGee (operator; 50%), Nexen (30%) and Cal Dive International (20%).

The Gunnison spar has daily production capacity of 40,000 barrels of oil and 200mn cf of gas. The facility has been designed with excess capacity to accommodate production from satellite prospects in the area. The Gunnison partners are currently participating in an initial satellite prospect, Dawson Deep.

Ups and downs of UK oil and gas

The latest Royal Bank of Scotland *Oil and Gas Index* (23 December 2003) reports that UK oil and gas production in October reached its highest level in six months, at 3,862,560 boe, although it was down 8.9% on the year.

Commenting on the results, Senior Economist Tony Wood said: 'The improving global economic picture is feeding through to oil demand forecasts, with both Opec and the IEA recently upgrading their forecasts for 2004... Production quotas have remained at current levels, although Opec has highlighted the negative impact of the weakening US dollar. As oil and gas is traded in dollars, the purchasing power of revenues in domestic markets is diminished as the value of the dollar reduces... In addition, there is ongoing concern of over-supply in the spring as a result of Iraqi production coming back to market alongside the growing Russian supply. Taken together the evidence points to quota reductions in the New Year. Our view is that Opec's aim will be to maintain prices at or around the top of their target price range of $22 to $28/b.'

Year Month	Oil production (av. b/d)	Gas production (av. mn cf/d)	Av. oil price ($/b)
Oct 2002	2,301,341	11,165	27.60
Nov	2,001,329	11,803	24.20
Dec	2,353,028	12,582	28.30
Jan 2003	2,274,870	12,890	31.20
Feb	2,215,831	13,599	32.20
Mar	2,251,714	12,420	29.90
Apr	2,092,765	10,868	27.50
May	1,948,620	9,659	25.60
Jun	1,940,265	9,221	27.30
Jul	1,957,888	9,250	28.49
Aug	1,858,409	9,842	29.50
Sept	1,957,226	9,706	26.80
Oct	2,009,036	10,528	26.90

Source: The Royal Bank of Scotland Oil and Gas Index

North Sea oil and gas production

First production from Na Kika project

Shell (50%) and BP (50%) have announced first production from the giant Na Kika project in Mississippi Canyon block 474 in the deepwater Gulf of Mexico. Na Kika consists of five independent fields – Kepler, Ariel, Fourier, Herschel and East Anstey – each of which would be uneconomic to develop on its own. Shell and BP have developed the fields with the installation of a centrally located, permanently-moored semi-submersible floating production facility – reported to be the first time a hub-type system has been used to develop a group of fields all of which are of small to medium size. Initial production from the first well in the development is projected to exceed 100mn cf/d.

The Na Kika semi-submersible production facility is moored in water some 6,300 ft deep, the deepest for any installation of its type in the world. The individual wells are in water depths that range from 5,800 ft to 7,000 ft. The Kepler, Ariel and Herschel fields are primarily oil, while the Fourier and East Anstey fields are primarily gas. A sixth field, Coulomb, which is 100% owned by Shell and located in 7,600 ft of water, will be tied back to the Na Kika host facility as production capacity becomes available. At peak production Na Kika is expected to produce some 110,000 b/d of oil and 425mn cf/d of natural gas. Ultimate recovery from Na Kika is estimated at about 300mn boe.

BP and Shell have also announced the start-up of the 75-mile Na Kika segment of the Okeanos gas gathering system from Na Kika to Main Pass 260, where the gas will be transported to various onshore markets via the BP/Shell Destin pipeline system. Okeanos will transport gas from deepwater discoveries in Mississippi Canyon and the eastern Gulf of Mexico. The Na Kika segment of the Okeanos pipeline system was built by Shell, but is operated by BP.

Shell is the operator for the development phase of the Na Kika project, responsible for the design, fabrication and installation of the floating host facility and subsea production system, as well as the drilling and completion of the ten development wells. BP is the production operator for the project, responsible for the operation of the host facility and the satellite subsea fields.

Seven Heads field produces first gas

The Seven Heads gas field came onstream in December, with production from the five wells expected to reach 60mn cf/d in the near future.

The field lies adjacent to Ireland's largest producing gas field – the Marathon-operated Kinsale field. This proximity to existing infrastructure enabled operator Ramco to develop Seven Heads on a fast-track basis via a subsea pipeline tied back to the Kinsale facilities. The Seven Heads development has achieved production in just nine months from development approval.

It is expected that the Seven Heads field will supply approximately 10–15% of Irish demand for gas in 2004, displacing imports from the UK. Ramco has agreed to sell its share of the field's gas production to Innogy Ireland, and will receive a price in excess of the UK national balancing point price. Proved and probable reserves have been independently assessed at 390bn cf (Ramco's share: 337bn cf).

Ramco has already acquired interests in several other blocks in the Celtic Sea and is planning a seismic work programme for 2004 to assess the potential for the future development of satellite structures, capable of being tied back to the existing infrastructure.

The company recently added to its Celtic Sea acreage with the award of licensing option 03/10 – East Kinsale.

The Seven Heads partners are: Ramco (operator; 86.5%), Island Petroleum Developments (12.5%) and Sunningdale Oils (1%).

Carrack gas field comes onstream

Shell Expro has produced first gas from the Carrack field in the southern North Sea. The £150mn project has been developed around a central 'hub' platform located over the Carrack field, from which three wells will be drilled in 2003/2004, with the capacity for additional wells should they be required. A second smaller platform is installed adjacent to Shell's Sole Pit Clipper platform complex to act as a reception facility for the Carrack gas production. The new platforms will facilitate tie-backs of any future marginal fields in the surrounding area. Similarly, the 85-km Carrack pipeline is suitable to tie-in potential exploration discoveries as well as stranded gas fields along its evacuation route. Carrack has reserves of around 300bn cf of gas. Production is forecast to peak at 160mn cf/d of gas.

In Brief

tender for building three gas separation stations in Kirkuk has also been issued. The planned oil wells are mainly in the south and are intended to replace lost production in the north.

Russia & Central Asia

***Turkmenistan produced 59.09bn cm of** gas in 2003, up 11% from 53.4bn cm in 2002. Exports of Turkmen gas rose 10% to 43.4bn cm.*

***Oil production in Russia in 2003,** including gas condensate, increased 11% year-on-year to reach 421.4mn tonnes, according to the Russian Energy Ministry. Gas production reached 616.4bn cm, up 3.6% year-on-year. Exports of Russian oil through the Transneft system to outside the CIS increased 9% to 149.8mn tonnes.*

***TNK-BP expects to produce 6.9bn cm** of gas, including 3bn cm of associated gas, in 2004 and 17.4bn cm, including 4.1bn cm associated gas, by 2007, according to Gas Director Rashid Nazirov.*

***Gazprom is seeking foreign partners to** help develop the Shtokmanovsk field in the Barents Sea in 2005/2006, with a view to supplying LNG to the US in 2009.*

Asia-Pacific

***South Korea's Daewoo International** (60%) is reported to have found significant gas reserves in block A-1 offshore northwest Myanmar. Initial results indicate that the structure has reserves of between 4tn and 6tn cf and could produce at an average rate of 500,000mn cf/d.*

***Oil production from China's huge** Daqing oil field is expected to continue its slide in 2004, falling 4.3% to 46.3mn tonnes. Output hit a 27-year low in 2003, down to 48.4mn tonnes.*

***Apache has revised upward total** gross recoverable reserves in the John Brookes field area in the Carnarvon Basin offshore Western Australia to approximately 800bn cf, up from 400bn cf, in light of results from a second appraisal well.*

***BHP Billiton (50%) and partner Esso** Australia Resources (50%) have signed an agreement with TXU Electricity for the sale and purchase of 825 PJ of Bass Strait gas from 2004 to 2017.*

In Brief

BG Group is to sell its 50% interest in *the Muturi production sharing contract (PSC) in West Papua, Indonesia, to Mitsui Indonesia Gas for $236mn in cash. BG's interest in the Muturi PSC provides Mitsui with a 10.73% interest in the Tangguh LNG project.*

Truong Son Joint Operating Company *has made an oil discovery in block 46/02 offshore Vietnam. The Song Doc-1X well flowed at 7,300 b/d of 38° API oil.*

Latin America

A referendum will be held on 28 *March 2004 to decide the future of Bolivia's vast natural gas reserves.*

Africa

Shell Nigeria Petroleum Exploration *Company (SNEPCO) is reported to have paid $210mn signature bonus to the Nigerian Government to acquire deep offshore block OPL 245.*

The Indian Government is reported to *have scrapped foreign investment limits for oil exploration, marketing and pipelines in order to further liberalise its hydrocarbon sector.*

Shell and ChevronTexaco are reportedly *holding talks over a possible Nigerian joint venture involving two adjacent deepwater fields that share the same structure. The joint project involves Shell's Bonga South West field, which lies in OML 118, and Chevron's Aparo discovery, which covers nearby exploration blocks OPL 249 and OPL 213.*

China National Petroleum Corporation *(CNPC) has signed an exploration contract with Algeria's state-owned Sonatrach – reportedly the first time that a Chinese company will prospect for oil and gas in Algeria. Under the contract, CNPC will invest about $31mn over the next three years.*

Joint venturers in the Woodside-operated *Chinguetti oil field off the coast of Mauritania in West Africa have declared the discovery commercial and a plan for field development is to soon be presented to the Mauritanian Government for approval. First oil is slated for late 2005–early 2006.*

The latest figures from Nigeria's *Federal Government indicate that the country's crude oil reserves have climbed to 34bn barrels..*

NEWS Upstream

First gas from Sable project's Alma field

ExxonMobil reports that natural gas production has begun at the Alma field, the first Tier 2 production from the Sable project located 125 miles offshore Nova Scotia, Canada. The Alma field is currently producing about 120mn cf/d of gas and 3,000 b/d of condensate and natural gas liquids. With the addition of Alma, average daily production at the Sable project has risen to 500mn cf of gas and 20,000 b/d of associated condensate and natural gas liquids.

The Alma platform is located in 220 ft of water and is connected to the Sable project's Thebaud central processing platform via a 32-mile subsea pipeline.

Tier 1 production from Sable began in late 1999 from three offshore fields – North Triumph, Venture, and Thebaud – and is processed at two onshore facilities in Nova Scotia. Alma is the first Tier 2 field; the second Tier 2 field – South Venture – is currently under development in Halifax and is expected onstream in late 2004.

The Sable project is owned by ExxonMobil Canada (50.8%), Shell Canada (31.3%), Imperial Oil Resources (9%), Pengrowth Corporation & Emera Offshore (pending sale to Pengrowth, due to close mid-December; 8.4%) and Mosbacher Operating (0.5%). Natural gas from the Sable project is transported to markets in the Canadian Maritime Provinces and to the northeastern US via the Maritimes and Northeast Pipeline (ExxonMobil interest: 12.5%).

UKCS investment and development

The UK Offshore Operators' Association (UKOOA) and DTI have published their latest analysis of the investment and development plans of the 29 oil and gas companies currently active in the UK Continental Shelf (UKCS). The report – available at **www.oilandgas.org.uk** – shows that while capital investment in offshore oil and gas developments remains strong, rising unit costs and declining production volumes point to deteriorating economics in the North Sea and the challenge ahead for companies to remain competitive and attractive to future investment.

Key findings are:

- The industry continues to meet investment projections with capex in new offshore developments expected to remain above the joint government/industry Pilot 'vision' of £3bn/y through to 2006. Capex in 2003 was estimated at £3.4bn, with a small increase forecast for 2004 at over £3.5bn. The outlook for overall capex to the end of the decade is also forecast to remain strong, up by 15% on last year's forecast at a total of £18.5bn over the period 2003–2010, albeit with no increase in reserves.
- Opex will remain above £4bn until 2006 (opex in 2003 was estimated at £4.3bn). Unit operating costs will rise by 60% by 2010, based on currently sanctioned development plans. Unit costs can only be held down if currently identified marginal developments can be made economic.
- Despite ten new field development approvals in 2003, forecasts for near-term oil and gas production continue to slip. Volume predictions for 2004 are just over 3.7mn boe/d, down by 280,000 boe/d compared with last year's outlook. Production in 2003 was estimated at just over 4mn boe/d. Industry production plans will develop up to a total of 10bn boe of reserves by 2010, and may develop up to a total of 14bn boe by 2030. The challenge will be to identify ways to find and develop the additional 9–16bn boe in the UKCS not covered by current plans.
- The number of possible future projects is down by around 500mn boe to 4.2bn boe, and is reduced by a further 400bn boe with the government's approval for the Buzzard development in November 2003.

The Pilot intermediary production goal for 2005 of 4mn boe/d is now unlikely to be met, states the report, while the 2010 vision of 3mn boe/d looks increasingly elusive, unless significant new reserves are added over the next two to three years through increased exploration and appraisal activity, improved marginal field economics and incremental investment in brown fields.

Commenting on the report, Steve Harris, UKOOA's Acting Director General, said: 'The estimated shortfall on the Pilot 2010 target is 570,000 boe/d, based on current production trends. To close the gap by the end of the decade, the industry will need to move urgently to explore and bring new discoveries into production within an ever-shortening time-frame. The second vital element will be the contribution of additional reserves recovered from existing fields. Both present considerable economic and geophysical challenges, which can only be overcome through the combined efforts of industry, its supply chain and government.'

Call to scrap Kyoto Protocol

A group of experts from International Policy Network (IPN), a London-based NGO, called on Ministers meeting in Milan for the 9th Conference of Parties to the UN's Framework Convention on Climate Change (FCCC) to scrap the Kyoto Protocol and consider alternative approaches to climate change.

'Environment Ministers and countries have an obligation under international law to consider policies which are consistent with the FCCC,' said Julian Morris, a lawyer and economist and Director of International Policy Network. 'The FCCC requires that action taken to mitigate climate change must be "cost effective, so as to ensure global benefits at lowest possible cost". However, Kyoto is an extremely cost-ineffective way to cope with climate change.'

According to the European Environment Agency, most EU countries will not meet Kyoto targets and need to enact more ambitious mitigation schemes. Yet estimates by many internationally respected economic forecasters show that Kyoto will cause serious economic damage and hundreds of thousands of job losses in European countries by 2010.

'By discouraging economic growth and disproportionately harming Europe's poor, Kyoto will harm Europe's ability to cope with any future effects of global warming,' commented Kendra Okonski, Director of IPN's Sustainable Development Project. 'Ironically, climate policy may expose us to unforeseen risks, and leave us less able to deal with those risks. Future mitigation schemes would cause even more harm to the poorest members of Europe and the world.'

The potential impacts of climate change may not be experienced for several decades. But disease, low agricultural yields, and general vulnerability to climate already affect millions of poor people across the world today. Such problems are exacerbated by poverty, which is largely caused by political instability and institutional corruption. 'Ministers should consider an adaptation strategy to climate change,' says IPN. 'Unlike Kyoto, adaptation considers the people of today as well as future generations, and yields benefits in a cost-effective manner. Adaptation could consist of:

- **Strengthening the institutions that drive economic growth and technological change, both in poor and wealthy countries, to enhance societies' abilities to cope not only with climate change, but adversity in general, regardless of its cause.**
- **Eliminating regulations that discourage economic growth and sustainable use of resources, especially in poor countries, to ensure that individuals, communities and businesses have incentives to achieve sustainable development.**
- **Take no-regrets actions, such as eliminating subsidies to producers and consumers, opening trade, encouraging adoption of more efficient technologies in India and China, and supporting blue-skies research into new technologies by companies.**
- **Invest in the study and understanding of the earth's climate, how humanity impacts the climate, and how climate change may affect humanity and the environment.'**

European energy transit talks suspended

Negotiations among 51 governments on a legally binding international agreement on energy transit issues were suspended at a meeting in Brussels of the Energy Charter Conference on 10 December once it became clear that a unanimous decision to adopt the agreement – known as the Energy Charter Transit Protocol – could not be achieved on the basis of the final compromise text put forward by the Chairman of the Conference, Henning Christophersen.

The Transit Protocol, negotiations on which were launched in 2000, aims to build on the existing transit-related provisions of the Energy Charter Treaty by developing an enhanced set of rules under international law governing energy transit flows across national borders. Agreement was reached on the bulk of the Protocol's text at the end of 2002. There remained only a few outstanding issues to be resolved before the Protocol could be finalised, all of which related to differences in position between the European Union and Russia. Bilateral talks held between these two parties during this year, with the aim of finding solutions to these remaining issues, led to the tabling of a final text for adoption at the meeting on 10 December.

At the conclusion of the meeting, the Conference Chairman issued a statement urging all Contracting Parties and Signatories to the Energy Charter Treaty to be guided by the principles of the draft Transit Protocol when regulating the transit of energy through their territories, pending the Protocol's formal adoption and signature.

In Brief

UK

***The UK Government has announced** 15 new wind farm sites around the UK coastline. Full details of the sites that are proposed can be seen at* **www.crownestate.co.uk**

***Petronas of Malaysia is proposing to** acquire a 30% stake in Dragon LNG, the Petroplus/BG joint venture that is planning to develop an LNG terminal and related facilities in Milford Haven, Wales, UK.*

***Norsk Hydro and German gas transportation** and supply company Wingas are to set up a joint venture for the marketing and sales of natural gas in the UK. The 50:50 joint venture company will be called HydroWingas.*

***An extra £18mn of funding for 16** renewable energy projects across the UK has been approved by the UK Government as part of its £20mn Major Photovoltaic Demonstration Programme.*

Europe

***A private equity syndicate comprising** Candover, European venture capital company 3I; and JPMorgan Partners, has signed a sale and purchase agreement to acquire part of the oil and gas business of ABB for a total $925mn. The new group will be known as Vetco International.*

***Aker Kvaerner has been awarded a** $21mn contract to perform front-end engineering design work for an LNG receiving terminal in the North Adriatic Sea. It will have a storage capacity of 250,000 cm and be capable of regassifying some 6mn t/y of LNG. Partners include ExxonMobil and Qatar Petroleum (45% interest each), and Edison of Italy (10%).*

North America

***ExxonMobil is understood to have** begun the pre-filing process for an LNG import facility in Corpus Christi, Texas. The $600mn Vista del Sol facility will import up to 1bn cf/d. It is due onstream in 2008/2009.*

***ConocoPhillips and TransCanada** Corporation are reported to be planning to build a new LNG receiving and regasification terminal to serve New England in the US.*

In Brief

__ConocoPhillips has signed an agreement__ with Freeport LNG Development to acquire 1bn cf/d of regasification capacity in the proposed LNG receiving terminal in Quintana, Texas, and a 50% interest in the general partner managing the venture. The terminal will be designed with a storage capacity of 6.9bn cf and send-out capacity of 1.5bn cf/d. Commercial start-up is slated for mid-2007.

__BG Group has completed an agreement__ with El Paso Merchant Energy (EPME) to acquire all of EPME's capacity in the Elba Island LNG regasification terminal near Savannah, Georgia, US, and related LNG purchase and gas sale agreements.

__ChevronTexaco has unveiled an $8.5bn__ capital and exploratory spending programme for 2004.

Middle East

__Saudi Aramco has inaugurated its__ Haradh natural gas and oil development project that comprises a gas plant capable of delivering 1.5bn cf/d of sales gas to Saudi Arabia's master gas system and a gas-oil separation plant (GOSP) capable of stabilising 300,000 b/d of crude oil. In addition, Haradh has a design capacity to deliver 170,000 b/d of condensate to Saudi Aramco's Abqaiq processing facility, and can produce 90 t/d of sulphur for export.

__The US has awarded a $1.8bn contract__ to Bechtel and Parsons to help rebuild Iraq's infrastructure. The new, two-year Iraq Infrastructure II deal will spend about $1bn on power projects.

__US advisers and Iraqi oil officials are__ reported to now favour the creation of a state run oil company.

__Qatar Petroleum and ConocoPhillips__ have signed a Statement of Intent regarding the construction of a gas-to-liquids plant in Ras Laffan, Qatar.

Russia & Central Asia

__BP has completed the deal to include__ Alfa Group and Access-Renova's (AAR) 50% interest in Slavneft into TNK-BP.

__Turkey and Greece have formally__ signed an agreement on 23 December 2003 to build a gas pipeline connecting the Middle East to Europe.

NEWS Industry

Industry names in New Years Honours

A number of energy industry personnel were recognised in the 2004 New Year Honours List: Bruce Dingwall, Chief Executive of Venture Production, was awarded a CBE for services to the oil and gas industry in the UK, while Dale Vince, Managing Director, Ecotricity, received a CBE for services to the environment and to the electricity sectors.

MBEs went to David Braithwaite for services to UK-Indonesian relations in the oil and gas sector; Malcolm Fleming, Chief Executive, CDA (a Group Member of the Energy Institute), for services to the UK oil and gas industry; Colin John Goddard for services to the nuclear industry; Robert Henry, Chief Executive, Corgi (EI Group Member), for services to the gas sector; Dr Andrew McCrea (FEI), Manager, Environmental Services, Northern Ireland Electricity, for services to the electricity industry; Colin Partington, Principal Safety Adviser, Sellafield, for services to health and safety in the nuclear industry; Richard Sobey, Director, Exploration and Development, Intrepid Energy North Sea, for services to the UK oil and gas industry; and Dr Anthony White (FEI) for services to UK energy policy.

ChevronTexaco to sell non-core US assets

ChevronTexaco has unveiled plans to sell its interests in additional non-strategic producing properties in the US, re-align strategic business units and evaluate opportunities to divest selected producing and midstream assets in western Canada. The plans are supportive of ChevronTexaco's drive to improve competitive performance and increase operating efficiency in North America. Longer term, the company expects to retain about 400 core fields. The US properties for sale are located in 15 states and the Outer Continental Shelf of the Gulf of Mexico. They represent more than 60% of ChevronTexaco's total US properties but only 5% of daily production. Most of these properties are non-operated joint ventures and royalty-only interests. Canadian assets being considered for divestment consist of mature producing fields and midstream assets in western Canada currently producing 35,000 boe/d. The decision does not affect strategically significant assets, which include the Athabasca oil sands project, MacKenzie Delta gas, East Coast Canada exploration, development and production activities, or the company's refining and marketing operations.

European Union news update

Binding energy conservation targets have been proposed for European Union (EU) Member States by the European Commission, a move that could further tighten fuel economy rules for Europe's transport sector, writes *Keith Nuthall.* Brussels has proposed a general energy saving target of 1%/y from 2006–2012, measured against average energy distribution from the previous five years. All kinds of energy would be taken into account, including natural gas and transport fuels. The 1% savings would take households, agriculture, commercial, public sectors, transport and industry into account.

In other EU news:

- An accord promoting joint research projects on transport air pollution has been struck between the EU, US, Japan and China, to create a global system to measure such emissions. The deal will provide for joint vehicle testing and should lead to the next generation of European emission standards for passenger cars and light vans.
- Meanwhile, additional political pressure will possibly be applied on EU Governments by the Commission to reduce greenhouse gas emissions, given that a Brussels report has concluded the EU will miss its Kyoto Protocol emission targets unless additional anti-pollution measures are taken. The Commission continues to wholeheartedly support the accord, despite doubts it will be ratified thanks to Russia's ambivalent position.
- The Commission has granted competition clearance for Norway's Statoil to purchase a stake in southern Algeria's In Salah gas joint venture, currently controlled by BP and Sonatrach of Algeria. First gas is expected in 2004.
- Commission attempts to secure significant powers over the movement of European gas supplies in a supply emergency have been rejected by the EU's Council of Ministers.
- A European Parliament special investigative committee tasked with improving maritime safety standards has formally asked the Spanish Government to allow the captain of the ill-fated *Prestige* tanker to leave Spain to be questioned by its members.

Liberalising electricity markets

Most International Energy Agency (IEA) countries are liberalising their electricity markets, shifting the responsibility for financing new investment in power generation to private investors. No longer able to automatically pass on costs to consumers and with future prices of electricity uncertain, investors face a much riskier environment for investment in electricity infrastructure. In a bid to provide some practical strategies to help move the liberalisation process forward, the IEA has published two new reports, the first of which – *Power Generation Investment in Electricity Markets* – examines how market forces are reshaping the roles of investors and governments. 'Electricity markets have, in general, encouraged adequate investment,' said Ambassador William C Ramsay at the launch of the book. 'But governments remain concerned about the performance of electricity markets and the reliance on volatile electricity prices to bring forward that investment.' While liberalisation was intended to limit government intervention in the electricity market, volatile electricity prices have put pressure on governments to intervene and limit such prices. This report looks at several cases of volatile prices in IEA countries' electricity markets, and finds that while market prices are a necessary incentive for new investment in peak capacity, government intervention into the market to limit prices may undermine such investment. For investment to thrive, the government's role in electricity market reform needs to be more carefully defined. Its role should include monitoring the level of investment, and being able to respond effectively to threats of market manipulation.

The report looks at how investors have responded to the need to internalise investment risk in power generation. While capital and total costs remain the parameters shaping investment choices, the value of technologies which can be installed quickly and operated flexibly is increasingly appreciated. Investors are also managing risk by greater use of contracting, by acquiring retail businesses, and through mergers with natural gas suppliers.

The second publication, *The Power to Choose – Demand Response in Liberalised Electricity Markets*, draws on the experience of IEA Member countries and demonstrates the benefits of demand response. That is providing electricity users both the incentive and the ability to vary their demand for electricity in response to changes in electricity prices. Electricity markets are inherently volatile. Demand for electricity rises and falls on a daily and seasonal basis and is highly sensitive to weather. Supply has to be continually varied to match these changing demands, and that drives up costs. In extreme cases, where there is not enough supply (or transmission and distribution) capacity, brown-outs or black-outs can occur.

By increasing demand response, price and demand peaks can be clipped and reliability improved. The 'response' involves voluntary changes in consumer behaviour – deferring power demands around the house such as hot water heating, clothes washing and drying, dish-washing, for example, or by reducing demands through installing more efficient air conditioners, heating or lighting systems. In the business sector, demand responses can include deferring demand to off-peak times for systems which store energy, such as freezers, cool rooms, or high-temperature processes such as aluminium smelters. For this to occur, electricity users must have an incentive to change their usage patterns. Often, households and smaller companies have to pay regulated prices which may be fixed for periods of up to a year or more. This, combined with bills that might arrive months after the electricity was used, means that these customers have no incentive to vary their electricity demands at times of peak demand and prices. With demand response, customers will be offered the choice of moving to dynamic tariffs, which typically involve short periods of higher prices (during which consumers are encouraged to reduce consumption) in return for lower prices at other times.

Providing customers actually respond, demand response results in lower electricity costs for consumers. This effect is reinforced by the fact that demand response reduces peak loads and prices, and over time reduces the system-wide costs of generating electricity, and hence average prices. Many electricity distributors and governments may wish to retain the option of offering customers fixed price tariffs. This can be compatible with effective demand response, since only a relatively small percentage of users need to respond in order to have a significant impact on peak prices.

The *Power to Choose* study shows that the economic benefits of demand response are large – between $10bn and $15bn for the US market alone. Given the additional benefits of improved reliability of electricity markets, reduced investments in peak capacity, more efficient energy use and associated reductions in greenhouse gas emissions, the incentive for governments to act to encourage demand response is strong. An electricity market with active demand response is a more efficient market, comments IEA.

In Brief

China National Petroleum Corporation *(CNPC) is to acquire 60% of Russian energy company Stimul in what is claimed to be China's first foray into the Russian energy sector.*

Fluor Corporation has been selected by *Lukoil to build a crude oil and petroleum products export terminal on Vysotsky Island in the Gulf of Finland. Work under the $330mn contract is expected to complete in December 2004.*

Asia-Pacific

India is to establish a 5mn tonne *strategic oil reserve – equivalent to about 15 days of the country's current consumption.*

BP is selling its 2% equity stake in *PetroChina through a book-built placing of the shares on public markets.*

Medco Energi Internasional, Indonesia's *only publicly traded oil company, is reported to have offered A$326mn to acquire Australia's Novus Petroleum.*

BP and BPMIGAS, Indonesia's *Executive Agency for Oil and Gas, have signed a Heads of Agreement with Sempra Energy LNG for the supply of 3.7mn t/y of LNG from Indonesia's Tangguh project over a 15-year period, beginning in 2007. The LNG will be delivered to Sempra's proposed LNG import and re-gasification terminal near Ensenada in Baja California, Mexico.*

Latin America

Terminal de LNG de Altamira S de RL *de CV, a joint venture company owned by Shell and Total, has awarded a consortium comprising Ishikawajima Harima Heavy Industries (IHI) and ICA Fluor the engineering, procurement, construction and commissioning contract for an LNG regasification terminal at the port of Altamira, on Mexico's Gulf coast. The facility is to be commissioned in 2H2006 and will supply 5bn cm/y of gas over 15 years under a contract awarded by Comision Federal de Electricidad (CFE).*

Shell International Gas and Sempra *Energy have unveiled plans to for a 50:50 joint venture to build, own and operate a $600mn LNG receiving terminal in Baja California, Mexico. The terminal will be capable of supplying 1bn cf/d of gas.*

In Brief

UK

A record total of 2.58mn new vehicles *were sold in 2003, a rise of 0.6% on 2002, according to a UK-wide study by the Society of Motor Manufacturers and Traders. Across all car manufacturers, diesel-powered vehicles are continuing to grow in popularity, posting record sales of 704,637 in 2003 – an increase of 16.9% on 2002.*

Stephen Timms, UK Energy Minister, *has announced plans to boost take-up of biomass by producers and power generators. Co-firing under the Renewables Obligation is to be extended to allow longer for an energy crop market to develop.*

Europe

Aker Kvaerner Engineering and *Technology is to perform engineering services for Gassco. The three-year contract includes a possible extension of up to four years. Gassco plays a major role in the operation of the Norwegian gas transportation system, including pipelines, some gas booster platforms and terminals.*

Norsk Hydro has transferred its 25% *share in the Scanraff refinery at Lysekil in Sweden to Preem Petroleum, which already 75%.*

Eastern Europe

ECO, the Hellenic Petroleum sub- *sidiary, is planning to build a 100-strong network of service stations in Bulgaria over the next five years, according to President Georgios Maraitis. The company is also planning to establish a supply base for fuels and motor oils by the end of 2008, writes* Stella Zenkovich.

North America

The Honda Motor Company has *announced plans to introduce a gas-electric hybrid version of its Accord. The V-6 engine on the new Accord version will reportedly provide fuel economy similar to a four-cylinder Civic. Honda already sells two other hybrids, the Insight and the Civic Hybrid. The company also said that it will introduce a Honda-developed fuel cell unit with increased performance and fuel efficiency in 2005 that will be*

NEWS Downstream

EdF/GdF part-privatisation postponed

Electricite de France (EdF) and Gaz de France (GdF), the giant former monopolies, were slated for part-privatisation at the end of 2003. However, the prospect of labour unrest due to vehement opposition from the unions led to yet another postponement. According to independent market analyst Datamonitor, both companies must now to come up with a Plan B, because 'simply waiting around for another year is not an option'.

Following the victory of France's political right in 2003's presidential and parliamentary elections, it was widely assumed the French Government finally had a strong enough mandate to restructure and part-privatise the country's unwieldy electricity and gas industries. This was in anticipation of fully opening the French industrial and commercial (I&C) energy market to competition.

Both companies (especially EdF) have come under increasing pressure from the European Commission because their state ownership is seen to confer an unfair advantage in Europe's liberalised and liberalising energy markets. In particular, the state guarantees that EdF and GdF make it cheaper for them to service commercial debt compared with privately owned rivals.

Over the years EdF has received substantial tax concessions from the French Government which, the EC claims, amounted to unfair subsidies that must now be paid back with interest, totalling €1bn. The state's generous contribution to the companies' pension schemes is also a bone of contention, reports Datamonitor.

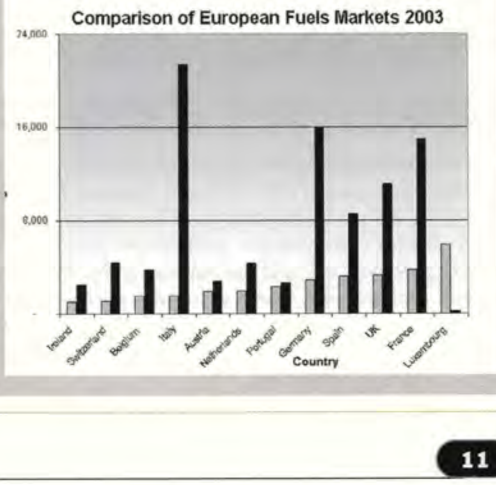
The proposed privatisation has strong support from the companies' management, not least because the status quo hampers their ability to compete both internationally and in France. The Italian Government barred EdF from exercising management rights over Edison, the country's second-largest power company, which EdF part-owns. In France itself, EdF and GdF are legally prevented from crossing over into gas and electricity supply, respectively, whereas their major rivals are increasingly pursuing multi-utility strategies.

France's trade unions rightly fear widespread redundancies and less generous pension arrangements, and have threatened to wreck any attempt at privatisation through nationwide strikes. Clearly, the present right-wing government has no more appetite for confrontation than its socialist predecessor, comments the analyst. Nevertheless, Datamonitor believes that the management will need to implement as many changes as possible under the current ownership structure, starting with trimming the fat and giving up government assistance in return for a relaxation of statutory restrictions on the companies' operations. That way, in a year's time the unions may find that there isn't much left for them that is worth protesting about.

Retail Fuel Throughput: European Comparisons

Catalist maintains comprehensive information on every single retail petrol station in Europe. The chart below is based on Catalist data and shows that the European fuels market is not as cohesive as some may think. The average fuel volume per outlet across the whole of Europe is 2,521 kl/y – but there is a vast range of outlet types, with the smallest selling under 20 kl/y to the largest selling a massive 25,000 kl/y. Average volumes by country range from just over 1,000 kl/y in Ireland to almost 6,000 kl /y in Luxembourg. The marked differences in performance can be linked to a number of factors, not least the level of investment in the market itself. Those countries with higher average volumes benefit from more modern sites offering a range of facilities. In comparison, those with the lowest average volumes suffer from lack of investment and, in the case of Italy in particular, there are simply just too many sites.

Catalist is the leading provider of objective and independent data, modelling and consultancy on retail petrol markets worldwide. For more information visit **www.catalist.com** or telephone +44 (0)117 923 7113.



Study highlights UK gas import problems

With Britain's need to import growing volumes of natural gas, a new report* from the DTI highlights the problems that will be encountered from the varying, but generally higher energy value, foreign gas, writes *Brian Warshaw*. The forecast for imported gas into the UK is 50% within six years, and 90% by 2020.

The report, produced by ILEX Energy Consultancy, analyses the potential sources of imported natural gas from Norway, Holland, Germany and Russia and concludes that most supplies will be above the Wobbe Index upper limit specified in the Gas Safety Management Regulations. Imports will need to be blended offshore or ballasted with a nitrogen injection at the terminal before being supplied to the consumer.

The consumption of LNG is also set to rise and the report anticipates at least three terminals being in use by 2020, providing in excess of 25% of the country's requirements. Although the import quality specifications have still to be determined, the authors forsee a problem with the LNG not exceeding the Wobbe Index upper limit of 51.41 MJ/Sm^3, without breaching Transco's maximum nitrogen content of 5-mol% to gain acceptance into the national distribution pipeline network.

The conclusion reached is that as the mismatch between the UK gas specification and gas availability widens, it could place the country at a disadvantage in the global gas marketplace, resulting in higher prices and less security of supply. Phase II of the study will consider solutions to the problems that have been posed.

The document can be accessed from the DTI website at* **www.dti.gov.uk /energy/domestic_markets/gas_market/index.shtml

Moves to protect Scottish energy subsidy

The UK Government has outlined proposals to protect Scottish energy consumers from large increases in fuel bills following the planned abolition of the hydro benefit subsidy scheme in Scotland. The government had been advised that the benefit is probably discriminatory and contrary to EU law.

Distribution costs in the north of Scotland are significantly higher than any other distribution area – £225 per customer compared to the next highest of £131 per customer. Traditionally consumers there have been protected by the hydro benefit subsidy, which is equivalent to around £40mn/y.

It is now proposed that distribution costs in the north of Scotland should continue to be subsidised at the same level but that that subsidy should be recovered from all suppliers in Great Britain, via their transmission charges paid to the GB System Operator. If the entire costs of this subsidy were passed through to consumers, the average bill may increase by approximately 0.2–0.3%.

Cutting sulphur in US autofuels

ExxonMobil has commissioned new facilities at its Baytown refinery that it claims will reduce the sulphur content of the motor gasoline it produces by 90%. The three-year project included construction of what is reported to be the world's largest SCANfining unit, which uses ExxonMobil's proprietary SCANfining process to selectively remove sulphur from cracked naphtha while minimising the loss of octane in the resulting gasoline.

The new facilities will also allow the refinery to meet the Environmental Protection Agency's (EPA) regulations that go into effect in 2004 for reduced sulphur gasoline. The regulations, mandated as part of the Clean Air Act Amendment of 1990, require refiners to reduce the maximum amount of sulphur in gasoline using a phased-in approach from current levels to 300 ppm in 2004 and 2005, and to 80 ppm in 2006.

Record year in energy trading for IPE

The International Petroleum Exchange (IPE) marked its sixth consecutive record year in 2003, reporting a 9.5% volume increase to 33,341,244 lots. Daily and monthly records were set during the year for all the Exchange's oil and gas futures contracts.

IPE Brent Crude futures volumes increased 12% in 2003, with a total volume of 24,012,969 lots. IPE Gas Oil futures grew 3%, with a total of 8,429,981 contracts traded. Collectively, these volumes represent 30.3bn barrels of crude oil and an underlying value of almost $914bn. The IPE Natural Gas contract, which trades exclusively electronically, grew by 39.6% year-on-year, with a total volume of 815,435 lots during 2003.

In Brief

capable of starting in below-freezing temperatures.

***Petro-Canada has unveiled plans to** upgrade and refine oil sands feedstock at its Edmonton refinery. By reconfiguring the refinery and supplying it with feedstock through an agreement with Suncor Energy, Petro-Canada will effectively process 53,000 b/d of bitumen, providing for existing and future SAGD (steam assisted gravity drainage) production from Petro-Canada's leases.*

***Saudi Refining (SRI), an affiliate of** Saudi Aramco, and Shell Oil Products US have reported that their Motiva Enterprises joint venture has signed a Letter of Interest to sell its 180,000 b/d Delaware City refinery to Premcor for an undisclosed sum.*

***Plains All American Pipeline is to pay** $158mn to acquire for an undisclosed sum Shell's 22% and 76% interests in the Capline and Capwood crude pipeline systems which link the US Gulf Coast with the Midwest.*

Middle East

***The Kuwait Government is reportedly** planning to privatise 120 service stations under buy, operate and transfer (BOT) agreements. Kuwait National Petroleum Company (KNPC) currently owns the sites. Three companies would eventually be formed to operate 40 outlets each. Each of the three companies would be allowed to own 30% of their network, with KNPC retaining 20% and the remaining 50% available for public offer.*

***Saudi Arabia has announced a $4bn** plan to upgrade and transform its 18-year-old Red Sea coast 425,000 b/d Rabigh refinery into a giant petrochemical complex by 2008, reports* Stella Zenkovich.

Asia-Pacific

***BP is to acquire a 35% stake in SK** Power, which is building a new 1,074 MW gas-fired combined cycle power station in Kwangyang Province, South Korea, at a cost of $600mn. Due to commence operations in 2006, the project is reported to be the first privately owned generation facility being developed to compete in Korea's newly liberalised electricity generation industry.*

In Brief

The $3.5bn Papua New Guinea to Australia gas pipeline project is understood to have signed a contract to supply up to 20 PJ/y of gas to WMC Resources for electricity generation at Roxby Downs in South Australia for 20 years, beginning in 2008. It is hoped the deal will make it possible for operator ExxonMobil to move to the engineering and design phase of the pipeline project, which has been struggling to secure enough gas sales contracts to make it economically viable.

Africa

Oil majors are reported to have once again rejected offers from the Nigerian Government to acquire controlling interests in the country's refineries.

Africa's Competition Tribunal is reported to have approved the merger of Sasol Oil and Exel Petroleum, to create what is claimed to be the largest integrated liquid fuels business in southern Africa.

NEWS Downstream

Call to support UK biodiesel market

Green*ergy*, a UK independent supplier of low emission fuels, is calling on the UK Chancellor of the Exchequer to support the development of the UK biodiesel market in response to rising consumer demand by introducing a targeted duty incentive to promote blended biodiesels. Blended biodiesel, containing 5% biodiesel and 95% ultra low sulphur diesel, not only meets the warranty requirements of all major vehicle manufacturers but also delivers improved environmental performance when compared to pure biodiesel, states Green*ergy*. The company recommends that the government introduce a duty rate for 5% biodiesel blends set at 1.4 p/l below the duty on ultra low sulphur diesel – the level at which it believes the correct economic conditions would exist to deliver a fully fledged domestic biodiesel marketplace.

The current duty for biodiesel is 'insufficient to cover the costs of producing quality-tested biodiesel', states Green*ergy*. 'As a result it has promoted production of low-quality biodiesel by small operators – many without the capacity, or expertise, to produce product of a standard acceptable to forecourt retailers, the motor industry and consumers... By making the production of blended biodiesel commercially viable, the government would bring onboard the mainstream suppliers who have the network capacity to make biodiesel blends available to all... Maintaining existing fuel duty incentives on pure biodiesel would also allow small producers to continue to supply end users, or to supply biodiesel as a feedstock for further processing and blending by the mainstream fuels industry.'

Green*ergy* has also called for the UK Government to introduce an objective means of evaluating the emissions impact of various low carbon fuels, the sustainability of the source, and the impact of different feedstocks and technologies on the fuels produced. It proposes using Green*ergy*'s Carbon-Certification process as a basis, which would enable the government to determine the cost-benefit ratio of its duty incentives, and to set and manage a coherent low-carbon transport strategy.

UK Deliveries into Consumption (tonnes)

Products	†Oct 2002	†Oct 2003	†Jan–Oct 2002	†Jan–Oct 2003	% Change
Naphtha/LDF	161,270	191,584	1,149,596	1,884,717	64
ATF – Kerosene	998,778	931,650	8,700,772	8,603,704	–1
Petrol	–	–	–	–	–
of which unleaded	1,594,669	1,578,227	16,222,371	15,648,979	–4
of which Super unleaded	61,128	68,515	486,673	681,551	40
ULSP (ultra low sulfur petrol)	1,533,541	1,509,712	15,735,698	14,967,428	–5
Lead Replacement Petrol (LRP)	32,615	11,800	456,660	171,802	–62
Burning Oil	311,310	369,353	3,025,507	3,070,875	1
Automotive Diesel	1,531,347	1,483,971	14,123,219	14,031,422	–1
Gas/Diesel Oil	514,771	584,838	5,028,729	5,263,795	5
Fuel Oil	157,741	213,122	1,551,329	1,958,757	26
Lubricating Oil	56,955	83,200	673,299	712,921	6
Other Products	699,326	634,237	6,794,808	6,737,858	–1
Total above	6,058,782	6,081,981	57,726,290	58,311,697	1
Refinery Consumption	361,858	414,867	4,093,086	3,750,546	–8
Total all products	6,420,640	6,496,848	61,819,376	62,062,243	0

Products	†Nov 2002	†Nov 2003	†Jan–Nov 2002	†Jan–Nov 2003	% Change
Naphtha/LDF	218,122	211,548	1,367,718	2,096,265	53
ATF – Kerosene	799,352	789,823	9,500,124	9,393,527	–1
Petrol	–	–	–	–	–
of which unleaded	1,606,839	1,480,291	17,829,210	17,129,270	–4
of which Super unleaded	61,957	61,341	548,630	742,892	35
ULSP (ultra low sulfur petrol)	1,544,882	1,418,950	17,280,580	16,386,378	–5
Lead Replacement Petrol (LRP)	31,146	9,867	487,806	181,669	–63
Burning Oil	350,640	361,784	3,376,147	3,432,659	2
Automotive Diesel	1,505,782	1,448,412	15,629,001	15,479,834	–1
Gas/Diesel Oil	505,864	503,085	5,534,593	5,766,880	4
Fuel Oil	206,669	204,461	1,757,998	2,163,218	23
Lubricating Oil	60,032	79,104	733,331	792,025	8
Other Products	631,049	645,643	7,425,857	7,383,501	–1
Total above	5,915,495	5,734,018	63,641,785	64,045,715	1
Refinery Consumption	361,337	445,050	4,454,423	4,195,596	–6
Total all products	6,276,932	6,179,068	68,096,208	68,241,311	0

† Revised with adjustments

All figures provided by the UK Department of Trade and Industry (DTI)

Shell shocked

Following the dramatic announcement of a 3.9mn boe downgrade of Shell's proved reserve base, the consultants *Robert Plummer, Derek Butter and Tom Ellacott* of Wood Mackenzie have produced an analysis of the reserves position of the three supermajors – Shell, BP and ExxonMobil.

On 9 January 2004 Shell unexpectedly announced a large decrease in its stated proved reserve base. Proved reserves as at 31 December 2002 are to be adjusted downwards by a total of 3.9bn boe. This represents 20% of Shell's total reported reserve base at that date. The reserve downgrade is split between 2.7bn barrels of liquids and 7.2tn cf of gas and relates mainly to its Eastern Hemisphere operations. In particular, it relates to the potential Gorgon LNG project in Australia and its Nigerian operations, which together account for around 50% of the total.

- Restating Shell's organic reserve replacement performance over the period 1997–2002 to take account of the downgrade in reserves would lower its overall rate from 105% to 57%. This compares to 116% for ExxonMobil and 152% for BP.
- Correspondingly, Shell's finding and development costs per barrel over the same period have risen from \$4.27/b to \$7.90/b. This compares to \$3.93/b for ExxonMobil and \$3.73/b for BP.
- Shell has also stated that reserve replacement for the calendar year 2003 is again likely to be below 100%, giving an estimated range of 70–90%. This continues its disappointing recent record of organic reserve replacement performance which has seen it average 51% during the previous two years, before any adjustment for the announced downgrades.
- While the reserve reclassification in itself will not affect the operational performance or future growth prospects of Shell, the fact that both reserve replacement ratios and finding and development costs are widely used to benchmark the relative performance of oil and gas companies and the fact that these have now changed so markedly will be cause for concern. Shell's reserve replacement ratio and finding costs per barrel will be significantly impacted and Shell has announced that its FAS69 standardised measure of discounted future cash flows will be reduced by around 10%.
- However, we believe Shell's underlying exploration performance in terms of commercial new field 2p reserves added over the period 1997–2002 has been in line with its peer group. We estimate that Shell added 5.3bn boe versus 5.5bn boe for ExxonMobil and 6.6bn boe for BP. Shell was also one of the top performers in a recent Wood Mackenzie study which examined the value added from exploration over this period.
- There is no indication that a widespread problem exists among the other oil and gas companies. Shell's restated proved reserves ratio to Wood Mackenzie's 2p (proven plus probable) reserve estimate is now in line with its peer group at 1:1.69 compared to 1:1.55 for ExxonMobil and 1:1.66 for BP. There is also no indication of significant gas reserves booked in the Asia-Pacific region by ChevronTexaco (operator of the Gorgon project) during the period indicated by Shell.

We believe that the current situation points to a need for greater transparency in the reporting of reserves. Questions would undoubtedly have been raised at the time concerning the booking of Gorgon reserves had a more detailed breakdown of reserve bookings been available. There is also likely to be a call for third-party certification of reserves given the importance of this area as a proxy for a company's exploration performance.

Peer group comparison

We have restated the overall reserve replacement performance and the finding costs of Shell versus its peers BP and ExxonMobil over the period 1997–2002 adjusting for the recent downgrade. With the reduction of 3.9bn barrels Shell's reserve replacement figure falls from 105% to 57% and its finding and development costs rise from \$4.27/b to \$7.90/b, far below the corresponding performance for BP (152% and \$3.73/b) and ExxonMobil (116% and \$3.93/b).

The reclassification reduces Shell's reserve life based on 2002 production to proved reserves to 10.9 years from 13.6 years. This compares to 12.9 years for BP and 13.3 years for ExxonMobil.

Reserves proved vs probable

The announcement has in no way changed our view of Shell's commercial reserve potential. In **Figure 1** we compare Wood Mackenzie's estimate of 2p (proven plus probable) reserves with the booked proven reserve figure for Shell, ExxonMobil and BP as at 31 December 2002. Removing 3.9bn from the proved category raises the ratio of Shell's proved reserves to the Wood

Mackenzie 2p reserve estimate from 1:1.35 to 1:1.69, a similar ratio to ExxonMobil's 1:1.55 and BP's (including its share of TNK-BP) 1:1.66.

There is little doubt that the reserves under discussion are commercial and will eventually be produced, the reclassification arose due to Shell's original decision to classify these as proven.

Taking the example of Gorgon, it is surprising that reserves from this project were initially booked as long ago as 1997 when a final development decision on the project has yet to be made. Typically for a large potential LNG project such as Gorgon to be classified as proven, final gas sales agreements plus a firm commitment to proceed with the project from the partners would be required. However, we view the Gorgon project as commercial and one of the leading potential LNG projects in the Asia-Pacific region. We would expect a final investment decision to be made in the near term and reserves to be booked at this point.

In Nigeria, again there is little doubt that Shell holds substantial reserves in commercial quantities and, given the appropriate investment, production levels could be raised substantially above their current levels. However, such an expansion would require a substantial increase in Shell's share of Nigeria's Opec quota allocation as well as agreement with its partners that this investment should take place. In the absence of the investment decision being made to develop these reserves on a near term basis, we would again not have expected these reserves to be booked. The reserves nevertheless exist in commercial quantities and will be utilised in the future as Shell and its partners require to develop additional fields to meet its Nigerian quotas.

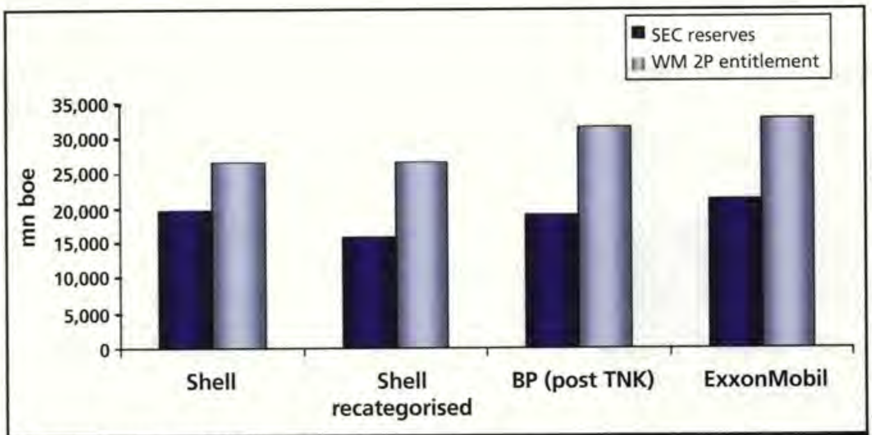


Figure 1: Reserves at 1 January 2003
Source: Wood Mackenzie, company annual reports, Shell press release 9/1/2004

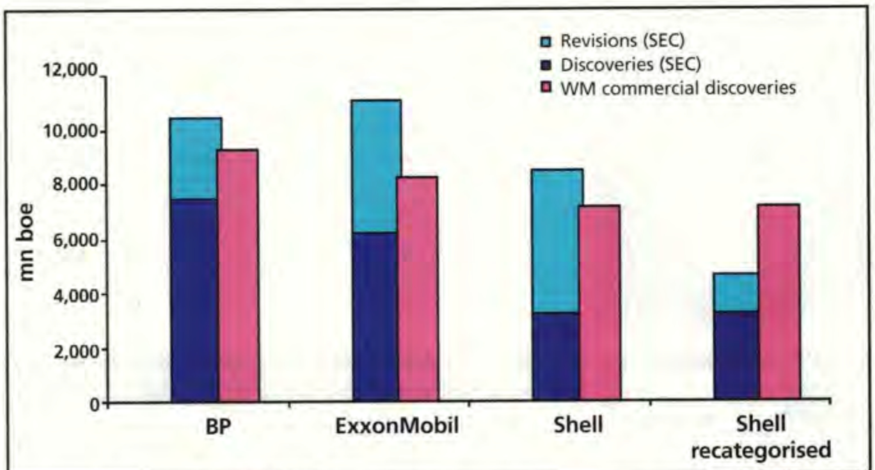


Figure 2: Reserve additions 1997–2002 *Source: Wood Mackenzie estimates, company annual reports*

Real exploration performance

Shell's announcement has highlighted the problem of relying solely on reported oil and gas metrics in assessing a company's underlying exploration performance. The control of reserve booking is largely regulated by the companies themselves and there is little transparency as to which discoveries are being included in the proved category. Shell, for example, reports reserves in only four geographic regions – Europe, other Eastern Hemisphere, US and other Western Hemisphere. In addition, reserve bookings will normally take place over a number of years and in most cases, some time after the initial discovery has taken place. This makes it difficult to assess the exploration performance of a company as it is not clear which reserves have and have not been booked and the period to which they relate.

During the period 1997–2002 Shell's underlying exploration performance has been broadly in line with its peer group adding an estimated 5.9bn boe of commercial new field 2p reserves. In addition, Shell performed well in comparison to its peer group in Wood Mackenzie's recently completed 'Value Creation Through Exploration' study which covered the period 1996–2002. Wood Mackenzie calculated that Shell achieved an overall internal rate of return of 14% on its exploration activities compared to 12% for ExxonMobil and 15% for BP.

Conclusion

While the reserve reclassification in itself will not affect the operational performance or the future growth prospects of Shell, the fact that both reserve replacement ratios and finding and development costs are widely used to benchmark the relative performance of oil and gas companies and the fact that these have now changed so markedly will cause concern. We believe that the current situation points to a need for greater transparency in the reporting of reserves. Questions would undoubtedly have been raised at the time concerning the booking of Gorgon reserves had a more detailed breakdown of reserve bookings been available. There is also likely to be a call for third-party certification of reserves given the importance of this area as a proxy for a company's exploration performance.

This revision highlights the challenges regarding reliance on SEC figures in analysing true exploration performance. While there will undoubtedly be calls to tighten the guidelines attached to booking proved reserves, this is only part of the story. To give a clearer picture of a company's exploration performance investors may call for greater disclosure of 2p reserves to supplement the current information together with a more detailed breakdown of the reserves booked.

More pipeline capacity needed to enable crude exports to expand

One of the major challenges facing Russia's oil industry today is the need for new pipeline capacity to take the country's growing production to international markets. This is important not only for Russia's new role in the world as a reliable and increasingly-important supplier of crude but also for the health of the domestic industry as well, writes *Stephen O'Sullivan*, Head of Oil Research, United Financial Group (UFG), Moscow.

Russian crude production went into sharp decline in the early 1990s as a result of a collapse in capital investment, only bottoming out towards the end of the last decade. However, with the confidence gained through the understandings that were reached between President Putin and the owners of much of Russian industry in July 2000 (as well as a high and stable oil price), Russian oil companies started investing in their own businesses, something they had not been doing. This increase in capital expenditure targeted at the upstream (exploration and production) sector to around $6bn each year has led to a surge in output from 6.1mn b/d in 1999 to a forecast 8.7mn b/d 2004.

This remarkable turnaround has brought many benefits to Russia – a trade balance that is solidly in the black, government revenues that allow the federal budget to be in surplus and GDP growth that is estimated as high as 6% this year. However, Russia's pipeline capacity – operated by Transneft – has not expanded at the same rate and both oil companies and Russia as a whole have performed sub-optimally as a result.

Current capacity

There are currently three major export outlets for Russian crude oil. A major pipeline system goes to the Baltic Sea and the export terminals which are located there. Similarly, pipelines run to the Black Sea and the loading terminals situated around its coast. Finally, the Druzhba pipeline system delivers Russian crude oil into Central Europe and the refineries located there. The Druzhba pipeline was constructed to support the Soviet Union's fraternal allies, exchanging cheap oil for political support. However, the original lines to the Baltic and the Black Sea were constructed in the 1970s to take advantage of the West's willingness to pay high prices for oil in the aftermath of the Yom Kippur War and the Arab oil embargo. They were not originally planned as major export channels, but simply to send crude surplus to the USSR's own requirements to a high-paying market. Over time, of course, as the USSR's troubles deepened, the country came to depend increasingly on hard currency earnings from European crude exports.

With the post-Soviet collapse in oil production (from 10.3mn b/d in 1990 to a low of 6mn b/d in 1996), additional export infrastructure was not top of anyone's list of priorities. However, faced with a combination of very low domestic crude prices and a much reduced ability to pay among Russian consumers, the Russian oil companies of the 1990s realized that their salvation lay in accessing the export market. Indeed, many fortunes were made in the turbulent days of the early 1990s when individuals with access to export capacity acquired low-priced crude within Russia and sent it through the pipelines to export markets.

Exports were a major focus of the Russian oil industry during the first post-Soviet decade. Despite this, little or no capacity was built to accommodate this desire to reach the export market.

Recently, just as the Russian oil industry itself was starting to see the benefits of investing in its business, the pipeline business operated by Transneft also started focusing on expanding capacity. The major project undertaken by Transneft was the construction of the Baltic Pipeline System (BPS), which would take 240,000 b/d from West Siberia and Timan-Pechora to a new export terminal located at Primorsk on the Baltic Sea coast of Russia. Transneft completed this project both successfully and relatively quickly. It commissioned in December 2001 and demonstrated that Transneft was more than capable of responding to the needs of the oil industry.

However, the completion of BPS only solved the problem of the rising demand for export infrastructure temporarily since Russian crude output continued to expand. In 2004 we expect it to rise by 8%, equivalent to some 600,000 b/d of additional oil. Given the nature of Russia's crude market, all of these barrels will be seeking export markets (see **Figure 1**).

Pricing problems

A glance at **Figure 2** will show why the issue of pipeline capacity is such an important one for both Russia and the Russian oil companies. Crude production has only three markets in which it can be sold – the export market, the domestic market or through a refinery where it is converted to products for sale on the export or domestic market.

It is clear that exporting crude is almost invariably the best option for oil producers in Russia, although refining the crude and selling the products often comes a close second. The very worst option is being forced to sell the crude on the domestic market. Not only are netbacks (prices less all the costs and taxes associated with getting the crude to market) for domestic crude much lower than for exports or refining, they are dangerously cyclical in a way that neither of the other two options come close to.

All of this stems from the lack of available pipeline capacity to take crude to market as previously noted. With insufficient pipeline capacity, alternative export routes are pressed into service. Rail and barge are the most commonly-used alternatives. As an example, November 2003 rail exports of crude oil were two-thirds higher against the year-earlier figure, although total exports of refined products in November (90% of which go by rail and barge) were up just 2% respectively against last year. These routes are higher cost, and some Russian oil companies refuse to use them for this reason. While oil prices are at the present high levels, these alternative export routes make sense. However, when prices decline they will be less attractive and their use will fall off – although so should the rate of production growth as lower prices reduce the incentive to invest in such rapid production growth.

However, every export route has its limit and there are many who believe the rail network is approaching capacity. Irrespective of this, there is still not enough capacity to take all the oil that wants to leave the country out to export markets. A surplus of oil in the domestic market pushes prices and netbacks down.

The past two years have seen the emergence of a significant cyclicality in the domestic market, with domestic crude prices falling as low as $5/b during the winter of 2001/2002 and $6/b during 2002/2003,with the second period of low prices lasting far longer than the first. The first period of low prices was caused by the government's decision to support (to some degree at least) Opec's output reductions to stabilize prices after the 9/11 attacks on the United States. Exports through the Transneft pipeline system were constrained for the first two months of 2002, driving domestic crude prices down to the levels seen above, even though the Russian oil companies did all they could to get round the ban, including delivering crude to their CIS refineries and then re-exporting it from there, raising rail exports of crude as well as exports of refined products in general.

The second occurred because of the combination of output continuing to grow faster than pipeline capacity and exceptionally bad weather at all the main loadports. The Baltic had 50-year ice while the Black Sea was disrupted by heavy storms. Together these forced down domestic prices once again and lasted much longer than the 2001/2002 price collapse. (See **Figure 3**).

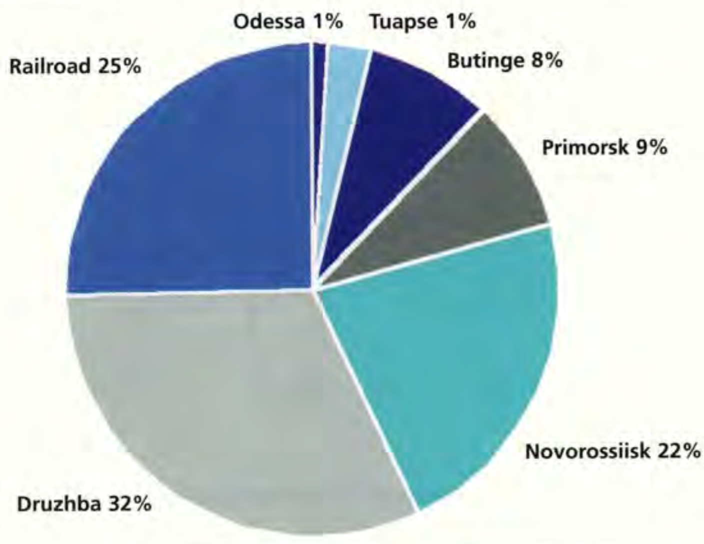


Figure 1: Russian crude routes

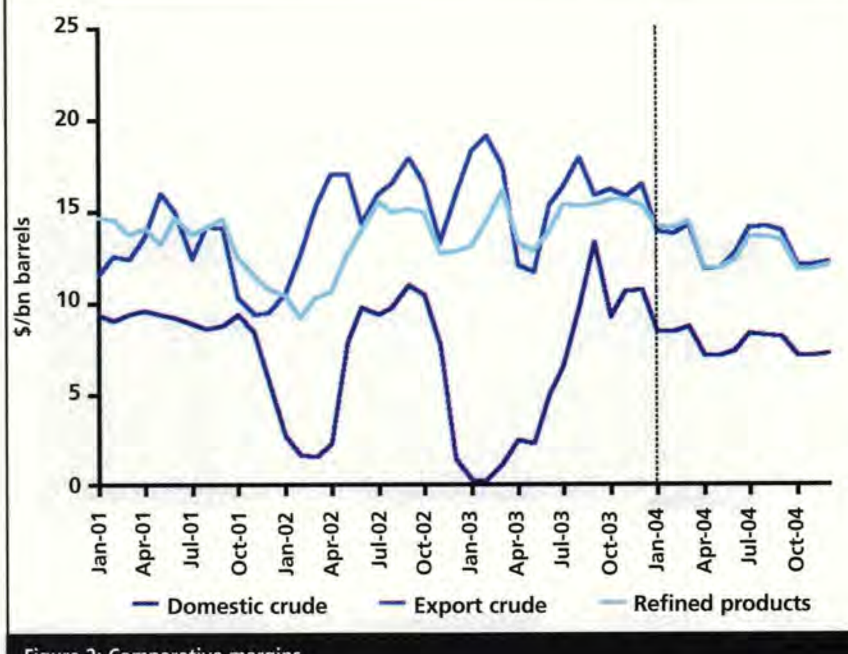


Figure 2: Comparative margins

Two points are worth making here. Firstly, we do not believe that the decision by Russia to suspend pipeline deliveries to Latvia's Ventspils terminal seriously affected the domestic price as some have claimed. **Figure 4** shows deliveries through the Baltic States over the past two years and it is clear that at the same time as pipeline deliveries to Ventspils were being curtailed, exports through the Lithuanian and Russian-owned terminals of Butinge and Primorsk were increasing. That rather supports Transneft's view that the capacity of the one pipeline into the Baltic States can be used to fully load Ventspils or the Lithuanian terminals, but not both of them. The dispute that led to the ending of pipeline deliveries to Ventspils remains unresolved, although Ventspils itself is constructing railcar unloading facilities in order to increase its throughput, which has fallen some 80% against 2002 levels.

The second point worth noting is that, while the integrated companies have been complaining about the lack of export capacity, it has not necessarily affected their earnings. Many of them are very integrated, with a broad balance between their upstream and downstream operations. A low domestic price has the effect of trans-

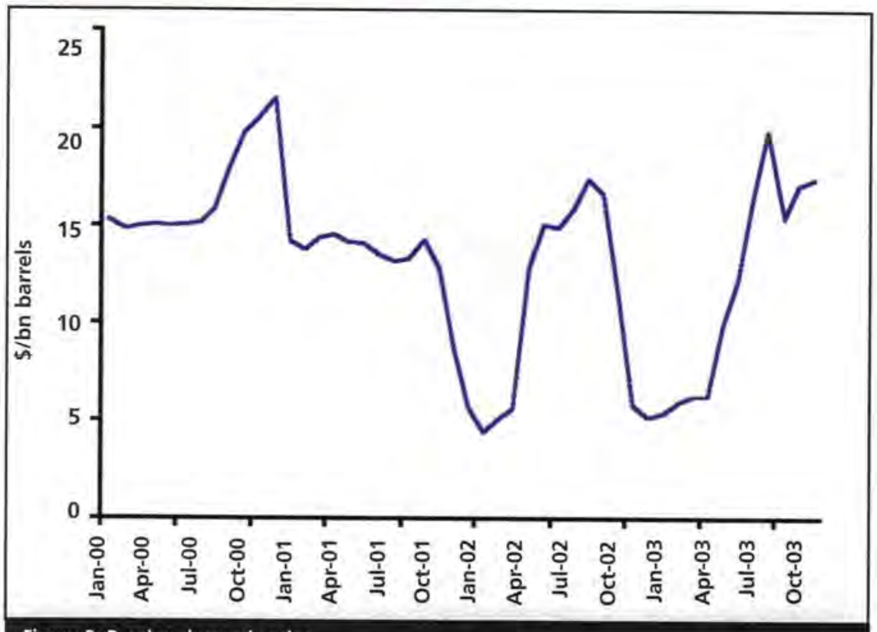


Figure 3: Russian domestic price

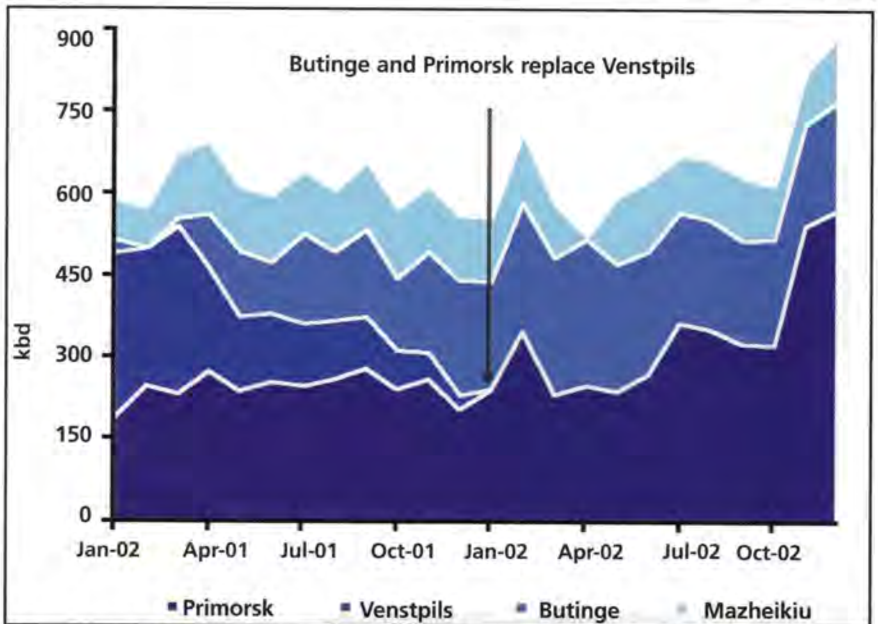


Figure 4: Baltic States' deliveries

ferring profits from the upstream sector (because of the low domestic crude price they sell at) to the downstream sector (which buys crude at the same low domestic price but which does not face serious price competition in the wholesale and retail product market and hence does not see its widening margin eroded). The losers are the pure upstream companies such as Tatneft or Bashneft and even foreign producers such as Marathon's KMOC which has not succeeded in getting access to refining capacity yet.

Future capacity

However, assuming that new capacity is not off the agenda for political reasons, in order to accommodate this output additional export capacity is needed. It remains unclear whether there is the political will to do all that is necessary. President Putin said after a meeting with Transneft President Semyon Vainstock that there was sufficient pipeline capacity to handle all Russian crude production, a statement which seems at odds with Transneft's decisions to sometimes reject deliveries into its pipeline system because of a lack of capacity.

There is a case to be made that the Russian Government would prefer to see the country's oil companies exporting value-added refined products rather than just crude oil, since the latter may create the impression that Russia is nothing more than a commodity producer. To that end, investing in additional crude pipeline capacity aimed at export markets may not have as much support within government as might appear to be the case. If little or no new crude pipeline capacity were to come onstream, oil companies would be forced to increase the volume of domestic refining and sell the products in the domestic or export markets.

Further expansion is underway, however and Transneft added 120,000 b/d of new capacity in July last year when the first stage of the expansion was commissioned. A further 240,000 b/d of capacity was commissioned in late 2003 with the final 240,000 b/d likely to come onstream in May. Primorsk and the pipelines linking the Russian oil fields to it will then have an export capacity of 840,000 b/d, with the potential to expand this to 1mn b/d and even 1.24mn b/d.

There are a range of other projects underway to provide a short-term fix to the problem of rising production and stagnant capacity. The Druzhba pipeline carries Russian oil into the countries of Central Europe, including Hungary. A separate line – Adria – delivers oil to Hungary from the Croatian deepwater port of Omisalj. There is some spare capacity on the Druzhba pipeline since its capacity is greater than current demand in the region.

One project which will expand export capacity is to reverse the Adria pipeline and take oil delivered to Hungary by the Druzhba line out of Hungary down to the Adriatic. This should add 100,000 b/d of capacity to the Russian system. It requires some technical work to reverse the line and install new pumping stations as well as agreement between the various governments in the region. Given the complexity of the pipeline, this project now seems likely to become operational in 2004. There is scope for additional expansion, although the costs mount quite significantly.

One of the major problems facing loadports in the Black Sea during the winter months is bad weather, with strong winds often closing the main loading terminal of Novorossiisk. With only limited storage tank capacity, delays are relatively frequent during the winter. The construction of additional storage at Novorossiisk is expected to provide an additional 50,000–100,000 b/d of capacity.

One idea that started with good intentions appears to have run out of steam. This is the proposal to end the dedicated export of Siberian Light. This is a high-quality crude oil that is around $1/b more valuable than the standard Urals Blend and has in the past been exported as a single stream, primarily through the Black Sea port of Tuapse. However, the volume of Siberian Light production is insufficient to fill the entire pipeline dedicated to its export, which meant that valuable scarce capacity was being wasted. In early 2003 the decision was made to end the segregation of Siberian Light from Urals Blend in order to use the available capacity more efficiently, a move which was estimated to provide additional export capacity of between 380,000–600,000 b/d by the end of that year. However, it appears as if a dedicated Siberian Light export stream continues to be exported and it is uncertain that the additional capacity expected to be freed up by this move has actually become available.

There are two major projects under discussion, both of which have much more significant long-term consequences for Russian oil exports. These are the Asian pipeline and the Murmansk pipeline and terminal. The exact route and destination of the Asian pipeline has been under discussion for some time. There are two competing projects. The first is a pipeline promoted by the pipeline operator Transneft from the existing terminus of the Transneft network at Angarsk to the Pacific coast port of Perevoznaya with the intention of supplying up to 1mn b/d of oil to Japan. Given Japan's almost complete dependence on imported oil, the country's keenness to secure the pipeline is understandable. The country is already potentially able to import oil from Sakhalin Island, where production is building up. However, with consumption of 5.3mn b/d and a reliance on the Middle East for imports, Russian mainland oil is an attractive option.

The second has been a Yukos-promoted project to take oil to China with a pipeline between Angarsk and the Chinese production area of Daqing in the northeast of the country. Initial capacity would be 400,000 b/d by 2005/2006 and this would rise to 600,000 b/d by 2010. Yukos and the Chinese side have already agreed a crude supply deal and the company proposes to dedicate reserves in Eastern Siberia to supplying the pipeline. However, the recent pressure on Yukos following the dispute between its major shareholder Mikhail Khodorkovsky and the Kremlin may mean that this route has lost momentum.

The choice between the two pipelines is essentially a political one, since both have their advantages and disadvantages. The Japanese pipeline is longer and costs more but delivers oil to a port from where it could in theory be shipped to Japan, Taiwan, Korea or China. The Chinese pipeline is shorter and cheaper but places the destiny of Russian oil exports in the hands of the Chinese. It has the advantage of tying the two nations together in energy terms and this may be one of the major drivers on the Russian side, although as we note domestic Russian politics may overwhelm this foreign agenda.

The choice raises one major issue, which is the concept of private sector oil pipelines in Russia, where up until now the vast majority of pipelines have been controlled by Transneft. This is a difficult issue for a government where control (of infrastructure, as well as much else) has been something to be retained. While Transneft may have accepted in public that the Japan pipeline is economically less attractive than the China line, behind the scenes the company cannot be happy that its monopoly control over the country's pipelines is in danger of being eroded.

On the other side of the country, a similar challenge is underway, only this time for a much larger project to take oil to a new terminal at Murmansk on the northern coast of Russia. The total capacity here is initially planned to be between 1.6–2.4mn b/d, although a figure of 3mn b/d has also been mentioned. The Murmansk pipeline is a major expansion of Russia's pipeline infrastructure and has the capacity to change the dynamics of Russian oil exports as well as the domestic market.

The project is promoted by a consortium of five oil companies: Lukoil, Yukos, Sibneft, TNK and Surgut although it was originally conceived by Lukoil as a means to export its Timan-Pechora crude production. The line will be between 2,500–3,600 km long, cost between \$3.5bn–\$4.5bn depending on whether the line goes under or around the White Sea and ought to commission around 2007/2008.

Strategically the project appears to make sense. At a stroke it would add between 1.6–3mn b/d of export capacity to Russia's pipeline network, with a positive impact on domestic oil prices and the country's export earnings. It would diversify Russia's exports away from the present dependence on Europe and provide year-round ice-free access to the steadily-growing US market. Finally it would enable VLCCs to ship crude to the US market rather than the LR1/LR2 vessels that are used for Europe because of the draught restrictions in the Baltic and the Bosphorus. However, once again we sense that the political momentum is lacking on both the Russian and US sides to see the project through at this stage.

Global role

In recent years Russia has been playing an increasingly important role in world oil markets as well as in the global economy and the two developments cannot be separated from each other. The major link between Russia and the rest of the world is oil (and gas) and if the country is to retain its new-found position of influence, Russia needs to expand its oil export capacity to allow it to get this oil to world markets and to improve the health of its oil industry in the domestic market. Those are the economic signals that the market is giving, signals that will only be enhanced by the political desire to diversify oil supplies, wherever possible, away from the volatile Middle East region.

Figure source: UFG Research

Book review – Russia

The Great Transformation: Russia's Return to the World Economy

Russia's growing economy presents 'massive opportunities' for foreign investors across an increasingly diverse range of industries, according to this latest, free report published from Heriot-Watt University's Centre for Economic Reform and Transformation. The two authors, Professors Mark Schaffer and Paul Hare, do not expect foreign investment to be put off by the Yukos affair, which they believe is 'essentially a domestic quarrel'. Whilst they believe it demonstrates that the implementation of business law and regulation in Russia still falls short of Western standards, the report argues that taken as a whole the 'existing business conditions are fair and getting better' for larger firms and foreign investors. Indeed, they suggest that rather than being a deterrent, the Yukos affair may in fact present opportunities for foreign investors if Russia's oligarchs respond by 'cashing out'.

Economic prospects for Russia are better now than they have been at any time since the transition to a market-type economy, exemplified by Moody's decision to upgrade Russia to investment status. Structural change in Russia has been more substantial than is often appreciated and market-type reforms have regained renewed momentum under President Putin. This is expected to underpin higher levels of foreign investment in the years ahead. The paper recognises, however, that there remain significant shortcomings in the business environment. These are driven more by poor enforcement than inadequacies of the legal framework, and need to be addressed as Russia's reform programme advances.

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Lukoil – Modern financial systems to promote value

Over the last five years Lukoil Overseas Holding has become the second largest company in terms of production (89.2mn boe) among Lukoil's affiliated subsidiaries and the one with the fastest production growth. In 2002, the overseas part grew production by 6.29mn boe, or 25% of Lukoil's total production growth. In the future, international projects are expected to increase to 12% of Lukoil's total production, while the adoption of the latest financial analysis will increase the value of the company, writes *Oktay Movsumov*, Vice President, Lukoil Overseas Holding.

Lukoil's foreign upstream assets are playing an increasingly important role in the valuation of the company by investors and analysts (see *Petroleum Review*, November 2003).

Lukoil Overseas Holding is Lukoil's operator for foreign hydrocarbon exploration and production. The company's portfolio currently includes 12 international projects located in Azerbaijan, Kazakhstan, Egypt, Iran, Iraq and Columbia. Lukoil operates seven of these projects, all of which meet the high technological demands and rate of return targets set by the company.

In 2002 the average well production rate at Karachaganak (Kazakhstan) was 3,124 boe/d, with 727.8 boe/d at WEEM (Egypt) and 324 boe/d at Kumkol (Kazakhstan). The lifting costs were \$1.3/boe, \$2.3/boe and \$1.25/boe, respectively. The profit of Lukoil Overseas earned on existing international projects was \$4.52/boe in 2002.

Seismic vessel in north Caspian waters

Value reporting

Lukoil's management is focussed on increasing the value of the company. To achieve this executives are implementing a value management concept aimed at improving the system for making strategic and operating decisions at all levels. Within the framework of these decisions a transfer is being made to 'value reporting'. Under value reporting a system of factors is established which can be influenced to achieve value growth.

The system represents a set of performance indicators of the company and its units, which are detailed for each management level. Here we assess both external value factors, which are beyond the influence of the management of the company, and internal factors associated with the management's actions and specific features of the industry in which the company is operating. Another classification of value factors, which describes their current performance is the economic value added (EVA), and future potential is characterised by real option value (ROV).

Growth of EVA requires that management address objectives such as:

- improvement of return on capital,
- optimisation of the amount of capital employed, and
- reduction of cost of capital (WACC), and ROV growth requires seeking strategic flexibility and management of uncertainty factors.

A whole range of actions are designed to reduce costs, increase return on invested funds, improve portfolio management, effect efficient cash management, arrange access to cheaper financing, improve forecast modelling based on the financial and economic model, and work with investors and creditors to address the objectives associated with growth of EVA. Simultaneously, the company has improved the reports provided to shareholders, investors and analysts, which are based on transparency and disclosure of information through the prism of value. As a result the company succeeded in closing 2002 with the return on average capital employed (ROAC) at 14.4% and reducing production costs by 5%.

Software

In order to improve ROV the company has developed a pilot project using the real options method to one of Lukoil's foreign projects based on 'FlexAble' software. Preliminary results of the analysis performed have shown that from the real options aspect the project under review has the potential to grow by 40%. This method is used in the petroleum industry to identify opportunities characterised as manageable risks, evaluate these opportunities and create schemes to provide an acceptable rate of return on invested capital. Data from real options allows the company to improve traditional approaches to analysis. By adding real options to such methods as discounted cash flow (DCF), decision tree and probabilistic modelling it will be in better position to realistically assess the investment opportunities offered by a project.

A system of key performance indicators (KPI) is being introduced in Lukoil

Overseas to manage value and compare performance with the KPIs of competing companies, as well as to support the personnel motivation system. A total of 25 operating, financial and other indicators have been adopted in Lukoil Overseas to ensure successful implementation of a set of operational and strategic objectives and to improve returns to shareholders. Among these indicators are production volume, ROACE, per unit operating and G&A (general and admin) costs, and finally investment in professional development of personnel.

Incentives

Working together with the Hay Group and consulting firm PricewaterhouseCoopers a system of material and non-material incentives was developed and implemented. The system takes into account best practise by international companies in the energy sector.

Another integral part of the value management system is the corporate risk management system (CRMS). Its implementation is designed to improve the efficiency of the company's activities by addressing the following objectives: effective allocation of capital taking into account the risk/return balance; reduction of profit volatility; reduction of probability of unforeseen losses; improvement of financial sustainability; objective assessment of investment projects with a high level of uncertainty, etc. A unified risk register database has been set up for this purpose. Levels of risks acceptable for the company have been identified and actions prepared to reduce these risks. At the moment several elements of the risk management system have already been implemented in the company – modelling of the impact of market risks (prices on hydrocarbons, interest rates, exchange rates) and a strategy to adopt objective decisions regarding hedging of market risks.

Portfolio approach

In addition, a project management system is in effect in Lukoil Overseas, covering both the acquisition and operational phases. A decision-making mechanism for the changing composition of the company's assets and project management based on a portfolio approach is in the process of implementation. Trials of the TERASTM integrated financial and economic modelling system, which allows quantitative project and portfolio risk management to be addressed, are planned.

An example is the joint Russian-Kazakh project for oil exploration and production in two areas of the Kazakh sector of the Caspian Sea. The purpose of this project, called 'Dostyk', or 'Friendship', is to develop the Tyub-Karagan and Atyshskaya oil fields (see box).

The probability of hydrocarbons' discovery on the contracted territory of Tyub-Karagan is high. A production sharing agreement (PSA) has been signed, envisaging both exploration and production of crude. The Atashskaya block requires additional geological studies and only an exploration contract has been signed so far.

The exploration activities will be carried out in phases. For instance, the drilling stage might be undertaken in 2004. However, a lot will depend on the ice condition of the northern part of the Caspian where Tyub-Karagan and Atyshskaya are situated, which becomes frozen in winter. If the drilling work, planned for the second half of 2004, fails to be done before the 'icy season', the work will have to be postponed until 2005. The exact exploration drilling programme will be determined by the end of 2004.

If commercial reserves of hydrocarbons are found, the next step will be to drill the delineation wells. Based on the results the involved parties will decide whether to proceed with full development.

In total our forecast of the potential recoverable oil reserves contained in Tyub-Karagan structure are around 100mn toe (750mn boe). For Atashskaya, however, estimation of reserves is difficult because of the absence of detailed seismic study data (see box).

Until commercial reserves are discovered all the risks and expenses on geological exploration will be covered by Lukoil. But after the actual discovery of commercial hydrocarbons, all expenses will be equally shared between the parties. Such practice is standard on international offshore projects. The total amount of capital expenditure to be invested by the both parties for the implementation of Dostyk project is projected to be as high as $3bn.

Go-ahead for Caspian projects

Andrey Kuzyaev, the President of Lukoil Overseas, and Bakhytzhan Khasanov, General Director of KazMunaiTeniz, recently signed in Astana, capital of the Republic of Kazakhstan, a joint operating agreement on the Tyub-Karagan offshore project in the Kazakh sector of the Caspian Sea.

The concluded agreement further develops the base documents on the Tyub-Karagan and Atashsky projects signed by the managers of the parent companies – Vagit Alekperov and Uzakbay Karabalin – on 9 January 2004, during an official visit by President of Russia, Vladimir Putin, to Kazakhstan.

Operating companies are to be established for implementation of both projects on a parity basis in Western Kazakhstan.

Representatives of KazMunaiTeniz will manage the companies during the exploration phase. In the event of the commercial discovery of hydrocarbons, managers of the companies will be appointed by the parties on a rotation basis every two years.

Tyub-Karagan block

The block is located 40 km west of the Tyub-Karagan peninsula. Water depth is 7–12 metres. A structure of the same name has been identified on the block. Forecast in-place reserves amount to 388mn toe, including 324.3 mn tonnes of oil. The minimum exploration programme starting from 2004 includes a seismic survey (655 line-km) and drilling of an exploration well. The probability of hydrocarbon discovery is estimated to be high. Commercial discovery of hydrocarbons may be made in 2005.

Production will start in 2012. The maximum annual production is estimated at 7.2mn tonnes with cumulative production by the end of the contractual period reaching 110mn tonnes of oil and 19.1mn cm of gas. There will be 83 production wells, including 79 oil and four gas wells.

The main field facilities are a central processing platform, six block conductors, a compressor plant, subsea multiphase pipelines, an export oil pipeline, an export gas pipeline and the onshore terminal.

A production sharing agreement (PSA) has been signed for a period of 40 years.

Atashsky block

Water depth is 7–35 metres. Three structures – Atashskaya, Maral and Kazakhstan – identified on the block. Forecast geological resources amount to 248.8mn toe, including 141.7mn tonnes of oil. The minimum exploration programme starting from 2004 includes seismic surveys (1,057 km) and drilling of an exploration well.

The base project document is a three-year exploration contract with an option to extend it for four more years. In the event of discovery of commercial oil reserves, the contractor will have a priority right to negotiate the production contract on the prospective fields with the Authority of the Republic of Kazakhstan.

Targeting Russian reserves

Continuing our series of articles analysing some of the smaller and intermediate oil and gas companies from around the world – based on information supplied by *Online-Data – we take a closer look at the activities of *Sibir Energy*.**

Sibir Energy is an independent UK oil and gas production company that is listed on the Alternative Investment Market of the London Stock Exchange. It focuses purely on the Russian market, with 100% of its reserves and crude oil production based in the oil-rich Khanty Mansiysk region of Western Siberia. Sibir's reserves base comprises the Yuzhnoye oil field and the Salym and Priobskoye group of fields – as at 30 June 2003 Sibir's attributable oil and gas reserves from these assets amounted to 1.4bn barrels.

Interim highlights

In its 2003 Interim Report, Sibir reported on two decisive 'breakthroughs'. First, the decision by both Sibir and Shell to proceed with the development of the Salym fields and their large reserve of oil. Second, the formation of Moscow Oil and Gas Company (MOGC) and fulfillment of the capitalisation obligations by both Sibir and the city of Moscow in respect of MOGC. Future plans include the proposed acquisition by MOGC of 25% of BP's retail network in Moscow.

Both these developments have helped Sibir achieve its principal growth objectives and have established it as a fully integrated oil company participating in the full value chain of the Russian oil industry, in particular playing an influential role in the expanding Moscow fuel market. As a result, Sibir forecasts that the attributable turnover arising out of its activities in Russia will increase from £22mn in 2002 to over £150mn in 2004.

Field developments

Sibir's Magma subsidiary is the licence holder and 100% owner of the Yuzhnoye oil field, which is currently producing 5,000 b/d from 32 oil wells. An $8mn facilities development programme to improve oil processing, water injection and accommodation facilities in the field will be completed by mid-2004. The programme is expected to increase sales volumes to 6,500 b/d. It is not planned to drill any new wells until 2Q2004.

Sibir's interest in the Salym group of fields is held through its subsidiary Evikhon's 50% interest in Salym Petroleum Development (SPD), a Dutch-registered 50:50 joint venture between Evikhon (82% owned by Sibir) and Shell. SPD is the holder of the field licences and has allocated a budget of $1bn for the development of the three fields – West Salym, Upper Salym and Vadelyp. Upper Salym, the smallest of the fields, is already in production, operated and funded by Sibir. First oil from West Salym is expected by the end of 2005, with production forecast to peak at 120,000 b/d in 2009. Oil will be evacuated via a tie-back to the existing Transneft pipeline system. Vadelyp will be developed following the start of production from West Salym.

Sibir is also involved in the development of the Priobskoye groups of fields – South Priobskoye and Palyanovskoye – which comprise a combined working interest of approximately 1.3bn barrels of oil. These assets are operated and funded in whole or in part (depending on the oil price) by co-venturers Shell and Sibneft. Current production under Phase 1 of development is in excess of 12,000 b/d. Peak production is forecast to be 16mn b/y in 2006. Under Phase 2 of the programme some 204 wells will be drilled between 2004 and 2006, ramping peak production up to 24.1mn b/y by 2008.

Western/Russian partnerships

It is well accepted by foreign companies working in Russia that success depends to a large extent on the quality of their Russian partners. Sibir believes that not only is it essential to have strong and enlightened Russian partners, it is also vital to have them sharing the same risks and enjoying the same successes.

Over 40% of the shares of Sibir are in the hands of Russian shareholders. In this way Sibir has insulated itself from the biggest risk of doing business in Russia, namely partner risk. Sibir's Russian shareholders have played a major role in planning and progressing the expansion plans of the company.

Sibir is now looking to acquire additional upstream interests, including some low-risk exploration interests. Although it plans primarily to expand its upstream activities in its core area of the Khanty Mansiysk region, the company does not exclude expansion elsewhere in Russia or the former CIS.

Visit **www.oilvoice.com** to view over 300 continually updated oil company profiles or contact Chris Pettit on e: **cp@online-data.co.uk**

For more information about Sibir Energy, visit **www.sibirenergy.com**

Source: Sibir Energy

Figure 1: Area of operations — Khanty-Mansiysk Okrug in Western Siberia

EU membership benefits for Eastern Europe's energy companies

Eight Eastern European countries are due to join the European Union (EU) in May 2004, followed by two more in 2007. This should create many opportunities for energy companies in the new member states; but the companies most likely to benefit look like being those from the applicant countries themselves. *Dr Paul McDonald*, Managing Director of Pearl Oil, an oil and energy consultancy based in the UK and Hong Kong, reports.

The first wave of applicant countries consists of the Czech Republic, Estonia, Hungary, Latvia, Lithuania, Poland, Slovakia and Slovenia. None of these is an oil producer of any note. Their oil production amounts to no more than 60,000 b/d, of which about half comes from Hungary. Consumption totals 900,000 b/d, of which Poland makes up over 40%. All eight used to rely on the Soviet Union for imports of oil and other fuels. In recent years, most have tried to reduce their dependence on their eastern neighbour, but Russia remains the dominant supplier of both oil and natural gas (see **Table 1** and **Table 2**).

The story has been rather different in other parts of the energy industry. As part of the process of applying for EU membership, Eastern European countries have begun both to privatise their state-owned oil, gas and electricity companies, and open up their energy markets to competition. This, in turn, has moved them away from the Soviet-style command economy towards a more liberal, western economic regime and helped them in attracting considerable investment from Western European, Russian and American companies. This process is set to continue with the gradual adoption of the single energy market now being developed across the EU.

Country	Oil consumption ('000 b/d)	Import dependence (%)	Russian share of crude oil imports (%)
2004 applicants			
Czech Republic	170	95	58
Hungary	140	77	99
Poland	380	96	96
Others*	210	98	72
2007 applicants			
Bulgaria	90	99	8
Romania	200	39	55

* *Estonia, Latvia, Lithuania, Slovakia and Slovenia*

Source: World Oil Trade, *Blackwell Publishing, 2003*; Oil and Energy Trends Annual Statistical Review, 2003

Table 1: Eastern European oil balances, 2002

Traditional influences

Much of the interest in the liberalising energy markets of Eastern Europe has come from Europe, especially from countries with historic ties to the region, such as Austria and Germany, along with Russia, which is particularly anxious not to lose its influence in its former satellites. Russian companies have shown particular interest in Bulgaria, Romania and the three Baltic states of Latvia, Lithuania and Estonia. Perhaps the most significant consequence of energy liberalisation, though, has been the desire of companies within Eastern Europe itself to extend their operations beyond their home markets into those of their near neighbours. In most cases this is a result of market reforms instigated mainly as a result of the EU membership process, which have ended energy monopolies across the region. One of the most active of these former monopolies now moving into nearby markets is the former state oil and gas company of Hungary, Mol.

Austria vs Hungary

Hungary, at 140,000 b/d, is one of the largest oil markets in Eastern Europe as well as being the second largest gas market, with a consumption of 1.2bn cf/d. The oil market has been gradually liberalised since the mid-1990s, when the state also began to sell off its shareholdings in Mol, leaving it now with only a minority stake. In June 2003 a law was passed to open Hungary's tightly regulated gas market to competition as part of the EU accession process. Faced with loss of its privileged position at home, Mol began a process of expansion during the 1990s into markets in Eastern Europe that were themselves opening up to competition. In 2002 it made its largest foreign move so far, with the purchase of 70% of the Slovakian downstream company Slovnaft, which owns Slovakia's sole refinery, the 115,000 b/d unit at Bratislava, and dominates the wholesale and retail fuel markets there. Mol also owns 25% of the Croatian refiner and pipeline operator Ina. These two deals give Mol 40% of the retail fuels market in Slovakia and 60% of the

Polski Koncern Naftowy (PKN) Orlen is the biggest company in the Polish refining sector. It is among the top 20 largest world refineries and is one of the top 10 most modern refineries in Europe. PKN Orlen manages a network of over 1,900 petrol stations in Poland with a further 500 in north-west Germany.

Croatian market, in addition to its 44% share of Hungary's retail market.

Another result of oil market deregulation in Hungary was the entry of Austria's former state company OMV – first as a gasoline retailer and then as an investor in Mol, with around 9% of the company's equity. Hungary was the start of a series of forays by OMV into the downstream markets of Eastern Europe. It has since opened service stations in the Czech Republic, Slovakia, Slovenia, Romania and Bulgaria, as well as acquiring 25% of refiner Rompetrol, which owns the 105,000 b/d Midia refinery, Romania's largest. OMV is now the third largest petroleum retailer in Hungary, after Mol and Shell, following its purchase in 2003 of 55 Aral service stations from Deutsche BP. Under the deal, OMV also obtained a further 11 retail sites in Slovakia.

OMV appeared to be trying at first to form a strategic partnership with Mol in its bid to establish a major presence across Eastern Europe, but the Hungarian company has latterly been acting more like a rival to its Austrian shareholder rather than a partner. Last year, Mol outbid OMV to obtain a 25% stake in Ina and, two years earlier, the two competed unsuccessfully to acquire a stake in Poland's refining and petrochemical company PKN Orlen. Mol and OMV currently have rival bids for a 51% stake in the partially privatised Romanian refining and marketing company Petrom. At the end of 2003 Mol even announced that it was proposing to expand in OMV's home base of Austria.

Strategic alliances?

Mol is nevertheless not completely against the idea of a strategic alliance as a way of expanding in Eastern Europe. Late in 2003 it signed a memorandum of understanding with PKN Orlen, paving the way for what could be Eastern Europe's biggest energy merger. The structure of the new company is not yet clear and would require the agreement not only of the two companies but also their respective governments. One option under discussion is for each firm to take a shareholding of up to 15% in the other and then for them to establish a joint venture to make acquisitions and run the operations outside Poland and Hungary. Petrom is likely to be the subject of an early joint bid by the two companies, and this could be followed by a further bid for the 63% government shareholding in the Czech refiner Unipetrol early in 2004.

The Polish Government, having once been hostile to the sale of PKN Orlen shares to Mol, is now supporting the union; no doubt hoping it will raise the value of its remaining 28% shareholding in PKN Orlen. It is probably also anxious to prevent PKN Orlen from falling into the hands of one of Russia's large energy companies. The thinking in both Warsaw and Budapest is that Eastern European companies need to approach the size of some of their western rivals if they are to expand and compete successfully in the region.

The Russians are coming

Several Russian energy companies see considerable benefits for themselves in Eastern Europe's EU membership and are not being slow to take advantage of the more liberal business conditions in the applicant states. The Baltic states, Bulgaria and Romania, have attracted most attention. Two Russian oil firms, Lukoil and Yukos, competed to buy the 33% of Lithuania's 263,000 b/d Mazeikiai refinery owned by Williams International, when the US energy merchant was forced by financial difficulties to sell its shareholding – Yukos being the eventual winner. Lukoil owns petrol stations together with refinery shareholdings in both Bulgaria and Romania. Yukos, which owns 49% of the Adria pipeline linking Eastern Europe to the Adriatic, is to join OMV in building a crude oil pipeline connecting Austria and Slovakia. Meanwhile, gas giant Gazprom has announced its intention to join the list of those bidding for Petrom.

Gazprom also joined Ruhrgas and Gaz de France (GdF) in taking a 49% stake in the Slovak state gas utility SPP. Slovakia has been one of the most enthusiastic of the accession states in liberalising its energy markets, having opened both its gas and electricity markets to competition. These industries are likely to attract foreign participation, particularly for gas-to-power schemes. Gas and electricity are of particular interest to Russian companies, which are likely to feature heavily as bidders in the privatisation of Bulgaria's seven electricity distribution companies, which is planned as part of

continued on p36...

Country	Gas consumption (mn cf/d)	Import dependence (%)	Russian share of gas imports (%)
2004 applicants			
Czech Republic	861	99	73
Hungary	1,151	74	87
Poland	1,083	64	92
Slovakia	735	97	100
Others*	500	100	92
2007 applicants			
Bulgaria	280	98	100
Romania	1,683	38	95

* *Estonia, Latvia, Lithuania and Slovenia*

Source: Oil and Energy Trends Annual Statistical Review, 2003; BP Statistical Review of World Energy, 2003; *US Department of Energy, Energy Information Administration;* Pravda *(various).*

Table 2: Eastern European gas balances, 2002

Sakhalin projects launch new offshore province

The Russian Far East is rapidly developing into one of the new frontiers in the offshore industry and is destined to become a new source of energy for the Pacific region – Japan, South Korea, China and Taiwan, countries where demand for oil, and especially gas, is increasing steadily – as well as for Russia itself and for the US, writes *Neil Potter*.

The Molikpaq (PA-A) platform

A world-class oil and gas province is being opened up in the shallow waters, 15–32 metres, off Sakhalin Island, which lies just 40 km north of the tip of Japan.

Two major projects are currently underway and will be the foundation of growth from 2006–2007. They are the $4bn, Phase 1 of the ExxonMobil-operated Sakhalin 1 project and the $9.5bn Shell-operated Sakhalin 2, Phase 2.

Climatic conditions offshore Sakhalin Island are extremely challenging for the industry – severe winters with temperatures of –50°C, heavy snowstorms, sea ice for six months of the year, high seas and strong currents as well as typhoons and heavy rainfall. And, as if this was not enough, the area is also subject to severe seismic shocks.

Much of the island's infrastructure, which was in a poor state, has had to be upgraded – bridges, roads, railways, ports and airports, to cope with the requirements during the development phases, at a cost of more than $250mn.

The $1.6bn first phase of Sakhalin 2 (The Sakhalin Energy Investment

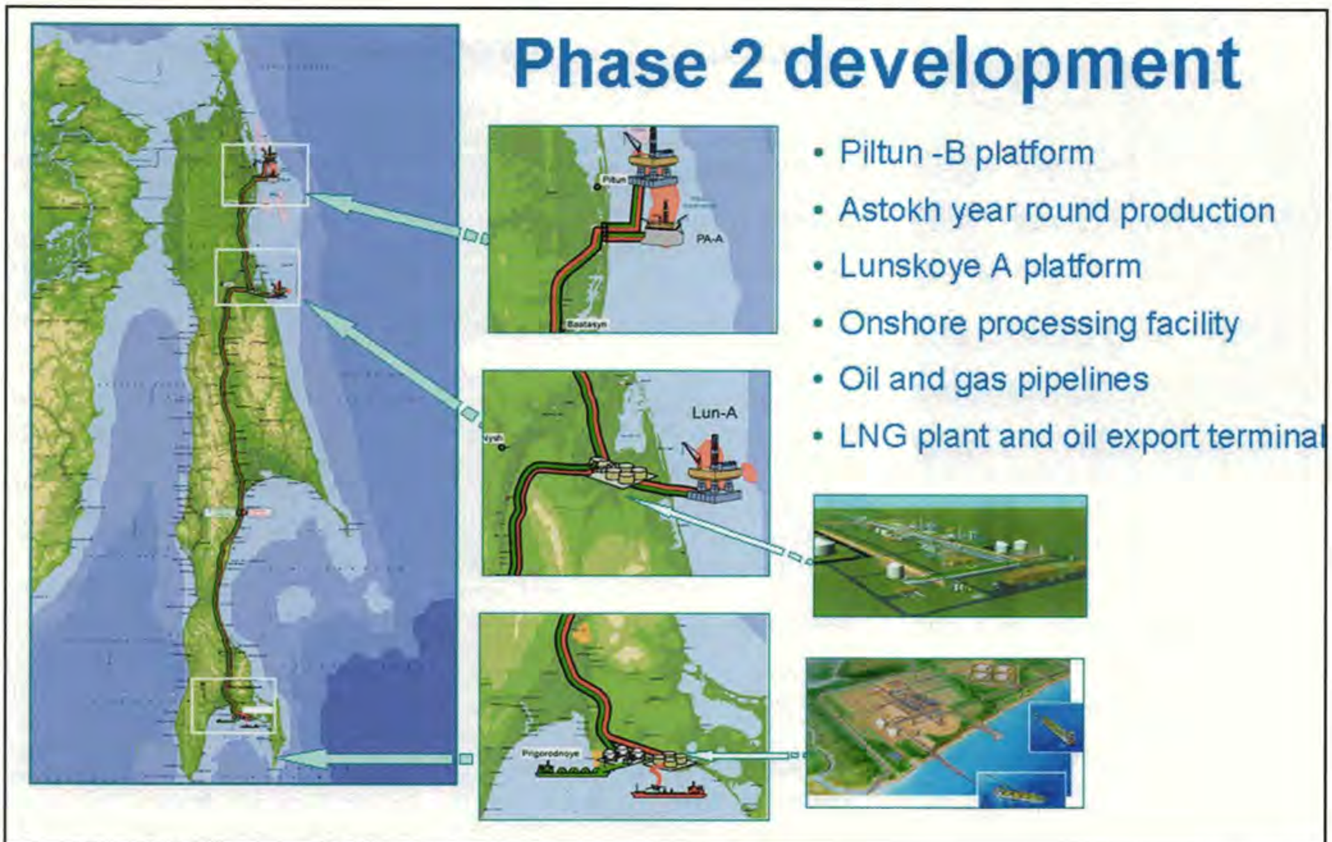

Figure 1: Phase 2 development of Sakhalin

Company – Shell 55%, Mitsui 25%, Diamond Gas (Mitsubishi affiliate) 20%, was established in April 1994), has been producing, only in the ice-free summer months, from the Astokhskoye reservoir in the Piltun-Astokhskoye field, via the Molikpaq platform (PA-A) since 1999, with offshore loading into tankers. More than 50mn barrels of the sweet 36° API crude has been sold to Japan, Korea, China, Taiwan and the Philippines, as well as to the US.

Last year $300mn was invested in the installation of a new water injection and power generation module. This has facilitated the pressurisation of the Astokh field by injecting around 140,000 b/d of water, and has boosted production from 70,000 b/d back to the Phase 1 target of 90,000 b/d. It is claimed that it will deliver an additional 260mn barrels of oil.

Biggest ever

Phase 2 is claimed to be the biggest single integrated oil and gas project ever undertaken. The combined recoverable reserves are put at 1bn barrels of oil and 18tn cf of gas. Maximum production rates are 175,000 b/d of oil and 9.6mn t/y of LNG.

A new 45-slot drilling, processing and production, concrete gravity based platform (PA-B) will be installed to produce oil and associated gas from the Piltun reservoir. Production capacity is put at 70,000 b/d of oil and 100mn cf/d of gas. Two 42-km pipelines to the Molikpaq platform will link the platform the 17.5-km from there to Piltun Bay onshore and enable all-year production.

The Lunskoye gas/condensate field will be developed via the 30-slot Lunskoye-A platform with minimum processing facilities. Production capacity will be 1,800mn cf/d and 34,000 b/d of condensate. There is also a small oil rim and the extra slots will be required for potential development.

KCA-Deutag, which already conducts drilling operations on Molikpaq, has a new $250mn contract to carry out drilling services for an initial period of seven years on Molikpaq, together with the two new platforms. On PA-B the initial drilling programme (October 2006–December 2008) will entail one well in 2006, seven in 2007 and eight in 2008. On Lun-A up to 15 gas producers are currently planned, starting in April 2006. The majority of cuttings will be re-injected.

Russian construction

The 151,100-tonne concrete gravity bases (CGBs) were designed by Aker Kvaerner and are being constructed by Quattrogemini Finland at a new dry dock at Vostochny, near Vladivostok. Initially, the platforms were designed for steel sub-structures, but Shell changed the design so that they could be built in Russia. Topsides were designed by Amec in London and are being built by Samsung Heavy Industries in South Korea.

Two 172-km, 20-inch oil and gas pipelines will take PA production to the new onshore production facility (OPF). This will also receive Lunskoye production. It will dry and compress the gas for pipeline transportation, remove condensate, stabilise and inject into the oil pipeline, recycle MEG hydrate inhibition and return it to the platform, and supply 18 MW of power to the platform. The plant, designed by Parsons E & C in London, with several Russian sub-contractors, is being constructed by the BETS joint venture – Bechtel, Enka of Turkey and Technostroyexport of Russia. At full capacity it will process 1,800mn cf/d of gas and 60,000 b/d of condensate. Production start-up will be phased from 4Q2005 to 4Q2006.

From the OPF a 637-km, 24-inch oil pipeline and a 48-inch gas line will take production to the LNG plant, the first to be built in Russia. All onshore pipelines will be trenched. The pipeline system crosses more than 1,100 rivers and streams, and will have a monitoring system installed to identify potential damage from seismic activity.

Figure 2: The Lunskoye-A platform

A $1.2bn engineering procurement and construction (EPC) contract to design for a total of 1,620 km of onshore pipelines was awarded to the Russian company Starstroi, in a joint venture with Saipem, Lukoilnephtegazstroi and Amec. Saipem is also designing the offshore pipelines as part of an EPC contract.

Last June the $2bn EPC contract was signed with a Japanese/Russian consortium, with Chiyoda of Japan as leader, to develop and build the two-train 9.6mn t/y LNG plant and oil export terminal at Prigorodnoye, at the southern end of Sakhalin Island. The design was by Fluor Daniel-Nipigaz, using a Shell Global Solutions patented process.

Three LNG sales contracts were signed last year with Tokyo Gas, Tokyo Electric and Kyushu Electric for a total of 2.8mn t/y for more than 20 years. Sakhalin Energy is negotiating with other potential buyers in the region, including Korea.

Not just Asia

Steve McVeigh, CEO of Sakhalin Energy, told the IBC 'Sakhalin 2003' conference in London: 'We do not limit our vision to Asia. I do not rule out the US West Coast. It is realistic to expect to be supplying Russian LNG to North America in 2007.'

Activity is now intensifying – a summary of planned contracting and procurement activities for this year (2004) lists almost 200 contracts, ranging from wellheads and Xmas trees to catering and language courses for Sakhalin Energy staff.

A joint commissioning team is already at work in Amec's London offices. Sakhalin Energy has appointed David Greer, who masterminded the Malampaya gas project offshore the Philippines, as Project Director and Deputy CEO of Sakhalin Energy.

Fabrication of the Lunskoye topsides is underway and will start for the PA-B platform in March. Later this year Amec will send a team to the yard as Russian regulations stipulate that the construction conforms to the design. In October, the fabrication of the gravity-base substructures (GBSs) will start.

This month (February), tenders closed for the building of one 145,000 cm LNG carrier, with an option for a second, with delivery in 3Q2007.

In July 2005 the GBSs for the Lun-A platform will be towed out to the field, under the supervision of Aker Marine Contractors. Then Saipem will install the 20,000 tonne topsides. In 2006 the GBS for PA-B will be installed and the 27,500 tonne topsides installed. At these weights they will be the largest topsides to be installed by the float-over method.

The start of continuous oil production at Molikpaq is expected in December 2005. First gas from Lun-A is scheduled to enter the onshore pipelines in March 2007 and the first LNG cargo to be loaded in November 2007.

Sakhalin 1 to produce 250,000 b/d

Sakhalin 1 is a $12bn, three-field, four-phase project with potential recoverable reserves put at 2.3bn barrels of oil and 17.1tn cf of gas. The project partners are Exxon Neftegas, operator, 30%; Sakhalin Oil and Gas Development 30%; ONGC Videsh 20%; and two Russian companies, Sakhalinmorneftegas Shelf 11.5% and RB-Astra 8.5%.

The first stage is the development from both onshore and offshore of facilities for the Chayvo oil field, where first production is scheduled for late 2005, and will peak at 250,000 b/d.

In August 2003 Parker Drilling, using the largest land-based, fully winterised rig in the world, began drilling the first of two trial 11-km extended reach (ERD) wells into the north-western flank of the main Chayvo reservoir. Ultimately, there could be a further eight wells.

Brought from Alaska

The 20-well, concrete gravity Orlan offshore drilling and living quarters platform was towed from Alaska to Russia, and modifications began in 2001 at the Amur Shipbuilding yard under a $140mn fixed price contract. This summer (2004) it will be towed to Korea for installation of new drilling modules. It will then be installed in the field in 2005, 11 km offshore in 14 metres water depth. It will be used to develop the south-western flank of the field with up to 20 ERD wells. KCA Deutag has a sub-contract for the detailed design of the drilling facilities, which will be built by Hyundai Heavy Industries in South Korea.

In the second phase of the development, the Odoptu field will be developed by drilling ERD wells from two onshore sites, with a total of nine oil producers being completed over a seven- to eight- year period. There will be full gas re-injection as well as water injection. Production start-up is scheduled for 2007 and will reach 90,000 b/d.

Offshore processing facilities on both platforms will be minimal, with the production going by pipeline for further processing at an onshore processing facility (OPF), with a capacity to handle 250,000 b/d of oil and 800mn cf/d of gas. From the OPF the oil will go via a 220-km, 26-inch pipeline across the island and the Tatar Strait to the DeKastri terminal, which is to be constructed by Russian companies on mainland Russia. Lukoil Neftegazstroy, as the major subcontractor to the contract manager Nippon Steel and its Russian affiliate NS Nephtegazstroy, will engineer, construct and install the pipelines.

Ice strengthened, newbuild tankers will load for export at a single point mooring, and be assisted by ice-breaking support vessels. Kvaerner-Masa's yard in Finland is designing and will build one, 4,000 dwt, 100-metre long icebreaking stand-by/ supply vessel, under a 65mn contract from Far-East Shipping Company. There is an option for a second vessel. Primorsk Shipping and Sovcomflot have the contracts for the charter of tankers.

Initially, limited gas sales will be to Russian Far East customers. But most of the gas will be reinjected for Phase 2 of the project – gas export will be via a subsea pipeline to Japan starting in 2008. This is the primary focus of Sakhalin 1. Feasibility studies with a group of Japanese companies have proved that such a plan is technically and commercially feasible. It is proposed that Sakhalin 1 would construct and operate the 900-km Russian segment, with a flexible plan to own and operate the 1,400-km segment in Japan. Other potential markets, including China and South Korea, are also being studied.

Phase 3 is production from the Arkutun Dagi field while Phase 4 is aimed at enabling gas production to continue to beyond 2050.

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Dry vs wet trees for deepwater development

One crucial question that must be answered during the front-end engineering of a deepwater development is whether dry or wet Xmas trees are to be employed, writes *Jeff Crook*. One economic consideration is that whilst subsea trees are relatively inexpensive to install, the cost of intervention is higher than for trees mounted above the surface.

Prosafe's *MSV Regalia* successfully completed a four-well riserless light-well intervention programme in the Norwegian sector during autumn 2003

Subsea wells are a popular method of deepwater oil and gas development, with around 2,400 wells so far installed on the seabed around the world. Some of these wells are connected to floating production facilities, whilst others are satellites from existing infrastructure. A large proportion are located in Norway, with 100 subsea wells installed on the Troll oil project alone.

However, one consequence of the high cost of subsea intervention is that oil recovery is much lower for subsea wells than for wells mounted on platforms. The performance of subsea wells has recently been evaluated in Norway, with statistics from the Norwegian Petroleum Directorate (NPD) showing that oil recovery is 8% lower for subsea wells than from wells on mounted platforms. Statoil plans to use innovative technology to close this gap, and is proposing to improve the average recovery factor on its Norwegian subsea fields from today's 43% to 55% in the future.

Riserless light-well intervention

Riserless light-well intervention (RLWI) could reduce the cost of subsea well intervention to one-third of present levels, with estimates suggesting that this would lead to an increased oil recovery worth NKr200bn in Norway over the next ten years. RLWI operations are based on the deployment of subsea wireline units from monohulls, or small semi-submersibles, which are both cheaper to charter and faster to mobilise than drilling rigs.

Well Ops, a wholly-owned subsidiary of Cal Dive, was formed in November 2002 when Cal Dive acquired the CSO Subsea Well Operation Business of Technip-Coflexip to provide cost-effective subsea well operations. It is able to perform a broad range of tasks for intervention, construction, inspection, repair and maintenance using its *Seawell, Uncle John* or *Q4000* vessels and utilising subsea technology provided via an alliance with Schlumberger (see *Petroleum Review*, February 2003).

More recently, another RLWI service provider has been approved by Statoil for the strictly regulated Norwegian sector. This particular subsea intervention technology was developed by FMC Kongsberg Subsea, in close cooperation with Statoil and Prosafe over the past three years as part of Norway's DEMO 2000 programme, and was field proven during autumn 2003.

The prototype subsea wireline unit was tested in late 2002 at the 'Coast Centre Base' – a quayside facility at Ågotnes, outside Bergen. The equipment was then transferred to Prosafe's *MSV Regalia* in early 2003. However, unexpected teething problems occurred with the equipment during final tests at the quayside, causing the field programme to be postponed while the *Regalia* completed contracted work for Norsk Hydro.

The vessel subsequently arrived at Statfjørd North on 27 September 2003, and after completing this workover operation it went on to carry out a workover on one Visund well and two Åsgard wells. The entire four-well programme was completed on 19 November 2003, with Statoil hailing the success of the new RLWI service.

'Applying this technology will reduce the cost of subsea intervention to a third of today's level,' says Øivind Reinertsen, Senior Vice President for the Tampen area of the North Sea. 'That'll help to cut operating costs, extend producing life and improve recovery from subsea fields. The resulting increase in activity will help to safeguard jobs for the future.'

Autonomous vehicle intervention

Looking further to the future it is hoped that some subsea intervention tasks will be performed by autonomous underwater vehicles (AUVs) which are able to 'fly' to the seabed worksite with no physical connection to the surface. This would be extremely useful for ultra-deepwater projects, where the umbilical could have a length of over 10,000 ft. There would also be cost savings for shallower fields, since an AUV would eliminate the need for a support vessel to control the subsea operations.

There is nothing new in AUV technology, in itself, with several of these vehicles already carrying out commercial survey work for the offshore industry. However, the aim is now to extend the range of tasks that AUVs can perform.

To achieve this the European Commission (EC) supports the 'ALIVE' programme, the aim of which is to design and build an AUV that is capable of carrying out light intervention work in water depths to 3,000 metres without the need for an umbilical. The French company Cybernétix is coordinator of the project and cooperates with IFREMER, Hitec and the Ocean Systems Laboratory of Edinburgh University.

The AUV was put through tank and shallow water tests off the south coast of France during autumn 2003. During tests the unit docked on to a subsea structure and successfully carried out pre-programmed tasks, such as opening and closing valves, with its hydraulic manipulator arm. The vehicle is equipped with video cameras and sonar to identify its position, with computer systems to guide it to its docking location and operate its manipulator arms.

However, its unlikely that an AUV could perform the range of heavy intervention tasks that are currently carried out by work-class ROVs, due to lack of power storage capacity. So, another proposal for this heavier work is to use an AUV to convey an ROV and to dock it on to a subsea manifold. Once docked, the ROV would receive power and communication through the manifold's own umbilical.

Statoil, FMC Kongsberg Subsea and Cybernétix have joined forces to take this concept one step further. The work currently involves preliminary studies into a concept known as 'Swimmer', which would be an AUV/ROV hybrid capable of providing a cost-effective solution for inspection, maintenance and repair activities on deepwater subsea fields. It is thought that the concept would be particularly beneficial for fields where there is limited infrastructure.

The Swimmer concept is based on using an AUV to transport a work-class ROV to a subsea field and to connect that ROV to the production control umbilical at the subsea production manifold. Reports suggest that studies are currently being carried out (a) to reduce the power requirements through the umbilical (b) to reduce the docking requirements and (c) to rationalise the intervention interfaces.

Dry-tree solutions

Even with this innovative technology the cost of subsea intervention will continue to be higher for subsea trees than for dry trees that are easily accessible to technicians. As a result, other efforts are focused on reducing the capital cost of dry-tree solutions through the adoption of innovative platform designs, and also by reducing the topside weight. Many platform solutions have emerged from the Gulf of Mexico, where some operators favour dry-tree solutions.

There are currently a small number of platforms in depths of more than 1,000 ft in the Gulf of Mexico, with Bullwinkle holding the depth record for a conventional steel fixed platform – standing in 1,353 ft of water. However, the Petronius compliant tower holds the overall depth record for a free-standing structure – standing in 1,754 ft of water. Some experts predict that this technology could be extended to depths of 3,000 ft.

Compliant towers

A compliant tower is a narrow, flexible tower with piled foundation that can support a conventional deck with Xmas trees, risers and production facilities. It can thus perform the functions of a conventional platform, but with far smaller steel weight for a given water depth. ExxonMobil installed the first compliant tower, called Lena, in 1,020 ft of water in the Gulf of Mexico during 1983.

Lena was a guyed-tower that was held in place by 20 weighted guy wires. The guy-wires were eliminated in second generation designs towards the end 1980s. As a further innovation a hinged section was incorporated into Baldepate, which was installed in 1,650 ft of water and came onstream in 1998. The purpose of the hinge was to enhance the structure's flexibility.

Although currently restricted to the Gulf of Mexico, a compliant piled tower (CPT) solution was selected for a West African development in June 2003, when ChevronTexaco announced the award of major contracts with a value of more than $820mn for its Benguela, Belize, Lobito and Tomboco (BBLT) project in Angola's block 14. This prolific block is also home to the Kuito field development, which began production in late 1999 and was Angola's first deepwater producer (see *Petroleum Review*, April 2000).

The BBLT development is located 80 km offshore in more than 1,250 ft of water and is operated by Cabinda Gulf Oil Co Ltd (CABGOC), a wholly owned subsidiary of ChevronTexaco*. The CPT will support drilling and production facilities for the Benguela-Belize fields, with subsea wells tied-back from Lobito-Tomboco.

Daewoo Shipbuilding and Marine Engineering (DSME) was awarded a contract for the engineering, procurement, construction and installation of the production facilities, CPT and the gas and oil export pipelines. First production from the Benguela and Belize fields is expected by the end of 2005. Combined BBLT annual production is expected to peak at 200,000 b/d by 2009.

Indonesian deepwater first

A dry-tree solution was also selected for West Seno – the first deepwater development in Indonesia, and the first deepwater field to employ tender drilling. Two tension leg platforms (TLPs) are to be installed in 3,200 ft of water, with weight saving achieved by tender drilling – this involves locating the ancillary drilling systems on a semi-submersible moored close to the platform. Further topside weight saving is achieved by processing the well fluids on a floating production unit (FPU).

This development is located in an emerging deepwater province offshore East Kalimantan. The gas resources in these deepwater fields are thought sufficient to supply 40% of the needs of the Bontang plant, currently the world's largest LNG facility. The field is being developed in two phases with two TLPs, the first with 28 wells and the second with 24 wells, together with the FPU. Production is expected to reach 60,000 b/d of oil and 150mn cf/d of gas by the end of 2005, when the second phase will be complete.

This field is located in the Makassar Strait production sharing contract (PSC) area and was discovered by Unocal in 1998. The development lies about 190 km north-east of Balikpapan in water depths of approximately 3,200 ft. Unocal Makassar operates the PSC and has a 90% working interest. Pertamina Upstream, a unit of the state-owned oil and gas company, holds the remaining interest.

**CABGOC, headquartered in Luanda, Angola, is the operator of the block 14 Contractor Group, which is comprised of Cabinda Gulf Oil (31%), Agip Angola Exploration (20%), Sonangol Pesquisa & Produção (20%), TotalFinaElf Exploration & Production Angola (20%) and Galp-Exploração e Produção Petrolífera (9%).*

RFID tagging for the oil industry – a brief introduction

A DTI Basic Technologies Study led by the Building Research Establishment (BRE), and including participation by the Energy Institute, is looking at the uses of radio frequency identification (RFID) in various other sectors to see whether there is the potential to transfer the technologies to the oil industry.

RFID technology has a proven track record in many applications and in several industrial sectors, examples being the tracking of livestock, maintenance of infrastructure and improving the logistics in retail and other industries. And it is now starting to be used in the oil sector.

A RFID system consists of two major components, the reader and the tag, which work together to provide the user with a non-contact solution to uniquely identify people, assets, and locations. Tags consist of two main parts: the integrated circuit and the antenna. The integrated circuit provides the working of the tag and includes the microprocessor and the memory. The antenna is the key factor in determining the read range of the tag.

There are two main types of tag – active and passive. Active tags have batteries whereas passive tags use the low-level radio frequency (RF) electro magnetic field generated by the reader. The RF magnetic field serves as a 'carrier' of power from the reader to the tag. When a tag is brought into the magnetic field the recovered energy powers the integrated circuit in the tag and the memory contents are transmitted back to the reader.

The RFID tags can be both read- and write-capable. This facility enables information to be written back to the tag. Unlike barcodes, RFID tags do not require a line of sight for identification. (**Figure 1** summarises the common types of tags available, their main features and uses.)

Standards

During their development barcodes were subjected to a bewildering range of different standards. As the technology matured many of the lesser-used standards disappeared, leaving only a handful of recognised standards that are widely used today on a global basis. RFID is following a similar path. At present, it is not easy to ascertain which RFID technologies will be adopted from the wide variety of standards currently available. This situation is improving as certain sectors have adopted international standards.

Animal tagging, for example, is universally tracked using uniquely numbered, injectable, read-only tags. Other standards are in development and these have arisen from the need for tags to meet certain conditions. The parcel and airline industries, for example, need inexpensive, read/write tags that are easy to apply and have anti-collision properties. These requirements have resulted in the development of easily attachable labels incorporating sophisticated tags. In order for RFID to be widely adopted within the construction industry, it must be thought of as part of an overall system, working alongside existing methods and technologies. New systems must be integrated smoothly within existing practices, making it important for barcode and RFID technology to become partners within single systems.

Reading from/writing to

There are two types of handheld devices suitable for recording information from RFID tags whilst on the move. The dedicated solution has an RFID reader integrated within a purpose built handheld computer. Alternatively, an external reader can be linked to an existing handheld in some way. These computers can form part of a larger system, which includes, amongst other things, supply, distribution, management and service records. The computing power offered by such solutions allows powerful applications to be developed with complicated logic. The increased storage capacity also allows applications to store large amounts of data about each individual object.

Many of these handheld computers are based around such operating systems as Microsoft's Pocket PC and Palm OS. This enables fast system development and easy integration to existing IT systems. The handheld can identify the tag, call up a database via GPRS, download the required information and display it on the handheld's screen. A simple tag

Areas of improvements in the supply chain	Wireless technology	Tags/bar codes	Handheld devices	Web application	Benefits of technology
Refining and blending processes	●	●	●	●	More efficient, effective, and profitable processes.
Delivery of goods	●	●	●	●	Improve traceability of goods and reduce number of disputes on whether goods have been delivered.
Paperless health and safety audits	●	●	●	●	Eliminate the use of paper based system.
Internet visible ordering and delivery service	●	●	●	●	Improve customer satisfaction.
Tanker logistics and movement	●	●	●	●	If used by the entire supply chain will improve communication flows, logistics and reduce costs substantially.
Locating material on site	●	●	●	●	Correct goods located and will save man-hours in locating goods.
Providing up-to-date information on site for a tagged plant items eg on health and safety, installation, etc	●	●	●	●	This will be possible when bandwidth increases for handheld Internet enabled devices. Provide a means to deliver drawings and information required in real time and assist identification and installation of correct parts. Improve information flow in the entire supply chain and aid problem and dispute resolving.
Maintenance/asset management of plant and assets	●	●	●	●	Allow better monitoring of operatives and maintenance scheduling. Reduce maintenance inspection times.
Maintenance/asset management of plant and assets	●	●	●	●	With increased bandwidth wireless technology to be used to download data required by operatives in real time and improve efficiency, accuracy and reduce number of visits.
Supply chain integration	●	●	●	●	All the above.

Figure 1: Summary of areas where the oil supply chain can be improved using different ICT technologies, and possible benefits

identity can therefore be used to provide the computer operator with potentially complicated information, as a trigger to carry out inspection routines or product installation and removal procedures. Finally, having completed an inspection or operation, the operator can synchronise the collected data with the rest of the PC system.

Handheld device

LXE's MX3 family of handhelds

The MX3 and 5 are an excellent example of handheld computers that can communicate using GPRS or a wireless network (WLAN) and incorporate barcode or/and tag reader into one ruggedised unit.

These units are based around Microsoft's Windows and Pocket PC and include up to 32 Mb of DRAM and 32 Mb of Flash, which is more than enough for most applications. This unit illustrates how easy it is to integrate different technologies within one handheld device.

Existing tag usage

1. Identifying individual pipe-joints in a harsh environment using RFID

Hydra-Tight, a division of Hydratight Sweeney, itself part of the Dover Corporation – a large multi-national Nasdaq quoted conglomerate – has a specialist bolt tensioning section that primarily operates in the oil and gas industry. The company used RFID technology to help it improve its pipework jointing identification systems.

A key element in the construction and maintenance of oil and gas facilities is the integrity of the pipeline joints in pressurised systems. Hydra-Tight's bolt tensioning role is to ensure that pipework systems are correctly assembled with the correct gasket, bolts and to the correct bolt tension (torque). Incorrect assembly invariably leads to leaks that are costly and can be a serious safety issue, due to the flammable/explosive nature of some of the products routed through the pipework systems.

The use of RFID tags to identify individual pipework joints is seen as a unique selling point for Hydra-Tight's services. Previously, identification had been by hand-written labels, metal asset labels or reference to drawings. By identifying each joint using autoID technology, a database could be built up to hold information specific to each joint thus ensuring the operatives carried out the correct procedures and used the right parts during a newbuild or rebuild of pipework systems. By recording electronically the identification of each joint as it was 'worked', a full traceability system could be set up.

Significant benefits obtained over barcode labelling and scanning were considered to be:

- No line of sight reading required (overcome 'dirty' conditions).
- Permanent attachment to the joint/asset in question.
- RFID Tags housed in ruggedised encapsulations that provide data integrity in the harshest of weather and operating environments.

2. Oil refinery check valves safety and audit with RFID tags

An oil and gas refinery in the US is using an asset management system based on RFID tagging to capture information on pressure safety relief valves in major vessels, pipework and process equipment. More than 80 valves are inspected and recertified as being fit for use. The system is based on a tag reader suitable for use in the hazardous and hostile environments typical for offshore oil and gas platforms, refineries and petrochemical processing.

The equipment for RFID has been designed to be intrinsically safe (IS) – that is, to be used in a live plant. A live plant is one that is fully operational, as opposed to one that is shut down for maintenance and all the product is flushed out so that it contains no flammable material. In live gas plants every piece of equipment has to be guaranteed IS, which means that even if the equipment breaks down, it does not have enough energy to cause a spark. It is similar to a standard piece of equipment but cannot cause an explosion.

In live plant the need is for 100% accuracy and assurance that the correct safety equipment is in the correct location and set at the correct pressure rating. This involves validating the safety equipment in a hazardous environment and identification of correct pressure settings. This information is normally carried on a visible nameplate or 'brass tag', which is 'cold stamped' and wired to the valve. Passive RFID tags were embedded in both the valve and the flange of the vessel or pipeline to keep records of relevant critical technical and process information.

The engineer uses the tag reader to read the RFID tags on the flange and the valve. This confirms that this is the correct valve, in the correct location, and set at the correct pressure. Data is transferred to the host PC by serial link when the user places the device in its cradle, which is connected to the PC.

Refineries have a statutory requirement to test every safety relief valve and certify that it is operational. By using the RFID system the cycle time for recertifying or repairing a safety relief valve was reduced by 64% over the traditional manual methods of hard copy inspection/repair sheets and certificates.

Oil industry applications

The potential for wireless tagging applications in the oil industry is large, ranging from improvements to:

- Supply Chain: Delivery, movement and tracking of fuel tankers, traceability of deliveries and logistics.
- Maintenance, together with legislative requirements: Management of equipment servicing and corrective actions. Tanks and cleaning regime.
- Health and Safety: Audit trial of trained operatives, restricted areas access management, traceability of safety equipment.
- Administration: Automation of procedures and compliance

Figure 1 is a summary of areas where the oil supply chain can be improved using different ICT technologies and possible benefits.

The DTI Basic Technologies Study led by the BRE will be publishing results of the findings and developing applications to meet the oil sector requirements. A questionnaire has been posted at **www.bre.co.uk/smarttag/questionnaire** *– designed to help assess the applicability of RFID tagging in the oil and gas industry. Readers are invited to fill this in. BRE, in partnership with the Energy Institute, will be demonstrating some of the technology products at the IP Week 2004 exhibition later this month.*

Drilling at Sporyshevskoye field.

... continued from p27

the EU accession process. In Romania, Eastern Europe's largest gas market (see **Table 2**), Gazprom is competing with GdF, Enel of Italy and two German companies, Ruhrgas and Wintershall, to buy two regional gas distribution companies recently put forward for partial privatisation.

Closing capacity

Energy market deregulation in Eastern Europe is not solely a matter of buying assets. The EU's Single Energy Market means that many uncompetitive facilities will have to be shut down. The ten candidate states have between them, for example, some 1.8mn b/d of crude distillation capacity compared with a total oil consumption of only 1.2mn b/d. Many of the region's 25 refineries, moreover, are small and out of date, and some of the smallest ones operate only sporadically. Romania, with ten refineries, probably stands to lose the greatest number of units. Refinery closures, however, are politically controversial and some governments have managed to extract promises from private investors not to close units but to upgrade them instead.

Similar considerations apply in the coal industry. Several closures appear inevitable in Poland and the Czech Republic, especially in the brown coal industry. Along with these, some older nuclear power stations may have to close. In some cases, such as Bulgaria's Kozloduy station and the Czech Republic's Temelin plant, existing EU members have pressed for plant closures. The loss of some coal and nuclear production should create new opportunities for natural gas, but opportunities may be slow to materialise unless some of Eastern Europe's governments soon start taking politically unpopular decisions – something some of them may prefer not to do until their EU membership is more widely accepted by their electorates.

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All delegates will be invited to attend a cocktail reception on the evening of 27 April at the Guildhall.
The reception is hosted by the Corporation of London and includes senior executives from Investment Banks, Fund Management Firms and Insurance Companies.

LNG's share of global gas market to soar

For the past few years LNG has experienced high levels of activity and investment in all sectors of its long-distance supply chain (Figure 1) and market indications suggest that it will continue to do so, reports *David Wood.**

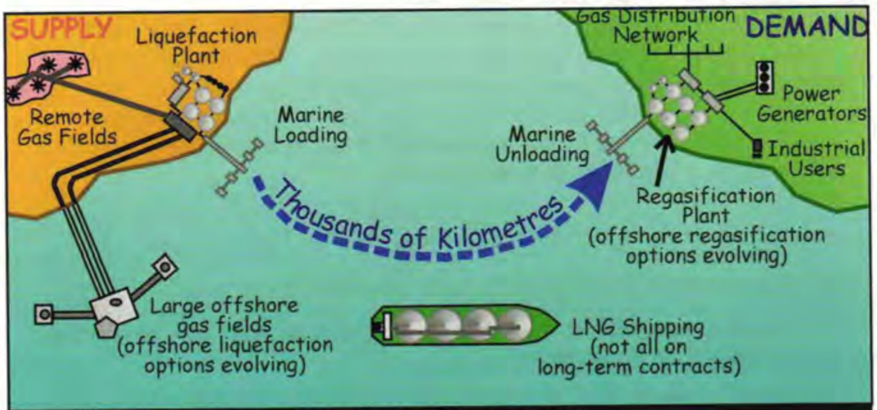


Figure 1: Diagrammatic representation of the LNG supply chain

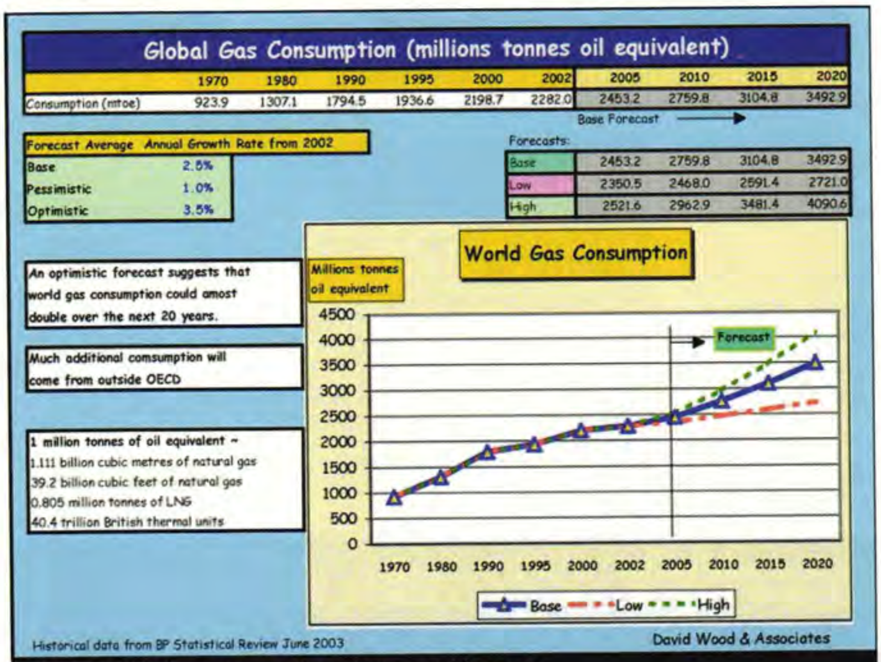


Figure 2: Global gas consumption – history and forecasts

Despite an impressive average year-on-year growth rate of some 6% since the 1960s, when the first commercial LNG cargoes left Algeria for Europe, it is only now that the market dynamics seem set to enable LNG to compete effectively in gas markets across the globe. Supply constraints associated with domestic North American gas for the US market are driving LNG supply opportunities in that market. New LNG receiving facilities and gas distribution infrastructure under construction in China are about to open up that market. However, it is the proliferation of new liquefaction trains, shipping, regasification terminals and evolving LNG contracting and pricing worldwide that is enabling LNG to make a step change in its contribution to the global gas market.

Until recently almost all LNG was sold to long-term customers that formed part of single dedicated LNG supply chains with prices indexed to crude oil and/or fuel products derived from oil. Such contracts are still underpinning the industry, but significant changes have occurred in recent years, including more competition in supply – larger trains and lower unit costs of newer plants (~$175 t/y in 2003); deregulation in import markets; short-term trading of LNG cargoes; and freelance LNG shipping. Such changes have opened up opportunities for gas buyers and sellers that improve the ongoing competitiveness of LNG.

If the US market opens up to LNG as forecast and cargoes continue to be sold at prices related to the Henry Hub benchmark more transparent pricing should be expected globally for both the LNG commodity and its transportation. The evolution of a short-term LNG market, operating in parallel with traditional long-term supply deals, takes the industry one step closer to a globalised natural gas market involving more extensive LNG spot and futures trading.

Global gas demand

The global appetite for gas as the fuel of choice is gathering pace. Many analysts expect global gas consumption to approximately double by 2020 and exceed more than 4bn toe/y. **Figure 2** shows a range of gas consumption forecasts; the uncertainty associated with these depends upon a range of issues, including global economic development; regulatory and political constraints; investment in gas infrastructure (pipelines and LNG); gas prices; and alternative fuel initiatives and developments.

Accelerated growth in global gas demand should also boost LNG opportunities. The remaining gas resources identified globally appear to be more than sufficient to meet increased demand. The problem is that they are not located close to the major markets. Less than 10% of the 155tn cm (5,500tn cf) of proved gas reserves (2002) are located in OECD countries (36% in FSU; 36% in Middle East; 18% in emerging economies). Moreover, converting undeveloped resources of stranded gas isolated from the main markets requires significant investment and strategies to mitigate the myriad of risks (technical, regulatory, environmental, fiscal, political and financial) that confront major energy development projects. LNG supply projects associated with stranded gas fields can compete effectively with other energy sources, particularly if the current investment in expanding the LNG receiving terminals, gas storage and distribution infrastructure in major markets is sustained.

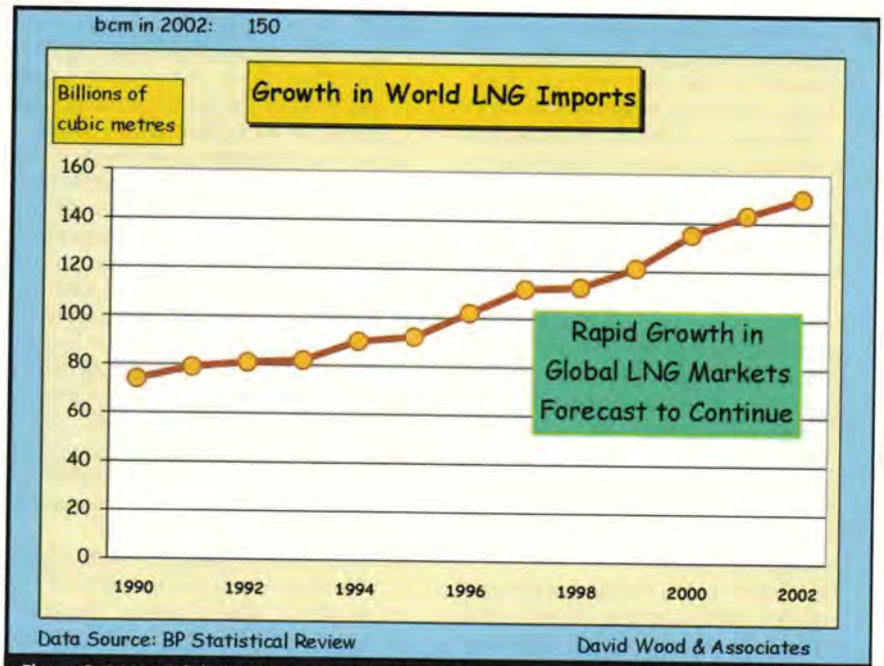
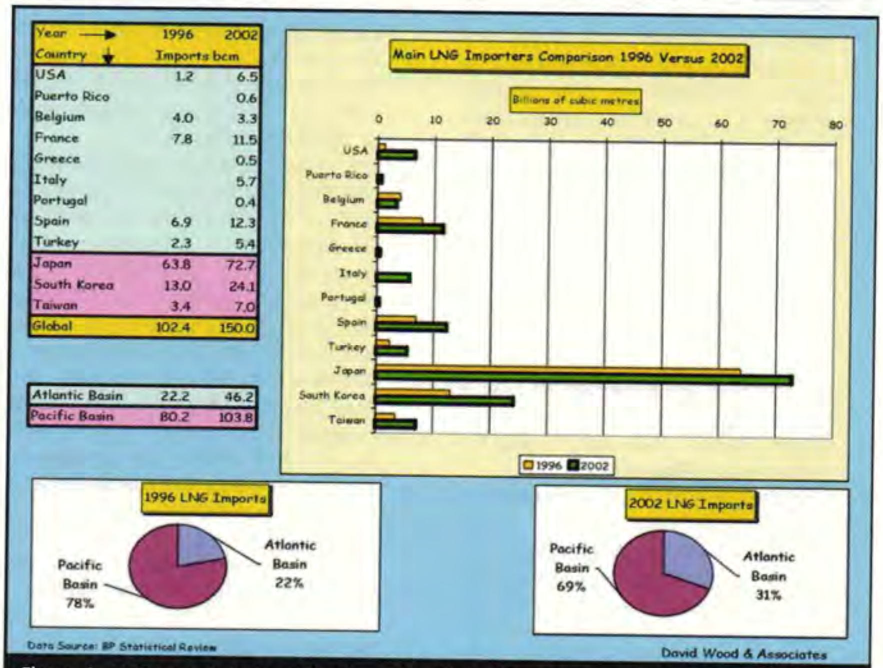


Figure 3: Recent global LNG consumption growth



Year → / Country ↓	1996 Imports bcm	2002
USA	1.2	6.5
Puerto Rico		0.6
Belgium	4.0	3.3
France	7.8	11.5
Greece		0.5
Italy		5.7
Portugal		0.4
Spain	6.9	12.3
Turkey	2.3	5.4
Japan	63.8	72.7
South Korea	13.0	24.1
Taiwan	3.4	7.0
Global	102.4	150.0

Atlantic Basin	22.2	46.2
Pacific Basin	80.2	103.8

Figure 4: LNG Imports to the Atlantic and Pacific Basins, 1996 and 2002

Global LNG consumption

According to the latest *BP Statistical Review* (June 2003) annual global gas production in 2002 was 2,527.6bn cm. International trade movements in gas by pipeline were 431.35bn cm (17.1% of global production) compared to international trade movements in LNG of 149.99bn cm (5.9% of global production). This leads to the conclusion that some 83% of global gas consumption is used domestically within national borders (US and Russia accounting for most of this).

Why then all the fuss about LNG? It seems to represent only a minor share of the global gas market? Its significance lies in its continued expansion (**Figure 3**), diversification and ability to bring stranded gas reserves into the main markets avoiding the political and technical issues associated with transporting gas by pipeline across national borders, extreme terrains and oceans. It also serves as a competitive force in gas pricing and can offer security of supply to those regions dependent on pipeline gas from a limited number of pipeline gas suppliers (eg Western Europe).

All the major gas markets have a vested interest in sustaining and developing global LNG supplies. LNG is now expected to meet at least 10% of global gas demand by 2010 and perhaps 15% by 2020, depending particularly upon developments in the US gas market.

Diversification of LNG markets

Until recently the LNG markets have been conveniently separated into the Pacific and Atlantic Basins. The Pacific basin has dominated demand and the US has represented only a minor consumer within the Atlantic Basin. **Figure 4** highlights not only the continued dominance of Japan, but also the diversification and expansion that has occurred in recent years within the Atlantic LNG basin.

The current evolution of the US LNG market makes it no longer valid to consider the East Coast US and Europe as part of a single Atlantic market and West Coast US and Asia as part of a single Pacific market. The market, dynamics in all of these regions differ significantly from each:

- *Southeast Asia*: Historically this region has been the dominant market for LNG. The region is short of gas (and oil) reserves and lacks integrated regional gas pipeline networks. Long-term agreements involving LNG have enabled buyers to secure supply and will continue to do so. However, emerging LNG markets in China and India, and volatile economic growth rates within the region, should provide more opportunities to trade short-term LNG both within Asia and to the other markets, so more flexible supply contracts are evolving. Short-term LNG supply surpluses can be expected in this region as the new markets develop and existing markets recover from economic recession.
  In recent years South Korea's gas market has expanded more rapidly than Japan's, with Kogas replacing Tepco in 2002 as the world's largest LNG purchasing entity.
- *Western Europe*: Over the past 50 years an extensive and integrated gas pipeline grid (>200,000 km) has been developed in this region linking it to pipeline supplies from Russia, North Africa (primarily Algeria) and the North Sea (primarily Norway and the Netherlands). LNG has represented minor price competition and provided security of gas supply to several countries (eg France and Spain) during this period. As market liberalisation progresses within the region shorter-term LNG agreements are expected to play a more important role as seen in Spain, France, Italy and Turkey in recent years (**Figure 4**).
  The decline of the UK's gas reserves and future supply issues have started to hit the UK domestic gas market and future pipeline gas supply contracts are now being established with Norway and are ongoing with Russia. Significantly, longer-term LNG contracts (eg with Qatar) to supply the UK from 2007 are also to play an expanding role, providing security and diversification of supply.
  Challenges and opportunities facing LNG gas suppliers into the European market include the ongoing regulatory changes related to market liberalisation centred on the EU Gas Directive opening the market to full competition; limited availability of underground gas storage close to major consumption areas; and price competition from the big four pipeline gas suppliers that together hold sufficient reserves to supply most of Europe for the next 30 years.
- *US*: A significant change has occurred in the US market over the past few years. Historically it has been able to meet growing gas demand from domestic production or through gas imports by pipeline from Canada, with LNG amounting to less than 1% of the gas mix. Gas production and commercially proved reserves in US and Canada are in decline and traditional sources of gas supply to the domestic market can no longer be relied upon to meet growing demand. Gas prices well in excess of $5/mn Btu during winter 2002/2003 and the historical low point of gas storage levels reached in June 2003 testify to the pressures on gas supply.
  The US has a vast network of gas pipelines and some 4tn cf of working gas storage, concentrated on moving gas through the Gulf of Mexico to the mid-west to the major East Coast markets. Gas trading forms part of the sophisticated US commodity and derivatives markets. As LNG imports to the US expand, a highly liquid LNG spot and futures market will undoubtedly develop.
  Many forecasts, such as those from the Energy Information Authority (EIA – department of the US Government) suggest that domestic US production will remain flat over the next 20 years based upon high levels of investment in drilling for deep gas and unconventional gas sources (eg coal-bed methane). Such forecasts suggest that growth will be met by a combination of unconventional sources, arctic Canadian and Alaskan gas and LNG. An Alaskan gas pipeline is currently forecast to cost some $12bn, take four years to build and not to come onstream until 2020. A Mackenzie Delta gas pipeline linking arctic gas from Canada into the US grid could be onstream by 2016. Neither of these projects are likely to supply cheap gas.

Declining US production

If US domestic gas production declines more rapidly than predicted by the EIA – and many in the industry would not bet against such an outcome – the requirements for LNG to meet US gas demand in the medium-term could be much higher than predicted – up to 10% of the market by 2010. The proliferation of current projects (now exceeding 20) to build new LNG import terminals within the US (and in neighbouring Mexico) to supplement the five existing terminals indicates that many companies and organisations also recognise a rapidly increasing role for LNG.

One issue that is currently being addressed in the US is how to make LNG interchangeable with pipeline gas. Most LNG has a calorific value of between 1,100 and 1,180 Btu/cf, but US pipeline gas is leaner (1,025 to 1,060 Btu/cf), because NGLs are stripped from it for use as refinery feedstocks. LNG therefore requires treatment to lower its calorific value for entry into the pipeline grid. How such treatment should be performed, together with planning regulations and environmental and safety issues, are delaying the approvals of some of the planned LNG receiving terminals. LNG regasification plants are being located in Mexico (Baja California to supply the West Coast US market) and offshore to ease some of the environmental and other regulatory objections being raised within the US.

It is clear that over the next few years the infrastructure will be in place for the US to receive LNG along the East, West and Gulf coasts to meet demand for gas imports.

LNG to become more competitive

The fundamentals of supply, demand and infrastructure that underpin the LNG industry are all strengthening. Extensive investment worldwide to build new liquefaction and regasification plants, together with shipping at lower unit capital costs due to technological advances and economies of scale, are expanding capacity and making LNG more competitive with pipelined gas. Increasing liquidity in the LNG shipping market and an evolving short-term LNG spot market means greater market flexibility to accompany the security of supply that continues to be provided by the long-term LNG supply contracts, which still underpin most LNG supply chains.

Several major companies have responded to the changing LNG market dynamics and have developed strategies to exploit opportunities in the three distinct regional markets as the LNG industry continues to expand and diversify.

David Wood is an independent oil and gas consultant focusing on training, economics, risk, portfolio and strategic issues. He will be directing a three-day course on the LNG industry for the Energy Institute (EI) in March 2004. Please contact Nick Wilkinson at the EI* **e: nwilkinson@energyinst.org.uk *or see the advertisments on p16–17.*

Photo: Erica Sciolti

Santos find triples Brazil's gas reserves

The recent announcement by Petrobras that close to 14tn cf of gas has been located in two areas 130 kms from the shore in the Santos Basin, off the shore of Brazil's most populous and wealthy state, will have enormous implications for Brazil, for the state of Sao Paulo and for Petrobras itself, reports *Patrick Knight*.

The gas find in the Santos Basin block BS-400 triples Brazil's known reserves of natural gas, pushing them above those of Peru. Brazil now has the fourth largest reserves in South America, after Venezuela, Bolivia and Argentina. The find, in 1,000 metres of water, is in one of the very large blocks allocated to Petrobras in 1998, prior to the first auction of concessions made by the National Petroleum Agency, the ANP.

Shell found gas in the Merluza field in the Santos Basin some years ago, and about 1mn cm/d is now flowing ashore from there. Other companies, including Agip, ExxonMobil, ChevronTexaco, Repsol-YPF, El Paso, Maersk, Statoil, Amerada Hess and Wintershall, have also been involved in exploration work in the Santos Basin.

Unexplored

Petrobras Exploration Director Guillerme Estrella says that only 2% of the Santos Basin has been explored so far, and that Petrobras has '20 years work there ahead of it'. Further announcements about the finds are expected soon, and it is widely expected that the reserves will be revised upwards, as Petrobras' drilling programme progresses (IHS Energy reports the finds as a 14.8tn cf discovery – see p46).

Most of the gas found in Brazil to date has been associated gas and almost half of the 42mn cm/d produced comes from wells in the Campos Basin. Significant finds, most of them associated, have also been made both on and offshore in five states in the north-east.

The only other large reserve of unassociated gas is at Urucu in the Amazon region, 400 kms upstream from the isolated city of Manaus, which itself is about 2,000 kms from the sea. Because of the absence of a large market nearby and the problems associated with building pipelines through thick jungle, strongly opposed by a series of NGOs, most of the Urucu gas is now re-injected and Petrobras is no longer prospecting in the region.

Gasbol line

More than two thirds of the 28mn cm/d of gas consumed in Brazil, about a third of it in the state of Sao Paulo, is brought along the 'Gasbol' line, which runs about 2,000 kms from reserves in southern Bolivia. Partly because of the high cost of transport, this gas costs about $3.30/mn Btu. Except where pollution is a problem, gas is usually not competitive with fuel oil, of which about 18,000 t/d is now sold by Petrobras.

Natural gas accounts for just 3% of all the energy consumed in Brazil. The high cost of gas explains why an emergency programme to build 50 gas-fired power stations in the late 1990s, did not come to fruition.

The price of Bolivian gas is pegged to the world price of fuel oil, while financial problems caused the Brazilian currency to lose two thirds of its value against the US dollar between 1999 and 2002, all of which made pricing and raising capital extremely difficult.

As a result only 11 gas-fired power stations have actually been built, most with Petrobras as a partner. None were ready in time to avert the electricity crisis in 2001, when low rainfall forced Brazil to adopt a rationing scheme, which obliged all consumers to use 20% less electricity in a programme that was surprisingly successful.

Santos to the rescue

Even if no more gas is now found in the Santos Basin, about 55mn cm/d is expected to be coming ashore from there within four or five years. This would mean close to 100mn cm/d would be available in Brazil by 2010. Most of the gas consumed in Sao Paulo now comes from Bolivia, with that produced in Rio de Janeiro and in the north-east used near the source.

The reliance on Bolivian gas makes the fuel even less competitive in Sao Paulo, which contains about 60% of Brazil's industrial capacity. Sao Paulo currently imports about half of the 10 GW of electricity consumed each day from other states. Some of it comes from the Amazon region and transmission losses are substantial.

Petrobras faces change

Until now, oil has dominated the culture at state-owned Petrobras, which until the late 1990s had enjoyed a monopoly of most operations for almost 40 years. The company gave priority to finding oil, producing it from reserves that are increasingly located under very deep water, and operating its 11 refineries.

Most of the refineries were built in the 1950s and 1960s and designed to make a high proportion of gasoline and fuel oil. Reconfigurations are now having to be made to deal with the increasing proportion of locally produced crude of 20° API or below.

Until very recently, gas has not been high on Petrobras' list of priorities, and offshore an extremely high proportion of the gas was flared in the absence of separation systems and pipelines to the shore. Before the gas finds in the Campos, the company had opposed plans to build facilities for unloading LNG, which it saw as a threat to its sales of fuel oil.

Planning challenge

Now, almost at a stroke, natural gas forms at least 25% of Brazil's total reserves of hydrocarbons. How to deal with this new situation will make preparing Petrobras' rolling four-year plan, updated annually and normally published in April, much more complex than usual this time.

Currently about 1.8mn b/d are produced in Brazil, 1.5mn b/d of it from fields in the Campos Basin. Most is refined in Petrobras' 11 refineries, but about 200,000 b/d of the low API crude now being produced at Campos, and which the refineries cannot handle, is exported. In turn, about 200,000 b/d of light crude is imported to make the mix of products the market needs.

Brazil exports about 100,000 b/d of fuel oil, which Petrobras is having increasing difficulty in selling, as well as about 200,000 b/d of gasoline. The reason for the large export of gasoline is that about 12bn litres of alcohol fuel are now produced each year from sugar cane in Brazil. Some is blended with gasoline at a proportion of about 20% alcohol; the rest is sold as 100% alcohol.

Brazil is a continental country and still relies overwhelmingly on road transport, so about 100mn l/d of diesel is sold. To make up the shortfall between what the refineries can produce and what is needed, about 150,000 b/d of diesel are imported. Large amounts of LPG, the most popular fuel for cooking purposes, are imported, as well as much of the naphtha used by the petrochemical industry and some aviation fuel.

Santos decisions by end 2004

It is expected to take until the end of 2004 for the government, Petrobras and other interested parties to agree on when the first gas from Santos should come ashore, what flow rates might be, and how much it will cost. But speculation and calculations are already being made about the impact the finds might have.

Until the Santos finds were made, it seemed inevitable that one, or possibly two new 200,000 b/d refineries would have to be built on greenfield sites in Brazil in the next few years. About 1.9mn b/d can currently be refined, but it was anticipated that extra capacity would be needed soon, as demand increases, to ensure that more refined products do not have to be imported.

Ildo Sauer, responsible for gas and energy matters at Petrobras, points out that with the equivalent of about 450,000 b/d of oil suddenly available adjacent to Brazil's largest industrial market, no new refinery might be required after all, or the need for one might be greatly delayed. At the moment about 10mn cm/d of gas is consumed in Sao Paulo state. Three companies distribute it – Comgas, owned by British Gas and Shell, which bought the company of that name from the state authorities in 1999 for about $1bn; the Spanish owned Gas Natural and Gas Brasileiro.

Before the finds were made at Santos, Comgas was predicting that, at the existing price of about $3.30/mn Btu, about 36mn cm would be being sold each day in the state by 2020. The company now thinks 90mn cm/d could be sold. Even before the Santos find, the left leaning government that took power in January 2003 had already decided to 'massify' the use of natural gas, as Sauer puts it. Petrobras plans to build a new 1,000-km pipeline, which would join the southern system, fed from Campos, Bolivia and now Santos, with that in the north-east.

New distribution systems are also to be built in the north-east. Sauer wants more natural gas to be used for domestic purposes, replacing LPG for cooking purpose and substituting the ubiquitous electric shower. Demand for electricity is extremely high at the evening peak in Brazil, when millions of people take showers simultaneously.

Sauer points out that now that a long-standing subsidy on LPG has been removed, and the price of electricity has also risen, fuel bills form a much higher proportion of the average wage than they did five years ago. The price of electricity will continue to rise as most new power sources will be more expensive than the power from the large hydroelectric power stations, which currently generate 80% of the electricity used in Brazil.

There is some concern in the private sector that the authorities in Sao Paulo might be tempted to follow the example of Rio de Janeiro. Revenues from the production and processing of oil and associated activities there are responsible for a large and steadily increasing share of state income. Because oil industry revenues do not meet the needs of the state, which has little industry but a large population, taxes on the oil business have been raised and new ones introduced in recent months – to such a degree that operations are being prejudiced and some companies plan to move elsewhere.

Sao Paulo dominates

The relative weight of Sao Paulo in the economy of Brazil has fallen slightly during the past two decades. Steadily widening cost differences have encouraged companies to move to the north-east, or centre-west, where wage levels and taxes are lower. But the state still dominates the Brazilian economy. Leaders of industry and in the state administration are already making plans to seize the opportunity offered by the abundant gas from Santos, which will be much cheaper than gas from Bolivia or any other fuel, to make a new round of investments. They aim to restore the competitiveness lost by Sao Paulo in recent years.

Sao Paulo reached its present pre-eminence mainly because of the huge revenues from the export of coffee that accrued to the state during the 19th, and first half of the 20th centuries. Much of the money was used to finance the industrialisation of the state and to build its still unparalleled infrastructure.

Roger Ottenheym, who is responsible for co-generation with Comgas, thinks that the gas from Santos could prove to be just as important for Sao Paulo as coffee was for a century and a half.

About 80% of the gas sold in Sao Paulo by Comgas is used by industry, while about 10% is now used as motor fuel, the great majority in taxis and high mileage private cars. The rest is shared between co-generation, residential and commercial. Sauer and Comgas anticipate that co-generation capacity will grow fast in the next few years as natural gas becomes steadily more competitive than fuel oil, diesel, gasoline and LPG.

Much cheaper

It is assumed that the gas from Santos will be sold for significantly less than $2/mn Btu. The recently set up Association of Co-generators of Sao Paulo, Cogen, of which Ottenheym is President, anticipates co-generation projects generating a total of about 4,000 MW by about 2020. Its Executive Director Carlos Silvestrin estimates that up to 500 co-generation projects, ranging between 1 MW and 25 MW will be built.

Silvestrin notes that 18% of the energy produced in European countries is now for co-generation purposes, and he sees no reason why Brazil should not follow suit. He also calculates that about 35,000 km of new gas distribution lines will be built in Sao Paulo in the next 15 years

Analysts calculate that about $30bn will be needed to install the extra infrastructure and pay for the new equipment. Electricity from co-generation plants is more expensive than hydroelectricity in Brazil. But the state of most of the electricity distribution system in Brazil is poor, exacerbated by the impact of rationing. As a result local generation is more reliable and is being encouraged by a government increasingly reluctant to build more hydroelectric stations in the Amazon in the face of increasing NGO opposition and 4,000 km from the users in Sao Paulo.

Gas infrastructure

Ottenheym points out that while crude oil can be shipped and sold as soon as it can be extracted, the facilities to deliver gas to the final user have to have been built to allow the fuel to be used as it is produced. Building these facilities will take time. For this reason, the companies that will distribute the gas are anxious for the production rates and the price of the extra gas to be defined as soon as possible.

Ottenheym thinks that several specialist industries could absorb large quantities of gas quite soon. However, the fact that the gas has been found close to Santos, the largest port in Latin America, is an added advantage. One of Brazil's largest petrochemical centres is at nearby Cubatao, where Petrobras already has a refinery.

At the moment large quantities of naphtha and other feedstock used by the chemical industry have to be imported, but much of this could be replaced by natural gas. About 16mn tonnes of fertiliser are now used in Brazil each year, with about 50% of the ingredients used being imported. Much of them come in through Santos, where most of the companies mixing fertiliser have their facilities. Many imported ingredients could be substituted by gas.

New gas use

A new generation of steel mills is also being planned, one of which is to be built at Cubatao. Gas could be used as a raw material there, as well as at other steel mills, most of which are located in Minas Gerais state, about 500 km from Santos.

Sauer points out, that should all the various projects using gas now being discussed come to fruition, Brazil would need much more than the 100mn cm/d that is now anticipated to be available by 2010.

Motor fuel

The second most important use for the extra gas is expected to be as a fuel for motor vehicles. New vehicles equipped with engines designed to run on natural gas are, as yet, not available. Consumers anxious to use a fuel that can cut the cost of motoring by up to 70% have to pay for a conversion, which costs about $1,000.

About 600,000 passenger vehicles are already running on the fuel, and 3.6mn cm/d of gas went to power them in July 2003. Brazil now has the world's second largest fleet of gas-fired vehicles after Argentina, where natural gas forms about 45% of the energy mix. This compares with the current 3% in Brazil.

Sauer thinks that natural gas should used to power Brazil's 60,000 buses, some 7,000 of them in greater Sao Paulo, as well as the 600,000-strong fleet of light delivery vehicles, most of which now use diesel. There is concern in some quarters that if gas becomes cheaper, prospects for alcohol fuel, which is already more expensive than gasoline to produce, may be prejudiced. The government also plans to add at least 5% of vegetable oil to diesel fuel, both to reduce pollution, and also to create new jobs in agriculture – and this might also be affected.

Bolivian impact

As well as affecting plans for the alcohol and biodiesel industry, the new find at Santos raises questions about what might now happen to the gas from Bolivia. The Gasbol line, which first started bringing gas from a series of fields in southern Bolivia in 1999, can now carry 30mn cm/d. Since the building of Gasbol was first mooted, Bolivia's reserves have increased from 5tn to 50tn cf.

Before gas started to be sent to Brazil, most of Bolivia's gas went south to Argentina, which has now become self sufficient and which now exports gas to Chile and the south of Brazil. As well making several large finds in Bolivia, where it is the company with the largest reserves, Petrobras is also the leading shareholder in the Gasbol line.

On the one hand Petrobras wants prices to remain high, so the debt incurred in building the $2bn line can be paid off. Because Gasbol was extended 1,500 km to the south of Sao Paulo for political reasons, it was very expensive. On the other hand, as the main shareholder in most gas-fired power stations, Petrobras wants the gas price to fall.

Until now the Bolivian Government has been adamant that the gas price should remain at the present level and has resisted pressure for delinkage from fuel oil prices. The new find at Santos completely changes Bolivia's bargaining power.

Against LNG exports

In Bolivia political resistance to the building of a new gasline to the Pacific in Chile, from where it was planned to ship LNG to the US, was largely responsible for the fall from power of the President in October 2003. The possibility of Bolivian gas being taken to LNG exporting facilities that might be built at Santos, or even for the some of the Santos gas itself to be exported, and more gas from Bolivia being used instead is also being examined.

Ottenheym feels that although high prices are now being paid for LNG in the US because of a temporary shortage, its price will fall again soon. Because there is an abundance of natural gas in the world only very large-scale producers such as those in the Middle East will be able to produce and transport such gas to the US at a profit.

After all costs for LNG exports had been paid Bolivia would only get about 50 cents/mn Btu at the wellhead. He anticipates that all the Santos gas will be used in Brazil itself, where a market for all of it will soon come into being, and that exporting is not a priority.

Few large wildcat discoveries in 2003

***IHS Energy* has just published its *Discoveries and Highlights 2003* as an annual supplement to its established *International Oil Letter* (*IOL*) news service. The report lists all completed wells that encountered hydrocarbons. It also highlights information on key corporate activity, such as mergers and acquisitions, on a month-by-month basis. The information in the supplement is global, but excludes onshore North America.**

According to Ken White, Senior Editor of the *IOL*, the *Discoveries and Highlights 2003* report provides a consistent, impartial review of significant E&P activity during the year. Subscribers can then link back to the *IOL* for more detailed reports.

'One of the most significant concerns was that 2003 didn't produce large, unpredicted finds,' White said. 'However, that concern was offset by the industry sustaining a high drilling success rate – with nearly 40% of exploration and wildcat drilling projects locating hydrocarbons (a majority of these projects required additional work to determine their commerciality). The year was also marked by significant political and corporate concerns and high-profile negotiation failures in both Russia and Saudi Arabia,' White added.

In the *Discoveries* section, the report lists discoveries by operator, well name, basin, location and status (oil, gas, or oil and gas, or gas condensate, etc). These discoveries are listed in a country-by-country format and include significant finds in Angola, Brazil, India, Russia and Trinidad.

Some of the key discoveries from the report include:

Sub-Saharan Africa

In Angola, 12 deepwater discoveries were made in 2003. One of the more important is the Total-operated Gindingo 1, which is the company's first strike in ultra-deepwater block 32. The well tested 7,400 b/d and 5,700 b/d of light oil from two separate zones. ChevronTexaco confirmed its Nsiko 1 wildcat, located offshore Nigeria in deepwater block OPL 249, as an oil and gas discovery, with pre-drill estimates in excess of 300mn barrels of oil.

South America

In Brazil, Petrobras enjoyed a record year, making a 14.8tn cf discovery in its Santos Basin block BS-400. The 4-SPS-035 discovery and 1-SPS-37A are so significant that they could conceivably change Brazil's natural gas strategy (see p42) In addition, the company appears to have discovered long-sought-after crude oil, both in the Sergipe/Alagoas Basin and Espirito Santo Basin. In the former, the 1-SES-147 discovery reportedly found 150mn barrels of oil.

In October 2003 Trinidad's Ministry of Energy & Energy Industries confirmed the BHP-Billiton-operated Howler 1 wildcat was a gas and condensate discovery. It is an important Upper Cretaceous find, since this reservoir unit has not been a significant producer in Trinidad & Tobago. Local sources indicate BHP-Billiton tested 18mn cf/d and 137 b/d of condensate from the Upper Cretaceous Naparima Hill Formation.

In Venezuela, PdVSA completed the Tacata 2X wildcat in the Maturin Sub-basin as an oil and gas discovery, which is estimated to contain 236mn barrels of light and medium oil and nearly 3tn cf of gas.

Far East

China had a particularly good year in regard to exploration drilling, with nearly 40 potentially commercial discoveries both onshore and offshore. Three of these discoveries led to reserves additions of 700mn barrels of oil and 4.1tn cf of gas.

In India, the latest Dhirubhai (D6-D 1) discovery well further extended the Dhirubhai structures, making them the biggest gas discovery in India for almost three decades. Latest revised figures suggest gross, in-place reserves for the structures of 8.6tn cf of gas. The eighth well drilled on the Reliance Industry KG-DWN-98/3 block, D6-D-1, is believed to have encountered in excess of 100mn of net-gas pay.

CIS/FSU

While the vast majority of Russian drilling remained onshore, two very important offshore discoveries were made in 2003. In the Caspian Sea, Lukoil recorded its fourth consecutive strike in the Severniy licence with the Sarmatskaya 1 wildcat. Pre-drill reserve estimates were 879mn boe. Forming part of Gazprom's drive to increase gas reserves off the Yamal Peninsula, its Gasflot subsidiary tested 13.7mn cf/d from the Obskaya 1 well, with reserves estimated at 1.7tn cf.

Corporate and political issues

In regards to corporate and political activity, 2003 was marked by some significant events. The year started badly – a protracted national strike in Venezuela, growing fears over a war with Iraq and a suffering world economy created an unprecedented 11 days of stock contraction in world markets and the loss of hundreds of billions of dollars. Opec reacted by calling a special meeting and agreeing to raise output by 1.5mn b/d.

In February BP agreed a $6.75bn deal with Tyumen Oil and Sidanco significantly increasing its presence in Russia – the world's second-largest oil exporting country. Environmental campaigners immediately condemned the deal.

In its 21st Offshore Licensing Round, the UK introduced 'promote licences', a new style of licence designed to attract smaller independents to the region.

In March, unrest with the outbreak of war in Iraq and ethic warfare in Nigeria was accompanied by falling oil prices.

The US and Libya moved closer toward a resolution of the Lockerbie incident, with Libya reportedly accepting responsibility and agreeing to make a staged payment of $2.4bn.

In August, the industry largely ignored Brazil's ANP Round 5, with just five companies and Petrobras participating.

November marked BHP Billiton's first commercial production in Algeria, with gas flowing from the $1bn Ohanet development project. Shell signed a landmark gas deal with Saudi Arabia, becoming the first company in decades to own rights to the Kingdom's huge gas reserves.

The Discoveries and Highlights 2003 *supplement is provided as part of the* IOL *service, which is available by subscription from IHS Energy. It includes 51 weekly issues plus four quarterly acreage reports. For non-customers, there is a free 30-day trial to* IOL*. For more information, please contact* **www.ihsenergy.com/iol/trial** *or T: +44 (0)1666 501226 in the UK, or +1 713 840 7420, ext. 321, in the US.*

NEW Publications

Adapt or Die – The Science, Politics and Economies of Climate Change*

Editor: Kendra Okonski (Profile Books, 58A Hatton Garden, London EC1N 8LX, UK. T: +44 (0)20 7404 3001; F: +44 (0)20 7404 3003; **www.profilebooks.co.uk***). ISBN 1 86197 795 6. 301 pages. Price: £14.99.*

Few people question that climate change is occurring, but this book challenges the view that 'climate control' will benefit humanity or the environment, or prevent the negative effects of climate change. Arguing that the best approach to climate change is not alarmism but adaptation, 13 expert contributors suggest policies that promote human and environmental well-being both now and in the future. They suggest that • global and European climate policies are driven by vested interests and will unjustly harm European consumers and taxpayers, and poor people everywhere • poor countries will suffer from global 'climate control' through trade restrictions, future limits on emissions, and slower development • eliminating disease, enhancing access to existing and new technologies, improving infrastructure and eliminating poverty would benefit people and the environment, and reduce vulnerability to climate change • our human ancestors survived by adapting to change, and we should do the same • adaptation is fostered by policies that promote certainty, flexibility and decentralised responsibility • an adaptation strategy would also help to solve unknown future problems.

Blowout and Well Control Handbook*

Robert D Grace (Gulf Professional Publishing/Elsevier, Linacre House, Jordan Hill, Oxford OX2 8DP, UK. T: +44 (0)1865 474010; F: +44 (0)1865 474011; **www.bh.com***). ISBN 0 7506 7708 2. 469 pages. Price (hardback): £85.*

This handbook provides a complete reference for blowout containment and well control for the drilling or petroleum engineer, outlining the most successful practices and procedures used today, including many techniques first developed in the Gulf War. The book also features updated case histories, along with detailed procedures and analysis of alternatives for solving specific problems that the engineer might face in the oil field on a daily basis. The final two chapters, documenting the author's adventures while capping well fires in Kuwait during the Gulf War, is a fascinating account of one US civilian's experiences in the war, of interest to the engineer and layman alike.

A Guide for Reduction and Disposal of Waste from Oil Refineries and Marketing Installations*

(Concawe, Boulevard du Souverain 165, B-1160 Brussels, Belgium. T: +33 2 566 91 60; F: +33 2 566 91 81; e: **info@concawe.be***). 36 pages. Available as free download from* **www.concawe.be**

This report has been written primarily for those in the oil refining and marketing industry who have responsibility for the management of waste and its disposal. It should also provide useful information to the authorities who exercise legal control over these activities. The guide lists the types of wastes commonly encountered in the industry and highlights techniques for minimising the quantities generated. Guidance is given on the methods of pre-treatment and disposal, together with information on how to select and monitor waste facilities and contractors, to ensure a high quality and safe disposal operation. Information is also provided on documentation and labelling of waste cargoes and reference is made to legislation and sources of additional information.

** Held in EI Library*

The Association for Science Education (ASE) Annual Meeting 2004

This year's ASE exhibition and conference was held at Reading University on 8–10 January, writes ***Gill Haben***, EI Education Manager. Considered *the* event for the science education community, thousands of people attended over the three days.

The Energy Institute stand proved extremely popular and I seemed to be constantly demonstrating *Discover Petroleum* – **www.energyinst.org.uk/discover** – on a large plasma screen whilst distributing our educational resources to eager attendees. I also took the valuable opportunity to gather ideas and feedback, and generally 'spread the word' about the Institute's work.

This year's meeting coincided with major developments in science education and the programme's many talks, lectures, workshops and booked courses covered a number of key aspects. The Rt. Hon. Charles Clarke, MP, Secretary of State for Education, addressed the conference. Key speakers included Sir Patrick Moore, as a guest of the Royal Society, who chaired a session on astronomy, entitled 'In conversation with… Sir Patrick Moore' and Dr Tim Hunt, Nobel Prize winner, who gave the Nuffield Foundation Lecture on cell growth and cell division.

The ASE designated the Saturday as a 'special primary day'. This was particularly relevant to our promotion of *Discover Petroleum,* as the site began life aimed at 7- to 11-year olds.

All in all it was an exhausting, but exciting and very valuable, event. Arriving home on Saturday evening I collapsed in a heap – however, I wouldn't have missed a moment…

The Commercial Benefits of Ergonomics

4 March 2004, London
Organised by The Ergonomics Society
(visit **www.ergonomics.org.uk/events/IDC0304.htm**)

For more information about the EI's activities in the human factors sector, visit **www.energyinst.org.uk/humanfactors**

Don't forget!

The March issue of *Petroleum Review* will arrive slightly later than usual next month. This delay enables us to bring you exclusive coverage of IP Week 2004 as well as the annual *Retail Marketing Survey*.