Petroleum review

NOVEMBER 2003

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Lubes and greases

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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: PL19-3A platform in China's Bohai Bay
Photo: ConocoPhillips

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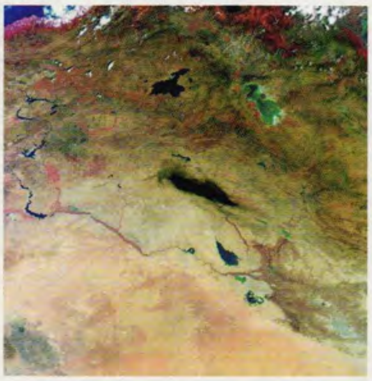

Right: Smoke from the oil fires blanketing central Iraq following pipeline sabotage in late September.
Photo: Envisat European Space Agency

ROUNDUP From the Editor

Good news about carbon dioxide

New technologies are emerging all the time, but only a fraction of these become commercial propositions – and only the tiniest fraction have major and lasting impact.

Researchers at Yamaguchi University believe that they have found a way to economically separate out carbon dioxide (CO_2) from flue gases using a zeolite molecular sieve (see *New Scientist*, 4 October 2003, p26). To date, the only commercial ways of stripping CO_2 from flue gas have been solvent stripping using monoethanolamine, with solvent recycling, or liquefying waste gases and distilling out the CO_2. Both processes are currently uneconomic, although Statoil uses the second process to generate the CO_2 it pumps into the Sleipner field – the economics being totally dependent on tax breaks from the Norwegian Government.

The Japanese researchers claim the CO_2 molecules at 0.33 nanometres diffuse through the sieve at 100 times the rate for N_2 molecules at 0.36 nanometres, and that the sieves can work at up to 200°C.

The power industry is reported to be excited by the prospect of an economic solution to CO_2 separation. Although the technology has not really got out of the laboratory yet, for the oil industry there is the prospect that CO_2 could be separated from flue gases on offshore platforms and injected into the reservoir. This would provide the double benefit of reducing emissions and enhancing recovery.

It is very discouraging to have to report that (according to *New Scientist*) environmentalists are hostile, seeing it as a 'quick fix' and, more strongly, 'a prescription for business as usual'. Once again this raises the question whether environmentalists are trying to solve contemporary problems or seeking to change our whole way of life?

Disappointing discovery

The latest discovery trends as reported by IHS Energy (see p36) can only be described as highly disappointing. As far as can be discerned only three countries have replaced reserves on a five- and ten-year basis – Angola, Brazil and Kazakhstan. Australia more or less joins the exclusive club, but most of the discovery has been gas liquids and its oil production is already in decline. North America is not documented by IHS but, if Canada's tar sands are added in as reserves (despite being found a long time ago), Canada could also join the elite group.

The effects of this failure to replace reserves is particularly apparent in the Asia-Pacific region (see p12), where the largest oil producer – China – is having great difficulty in expanding production and may move into decline as early as 2005/2006. Indonesia, the other regional giant is experiencing quite rapid production decline, as is Australia. So far, Malaysia and Brunei are holding their own and expanding a little.

Challenge to Opec

A certain amount of publicity has been given to Opec countries such as Algeria and Nigeria, who are seeking higher production quotas that are more in line with their production capacities. In the case of Nigeria recent political tensions have restricted its ability to use its installed capacity. But, the real problem for Opec is how to deal with Indonesia and Venezuela, both of which have production quotas that are significantly larger than their production capacities (Orinoco extra-heavy oil is not included in Opec quotas).

UK forecourts battle

The UK retail business had suddenly become exciting again. A year or so ago Shell launched a high octane differentiated petrol – Optimax – which appears to have triggered the revival of sales of premium petrol grades (see p11). BP has now launched two new grades under the Ultimate branding – a higher octane premium and a high cetane (58) premium diesel with both claimed to offer superior performance (see p10). Some people are already noting that high performance, high cetane diesel would be the logical end use for the 70–75 cetane diesel produced by GTL plants.

First chill

The first chills of the northern hemisphere winter have seen spot Brent prices moving above \$30/b, while spot gas prices in the US are now back above \$5mn Btu (a level that makes LNG imports very profitable). With Iraq struggling to export significant quantities of oil prices this winter will largely be determined by the weather.

Chris Skrebowski

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

e world

The UK Health & Safety Executive (HSE) recently published its latest detailed statistics on fatal injuries in HSE and local authority enforced sectors in 2002/2003. The *Statistics of Fatal Injuries 2002/2003* document can be found on the HSE website at **www.hse.gov.uk** For the combined three-year period of 2000/2001 to 2002/2003, the rate of fatal injury to employees in 'the extraction of crude petroleum and natural gas' was 8.5 per 100,000 workers – there were no fatal injuries in the sector in 2002/2003.

A new website has been launched as part of the Respect for People initiative that is aiming to develop and implement voluntary workforce key performance indicators and benchmark measures to improve the status and workplace conditions of lorry drivers and enhance driver retention, recruitment and development. Visit **www.respectforpeople.org** for more information.

The TWI has launched two new personnel certification schemes under the Certification Scheme for Welding and Inspection Personnel (CSWIP) umbrella, including a General Inspector scheme for topside personnel. For more information, visit **www.cswip.com**

Improvements to the 'Customer Lounge' – the Shell Chemicals business-to-business website – are reported to have made 'purchasing petrochemicals as easy as bidding on eBay'. The website allows customers to place product orders, check order status, share documents and download technical information. Besides providing order and account history, the site also offers material safety data sheets, certificates of analysis and a 'my documents' section that can be tailored for each customer.

Among the site's new features is a Health, Safety and Environment/Technical Tab that allows Shell chemicals companies to share technical information with customers. In addition, solvents customers can access a technical service database that enables them to find and compare solvents for specific applications. Another recent addition is a railcar tracking feature where customers in North America can follow rail deliveries via the Customer Lounge. This is part of the order status function that enables customers to check the status of any order, regardless of whether it was placed online or via traditional channels.

Visit **www.shellchemicals.com** for more information.

In Brief

UK

Total has brought onstream the *Nuggets N4 gas field in the Alwyn area of the northern North Sea at an initial rate of 1.5mn cm/d.*

Tullow Oil UK has increased its interests *and assumed the operatorship of the offshore Hewett gas field complex, the export pipelines and the associated onshore processing terminal at Bacton on the East Anglian coast.*

Marathon Oil has commenced production *of gas and condensate from the Braemar field in North Sea block 16/3c. The field is producing 50mn cf/d of gas and 4,500 b/d of condensate.*

The Faroese Ministry of Petroleum is *preparing for a second licensing round to open in 1H2004.*

Talisman Energy has announced first *oil from the Blake Flank development located in UKCS block 13/24 in the central North Sea. Current production is 5,200 b/d and the development will add an estimated 20mn barrels of reserves to the Blake field.*

Apache North Sea Limited, which first *entered the North Sea in April this year with its acquisition of the giant Forties field from BP, has joined the UK Offshore Operators' Association.*

BG has completed the sale of a package *of its North Sea assets to Perenco for $135mn. The sale includes BG's interests in 11 non-operated fields as well as the site and onshore processing facilities at Bacton in North Norfolk.*

Europe

Norsk Hydro has brought the Fram *Vest field onstream on schedule and 15% below the original budget estimate of NKr4.3bn. The field is expected to produce for 15 years, plateauing from January 2004 at just over 60,000 b/d of oil. Recoverable reserves are put at 100mn barrels of oil and 3.5bn cm of gas.*

The first of 12 pre-drilled wells on the *North Sea Grane oil field entered production on 23 September at NKr1.5bn less than budget and three weeks ahead of schedule. The Norsk Hydro-operated field is expected to produce 210,000 b/d. Some 700mn barrels of oil are forecast to be recovered.*

Historic North Sea gas pipeline agreements

UK Energy Minister Stephen Timms and his Norwegian counterpart, Einar Steensnaes, have signed an agreement on principles that will be incorporated in a new Framework Treaty for future cross-border oil and gas cooperation between the two countries. The deal is a substantial step towards addressing and overcoming the UK's predicted reliance on imported gas from 2007. It has the potential to fulfil up to one-fifth of the UK's annual gas demand.

According to Timms, the agreement provides a firm basis for new investments by industry, most notably the proposed Britpipe project from the Ormen Lange field that will bring an estimated 20bn cm/y from winter 2006/2007 – some 20% of the UK's current annual demand.

The regulatory terms for a prospective link between Norway and UK dry gas infrastucture has also been agreed.

In addition, Shell UK and Esso Exploration and Production UK have signed landmark agreements with Statoil, Norske Shell and Esso Exploration and Production Norge for the export of some 20bn cm/y of Norwegian wet gas (rich in natural gas liquids), to the UK. The deals, which are subject to the Statfjørd partners sanctioning the redevelopment of the field, are expected to begin in 2007. They will last more than 10 years, help to secure Britain's future supply of gas and prolong the life of existing infrastructure.

Gas from Norway's Statfjørd reservoir will be transported across the median line to the Shell and ExxonMobil-owned Far North Liquids and Associated Gas (FLAGS) pipeline. The gas will be landed at the St Fergus gas terminal where it will be processed to extract natural gas liquids and to produce sales quality dry gas that will enter the UK's National Transmission System. The natural gas liquids will be transported to Fife NGL plant, with LPG subsequently exported via the Braefoot Bay marine terminal. Some product will be transferred to the ExxonMobil Chemical-operated Fife ethylene plant, thereby providing feedstock to the UK and European chemicals industry.

In addition to being the most attractive option for the Statfjørd owners, the transportation route established is expected to be an economic option for further imports of natural gas from Norway to the UK. Extending the life of existing infrastructure will also help support the commercialisation of remaining reserves in the UK Continental Shelf. The deal will also safeguard 450 jobs in Mossmorran in Fife, and 120 jobs at St Fergus, Aberdeenshire.

UFG comments that the gas supply agreement may delay the implementation of Gazprom's $5.7bn North European gas pipeline project to carry Russian gas to Germany under the Baltic Sea and from there to the UK as Norway will initially be able to satisfy all of the UK's import needs. Gazprom had been negotiating supply agreements with the main consumers for some time but has been unable to win a long-term agreement from the UK, which over recent years has tended to only buy gas on the spot market.

'The very fact that the contract with Norway has been signed means that the UK now recognises the need for long-term off-take guarantees (and the share of gas imports should reach up to 90% of UK consumption in 2020),' said the analyst. 'These guarantees should enable Gazprom to calculate a return on investments from its North European pipeline project.'

Aker Verdal wins Buzzard fabrication

Aker Verdal has secured the contract from EnCana for the construction of three steel jackets for the Buzzard field in blocks 19/5, 19/10, 20/1 and 20/6 of the UK sector of the North Sea. The contract – which covers the engineering, procurement, construction, load-out and sea-fastening of the three jackets and piles – has been valued at NKr750mn. Fabrication will start in spring 2004. Delivery is slated for 2005.

'The capital expenditure is four times higher than anything else in the next few years; it dwarfs the spend on the other oil fields,' reports Geoff Gillies of independent consultancy Wood Mackenzie. 'It is a very significant development for the industry in the UK.' He puts the value of the contracts at £1.2bn.

Discovered in 2001 and with reserves estimated at 460mn barrels, Buzzard is the most significant find in the past decade. The field is due onstream in 2006.

Karachaganak setback to 4Q2003

Initial pumping of condensate from the Karachaganak field into the CPC export pipeline has now been delayed to the fourth quarter despite the successful completion of Phase II of the $4bn project this summer, reports *Chris Skrebowski*. The cause of the delay is said to be contamination of the condensate with mercaptans (*IEA Monthly Report*, October 2003) or contamination by caustic soda (Interfax), although the two explanations are not incompatible. Initial production into the Atyrau pipeline linking to CPC actually began in mid-July and gas injection in the reservoir began on 2 July.

The Karachaganak field was discovered in 1979, with production starting up in 1984. Treatment facilities were at Orenburg and the field was essentially part of the Russian gas production system. The emergence of an independent Kazakhstan effectively cut the field off from the Russian system and the new Kazakh Government started negotiations on a production sharing agreement (PSA) with Eni and the BG Group. Although the production sharing principles were agreed in 1995, it wasn't until November 1997 that a final 40-year PSA was signed. By this time the consortium had expanded to include ChevronTexaco (20%) and Lukoil (15%; which had taken over Gazprom's share in the consortium), with Eni and BG each holding 32.5% of the new consortium.

A major expansion and redevelopment programme was initiated, with construction starting in 1999 and the main works contracts awarded in 2000. The scope of the so-called Phase II involved gas treatment facilities, the workover or deepening of 102 wells, and the construction of a 635-km export pipeline to Atyrau to join into the CPC export pipeline to Novorossiysk. The production and injection network of flowlines and infield lines was also refurbished and extended, and a 120-MW power station constructed.

In 2002 production hit a record 5.2mn tonnes of condensate and 4.7bn cm of gas, accounting for 11% of Kazakh liquids production and 42% of Kazakh gas production. All 2002 output flowed via the Orenburg processing facilities into Russia.

Once condensate exports via the link to Atyrau and the CPC commence in the fourth quarter production will expand up to 200,000 b/d of condensate and 700mn cf/d (7bn cm) of gas. The availability of better prices in the Mediterranean market means that most of the condensate will flow via Novorossiysk, although gas sales and some condensate will continue to be sold via Orenburg. With condensate reserves of 2.4bn barrels and gas reserves of over 16tn cf the Karachaganak field could support higher output levels. Further expansion phases are anticipated by the operators, but timing will depend on how the market and prices develop.

Opec to cut member production quotas

Having reviewed the current oil market, the recently convened Opec meeting noted that, whilst the global economy appeared to be improving, only normal, seasonal growth in demand is expected for the fourth quarter and the market continues to be well-supplied. In view of the continued rise in non-Opec supplies and the ongoing recovery in Iraqi production, stocks have been replenished and are rapidly reaching normal seasonal levels, with the supply/demand balance for the 4Q2003 and 1Q2004 indicating a contra-seasonal stock build-up. This could have a destabilising effect on the market that requires a reduction of supplies from all producers to ensure stability, stated Opec.

Also noting the gradual return of Iraq to the market, and in order to ensure balance to the market, Opec decided to remove 900,000 b/d of output and return to a ceiling of 24.5mn b/d, that was due to take effect from 1 November 2003.

Improving Nigeria's JDZ fiscal regime

Following extensive consultations between the Nigeria-Sao Tome & Principe's Joint Development Authority (JDA) and potential investors on the terms of the 2003 Joint Development Zone (JDZ) licensing round, the JDA has announced the introduction of an investment tax allowance (ITA) as an integral part of the fiscal terms applicable to the round. The ITA – 50% of qualifying capital costs – is an additional allowance for tax and will enhance the overall competitiveness of the JDZ fiscal regime, states the JDA.

Furthermore, a variety of other issues have been reviewed and a number of clarifications have been made – all of which will be addressed in updated versions of the model production sharing contract (PSC) and other legislation, which will be circulated to all interested parties as soon as possible.

In Brief

Marathon Petroleum Norge and Norsk *Hydro have announced an oil discovery on the Klegg well in production licence (PL) 036 offshore Norway. The find is thought to hold between 3mn and 5mn cm (20–33mn barrels) of oil reserves.*

Eastern Europe

Romania's state-owned Romgaz and *Wintershall are understood to have signed a 50:50 joint operating agreement to develop the Sighisoara gas field in Transylvania, central Romania. First gas is slated by the end of 2003.*

North America

Unocal's Gulf Region business unit has *agreed to sell 70 properties in the Gulf of Mexico and onshore Louisiana to Forest Oil for $295mn. Asset reserves are put at 34mn boe, with net production of about 18,000 boe/d.*

The Alberta Government is reported *to have drafted an interim compensation plan for gas producers whose wells have been shut-in in a bid to protect Canada's oil sands reserves.*

Devon Energy is understood to plan- *ning to drill for gas offshore the Mackenzie Delta – reportedly the first at-sea exploration there in over 15 years.*

Middle East

Petrovietnam is reportedly hoping to *resume operations at Iraq's Amara oil field later this year. Its $300mn development contract was signed with the Government of Saddam Hussein in March 2002, one of only three contracts with foreign oil companies approved by the former ruler.*

The much-delayed Shaybah gas devel- *opment project between a Shell-led consortium and Saudi Arabia is understood to have entered the final approval process after legal documentation agreements were signed in early October. Plans for the $5bn project are to be submitted for official approval. Shaybah is the only survivor of what was originally offered to multinationals as three core venture projects worth $25bn under the Saudi Gas Initiative (SGI). Two consortia led by ExxonMobil were scrapped earlier this year and the SGI was reopened to international bidders.*

In Brief

***Iranian state oil company NIOC has** given approval for Russian company Lukoil to take over 25% of Norsk Hydro's 100% stake in the Anaran block in Iran. Lukoil is understood to be planning to drill five exploration wells. The field may come onstream as early as 2005.*

***Sinochem subsidiary Atlantis Oman is** reported to be drilling a gas reservoir in block 40, onshore the Musandam Peninsula in northern Oman, which holds up to 300bn cf of reserves. It is thought that the block contains other reservoirs with the potential to yield 1.5tn cf of gas.*

***Snamprogetti is reported to have** signed a $381.8mn engineering, procurement and construction (EPC) contract with the Abu Dhabi Company for Onshore Oil Operations (ADCO) for the Bu Hasa field. The project, expected to be completed by 4Q2006, involves the construction of a plant with a total capacity of 730,000 b/d of oil.*

Russia & Central Asia

***Surgutneftegaz has purchased two** new oil fields in western Siberia – North-Yutymsk and South Yutymsk – in order to increase its oil reserve base. The fields are thought to hold reserves of 242mn barrels of oil.*

***Russia will produce about 600bn cm** of gas in 2005, according to the head of the Ministry of Economic Development and Trade, German Gref.*

***Kazakhstan is planning to increase gas** production from 10bn cm to 80bn cm by 2015, Kazakhstani President Nursultan Nazarbayev recently declared.*

***Shell has approved a budget of over** $1bn for the development of the Salym fields – West Salym, Upper Salym and Vadelyp – in Western Siberia, Russia. West Salym is the largest of the three fields, accounting for about 80% of the total estimated reserves. It is due onstream by the end of 2005, with production expected to peak at 120,000 b/d in 2009.*

Asia-Pacific

***Cairn Energy is reported to have** encountered hydrocarbons at its RJ-Q-1 exploration well in block RJ-ON-90/1 in Rajasthan.*

NEWS Upstream

Rebuilding the Iraqi oil industry

Security problems and dilapidated equipment will prevent Iraq's oil production capacity regaining levels seen before the US occupation until at least 2H2004, according to a recent Reuters poll of energy analysts. In the poll of 13 analysts, the mid-range forecast saw Iraqi output capacity restored to a pre-war 2.8mn b/d in 4Q2004. However, estimates ranged from mid-2004 to not before 2006.

As well as looting of equipment, a major problem is the pipeline connecting the northern Kirkuk oil fields to Turkey. Sabotage has kept it out of action since the March occupation. The pipeline could carry 900,000 b/d before the war and was due to re-open in October, barring further sabotage. Meanwhile, extra power generators have improved production in the south, which is now nearing pre-war output. Before the war, Iraq exported around 2.2mn b/d and used 0.5mn b/d.

The poll's median forecast put capacity at 1.8mn b/d by the end of this year. By the end of 2004, it was expected to rise to 2.8mn b/d. Most analysts thought the 3.5mn b/d level, Iraq's capacity before the 1990–1991 Gulf War, was at least two years away and possibly as far out as 2008. 'It hinges entirely on the security situation in Iraq,' said John Waterlow at Wood Mackenzie in Edinburgh. Frederic Lasserre at SG Securities in Paris added: 'There is no way they can do it by just fixing the existing facilities here and there. They need new technology. They need to revamp most, if not all, of the existing infrastructure.'

After the Gulf War, UN sanctions forced Iraq to slash production, leading to years of under-investment in the industry. Exports resumed in 1996 under the UN oil-for-food-scheme. Under the programme Iraq can claim some $1.7bn in oil equipment, but greater investment is needed.

At around 112bn barrels, Iraq's proven oil reserves are second in size only to Saudi Arabia, so production could eventually go far higher. 'They need some new fields to get to the 4.5 to 5 [mn level],' said Leo Drollas at the Centre for Global Energy Studies. 'They have those new fields lined up but that needs a different environment and foreign investment and that's down the line – 2007, about that sort of timeframe.'

UK revenues buoyed by higher oil price

Monthly UK oil production increased 1.5% in July to 1,967,643 b/d, while gas production fell 6.4% to 9.011mn cf/d. This was in contrast to the figures for the year which saw gas production increase by 11.5% and oil production decrease by 5%, according to the latest Royal Bank of Scotland *Oil & Gas Index*. However, sustained high oil prices maintained revenues, which were up on both the month and the year at $28.4/b.

'Opec's latest decision to cut production at a time when market over-supply could result in lower prices, has sent a signal to markets that Opec intends to work very hard to maintain prices within its target range of $22–$28/b,' commented Tony Wood, Senior Economist. 'A wide range of factors will influence future oil prices. However, we have to bear in mind that the current agreement is the most successful in Opec's history.'

Year Month	Oil production (av. b/d)	Gas production (av. mn cf/d)	Av. oil price ($/b)
Jul	1,938,677	7,569	25.70
Aug	1,831,386	8,744	28.40
Sep	2,001,329	8,699	28.40
Oct	2,133,641	10,611	27.60
Nov	2,165,277	11,276	24.20
Dec	2,257,244	12,114	28.30
Jan 2003	2,158,924	12,114	31.20
Feb	2,086,517	12,374	32.20
Mar	2,104,855	13,015	29.90
Apr	1,922,505	12,155	27.50
May	1,934,653	9,966	25.60
Jun	1,937,643	9,629	27.30
Jul	1,967,643	9,011	28.40

Source: The Royal Bank of Scotland Oil and Gas Index

North Sea oil and gas production

Expanding operations at Tengiz

Kazakhstan and partners of the Tengizchevroil oil producing joint venture are understood to have signed a key agreement to expand operations at the Tengiz oil field at a cost of approximately $3.5bn. The Second Generation (SGP) and Sour Gas Injection Projects (SGI) will increase oil production capacity from the current rate of around 13mn t/y to 20mn t/y.

Shareholders in Tengizchevroil are ChevronTexaco (50%), ExxonMobil (25%), the Kazakh Government as represented by KazMunaiGaz (20%) and the Russian-US joint venture LukArco (5%).

The field is also producing between 2bn and 3bn cm/y of associated gas.

In addition to increased crude oil production, SGP will also increase production of associated dry gas, propane, butane and saleable sulphur products. The SGI project will increase oil production and will develop state-of-the-art gas injection technology for enhancing oil recovery by injecting produced sour gas to maintain reservoir pressure. This will enable Tengizchevroil to pump more export crude along the Caspian Pipeline Consortium's pipeline to the Russian Black Sea port of Novorossiysk.

Lukoil plans Caspian terminal expansion

Lukoil has put onstream the first part of its crude oil and product terminal on the Caspian Sea located in Russia's Astrakhan region. The terminal's current capacity stands at 1mn t/y, but is expected to be increased to 3mn t/y by 2005. The terminal will load crude oil and products transported by railway to the port of Astrakhan, from where they can be exported in sea-river class tankers. The introduction of the new terminal will allow the company not only to reload crude and oil products from railway cars into tankers, but also in reverse. Lukoil intends to use the terminal to supply its crude oil and products to Iran, within the framework of its oil-swap agreements.

Lukoil reportedly plans to borrow around $200mn to expand its Varandey port on the Arctic Sea to 500,000 b/d, or 25mn t/y, of oil.

Recent African E&P developments

***Stella Zenkovich* reports on recent African E&P developments.**

- **Centurion Energy International of Calgary and Petro-Canada have struck a deal to explore the former's oil and gas prospects off the coast of Tunisia. As a result of the agreement, Centurion expects to take direct control of the Mellita permit, currently owned by one of its subsidiaries. For committing $13.5mn to exploration, Petro-Canada will get a 72.5% stake in the permit. State oil company ETAP will acquire a 50% stake if oil is discovered.**
- **The Sudanese Ministry of Energy and China's CNPC are to set up a geophysical prospecting joint venture following CNPC's discovery of a 2bn barrel oil field in Sudan.**
- **Shell's *Sea Eagle* FPSO has produced 10mn barrels of oil from Nigeria's EA field since it came onstream eight months ago. Some 30 of the 35 planned wells have been completed, with a combined production potential of 129,000 b/d.**
- **Having registered a representative office in Libya in February, Naftagaz Ukrainy is now in the final stages of registering as a foreign oil company allowed to sign PSAs for oil and gas exploration and production.**

Chad-Cameroon project officially inaugurated

The Chad-Cameroon oil development and pipeline project was officially inaugurated at a ceremony held at the project's operations centre in Kome, southern Chad, on 10 October. Completed one year ahead of schedule, the pipeline transports previously landlocked oil 660 miles from the Bolobo, Miandoum and Kome oil fields, near Doba, in southern Chad, through eastern Cameroon to an export terminal facility at Kribi, Cameroon in the Gulf of Guinea. From there the oil is transshipped from a floating storage and offloading (FSO) vessel, located seven miles offshore, for export to world markets.

The next steps for the project include completion of the central treatment facilities by the close of 2003. Full production capacity of 225,000 b/d is targeted for early in 2004, while drilling operations will continue in the oil fields over the next two years.

Project partners are ExxonMobil (operator, 40%), ChevronTexaco (25%) and Petronas (35%). Project construction began in October 2000.

In Brief

***GTL Resources has confirmed that it** will proceed to finalise the construction and financing of a 1mn t/y methanol plant on the Burrup Peninsular in Western Australia. Construction is due to begin in 1Q2004.*

***Shengli Oilfield's Heba No 1 well is** reported to have discovered a large gas reserve near Bazhong city in the Sichuan Province, southwest China. Reserves are put at between 110bn and 150bn cm.*

***OMV has sold a 9.8% stake in the** Pohokura gas field to its consortium partner Todd Petroleum Mining, together with shares in three other exploration licences in New Zealand, for an undisclosed sum.*

Latin America

***Algeria's state-owned Sonatrach is** understood to have acquired a 10% stake in the Camisea gas project from Pluspetrol, reducing the latters's stake in the project to 26%.*

***Petrobras is reported to have discovered** a field containing 14.8tn cf of gas and 3.95bn barrels of oil. First gas is slated for 2006; production is destined for the Brazilian domestic market.*

Africa

***ChevronTexaco has announced a significant** extension of the Usan field discovery in deepwater oil prospecting licence (OPL) 222, offshore southeastern Nigeria. Two zones were tested in the Usan-4 appraisal well and flowed at 4,400 b/d and 6,300 b/d under restricted flow conditions.*

***Drilling on the East Espoir field in the** Cote d'Ivoire has finished with the completion of the fifth Espoir production well, which went into full production on 6 September 2003. Gross production from Espoir averaged 26,000 boe/d for the first week of production following completion of the well. The West Espoir development project is due to be sanctioned by the field co-venturers, including Tullow Oil (21.33%), in October 2003, with first oil expected during 2Q2005.*

***Deloitte & Touche is soon to launch a** new product – Petroview North Africa – that it claims will help companies break into the markets of Algeria, Egypt, Libya, Morocco and Tunisia.*

In Brief

UK

***The UK Department of Trade and** Industry (DTI) has published its latest editions of Energy Trends and its Quarterly Energy Prices bulletins, which provide detailed statistics for 2Q2002. The publications are available in hard copy from the DTI on subscription, price £35/y and on the Internet at* **www.dti.gov.uk/energy/inform/energy_stats_overview/index.shtml**

Europe

***European Union (EU) Energy Ministers** have agreed new rules for applying value added tax to cross-border gas supplies that will reduce confusion created by increasing cross-border trading in energy supplies, reports* Keith Nuthall. *Now, traders re-selling supplies who are not established in the same country as the supplier will pay VAT through an obligatory reverse charge system.*

***A request by the Commission for** tough powers to order the distribution of natural gas stocks around the EU during a supply emergency are being vigorously opposed at the European Parliament, writes* Keith Nuthall. *It wants Brussels to drop its planned assumption of discretionary powers and a rule telling Member States to maintain 120 days worth of minimum stocks, which it views as excessive.*

***Statoil has entered into an agreement** with EDF Trading Limited (EDFT) to deliver 900mn cm of gas over a two-year period. The delivery point will be the Zeebrugge Hub in Belgium. The agreement will run from 1 January 2004 to 1 October 2005.*

***Leif Terje Løddesøl has resigned from** his position as Chairman and member of Statoil's Board of Directors.*

North America

***Enbridge is reported to have proposed** the construction of a $800mn pipeline to link its terminal at the west end of Lake Superior to a hub in southern Illinois to carry more crude from the Alberta oilsands to US markets. The 1,014-km Southern Access Pipeline would initially carry 250,000 b/d of oil, with start-up expected in 2007.*

***US natural gas stocks should rise to the** key 3tn cf level by 1 November,*

NEWS Industry

Russian oil – the real opportunities

According to a recently released Wood Mackenzie study — *Russian Oil: Where Are The Real Opportunities?* – Russia has a number of attractions for US oil companies, despite the risks and challenges involved. 'Russian reserves can be acquired cheaply, relative to alternatives, and there is scope to create value by improving efficiency and applying western management techniques to Russian fields. Assets and ventures vary significantly in scale, so there are opportunities for smaller companies as well as the super-majors,' states the report.

According to Tim Lambert, a Director in Energy Consulting at Wood Mackenzie: 'Russian production has been growing rapidly in recent years, and many observers consider that it should exceed 10mn b/d by 2010. On an unconstrained basis – assuming that all required investment was put in place – we believe that production could reach 12mn b/d in 2010 and 2011.'

The study presents a range of opportunities that Wood Mackenzie shows will vary significantly in terms of timing, materiality, risks and barriers to entry. 'Realising any of the opportunities will present significant challenges and will be highly competitive,' states the analyst.

Tidal power first to come onstream

Statoil reports that the tidal power plant located in Kval Sound outside Hammerfest in northern Norway will soon start generating electricity. It is claimed to be the first tidal power station of its kind in the world.

Statoil owns 20% of Hammerfest Strøm, the company responsible in collaboration with ABB, Rolls Royce and Sintef for development of the prototype that will supply 700,000 kWh/y – corresponding to electricity consumption by 35 Norwegian homes.

The environment-friendly power supply is achieved by submerging large water turbines which can harness the strong tidal current in the Kval Sound. Unlike other tidal power stations, the new facility does not depend on the regular alternation in water height between high and low tide. The submerged structure weighs 120 tonnes. Its turbine blades have been made in glassfibre-reinforced plastic and measure 10 metres from hub to tip. Their rotation is converted to electricity via a generator, with the power transmitted to the land station via a submarine cable.

Aktau port to initially support BTC pipeline

Kazakhstan plans to initially use the port of Aktau to transport oil to Baku to be supplied into the Baku-Tbilisi-Ceyhan (BTC) pipeline, according to Kazakh Deputy Energy Minister Lyazzat Kiinov. It is planned to build a new terminal, either in the port of Kurik (76 km southeast of Aktau) or further to the south, close to the border with Turkmenistan, at a later date.

He also reportedly noted that at the moment the issue of building a subsea pipeline between Azerbaijan and Kazakhstan is not being discussed as calculations have shown that transportation of up to 20mn t/y of oil is profitable by tanker. Construction of a pipeline may be discussed for larger volumes.

Construction work on the 1,767-km, 50mn t/y Baku-Tbilisi-Ceyhan pipeline will complete in 4Q2004. Plans are to export Azeri oil from Ceyhan in 2Q2005.

BP is to lend $500mn for the construction of the oil pipeline. Some 70% of the project's $2.95bn costs are to be covered by international creditors.

Methanex cancels Burrup project

North West Shelf Gas has stated that the amended conditional gas sale and purchase agreement between Methanex Australia and participants in the North West Shelf Venture lapsed on 30 September 2003 after Methanex announced that it would not be proceeding with its proposed methanol project on the Burrup Peninsula in Western Australia.

The two organisations first signed a sale and purchase agreement on 20 December 2001 for the supply of 200 terajoules of gas per day over 25 years from 2005. This was later extended by a further 130 terajoules of gas per day over 16 years, starting in 2006. Methanex is now studying an alternative design to support its long-term methanol supply to its customers in the Asia-Pacific from the Burrup.

Norwegian energy budget unveiled

The Norwegian Ministry of Petroleum and Energy has proposed expenditures of NKr22.56bn and income of NKr81bn in the 2004 budget. The most important measures will be related to:

- prioritising the work for sustainable changes in energy use and energy production;
- increased commitment to petroleum research;
- increased commitment to research related to the development of sequestration technology for gas fired power plants; and
- increased safety in landslide areas.

The commitment to supply security and change in energy use and energy production through the Energy Fund and Enova SF will be strengthened in 2004. The mark-up on the electricity transmission tariff increases from 0.3 to 0.8 øre per KWh in 2004. This will increase the income to the Energy Fund from approximately NKr190mn in 2003 to approximately NKr460mn in 2004. In addition to income from the mark-up, the government proposes to transfer NKr130mn to the Energy Fund over the State Budget. Including income from interests, the income to the Energy Fund will increase to approximately NKr600mn in 2004, an increase of NKr130mn compared to 2003. The government also proposes to allocate NKr19mn to stimulate increased onshore use of natural gas in 2004.

For 2004 the government also proposes to allocate NKr321.4mn for research and development in the energy sector, an increase of NKr61.7mn – approximately 24% – compared to 2003. The increase is mainly related to a new research programme within the petroleum sector (NKr28.5mn) and increased commitment to research related to developing sequestration technology for gas-fired power plants (NKr30mn).

The government proposes to allocate a total of NKr50mn to strengthening the development of technologies and solutions for reducing emissions from gas-fired power plants. It also proposes to increase the commitment related to micro-scale power plants through the Norwegian Water Resources and Energy Directorate.

The total net cashflow from State petroleum activity is estimated to be approximately NKr143.5bn. The net cashflow consists of about NKr54.1bn in net income from the State's Direct Financial Interest (SDFI), NKr84.3bn in taxes and approximately NKr5.1bn in stock dividend from Statoil.

SDFI's operating profit for 2004 is estimated at approximately NKr52.4bn. The current oil price estimate is NKr170/b for 2004. SDFI's share of investments on the Norwegian Continental Shelf is estimated at NKr19.7bn, an increase of NKr4.6bn compared to 2003.

CPC pipeline needs to increase capacity

CPC General Director Ken MacDonald is reported to have stated that oil companies have applied to transport 26mn tonnes of oil through the Caspian Pipeline Consortium pipeline in 2004. The pipeline currently transports about 1.4mn tonnes of oil per month and the inclusion of output from the Karachaganak field will boost volumes to about 20mn tonnes of oil by the end of this year.

MacDonald noted that CPC would have to increase the capacity of the system in the future in order to satisfy the forecast requirements of shareholders, beginning in 2006. Operator Tengizchevroil is currently implementing an investment programme that will increase production at Tengiz by 12mn t/y – to about 20mn t/y in 2007 (see p6). The development of other fields, in both Kazakhstan and Russia, will increase demand for the CPC's oil transportation capacities from the Caspian region to more than 50mn t/y.

The CPC chief also said that Russia plans to build connector pipes to provide additional access for oil produced in Western Siberia. He also noted that CPC has signed an agreement with KalmTEK to receive oil from Kalmykia. He stressed that CPC will have to increase the system to its full 67mn tonne capacity several years earlier than the date set down in the feasibility study.

Power blackout hits Italian mainland

A massive power cut on 28 September left almost all of Italy in darkness. An accident on a power supply line in neighbouring Switzerland is thought to have caused a domino effect that triggered grid failure across Italy. Only the island of Sardinia escaped the blackout.

Italy is heavily dependent on energy imports, importing up to 17% of its power compared with a Europe-wide average of just 2%.

In Brief

according to US Energy Secretary Spencer Abraham in mid-September.

***ConocoPhillips is understood to have** proposed a new LNG import terminal to be located on an abandoned US Navy site in Harpswell, Maine. ConocoPhillips is a 50:50 partner with TransCanada in a $350mn, 500,000mn cf/d LNG import project known as Fairwinds.*

Middle East

***Iraqi Oil Minister, Ibrahim Bahr al-**Uloum, is reported to have survived an assassination attempt in Baghdad on 5 October 2003.*

***BP claims to have broken a world** record in LPG recovery, achieving 99.75% recovery of propane and essentially 100% recovery of butane and condensate at its plant in Sajaa, which it operates on behalf of a joint venture with the Government of Sharjah.*

***Qatar's Oil Minister Abdullah Al** Attiyah is reported to have stated that the country is planning to invest up to $30bn to boost its exports of LNG to more than 45mn t/y by 2010. The state currently exports around 15mn t/y.*

***Iraq oil exports through the Mina Al** Bakr terminal reportedly rose to over 1mn b/d in September, a rise of 55% on August.*

***Robert E McKee, a former executive** from ConocoPhillips, is reported to be the new senior advisor to the Iraqi Oil Ministry. He will replace Philip Carroll.*

***Saudi Aramco has reportedly awarded** a $1.7bn contract to Jacobs from the US for the construction of a natural gas liquids (NGL) recovery plant. The plant was intended to be built under the collapsed Saudi Arabian gas initiative with ExxonMobil.*

Russia & Central Asia

***Transneft, the Russian pipeline** monopoly, is reported to have announced that it is no longer interested in taking a stake in the Latvian oil port in Ventspils.*

***Gazprom has announced that it will** not start pricing all its gas sales in euros. Instead, it will have contracts in both euros and dollars. The company has stated that it is 'well able' to deal with the currency risk.*

In Brief

Gazprom is reported to have stated *that Shell and Total are interested in participating in a $5.7bn pipeline project to transport gas from Russia to Germany.*

Transneft is reported to have approved *a Rb10bn ($330mn) loan from Sberbank to expand the Baltic Pipeline System from 360,000 b/d to 840,000 b/d in May–June 2004.*

The EBRD (European Bank for *Reconstruction and Development) wants to lend up to $120mn to the ACG (Azeri, Chirag, Deep Water Gunashli) Phase 1 offshore Caspian oil drilling project, reports* Keith Nuthall.

ExxonMobil was reported to have *been in discussions with Yukos about taking a 40% stake (possibly even 50%), worth up to $25bn, in YukosSibneft as the $45bn merger was finalised on 2 October.*

Lukoil has put onstream the first part *of its crude oil and product terminal on the Caspian Sea located in Russia's Astrakhan region. The terminal's current capacity stands at 1mn t/y, but is expected to be increased to 3mn t/y by 2005.*

Gazprom is reported to be planning *to buy 87bn cm of gas from Uzbekistan in 2004–2012.*

Russia has committed itself to *increase its oil supplies to China by railway following the delay in construction of an oil pipeline from Eastern Siberia.*

Latin America

Venezuela's state-owned PdVSA is *understood to be planning to sign a financing agreement before the end of the year with Shell and Mitsubishi to build the $2.7bn Mariscal Sucre liquefaction plant, with work on the 4.7mn t/y plant to begin in 2004.*

Africa

BG has signed a sale and purchase *agreement with Nigeria LNG (NLNG) for long-term LNG supply into the Lake Charles import terminal in Louisiana, US. BG will acquire 2.5mn t/y of LNG for 20 years, beginning in 2005 or early 2006, from the NLNG Plus project (Trains 4 and 5) on Bonny Island, Nigeria.*

Enel in gas talks

Italian power utility Enel is reported to be in talks with Russian and Middle Eastern suppliers regarding new gas imports to fuel an expansion into domestic retail gas sales. The Russian talks are said to be for gas in addition to the 3bn cm that Gazprom has already agreed to begin supplying Enel in 2005.

Enel needs some 20bn cm by 2006 for all its gas needs, with supplies coming from Algeria, Nigeria and Qatar. A new LNG plant is also planned by an Enel-BG joint venture in Brindisi, Italy. Gas and LNG projects in Iran, Qatar, Egypt are also under consideration.

NLNG delivery deal

Total and Nigeria LNG (NLNG) have signed a sales and purchase agreement covering the supply of 1.2bn cm/y of LNG produced at the Bonny LNG plant in Nigeria. Deliveries are slated to begin in 2007, for a duration of 20 years. Total's gas and electricity trading and marketing arm, Total Gas & Power, will distribute the gas in Europe and North America.

Total holds a 15% stake in NLNG. With three trains currently in operation, two trains under construction and one additional train under development, the NLNG-operated plant is set to become one of the world's largest LNG facilities.

Final commissioning for OCP pipeline

EnCana recently sold its first tanker load of Ecuador oil that was shipped via the country's new OCP Pipeline. The oil tanker *Fidelity*, with a cargo of 705,000 barrels of Napo crude oil, departed from the Balao loading terminal on the Pacific coast of Ecuador on 19 September, headed for markets in the US.

The $1.4bn OCP Pipeline, with a design capacity of 450,000 b/d, is in the final stages of commissioning. It is financed 75% with non-recourse project debt. EnCana holds a 36% interest in OCP and holds a shipping commitment of 108,000 b/d. This major Ecuadorian infrastructure project stretches more than 500 km from the Oriente Basin of Ecuador, across Latin America's Andes Mountains, to the Pacific coast. The pipeline is expected to be fully operational this autumn, shipping more than 220,000 b/d by the end of 2003.

Ecuador's oil production growth has been constrained until now as the country's only other export pipeline was operating at capacity.

Pipeline expansion

Gazprom and KazMunaiGaz are reported to have discussed an expansion of the Kazakh gas pipeline network – currently the only route for both Turkmen and Uzbek gas to flow into European Russia. The design capacity of the pipelines is 50bn cm/y, although technical problems have reduced this to between 35bn and 40bn cm/y.

UFG states that the discussions indicate that Gazprom prefers to import gas from Central Asia rather than to develop the Yamal Peninsula field. Choosing one of the options is vital in order to compensate for decreasing output from Gazprom's main fields in the medium term as the company has, so far, refused to provide much encouragement to independent gas producers in Russia, comments the analyst.

Gazprom has signed contracts to import up to 10bn cm/y from Uzbekistan and between 6bn and 7bn from Turkmenistan starting in 2005, with a gradual increase to 60–70mn bn cm/y by 2007, and up to 50bn cm/y from Kazakhstan by 2010.

Calls to US government

Greater energy efficiency and conservation are vital to keeping natural gas prices lower and less volatile as North American production levels off, according to a report from the National Petroleum Council. The report also calls for a relaxation on onshore and offshore drilling restrictions, and moves to encourage natural gas imports because 'production from traditional US and Canadian basins has plateaued'. Indeed, North American gas production is reported to be declining at a rate of more than 25%, which would lead to depletion in under four years.

Without significant advances in energy efficiency, the country's annual demand is forecast to rise above 30tn cf by 2025, up from about 23tn cf today, states the report. Yet even if advances in conservation are made, the Council has said that US natural gas resources would be insufficient to meet demand in the long term. Satisfying the nation's natural gas appetite will, therefore, require increased imports of LNG. To make that happen, the report recommends a quicker permitting process for new LNG terminals.

Ultimate road fuels for BP

Using the 'Ultimate' branding BP recently unveiled a new premium diesel and a reformulated premium petrol with comprehensive demonstrations at the Millbrook Proving Ground near Bedford, UK, on 7 October. The new fuels were rolled out to 400 service stations in the first week and were then to be supplied across the full network by January 2004. John Mumford OBE, Director of BP Oil UK, told *Petroleum Review* that Ultimate diesel will be priced around 3 p/l above regular, while the Ultimate petrol will cost up to 5 p/l more that regular unleaded.

Graham C Sims, Retail Director for BP, explained that customer research had shown that customers were interested in having greener, more environmentally friendly products – but only if there was either no cost penalty or a performance gain.

The new petrol formulation is a 97 octane premium unleaded with enhanced additives that are are said to offer double the usual cleaning power of normal grades, thereby restoring engine performance while reducing emissions. The additional octane will boost performance over the 95 octane regular grade. The new fuel will replace the existing premium unleaded on BP forecourts. In contrast, the new Ultimate diesel grade will be sold in addition to the normal BP diesel. Higher performance is offered as the Ultimate diesel has a cetane rating of 58 compared with the normal diesel cetane of 51/52.

Bernard Bullin, BP's Chief Scientist told *Petroleum Review* that although the exact formulations were proprietary secrets, he could confirm that in addition to the extra additives the enhanced performance was the result of the 'tighter' cutting of the blendstocks in the refinery. He explained that the dramatic reductions in the noise from diesel vehicles using the new fuel was largely the result of this tighter specification of the blendstocks.

Claimed benefits of using BP's Ultimate premium and diesel fuels

BP Ultimate unleaded:

Reduction in	carbon monoxide up to 14.5%
	nitrogen oxides up to 5.3%
	carbon dioxide up to 2.2%
	unburnt hydrocarbons up to 5.6%
Improvements in	power output up to 7%
	acceleration up to 5%

BP Ultimate premium diesel:

Reduction in average	nitrogen oxides of 4.5%
	carbon monoxide of 7.6% (urban cycle)
	hydrocarbons of 36%
	smoke of 11%
Improvements in	power output up to 10%
	acceleration up to 8%
	noise output up to 58% (4 Db); average 15%

Diesel fuel rule 'here to stay'

The Freight Transport Association (FTA) has branded the UK Government's proposed regulations that treat diesel fuel as dangerous goods as unwelcome, but recognise that they are 'here to stay'. The FTA also warned that the new regulations will cost operators an estimated £75mn over ten years.

The main impact of the rules – which will enter force on March 2004 – will not be on fuel suppliers and distributors, but on equipment users such as construction and infrastructure maintenance organisations and plant hire companies carrying fuel in drums and bowsers, claims the Association.

Chris MacRae, FTA's Dangerous Goods Policy Manager, said: 'We have made it clear to the HSE and the Department for Transport just who will be affected and the potential for operational disruption that will be caused by rules that treat an empty 500-litre diesel fuel bowser in the same way as a 30,000-litre petrol tanker.'

FTA has called for the proposals to be pragmatically handled and believes that the existing Control of Pollution Regulations already provide adequate precautions against spillages. Whilst HSE has agreed to look again at certain aspects of the new rules it argues that it must take action in order to meet EU harmonisation requirements.

In Brief

UK

The UK Natural Gas Vehicle** Association (NGVA) has published its response to the UK Government's consultation on road fuel gases (a copy of which can be viewed at **www.roads.dft.gov.uk/consult/fuelgases/index.htm

***Shell Aviation has arranged an urgent** out-of-hours refuelling service for aeroplanes that have been diverted to airports where the airline does not have a fuel supplier.*

***Rothschild has entered the oil risk** management business to trade over the counter swaps and hedging products in the oil sector.*

***A new report published by the AA** motoring organisation suggests that for every £1 collected in the UK in motoring tax, just 20 pence is spent on roads and transport. This compares with Japan where more is spent on transport than is collected in tax, and the US which spends the equivalent of what it collects. In France twice as much is spent on roads and transport, while the ratio in Spain is reported to be four to one.*

***Ken Rivers, Manufacturing Director of** Shell UK Oil Products, has been appointed President of the UK Petroleum Industry Association (UKPIA), the trade association representing the main oil refiners and marketers in the UK. He succeeds Gary Jones, Managing Director of Total UK, who will be taking up a new overseas post within the Total group.*

Europe

***H&R WASAG is to acquire BP's entire** special products business in Europe which produces and markets specialist products such as waxes, process oils and rubber additives.*

***Vopak is to sell Chemgas, its European** gas shipping operation, to German inland shipping company Reederei Jaegers for more than €45mn as part of a strategic review of all Vopak's non-tank terminal activities.*

***Air Products and Chemicals has signed** a long-term hydrogen supply agreement with Petroplus Refining to build, own and operate a 7,000 t/y hydrogen facility for Petroplus' 68,000 b/d refinery in Cressier, Switzerland.*

In Brief

***Norsk Hydro is to sell for NKr1.4bn its** 25% stake in the 10mn t/y Scanraff oil refinery in Sweden to Preem, which already holds a 75% interest.*

North America

***ConocoPhillips has signed an agreement** with leading Canadian convenience retailer Alimentation Couche-Tard for the sale of the capital stock of the Circle K Corporation, which comprises 1,663 retail marketing outlets in 16 states and the Circle K brand, as well as the assignment of the franchise relationship with more than 350 franchised and licensed stores.*

Middle East

***Saudi Aramco has increased the** capacity of its Ras Tanura refinery from 325,000 b/d to 525,000 b/d and is building diesel hydro-treater complexes at its Yanbu and Riyadh refineries for the production of low-sulphur diesel, reports* Stella Zenkovich.

Russia & Central Asia

***Lukoil is to pay €117mn for a 79.5%** interest in Beopetrol of Serbia and is to invest €85mn in the company over the next five years.*

Asia-Pacific

***Foster Wheeler has been awarded a** $90mn contract by the New Zealand Refining Company (NZRC) for the Future Fuels clean fuels project.*

NEWS Downstream

Sharing supply risk

Recent research from independent market analyst Datamonitor suggests that Western Europe's energy suppliers are increasingly eager to share the risk of adverse wholesale market movements with their major customers by moving them away from fixed-price deals. Many customers are reported to be willing to accept some risk, but only if substantial price savings are on offer.

The survey of 1,500 major energy users in the UK, Germany, France, Italy, Spain and the Netherlands suggests a growing popularity in variable-price deals. By 2005, not only will flexible pricing arrangements become the norm but many contracts will include quantity restrictions allowing suppliers to respond more efficiently to fast changing circumstances in the wholesale market.

Fuel tests for bus fleet

Cerulean International, the Oxford, UK-based subsidiary of nanomaterials company Oxonica, has announced that its new product Envirox is to be commercially evaluated by Stagecoach UK, with a view to adopting the product over Stagecoach's 7,000-strong UK bus fleet.

Envirox is a product based on a well-established oxidation catalyst that has now been formulated for use within fuel to deliver a cleaner and more complete burn within the combustion chambers, explains Cerulean.

The product is claimed to deliver 10% fuel economy benefits as well as reducing carbon deposits in the engine and lowering emissions. No engine modifications are required to use Envirox, states the company.

i2 Downstream Oil takes off

Supply chain management solution provider i2 has launched i2 Supply Chain Strategist Downstream Oil and i2 Demand Manager Downstream Oil.

i2 Demand Manager Downstream Oil has been prototyped in the East Coast/Gulf Coast region of Shell Oil Products US. It is also being implemented in the Asia-Pacific region of Shell Oil Products and the Rhine region of Shell Europe Oil Products. The solution allows users to produce accurate forecasts of customer demand, which can then be used to synchronize manufacturing and distribution levels, leading to improved sales levels, reduced inventories and lower distribution and fulfilment costs.

i2 Supply Chain Strategist Downstream Oil is designed to enable oil and gas companies to plan their supply chain networks to meet required service levels at lower capital and operating costs. Through the use of modeling and simulation capabilities, companies can improve their strategic alignment with greater foresight as to how capital allocation and policy decisions will impact supply chain operations.

The initial Downstream Oil modules provide the foundation for downstream oil companies to develop their demand driven supply chain transformation programmes. Planned subsequent releases of i2 Downstream Oil will complete a fully integrated, decision support suite that spans the supply chain from end-customer demand through crude oil acquisition and supply to refineries.

UK Deliveries into Consumption (tonnes)

Products	†Aug 2002	†Aug 2003	†Jan–Aug 2002	†Jan–Aug 2003	% Change
Naphtha/LDF	170,567	168,900	802,090	1,501,634	87
ATF – Kerosene	919,913	899,676	6,687,258	6,749,493	1
Petrol	–	–	–	–	–
of which unleaded	1,621,596	1,542,098	13,072,874	12,431,038	–5
of which Super unleaded	52,579	69,228	372,093	542,911	46
ULSP (ultra low sulfur petrol)	1,569,017	1,472,870	12,700,781	11,888,127	–6
Lead Replacement Petrol (LRP)	46,410	13,382	392,461	146,565	–63
Burning Oil	210,713	143,798	2,411,270	2,418,242	0
Automotive Diesel	1,452,915	1,344,581	11,167,843	11,057,928	–1
Gas/Diesel Oil	485,150	457,273	4,000,983	4,086,070	2
Fuel Oil	123,934	181,638	1,254,220	1,592,847	27
Lubricating Oil	57,785	69,414	553,548	560,324	1
Other Products	597,302	680,038	5,451,459	5,572,404	2
Total above	5,686,285	5,500,799	45,794,006	46,343,413	1
Refinery Consumption	493,467	3887,703	3,323,807	3,058,234	–8
Total all products	6,241,255	5,888,502	49,117,813	49,401,647	1

† Revised with adjustments

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

Recovering economies boost energy demand

Bongkot field, Gulf of Thailand *Photo: PTTEP*

In the first of a two-part review, *Petroleum Review* looks at recent oil and gas developments in the Asia-Pacific region, one of the fastest growing energy markets in the world.

The latest available data (see p14) for the Asia-Pacific region comparing 2002 with 2001 shows oil consumption growing at 1.5% and gas consumption at 4.8% in 2002. This compares with global growth rates of 0.1% and 2.8% respectively, confirming the view that economic recovery in the Asia-Pacific region is closely linked to increased energy use.

As a number of major consumers – including Japan and Indonesia – recorded oil demand falls in 2002, the full impact of economic recovery has yet to fully feed through. It is notable, however, that for gas consumption, only Japan and Hong Kong recorded small declines, with all other markets expanding – some very slowly.

Gas expansion

Regional gas reserves rose by around 600bn cm, or 0.34%, but still only account for 8.1% of global reserves. In contrast, regional demand – at 330bn cm in 2002 – represented 13% of global consumption. Gas consumption was around 10% higher than regional production of 302bn cm. The balance was made up by LNG imports from the Middle East.

All the Asia-Pacific gas producers expanded production in 2002, with the regional total rising by 6.5%. Notable gains were seen from China (7.7%), Indonesia (6.4%), Malaysia (6.3%) and from some of the smaller regional players. The largest increases in gas consumption were recorded from China (8%), Taiwan (14.7%) and South Korea (13.4%), while Singapore and the Philippines recorded spectacular growth on a low base.

In 2002 regional gas consumption grew by 25bn cm – but regional production only rose by 20bn cm, increasing the region's dependence on extra supply by around 5bn cm. For gas the regional outlook is good – although more discovery and expanded domestic production would be desirable.

LNG will play a key role in the energy future of the Asia-Pacific region where, according to Philip Aiken, President and CEO of BHP Billiton, Australia, demand is expected to double to 150mn tonnes in 2015 following sharp increases in demand from Japan, South Korea, China, India and Taiwan. Such an increase in domestic LNG requirements is expected to ignite a severely competitive war between suppliers, leading to lower prices and lower profit.

Annual LNG consumption demand in China is forecast to double, from 10mn tonnes in 2001 to 20mn tonnes in 2015, while demand in India will rise from 5mn tonnes to 12.5mn tonnes during the period. Japan, the world's second largest economy, will be the key importer of LNG in the region, with 72.9mn tonnes in 2015 compared with 55.2mn tonnes in 2001.

In 2002, Indonesia was the largest natural gas supplier in Asia, accounting for a quarter of regional output, followed by Malaysia, Qatar and Australia.

Oil a problem

In sharp contrast, the outlook for oil is much more problematic. In 2002 regional oil reserves fell by 5% due to a large downward revision in China (-5.7%). The only recorded increases were in India (0.6%) and marginal 0.1% gains in Thailand and other Asia-Pacific countries. Regional oil reserves are now (2002) just 3.7% of the global total, down from 4.2% in 2001.

Despite the weak reserves base, Asia-Pacific production expanded by 0.7% in 2002, to 7.987mn b/d. This, however, should be compared with regional oil consumption of 21.399mn b/d. Regional production now accounts for 37.3% of regional consumption, down from 37.9% the year before.

The great challenge for the Asia-Pacific is that the region's largest producer – China – which, despite recording a 2.5% output growth in 2002, is widely believed to be close to peaking. Indonesia, the region's second largest producer, is already in decline, recording a fall of 8% in output in 2002. The next largest regional producers – Malaysia and India – recorded output growth of 5.6% and 2% respectively, while Thailand expanded by a spectacular 13.4%.

The region's refining capacity grew by 1.5% in 2002, somewhat ahead of world growth of 1%. Its 21.9mn b/d of refining capacity was a little ahead of oil consumption of 21.4mn b/d, implying high rates of refinery utilisation although in practice some petroleum products are sourced from outside the region.

Looking ahead

In summary, the Asia-Pacific region is becoming more dependent on gas and remains fairly well supplied with discovery continuing to expand reserves. In contrast, oil represents a considerable challenge if the region's dependence on Middle East or Russian supplies is not to escalate dramatically. Refining capacity continues to be expanded broadly in line with demand growth, which means refining almost certainly remains more profitable than in many parts of the world.

BANGLADESH

US company Unocal is understood to have submitted an exploration plan to Bangladesh's state-run Petrobangla for the development of the Moulavi Bazar gas field in north-east Bangladesh. The field has reserves of 400bn cf of gas and is estimated to be capable of producing 100mn cf/d, which will help meet the country's 1,250mn cf/d of gas demand. Bangladesh is facing a gas supply shortfall, with Petrobangla only currently able to meet 1,235mn cf/d of present-day demand.

Meanwhile, Bangladesh Petroleum Exploration Company has reported that preliminary studies of the Sujanagar Upazila northern district of Bangladesh have indicated that hydrocarbons are highly likely to be found in the Mobarakpur (Birahimpur) area. The company is to now carry out an exploration programme.

Other developments include Cairn Energy's acquisition of the upstream assets and undertakings of Shell in Bangladesh, including a 37.5% operated interest in the Sangu development area (SDA), increasing its total stake to 75%, and a 45% operated interest in exploration blocks 5 and 10, giving the company a 90% holding in the blocks. The consideration for the acquisition is \$50mn payable on closing and a 24 US cents/mn cf royalty payable, following receipt of payment by Cairn on entitlement gas production from the acquired interest in the SDA.

Remaining gross proven plus probable reserves for Sangu as at 30 June 2003 were approximately 1,127bn cf. Gross production from the field during 1H2003 was 136mn cf/d. Production sharing contracts (PSCs) for blocks 5 and 10 were entered into in July 2001. It is intended that a seismic programme will be carried out over both blocks in late 2003.

ChevronTexaco has also sold its Bangladesh subsidiary and block 9 upstream assets – to Niko Resources (Caymen), a Canadian company, for an undisclosed sum.

Meanwhile, debate continues regarding whether Bangladesh should export gas to India. Unocal has proposed a 1,360-km pipeline to India's western state of Gujarat, which the company claims will also increase energy access within Bangladesh itself. However, many politicians are opposed to the move amidst fears that it would pose 'a major political risk'. The Communist Party of Bangladesh is reported to have warned that it would call a general strike if the ruling government decided to approve gas exports, while the Awami League maintains that exporting gas to India would hurt national interests as Bangladesh must first be sure that it has a 50-year reserve.

BRUNEI

According to Scottish Development International, Brunei's economy is almost totally supported by oil and gas exports, with revenues from the hydrocarbons sector accounting for over 50% of GDP, around 80–90% of exports, and 75–90% of government revenues. Japan takes some 90% of Brunei's LNG exports, while South Korea takes the remainder. Japan, South Korea, Singapore, Taiwan and Thailand are the main customers for its oil. Economic growth in all sectors could accelerate with an increase in drilling activities and production of oil and gas from the deepwater areas of Brunei's Exclusive Economic Zone (EEZ). This is dependant on a positive resolution of the current dispute with Malaysia over the acreage.

A joint development area type solution was recently suggested by Malaysia in settlement of an ongoing dispute between it and Brunei regarding the sovereignty of deepwater acreage offshore Borneo. The dispute arose following the discovery of the Kikeh oil field offshore the coast of Sabah by Murphy in July 2002. The field, which lies adjacent to the Brunei border, has estimated reserves of up to 700mn barrels, equivalent to 21% of Malaysia's current oil reserves. Subsequent to the discovery, Malaysia licensed two deepwater blocks which had previously been offered for licence by Brunei. One of the Brunei blocks has been awarded to a Total-led consortium and negotiations with Shell are ongoing regarding the terms of the PSC for the second block. Activity on the blocks has now been suspended until the dispute is resolved.

In other news, Total has confirmed the discovery of significant gas reserves in the deep horizons of block B offshore Brunei. The discovery was made some 4,400 metres below the currently producing gas and condensate reservoirs of the Maharaja Lela Jamalulalam field, which came onstream in 1999.

There are significant long-term prospects for gas development in Brunei. Despite fears of LNG overcapacity, BLNG hopes to add 11.5 tn cf of gas to meet its expansion plans, including the addition of a new, 4mn t/y gas liquefaction train at its 7.2mn t/y Lumut facility by 2008. Expenditure required for the new train has been put at some \$0.9bn, with an additional \$0.5bn required to be spent on existing facilities. Should construction of the new train at BLNG proceed, it is understood that the long-term plan includes spending of up to \$1.1bn on six specially-designed LNG tankers.

CAMBODIA

LG-Caltex Oil Corporation is understood to have acquired a 15% stake in ChevronTexaco's block A offshore Cambodia in the South Korean refining company's first move into the upstream sector. ChevronTexaco's stake in the block has reduced to 55%, with Japan's Mitsui & Company holding the remaining 30%. Block reserves are put at 400mn barrels of oil and up to 3tn cf of gas. A second well is to be drilled soon; the first was abandoned in February 2003 as it was not commercially viable.

ChevronTexaco has also reported disappointing drilling results on its block A prospect, recently plugging and abandoning its Kdang Ngea-1 exploration and appraisal well. Although a small zone of hydrocarbons was discovered, reserves were not deemed sufficient for commercial production.

CHINA

CNOOC offered 10 new exploration blocks and two new areas for contracts or agreements in its latest offshore licensing round. In addition, the remaining deep-water blocks continue to be open to interested parties. Six of the 10 new blocks are located in the East China Sea, three in the Pearl River Mouth Basin of the eastern extent of the South China Sea, and three are in the Beibuwan Basin of the western part of the South China Sea.

According to independent analyst Wood Mackenzie, the success of the 2003 licensing round will shape CNOOC's future approach to domestic exploration. The lack of foreign interest in deepwater acreage in the past could leave the company in the difficult position of being an inexperienced operator tasked with frontier exploration and the prospect of continued sole risk exploration in the South China Sea. 'With significant areas of the East and South China Sea remaining relatively unexplored, CNOOC may be faced with a stark choice,' comments the analyst, 'continue CNOOC's sole exploration efforts or attract foreign interest through a reduction in CNOOC's back-in rights.' However, an early and significant deepwater discovery could change this picture.

A number of fields have come onstream over the past year, including ConocoPhillips and CNOOC's Peng Lai 19-3 field located in block 11/05 in the Bohai Bay. The field is expected to produce between 35,000 b/d and 40,000 b/d during the first phase of development via a 24-slot wellhead platform and FPSO.

Apache Corporation and partner PetroChina brought onstream their shallow-water Zhao Dong field in Dagang, Bohai Bay, at a rate of 6,000 b/d of oil from three wells. Production is expected to peak at 22,000 b/d by 1Q2004. The offshore infrastructure at Zhao Dong includes two large platforms, each weighing 6,000 tonnes – claimed to be the largest ever fabricated in China.

Production from the Daqing field – China's largest oil field and which accounts for one-third of the country's total oil production – is reportedly to be cut by 2mn t/y from 2004 to 2010. It is hoped that such a move will help extend field life to 20 or 30 years after output fell below 50mn tonnes in mid-2003 for the first time in two decades. The decision to cut production from China's most important oil field means the nation will have to increase its imports in order to feed economic growth if no new reserves are found elsewhere. China is expected to import 40% of its oil by 2010.

Gas will play a key role in the future growth of the Chinese economy. A number of major projects are in the pipeline, including the country's first LNG import terminal in Guangdong Province that will be supplied with 3mn t/y of LNG from the North West Shelf project offshore Australia. According to Wood Mackenzie, CNOOC's initial 5.3% stake in the North West Shelf project (it has an option to increase this to 25%) equates to a proven plus probable gas reserve of 1.2tn cf of gas and 60mn barrels of liquids.

Construction of a second terminal, at Fujian, is slated to begin in 2007. This will be supplied with up to 2.6mn t/y of LNG from Indonesia's Tannguh LNG project, due onstream in 2006 (see p17). CNOOC holds a 12.5% stake in Tannguh, which, according to Wood Mackenzie, is equivalent to the purchase of proven plus probable reserves of 2.2tn cf of gas and 10mn barrels of liquids.

Photo: ConocoPhillips

Meanwhile, work on the 4,200-km West-East pipeline that will transport some 12bn cm/y of gas from the remote Xinjiang Uygur Autonomous Region to Shanghai as part of the government's drive to develop the economy of remote western China is proceeding well. The east section of pipeline project, from Shaanxi's Jingbian County to Shanghai, started trial operations in September in preparation for commissioning on 1 January 2004. Jingbian will supply gas to the pipeline before being replaced by the Tarim Basin as the prime gas source at the beginning of 2005, when the western section – from Xinjiang's Lunnan to Jingbian – is hooked up with the Jingbian-Shanghai section.

Jingbian forms part of the Changqing oil field, that has proven natural gas reserves of 1.1tn cm, of which 751bn cm are recoverable. The field currently produces 4.8bn cm/y of gas, enough to satisfy not only the existing pipelines carrying gas to Beijing, Tianjin, Xi'an, Hohhot, and

Country	Oil res (bn b)	Change 01/02	R/P ratio (years)	Oil prodn (,000 b/d)	Growth 01/02 (%)	Oil consmpt (,000 b/d)	Growth 00/01 (%)	Gas res (tn cm)	Change 01/02	R/P ratio (years)
Australia	3.5	n/c	14.1	730	–1.0	846	–0.4	2.55	n/c	73.9
Bangladesh	–	–	–	–	–	71	2.0	0.3	n/c	26.8
Brunei	1.4	n/c	18.0	210	3.5	–	–	0.39	n/c	34.1
China	18.3	<5.7	14.8	3,387	2.5	5,362	5.8	1.51	0.14	46.3
China/Hong Kong	–	–	–	–	–	272	11.8	–	–	–
India	5.4	0.6>	19.4	793	2	2,090	1.0	0.76	0.11	26.9
Indonesia	5	n/c	11.1	1,278	–8.1	1,072	–1.7	2.62	n/c	37.1
Japan	–	–	–	–	–	5,337	–2.0	*	–	–
Malaysia	3	n/c	10.6	833	5.6	489	9.1	2.12	n/c	42.2
Myanmar	–	–	–	–	–	–	–	*	–	–
New Zealand	–	–	–	–	–	145	5.6	0.35	–	–
Pakistan	–	–	–	–	–	359	–2.5	0.75	0.04	100+
Papua New Guinea	0.2	n/c	14.3	46	–20.7	–	–	0.35	n/c	35.8
Philippines	–	–	–	–	–	333	–5.2	*	–	–
Singapore	–	–	–	–	–	699	–2.6	*	–	–
South Korea	–	–	–	–	–	2,288	1.8	*	–	–
Taiwan	–	–	–	–	–	817	–1.0	*	–	–
Thailand	0.6	0.1>	9.6	197	13.4	746	6.7	0.38	0.02	20
Vietnam	0.6	n/c	4.7	354	1.0	–	–	0.19	n/c	80.2
Other Asia-Pacific[a]	0.8	0.1>	14.7	160	10.9	474	5.1	0.69	0.03	34.1
Total Asia-Pacific (A-P)	**38.7**	**<5.6**	**13.7**	**7,987**	**0.7**	**21,399**	**1.5**	**12.61**	**0.34**	**41.8**
Total World	**1,047**	**<2.6**	**40.6**	**73,935**	**–0.7**	**75,747**	**0.1**	**155.78**	**0.14**	**60.7**
A-P as % of World	3.7	n/c	–	10.70	–	28.10	–	8.10	n/c	–

Asia-Pacific production, consumption and refinery capacity, 2001–2002
Source: BP Statistical Review, June 2003, *interpreted by* Petroleum Review; [a]Totals for countries not individually itemised; *included in 'other Asia-Pacific'

Yinchuan, but also the east section of the West-East gas pipeline which may require 2.1bn cm of gas in 2004.

The trunk line and the Xiangfan and Huangshi branches of the project are scheduled to be put into operation by 30 December 2004, to supply commercial natural gas to users in Wuhan and other cities along the pipeline. The Xiangtan branch will start operation on 1 July 2005, supplying gas to users in Changsha and cities along the pipeline.

The gas to be transported by the Zhongxian-Wuhan pipeline will be supplied from fields in the Sichuan Basin. With total reserves exceeding 7tn cm, the basin has 680bn cm of proven reserves.

Draft purchase contracts have been signed with a number of prospective gas users – including BASF-YPC, based in east China's Jiangsu Province, Shanghai Natural Gas Pipeline Networks and Zhejiang Natural Gas Development Co in east China's Zhejiang Province.

Other pipeline projects include Sinopec's 10mn t/y refined product pipeline project in Binyang County of the Guangxi Zhuang Autonomous Region. The 1,691-km pipeline will start in Maoming City, a major oil refinery base in south China's Guangdong Province, and go through Guangxi as well as Guizhou and Yunnan Provinces, terminating in Kunming, the provincial capital of Yunnan, in the southwest. The project, said to be the largest of its kind in the country, is scheduled to complete by March 2005.

Looking to future E&P prospects, CNOOC is understood to be planning to develop and produce some 100mn cf/d of gas from its Pearl River Mouth fields in the South China Sea by 2006/2007. The company's most recent finds, Panyu 30-1 and Panyu 34-1, are reported to hold some 1.5tn cf of reserves.

ConocoPhillips has made two additional exploration discoveries in its Bozhong 11/05 block in Bohai Bay that, together with adjacent structures, will be part of the PL 19-3 Phase II development. Phase I came onstream in December 2002 and the field is currently producing 30,000 b/d of oil.

Looking to the East China Sea, Shell (20%) recently finalised an agreement to explore, develop and market gas, oil and condensate in partnership with CNOOC (30%), Sinopec (30%) and Unocal (20%). The project comprises three exploration and two development contract areas of the Xihu Trough, covering some 22,000 sq km. CNOOC will act as operator of all five contract areas and will establish the Xihu Oil and Gas Operating Company.

The first development will be the Chunxiao area, where offshore production facilities are due onstream in mid-2005. Production is expected to reach 2.5bn cm/y within two years. The production facilities will process gas, oil and condensate from wells to be drilled in the Chunxiao, Tianwaitian, Can Xue and Duanqiao fields. A 350-km subsea pipeline will carry gas to an onshore terminal in Ningbo, Zhejiang Province. The gas will be marketed jointly by the contract partners to users in East China. Oil and condensate will be exported via a 60-km pipeline to the Pinghu oil platform.

Other news includes an upgrading of proven reserves in the Sulige gas field in north China's Inner Mongolia, which were increased by 313.1bn cm to 533.6bn cm – making it the largest natural gas field in China.

China has also proposed the joint oil exploration and development of the disputed Spratlys area of the South China Sea. Brunei, Malaysia, the Philippines and Vietnam, as well as China and Taiwan, have claimed the Islands. Only the Philippines is reported to have expressed an interest in such a solution. For the other countries there appears to be the wider issue of maintaining solidarity in the face of economic imperialism from China, which is already carving deep inroads into the Asia-Pacific's low-cost export markets. In a bid to dispel these fears Beijing is reported to have offered to rotate the leadership of a joint venture resources management body.

Although it is believed the Spratlys sit on top of huge oil and gas reserves, their commercial potential has never been confirmed. The islands also flank international shipping lanes.

INDIA

India's domestic gas production is currently able to meet just half of the 115mn cf/d of demand. To bridge the gap

Country	Gas prodn (bn cm)	Growth 01/02%	Gas consmpt (bn cm)	Growth (01/02)%	Refinery cap (,000 b/d)	Growth (01/02)%	Refinery t'pt (,000 b/d)	Growth (01/02)%
Australia	34.5	2.7	24	0.8	926	n/c	822	0.01
Bangladesh	11.2	4.3	11.2	4.3	–	–	–	–6.4
Brunei	11.5	0.5	–	–	–	–	–	–
China	32.6	7.70	30.1	8	5,744	1.8	4,409	4.6
China/Hong Kong	–	–	2.4	–5				
India	28.4	4	28.2	3.8	2,289	1.2	–	–
Indonesia	70.6	6.4	34.7	4	1,116	n/c	–	–
Japan	–	–	77.4	–2	4,721	–1.9	3,986	–2.9
Malaysia	50.3	6.3	27	4.9	–	–	–	–
Myanmar	–	–	–	–	–	–	–	–
New Zealand	–	–	5.5	–3.5	–	–	–	–
Pakistan	20.9	5.1	20.9	5.1	–	–	–	–
Papua New Guinea	–	–	–	–	–	–	–	–
Philippines	–	–	1.8	100+	–	–	–	–
Singapore	–	–	1.8	38.6	1,255	n/c	–	–
South Korea	–	–	26.20	13.4	2,316	n/c	–	–
Taiwan	–	–	8.5	14.7	1,159	32.6	–	–
Thailand	18.9	4.8	25.9	14.9	983	–0.9	–	–
Vietnam	–	–	–	–	–	–	–	–
Other[a]	16.5	31.2	4.7	–5.2	1,417	0.3	8,808	–2.7
Total Asia-Pacific (A-P)	**301.7**	**6.5**	**330.3**	**4.8**	**21,926**	**1.5**	**18,025**	–
Total World	**2,527.6**	**1.4**	**2,535.5**	**2.8**	**83,900**	**1**	**69,360**	**–0.7**
A-P as % of World	11.9	–	13	–	26.1	–	25.99	–

Asia-Pacific production, consumption and refinery capacity, 2001–2002
Source: BP Statistical Review, June 2003, *interpreted by* Petroleum Review; [a]Totals for countries not individually itemised; *included in 'other Asia-Pacific'

between demand and supply, the country has been stepping up exploration with encouraging results while simultaneously looking for imports. The introduction of the New Exploration Licensing Policy (NELP) in 1999 has led to improved fiscal terms and the country can be regarded as competive to would-be investors in comparison with other fiscal regimes. However, according to analyst Wood Mackenzie: 'Improved fiscal terms and licensing rounds alone are not enough to convince overseas companies to invest in India... the country is still perceived by the international oil and gas community as being a challenging place to invest. Only through continued improvements in the licensing process will India have access to foreign experience and technology to improve recovery and realise the full potential of its hydrocarbon resources.'

The government recently invited bids for 24 blocks for exploration under the fourth round of NELP. Twelve of the blocks are in deepwater. In view of the huge financial investments and technical expertise needed for exploration in deepwater, the government altered the bid evaluation criteria for these blocks.

It will be interesting to see how many foreign players are awarded blocks under NELP-IV as participation in NELP-III was dominated by Indian state companies. ONGC, IOC, OIL and GAIL secured 14 of the 23 blocks either as stand-alone companies or within a consortium. According to Wood Mackenzie, the dominance was only broken by the Reliance-Hardy consortium which picked up nine blocks and the GSPC consortium which picked up one. Indeed, since NELP's introduction in 1999 only three foreign participants have submitted successful bids. This appears somewhat strange, bearing in mind the original purpose of setting up NELP was to attract foreign investment.

Projects to have come onstream over the past year include Cairn Energy's (50%) Lakshmi gas field in block CB/OS-2 in western India. Partners are ONGC, which holds a 40% stake, and TATA Petrodyne with 10%. The project is contracted to supply 120mn cf/d to Gujarat Gas Company and Gujarat Powergen Energy once production reaches plateau at 120bn cf/d.

Cairn Energy has also submitted development plans to the Indian Government for the development of the Gauri field in block CB/OS-2 offshore western Gujarat state. It is hoped to bring the field onstream in 2004, via a platform tied-back to Lakshmi. Gauri is expected to produce between 50bn and 60bn cf/d of gas.

More recently, the company farmed out to ONGC a 90% operated interest in deepwater exploration block KG-DWN-98/2, a 15% exploration stake in block CB/OS-2 and a 10% interest in the Lakshmi and Gauri development areas. In exchange, Cairn has taken a 30% farmed in interest from ONGC in each of blocks GV-ONN-97/1 onshore northern India and CB-ONN-2001/1 onshore Gujarat. Cairn is to pay to ONGC a cash consideration equivalent to the economic monetary value of the blocks as assessed by ONGC at the time of bidding for the farm-in interests, while ONGC will pay to Cairn a cash consideration of $135mn for the farm-out interests.

In addition, Cairn and ONGC have submitted joint bids for three blocks onshore Gujarat in the NELP-IV licensing round. If successful, Cairn will retain a 30% interest in these blocks and ONGC will be operator.

Cairn retains its 50% operated interest in exploration block KG-OS/6 offshore eastern India and is currently planning to re-drill prospect 6 on that block. An active drilling campaign on block KG-DWN-98/2 is also planned for 2004.

Looking ahead, India's Raniganj South coal bed methane (CBM) block in West Bengal is expected to come onstream in 2005, producing 1.5mn cm/d of gas. India will be the fourth country after the US, Australia and China to be producing CBM gas and is forecast to be producing some 10–12mn cm/d by 2006.

A total of nine CBM blocks, with a combined resource of 500bn cm of gas, were offered in India's second CBM licensing round, bidding for which was due to close as *Petroleum Review* went to press. The blocks are located in Andhra Pradesh (1), Chattisgarh (1), Gujarat (1), Jharkhand (2), Madhya Pradesh (1), Maharashtra (1) and Rajasthan (2).

India's Reliance Industries is reported to have made a new gas discovery in the Godavari Basin, doubling its reserves to 14tn cf. The company is planning to invest some $300mn on exploration in the region over the next two years, and is to further extend its gas infrastructure.

Meanwhile, the Indian authorities are reported to have approved a $138mn development plan for enhancing oil and gas production in the Panna-Mukta and Tapti oil and gas fields off the west coast. Jointly operated by ONGC, Reliance and BG, the fields account for 7% of India's total oil and gas production. The enhancement projects involve an infill-drilling programme of up to 18 wells in the Panna-Mukta oil and gas fields and a four-well re-completion drilling programme in the Tapti gas field.

Qatar-based Ras Laffan Liquefied Natural Gas Company (RasGas) is understood to have finalised a 25-year gas supply agreement with India's Petronet LNG, a consortium of state-owned energy majors. Under the agreement RasGas will supply 2.5mn tonnes of LNG in the first year and double it from 2005. The deal is expected to provide Indian domestic consumers, mainly power and fertiliser units, with access to LNG supplies at $3.6/mn BTU (British Thermal Unit) – a figure said to compare favourably with what other private gas producers are promising to supply in future. The Petronet LNG terminal at Dahej in Gujarat is to be commissioned in December, with supplies from Qatar to begin early 2004.

Two large cryogenic LNG storage tanks were also recently unveiled at India's first private sector LNG receiving terminal, at Hazira (Surat) in Gujarat on 19 September. Costing some $600mn, the Hazira project is reported to be amongst the largest greenfield foreign direct investments in the energy sector in India. Upon completion by end 2004 the LNG terminal will have a capacity of 2.5mn t/y of LNG, rising to 5mn t/y (equivalent to approximately 19mn cm/d of gas). Capacity can be expanded to 10mn t/y.

INDONESIA

Photo: ConocoPhillips

Indonesia recently declared as open acreage some 20 blocks that remained unawarded in its previous tender rounds of 2001, 2002 and 2003. It had also prepared 10 new blocks due to be offered in a tender as *Petroleum Review* went to press. The open acreage is being offered with standard PSC terms and conditions, although it has been suggested that the Directorate General of Oil and Gas (Migas) may be willing to re-evaluate these. At present the profit split remains 85:15 for oil and 70:30 for gas between the government and the contractor.

The 10 new blocks to be offered in the fourth round are spread over proven oil/gas provinces and frontiers in the country's far east. The 20 open acreage blocks are: Amborip I to VI blocks in the Arafura Sea, Segaf and Biga in Ceram Sea, Pole Wali and Enrekang onshore South Sulawesi, Mentana and Tigau offshore East Kalimantan, Bangkanai onshore East Kalimantan, Anambas in the Natuna Sea, Taritip and Jangeru in the Strait of Makassar, East Kangean and Bawean II off East Java, Rembang offshore north-Central Java, and North Bali II off Bali.

Other recent developments include Unocal's (operator, 90%) first oil production from Phase 1 of the deepwater West Seno project offshore East Kalimantan, reportedly the first deepwater oil and gas project in Indonesia. Current production is 14,000 b/d of oil and 18mn cf/d of gas from the first four wells. A fifth well will soon bring production to over 17,000 b/d. Gross production from Phase 1 is expected to reach 35,000–40,000 b/d by the end of 2003 as further wells are completed, with additional production expected in 2004 as development drilling continues.

Daily production is expected to peak at 60,000 barrels of oil and 150mn cf of gas per day by year-end 2005 with the completion of the Phase 2 development at West Seno. Unocal expects to ultimately recover between 210mn and 320mn boe from the field.

Unocal has also reported several potentially commercial deepwater discoveries offshore East Kalimantan that are expected to come onstream over the next few years. These discoveries include significant gas resources that could supply as much as 40% of the needs of the Bontang plant, the world's largest LNG facility to date.

Indonesia is a major source of LNG supply to neighbouring Japan, South Korea and Taiwan, and is looking to export to China and India from Bongtang and from Tannguh in Irian Jaya. The Tannguh LNG project, due onstream in 2006, will have an annual production of 7mn t/y from two initial processing trains. Feedstock gas will be supplied from BP's nearby Wiriagar and Muturi fields that hold 14.4tn cf of reserves. The project is to supply up to 2.6mn t/y of LNG to the Fujian LNG terminal in China (see p14).

The expanding LNG market is likely to play a big part in the development of Indonesia's resources, comments Scottish Development International, as are the plans for an international gas pipeline network. Other plans under consideration are several gas-to-liquids projects to produce naphtha, kerosene and other products. In addition, natural gas in the power sector is set to double in the next five years, not least as a substitute for diesel.

In other news, gas sales commenced from the Corridor block production sharing contract in South Sumatra to Gas Supply in Singapore – the first sale of gas from the block to markets outside Indonesia (see p19). Under the terms of the 20-year gas sales agreement signed in February 2001, sales from the Corridor block and two other blocks in Sumatra are expected to peak at 367mn cf/d in 2009, of which gas sales to Singapore from Corridor will be about 155mn cf/d. Talisman holds a 36% interest in the Corridor block, with ConocoPhillips holding 54% and Pertamina 10%.

Santos signed a heads of agreement contract with state-owned utility PT Indonesia Power to buy the entire gas reserves of the Oyong gas field in East Java. Field reserves are put at more than 90bn cf of recoverable gas. First supplies are expected in late 2004, with a minimum of 60mn cf/d of gas to be delivered to the 766-MW Grati facility.

Technip-Coflexip was awarded a $82mn EPIC contract by ConocoPhillips Indonesia for the block B subsea development gas project in the Natuna Sea. The contract involves the subsea tie-back of 14 subsea wells to existing platforms in block B over three installation campaigns from 2003–2005. Work will also include topsides modifications on the existing Belida and Hang Tuah facilities.

Amerada Hess completed the sale of its 30% interest in the Jabung production sharing contract onshore Sumatra, to a consortium comprising PetroChina and Petronas Carigali for $164mn. The sale included the company's 20% stake in an associated downstream project for development of facilities for the processing and sale of LPG and light naphtha. The Jabung PSC includes the North Geragai, Makmur, Gemah, Northeast Betara and North Betara oil and gas fields.

Meanwhile, Amerada Hess' 460bn cf Ujung Pangkah gas field is expected onstream around 2005.

The Indonesian authorities are reported to have proposed the joint development of the Cepu field, situated on Java island, which has become the centre of a dispute between ExxonMobil that has a contract to develop it until 2010 and local politicians that want Pertamina to take control. The block is estimated to have reserves of 2bn barrels of oil and 11tn cf of gas.

The Cepu reserves are significant for Indonesia, which risks becoming a net importer of oil due to the slow development of new projects. The country currently has about 5bn barrels in total proven reserves, probably enough to last about 10 more years at current production rates, according to industry estimates.

Looking downstream, state-owned Pertamina is reported to be planning to build an oil refinery in East Java in 2004. The plant, which is expected to be ready in 2008, will have the capacity to process between 125,000 b/d and 150,000 b/d of oil. The crude is expected to come from the Cepu block.

JAPAN

Japan is heavily reliant on imports to meet its energy needs. Earlier this year the country imported oil for the first time from Central Asia following Nippon Oil Corporation's purchase of 1mn barrels of CPC blend oil from the Tengiz field in Kazakhstan. Continuing its search for alternatives to Middle East supplies, the deal followed the delivery of 2mn barrels of Russian Urals crude in December 2002. More recently, the country began taking delivery of some 40,000 b/d of Basra Light crude oil from Iraq. Meanwhile, Tokyo Electric Power and Tokyo Gas have contracted to buy nearly all of Bayu-Undan's 3mn t/y of LNG output for 17 years. Partners ConocoPhillips, Eni, Inpex and Santos have trimmed their stakes in the project to enable the two Japanese companies to take a 10.1% stake.

Looking to secure additional foreign supplies, a consortium of Japanese companies – Inpex, Japan Petroleum Exploration Company and Tomen – obtained preferential rights to develop Iran's 26bn barrel (in place reserves) Azadegan oil field in November 2000. However, a request from the US to delay the contract amid mounting suspicion of Iran's nuclear development meant that the preferential rights were allowed to expire at the end of June 2003. Iran has continued negotiating with Japan for the development project since then, but Japan has been reluctant to conclude the contract. As a result the Iranian Government recently invited several major international oil companies – thought to be Total, Sinopec and Shell – to bid on development of the field. Director-General of the National Iranian Oil Company (NIOC) Mehdi Mir-Moezzi also stated that Iran will sign contracts to develop the field – as well as the oil layer of the South Pars gas field – by March 2004.

Looking closer to home, a joint venture between Japan Energy and Idemitsu Kosan is understood to be planning to develop a deepwater oil and gas field offshore Sado Island in the Niigata Prefecture. First production is slated for 2008.

In other news, state-run Japan National Oil Corporation (JNOC) is to sell its shareholdings in 34 companies as a step toward liquidating its assets before it is due to be abolished at the end of March 2005. Proceeds from the planned sale are expected to range from Y50bn to Y100bn. Included in the planned auctions is JNOC's 65.74% stake in Japan Petroleum Exploration (Japex), which currently produces 66,000 b/d from projects in North America, Europe and Asia. The stake has been valued at $80mn.

MALAYSIA

Photo: ConocoPhillips

State-owned Petronas has embarked on an international E&P strategy in recent years in a bid to counter lack of oil reserves growth. To date it has invested in projects in Gabon, Indonesia, Turkmenistan, Iran, Pakistan, China, Vietnam, Algeria, Myanmar, Libya, Tunisia, Sudan and Angola. Overseas operations now account for nearly one-third of the company's revenue, reports Scottish Development International.

Recent domestic discoveries include Talisman Energy's oil find in offshore block PM-305. The South Angsi-1 well tested at a combined rate of 11,300 b/d. Proved and probable reserves are estimated at 25mn barrels, with first production anticipated in mid-2005 at a gross rate of between 15,000 b/d and 20,000 b/d. Talisman holds a 60% interest in the block, the remaining 40% interest held by Petronas Carigali, the exploration and production subsidiary of Petronas.

Meanwhile, Petronas signed a production sharing contract with Pertamina and PetroVietnam to jointly explore for and develop hydrocarbon resources in block SK305 offshore Sarawak. Under the terms of the PSC, the three parties have formed a joint venture company, PCPP Joint Operating Company (PCPP), to operate the block.

Petronas has also signed with Shell Malaysia (40%) and partner Petronas Carigali (60%) a new production sharing contract for Baram Delta, also offshore Sarawak. The new PSC will allow the companies to continue to participate in development of the Baram Delta fields following the end-March 2003 expiry of their 1989 PSC.

Talisman recently commenced oil production from the PM-3 Commercial Arrangement Area (CAA) Phase 2 & 3 project offshore Malaysia/Vietnam. Phase 1 oil production commenced in July 1997. The PM-3 CAA project involves the development of the West Bunga Kekwa, East Bunga Kekwa-Cai Nuoc, East Bunga Raya, West Bunga Raya, NW Bunga Raya and Bunga Seroja fields located in the overlapping zone between Malaysia and Vietnam. To date one-third of the planned 60-well development drilling programme has been completed and development drilling is planned to continue throughout 2004.

Four new wellhead platforms, a central processing platform, compression annex platform, floating storage offloading vessel as well as inter-field pipelines have been installed. These facilities have a production capacity of 60,000 b/d of oil and 270mn cf/d of gas.

Talisman holds a 41.44% interest in Block PM-3 CAA. Petronas Carigali holds a 46.06% stake and PetroVietnam Investment & Development Company holds 12.5%.

Meanwhile, a joint development area type solution was recently suggested by Malaysia in settlement of an ongoing dispute between it and Brunei regarding sovereignty of two blocks of deepwater acreage off the coast of Borneo. This dispute may impact on the timing of development of the Kikeh oil field – Malaysia's first ever deepwater oil discovery – that is adjacent to the Brunei border. There is understood to be the potential that the Kikeh structure straddles the border, however faulting may allow the field to be developed prior to resolution of the dispute (see p13).

MALAYSIA–THAILAND JDA

The Malaysia-Thailand Joint Development Area (JDA) is an overlapping economic zone located in the Gulf of Thailand, which was established to resolve the overlapping claims between the two countries over the area's hydrocarbon reserves. It is divided into three blocks – A18, B17 and C19 and it is administered by the Malaysian-Thailand Joint Authority (MTJA).

The first field to enter production will be the Cakerawala gas field, due onstream in 2005. Gas production is forecast to be in the region of 390mn cf/d.

Meanwhile, it has been reported that work on the long-delayed Thai-Malaysian gas pipeline has begun and is expected to complete in 1H2005. The original date of completion had been October 2002. However, until recently the project had been beset by problems amidst fears of ecological damage that may result from the pipeline's construction.

More recently, BP announced that it is to swap its 25% stake in block A018 of the Malaysia-Thailand JDA for Amerada Hess' interests in Colombia, which adds some 58mn barrels to BP's Colombian portfolio. Amerada's Colombian interests include a 12% stake in the Santiago de las Atalayas, Tauramena and Rio Chitamena contracts, in which the Cusiana and Cupiagua fields are located; 10% in the Recetor Association contract; and a 9.6% stake in the Ocensa pipeline. Amerada also made a balancing payment to BP of $10mn.

NORTH KOREA

The US is seeking to supply North Korea with Sakhalin gas via the KoRus project. Up to $4bn will be invested over four years in the 2,300-km pipeline, which will run from the Sakhalin gas field, for which ExxonMobil has the development rights, through North Korea, down to South Korea. Although it is evaluated to be less profitable than the pipeline already being pursued in Irkutz, Russia, by Korea, ExxonMobil is said to be aggressively lobbying through the Bush administration for the project.

In other news, the Korea National Oil Corporation (KNOC) has discovered an additional 50bn cf of gas reserves in the Donghae-1 field – the nation's first offshore gas field in the Sea of Japan. The field was originally discovered in March 2002, with reserves put at 200bn cf of gas, equivalent to 4mn tonnes of LNG. First production is expected in December 2003.

(See also *Petroleum Review*, July 2003.)

PAKISTAN

Photo: BHP Billiton

Pakistan imported 5mn tonnes of fuel oil in the fiscal year to June 2003, to meet annual demand of about 8.5mn tonnes, the difference being met by domestic production.

An important addition to domestic production was the coming onstream of Phase 1 of BHP Billiton's Zamzama gas development in August (see photo) – which completed nearly four months ahead of schedule and under the original $100mn budget. Phase 1 will triple the current gas processing capacity, facilitating the supply of up to 320mn cf/d of gas to Sui Southern Gas Company and Sui Northern Gas Pipelines over the expected field life of 20 years.

Three new development wells (Zamzama-3, -4 and -5) were drilled during this phase of development, and are tied into two new processing trains with a nameplate capacity of 140mn cf/d each. A fourth well (Zamzama North), designed to further appraise the field, is nearing completion. First production from the Zamzama field commenced in March 2001 via an extended well test fed by two wells, and has supplied on average 100mn cf/d of gas to Sui Southern Gas Company under a 21-month contract.

The core area of the Zamzama field has estimated proven and probable reserves of 1.7tn cf, with significant additional reserves potential outside the area. Project partners are BHP Billiton (38.5%), Pakistan Government (25%), Kufpec/Premier Oil joint venture PKP Exploration (18.75%) and Eni (17.75%).

Other developments over the year include Premier Oil (23.75%) and Kufpec Pakistan's (23.75%) acquisition of 50% of Shell's 95% working interest in block 2365-1 Offshore Indus E, a deepwater oil exploration licence in the Indus Basin. The deal will leave Shell with a 47.5% interest. The remaining 5% stake is held by Government Holdings (Private) Ltd (GHPL).

Pakistan Oil Fields is reported to have found additional oil and gas reserves in the Pindori field. The discovery will add about 2,000 b/d of oil to the field's output of 6,200 b/d and 7mn cf/d of gas to its daily output of 19mn cf. Pindori is being developed by a joint venture between Pakistan Oil Field (35%, operator), Oil and Gas Development (50%) and Attock Oil (15%).

Looking to the pipeline sector, the Gulf-South Asia Gas (Gusa) gas pipeline project is reported to be close to becoming reality with major agreements governing project development, funding and gas sales soon to be signed between Qatar's Crescent Petroleum and the Pakistani authorities. Under the project some 1,600mn cf/d of Qatari gas will initially be supplied via pipeline to Pakistan. However, it is thought that the ultimate capacity could be 3,400mn cf/d of gas.

Meanwhile, the completion of the $481mn White Oil Pipeline Project that is being laid down from Port Qasim, Karachi, to the Pak Arab Refinery Company in Mahmood Kot, Multan, is to be delayed by one year. As a result the cost of the project may rise to over $500mn, an official source in the Pakistan Ministry of Petroleum and Natural Resources is reported to have said.

PHILIPPINES

The Philippines is almost entirely dependent on oil imports to meet its 333,000 b/d consumption and recently took delivery of its first ever cargo of Russian Far East crude from Sakhalin Energy Investment. Sakhalin Energy has also sold Sakhalin oil to a number of other Asia-Pacific countries, including Japan, South Korea, China and Taiwan, as well as to the US.

Meanwhile, the Philippine gas sector is totally dominated by the $4.5bn Malampaya gas-to-power project that completed in 2001. The deepwater field, tied back to a large concrete platform in shallower water, supplies gas to an onshore processing plant and three power plants via a 504-km subsea pipeline. Further gas distribution lines are being planned to meet burgeoning domestic demand, which currently stands at some 1.8bn cm.

Reflecting the importance of imports to the Philippine economy, Caltex, a subsidiary of ChevronTexaco, is to convert its Batangas refinery into a 'world-class finished product import terminal'. The $13.6mn-plus conversion is part of the company's long-term strategy to 'enhance its competitive position as a major oil company and reinforce its commitment to provide competitively priced fuels and energy products to its millions of customers in the Philippines'. The terminal is expected to be operational by 4Q2003.

The Batangas refinery has a 72,000 b/d total capacity. The converted terminal will have a storage capacity of roughly 2.7mn barrels.

The move to adopt an import strategy was driven by the competitive conditions in the Philippines marketplace, states the company. These conditions require cost efficiencies only available in refineries with greater scale and modern technology. There also continues to be overcapacity in the market, and this is expected to continue to depress refining margins. There is roughly 1.2mn b/d in excess refining capacity throughout the Middle East and Asia Pacific at present.

SINGAPORE

Singapore buyers recently began commercial offtake of piped gas from fields in Indonesia's Sumatra island via a newly laid 477-km onshore and subsea pipeline running from the Grissik gas plant in ConocoPhillips' Corridor block in South Sumatra to PetroChina's Jabung block in central Sumatra and then to Singapore's Sakra Osland. The gas is being sold under a 20-year contract that will see the delivery volume peak at 350mn cf/d in 2009. The initial rate nominated by the Singapore buyer is 90mn cf/d.

In Singapore, Gas Supply will sell the gas to major power producer Senoko Power and industrial gas supplier City Gas. The gas will be transported by Power Gas, a subsidiary of Singapore Power, which owns the gas pipeline network in the island state. The $9bn gas sales and purchase contract between Indonesia and Singapore was signed in February 2001. The project marks the second pipeline gas sales from Indonesia to Singapore after the supply of West Natuna gas to Singapore, which began in January 2001.

SOUTH KOREA

The proposed pipeline to carry gas from Siberia's large Kovykta gas field to South Korea and China is forecast to cost some $11bn, according to South Korea's Finance Ministry. Partners in the project include Kogas, Rusia Petroleum and CNPC. The Kovykta field has reserves put at 840mn tonnes of gas and is thought capable of supplying up to 7mn t/y of gas to South Korea for 30 years, also supplying 14mn t/y to China. The field could come onstream as early as 2008.

Meanwhile, a Fluor/Amec joint venture has been chosen to provide operations, maintenance and production management services for Korea National Oil Company's Donghae-1 gas field – South Korea's first offshore gas development project. The field is to be developed via three satellite subsea wells tied back to a fixed offshore gas processing platform that will be connected via a subsea pipeline to a new onshore receiving terminal on the Korean coast at Ulsan.

(See also p22.)

TAIWAN

(See *Petroleum Review*, October 2003.)

THAILAND

Photo: PTTEP

Unocal is seeking Thai Government approval for the second phase of its oil development in Thailand, which would double current gross oil production from the offshore Gulf of Thailand Yala and Plamuk fields to 40,000 b/d. Current plans are to have the new facilities installed by mid-2005, with start-up commencing soon thereafter.

The company has already signed an agreement with Teekay Shipping Corporation for the long-term lease and management of an FPSO vessel for its development plans. The new vessel, to be named Pattani Spirit, will replace the tanker Sibeia that is currently used to store crude oil produced from the Plamuk, Surat, Yala, Platong and Kaphong fields.

Teekay Shipping will convert its 1988-built Aframax tanker Namsan Spirit at a shipyard in Singapore. After the conversion, the unit will be re-named Pattani Spirit. Installation is scheduled for 2Q2004.

Unocal is currently producing some 20,000 b/d of oil from its Gulf of Thailand fields, which account for about one-fifth of the country's indigenous oil production. To date, the fields have produced about 8.5mn barrels of high-quality, light sweet crude since initial production in July 2001. The crude has been sold to domestic customers in Thailand and into the international market.

Meanwhile, Amerada Hess has unveiled plans to invest $200mn on exploration and production in Thailand over the next five years. The money will be spent on the company's Phu Horm-3 concession block in Udon Thani Province in the northeast of the country. The province is estimated to contain between 400bn and 800bn cf of gas. Plans are to commence production mid-2005.

An important future development is PTTEP's Arthit field in block 15A, which is due onstream in 2Q2006 at 330mn cf/d. Gas will be carried by pipeline to Rayong. Unocal is a partner in the project, holding a 16% stake.

Looking downstream, the Thai authorities are reportedly planning to invest $700mn in oil pipelines and oil storage tanks, and simplify and cut taxes for oil and gas companies, in a bid to attract energy companies. The country wants to compete with Singapore as a regional oil trading centre within the next two years. Thailand's current oil refining capacity stands at 1mn b/d, compared with 1.2mn b/d in Singapore.

The funds will be used to build a pipeline and oil storage facilities along a new 230-km road crossing the Malay peninsula in southern Thailand, which is already half completed. Thailand is hoping to use the road as an 'energy corridor' between the Andaman Sea and the Gulf of Thailand.

VIETNAM

Photo: ConocoPhillips

Vietnam is understood to have produced 17.1mn tonnes of oil and 2.26bn cm of gas in 2002, exporting nearly 16.9mn tonnes of oil for $3.2bn – a year-on-year rise of 3.2%.

This year saw first gas from BP's $1.3bn Nam Con Son project. Up to 3bn cm of gas is expected to flow ashore annually during the project's first phase, providing power and a new energy source to feed Vietnam's growing industrial base. Partners BP, PetroVietnam, ONGC Videsh and ConocoPhillips estimate the gas could be used to generate about 40% of the country's existing electricity supply.

The project included the development of the offshore gas field, construction of a 399-km pipeline to carry gas to shore, onshore processing facilities and the construction of the 716-MW Phu My 3 power plant. Gas is marketed directly to PetroVietnam, which will serve as marketer and will deliver the gas to end users in the Phu My industrial zone.

The project taps the reserves of the Lan Tay and Lan Do gas fields in block 06.1. Combined field reserves are put at 58bn cm (2tn cf).

PetroVietnam is reportedly planning to increase domestic gas production by 70% in 2003, to 3.7bn cm, following the inauguration of the project's gas pipeline. The company is also understood to be targeting a small rise in oil production from 17.10mn tonnes in 2002 to 17.16mn tonnes in 2003.

In the last quarter of 2002, ConocoPhillips reported that the Rang Dong field in block 15-2 achieved first oil from two new wellhead platforms, boosting total field production by 40% to 65,000 b/d. The company holds a 36% stake in the project. Rang Dong is the second most productive oil field in the country after the Bach Ho (White Tiger) field. Japan Vietnam Petroleum holds 46.5% and is operator; the other partner is PetroVietnam. Meanwhile, Vietsovpetro discovered additional commercial reserves of oil and gas at its Dai Hung oil field offshore Vietnam. Initial estimates of production capacity from well 05 are 650,000 cm/d of gas and 220cm/d of oil.

On a more negative note, ConocoPhillips plugged and abandoned its Silver Jaguar project in block 16-02 having found no commercial volumes of hydrocarbons.

Looking ahead, the Su Ten Den (Black Lion) oil field in south Vietnam is expected to come onstream this month, producing some 10,000 b/d.

Meanwhile, the Vietnamese Ministry of Industry and PetroVietnam is planning to launch the country's first licensing round in June 2004, with an offer of approximately 10 blocks for exploration and development.

(See also *Petroleum Review*, October 2003.)

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The December issue will review the latest E&P developments relating to Australia, New Zealand, Papua New Guinea and East Timor.

Country/Field	Operator	Oil or gas output	Start-up date	Oil res. (mn b)	Gas res. (bn cf)	Capex ($mn)	Production system
BANGLADESH							
Bibiyana (block 12)	Unocal	gas/cond	2006		2,400	341	onshore
Jalalabad (block 13)	Unocal	gas/cond	1999		900	183	onshore
Moulavi Bazar (block 14)	Unocal	gas	2006		400	70	onshore
Sangu (block 16)	Shell (to be Cairn)	gas	1998		960	511	onshore
Shahbazpur	Unocal	gas	2006+		333		onshore
BRUNEI							
Bugan	BSP	gas			140		
Egret Ph1	BSP	gas	Sep–03	50	700		12-slot platform
Kikeh (see Malaysia)							
Mampak	BSP	oil/gas	evaluation				
Merpati	BSP	gas	evaluation				
CHINA							
Bonan fields (Bohai Bay)	CNOOC	oil/gas	2005	30	300		
Bozhong 25-1	CNOOC	hvy oil	2005	30			FPSO
Caofedian 11-1 (Bohai Bay)	CNOOC/Kerr-McGee	oil	2005	130			FPSO + platform
Changbei (Ordos Basin)	Shell	gas	2006+		2,500		onshore
Cheng Dao Xi (Bohai Bay)	Noble Energy	oil	Feb–03	30			platform 11 wells
Dongfang1-1 (S China Sea)	CNOOC	gas	2003		1,750		
East China Sea fields	CNOOC	gas/cond	2005	30	1,500		
Erdos Basin (Inner Mongolia)	PetroChina	gas			21,268		
Futai (Shengli area)	Sinopec	oil		160			
Huizhou 19-1/2/3 (S China Sea)	CACT	oil	2004	60			subsea to Huizhou 26 plat
Huizhou 21-1 (S China Sea)	CACT	gas/cond	2006	10	115		
Jinzhou 21-1 (Bohai Bay)	CNOOC	oil/gas	2008	7	60		
Luda 4-2 (Bohai Bay)	CNOOC	hvy oil	2005	90			
Luojiazhai (Sichuan) + 3 fields	Sichuan	gas	2005		5,600		
Lungu (discovery in Tarim)	PetroChina	hvy oil		500			onshore
Mosuowan	PetroChina	gas/oil		150			
Nanbao 35-2	CNOOC	hvy oil	2005	110			platform
Panyu 4–2/5-1 (S China Sea)	Devon Energy	oil	2003	90			FPSO + 2 wellhead plats
Pearl River Mouth fields	CNOOC	gas	2006/7		1,500		
Peng Lai 19-3(Bohai) Ph1	ConocoPhillips blk 11–05	oil	Dec–02	700			FPSO +24-slot platform
Peng Lai 19-3(Bohai) Ph2	ConocoPhillips blk 11–05	oil	2001	700			multiple plats cent process
Qikou 17-2	CNOOC	oil/gas	2000	26			Boxi area development
Qikou 18-2/9	CNOOC	oil/gas	2004	9	10		
Qinhuangdao 32-6 (QHD)	CNOOC/ChevronTexaco	oil	Oct–01	200		800	FPSO (80 kb/d) + 6 plats
Shulige (Ordos Basin)	PetroChina	gas			17,500		
Suizhong 36–1 (Ph 2)	CNOOC	oil	end–01	337.6		1,300	6 platforms, peak 69kb/d
Weizhou 12–1 (Beibu Gulf)	CNOOC	oil	2004	30			
Wenchang 13–1, 13–2	CNOOC	oil	2005	40			
Wenchang 13-1, 13-2	CNOOC	oil	Jun–02	100		300	platforms and FPSO
Zhao Dong (Bohai Bay)	Apache/PetroChina	oil	Aug–03				2 platforms, 17 wells
INDIA							
Bombay Offshore	ONGC	oil/gas	1976	5,500	15,800		offshore
Dhirubhai	Reliance Industries	gas	2005		5,000	2,573	offshore
Gauri	Cairn Energy	oil/gas	2004		92	88	platform tie/bk to Lakshmi
Hazira	Niko Resources	gas	1995		1,037	259	offshore
Kharsang	Geo Enpro	oil	1983	56			onshore
Lakshmi	Cairn Energy	oil/gas	2002		285	203	2 platforms offshore
Panna & Mukta	BG.ONGC/Reliance	oil/gas	1986	180	550	751	offshore
PY–1	Mosbacher Energy	gas/cond	2007		230	97	onshore platform
PY–3	Hardy	oil/gas	1997	21		124	floating production
Ravva	Cairn Energy	oil/gas	1993	221	230	399	offshore
Tapti Mid & South	BG/ONGC/Reliance	gas/cond	1997		3,740	1,207	offshore
INDONESIA							
Banyu Urip (Cepu block)	ExxonMobil	oil/gas	1Q2003	250+			platform + FSO
BD (Madura)	ExxonMobil	gas/oil	2005+	20	465	310	platform
Belanak (block B)	ConocoPhillips	gas/oil	4Q2004	75.2	500		FPSO (100k b/d + gas)
Block A, North Sumatra	ConocoPhillips	gas	2005+		476	240	onshore to fertiliser plt
Dongi & Senoro (Sulawesi)	Pertamina/Medco Energi	gas	2007+		4,000		onshore
Gajah Baru (New Elephant)	Premier Oil	gas	2005+				Natuna Sea, no sales contract
Jabung (Makmur, N Geragai)	Petrochina	oil/gas	2003				
Kerisi	ConocoPhillips	oil	2005				
Langsa	Matrix Oil	oil	2000	33.5			FPSO
Merah Besar	Unocal	oil/gas	2005+	52	160		mini TLP to West Seno
Natuna D Alpha	ExxonMobil	gas	2010+		46,000		16 platforms
Nubi/Sisi	Total	gas	2007	40	2,700	200	platform joint dev
Oseil	Kufpec	oil	Oct–02	40			onshore
Oyong (gas)	Santos	gas	2005+		90		
Ranggas (off Kalimantan)	Unocal	oil	evaluation	400	200–350		
Singa, South Sumatra	Exspan	gas	2005+		400		onshore
Sirasun/Terang	BP	gas	2005+		800	500	subsea via Pagerungam
Sungai Kenawang	Respol/YPF	gas/cond					test 380,000 cm/d, 370 b/d
Tangguh (Weriagah)	BP	gas/oil	2007	80	18,300	1,750	
Ujung Pangkah	Amerada Hess	gas/oil	2005+		450		
West Seno Phase I	Unocal	oil/gas	Aug–03	250	180		TLP FPSO
West Seno Phase II	Unocal	oil/gas	2005	250	180		second TLP
Donggi and Senoro	Pertamina/Exspan	gas			5,000		onshore

Current and planned key field developments in the Asia-Pacific region

Country/Field	Operator	Oil or gas output	Start-up date	Oil res. (mn b)	Gas res. (bn cf)	Capex ($mn)	Production system
JAPAN							
Sado Island (offshore)	Japan Energy/Idemitsu	oil/gas	2008				
MALAYSIA							
Angsi/Larut	ExxonMobil	gas/oil	Feb–02	300	1,350	1,500	platform
B12, off Sarawak	Sabah Shell?	gas	2005	3	500		platform
Belumut	EPMI	oil	2004	11		50	platform
Beryl	Petronas Carigali	gas	post–2010		400		platform
Bintang	Esso Malaysia	gas/oil	Feb–03	25	1,000	250	platform
Bunga Orkid	Talisman	gas/oil	2007	3	415		platform
E6, off Sarawak	Sabah Shell Carigali	gas	Tech res				
E8, off Sarawak	Shell/Petronas Carigali	gas	2005	36	2,100		platform + compression
F13, off Sarawak	Shell/Petronas Carigali	gas	2009	23	3,100		platform + compression
F14, off Sarawak	Shell/Petronas Carigali	gas					platform
F28, off Sarawak	Shell/Petronas Carigali	gas					platform
F29, off Sarawak	Shell Malaysia	gas	post–2010	1	100		platform
G7, off Sarawak	Shell Malaysia	gas	post–2010		100		
M4, off Sarawak	Shell Malaysia	gas	2002	27	600		platform
Cendor	Amerada Hess						
Congkak	Murphy Oil (SK 309)	oil					
Guntong Hub	ExxonMobil	gas	2006				
*Helang (blk SK 10)	Nippon Oil Exploration	gas	2003		1,600		platform
*Jintan (blk SK 8)	Shell	cond/gas	2003	56	2,800		platform
Kikeh (blk K, off Sabah)	Murphy/Petronas Carigali	oil	2007	400–700			discovery
Kebabangan- 3 (Discovery)	Open – Petronas	oil		10,000 b/d (test)			
Laila	Petronas Carigali	gas	2010		300		platform
Larut	ExxonMobil		**Feb–02**	70		200	platform
Lawang/Langat	Esso Malaysia	oil	2002	30	–	200	platform
PM Blocks 5,8,9,10	Esso Malaysia	gas	1998 onw'ds				Peninsular gas project
PM3 CAA Phase II	Talisman		Sep–03				platforms
*SK8 other fields	Shell	gas/cond	2004 onw'ds	31	2,400		platform
*SK10 other fields	Nippon Oil	gas/cond	2012	4	100	37	subsea tie-back to Helang
West Patricia (off Sarawak)	Murphy Oil (SK 309)	oil	May–03	38			
MALAYSIA-THAILAND JDA							
A18 fields	CTOC	gas/cond	2005	100	5,200	1,230	Cakerwala is phase1
B17 fields	CPOC	gas/cond	2011	57	1,600	780	Muda plat + pipeline link
Cakerawala	CTOC	gas/cond	2005	51	2,100	800	platform
KOREA (SOUTH)							
Donghae	KNOC	gas	Dec–03		250		3 subsea to prodn plat
Gorea-V		gas	Jun–02		200–300		
MYANMAR							
Yetagun Ph2	Petronas	cond/gas	May–00	80	3,200		2 plat (20 wells), 8 subsea
PAKISTAN							
Adhi	PPL	gas/cond	1980	35	173	185	onshore
Badin–1 fields	BP	oil/gas	1982	157	844	914	onshore
Badin–II	BP	oil/gas	1986	2.5	333	88	onshore
Bhit	ENI	oil/gas	2003		896	340	onshore
Dhurnal	Orient Petroleum	oil/gas	1984	53	128	255	onshore
Kandanwari	ENI	gas	1995		278	354	onshore
Kandhot	PPL	gas	1987		964	52	onshore
Mari & Mari Deep	MGCL	gas	1968		6,043		onshore
Miano	OMV	gas	2001		700	161	onshore
Qadirpur	OGDCL	gas	1995		4,017	517	onshore
Sawan	OMV	gas	2003		1,300	329	onshore
Sui Area	PPL	gas	1955		9,995	236	onshore
Zamzama	BHP Billiton	gas	2001–03		1,912	420	onshore
PHILIPPINES							
Malampaya (oil)	Shell	gas/cond	2002	80	3,100	1,800	subsea tieback
THAILAND							
Arthit	PTTEP	cond/gas	2007	40	3,200		
Bongkot redevelop 3C	PTTEP	gas/cond	2003	6	500		platform + gas processing
Dara	Unocal	gas/oil	2005+	3	160		
Maliwan	ChevronTexaco	gas/cond	2002	30	220		FPSO
North Jarmjuree	ChevronTexaco	oil/gas	2003	65	400		discovery
Pailin ph2	Unocal	gas/cond	2002	30	1,000	1,700	central plat +25 wellhead
Yala/Plamuk/ Platong/ Surat/ Kaphong	Unocal	oil	2002				FPSO (50kb/d) via Plantong
VIETNAM							
Bunga Kekwa PhII	See Malaysia						
Hai Thach	BP	gas/cond	2007	90	1,800		platform
Lan Tay/Lan Do	BP	gas/cond	2002	10	1,600	1,230	2 platforms
Rong Doi	KNOC	gas/cond		12	800		platform
Su Tu Den (Black Lion) blk 15-1	Cuu Long Op Co	oil	2004	240			FPSO (70kb/d)
Su Tu Vang	Cuu Long Op Co	oil	appraisal				

Key: *to Tiga LNG project

Current and planned key field developments in the Asia-Pacific region *Source:* Petroleum Review energy INSTITUTE

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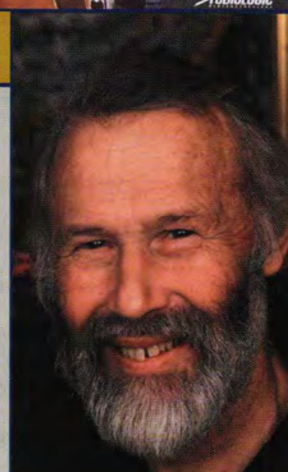

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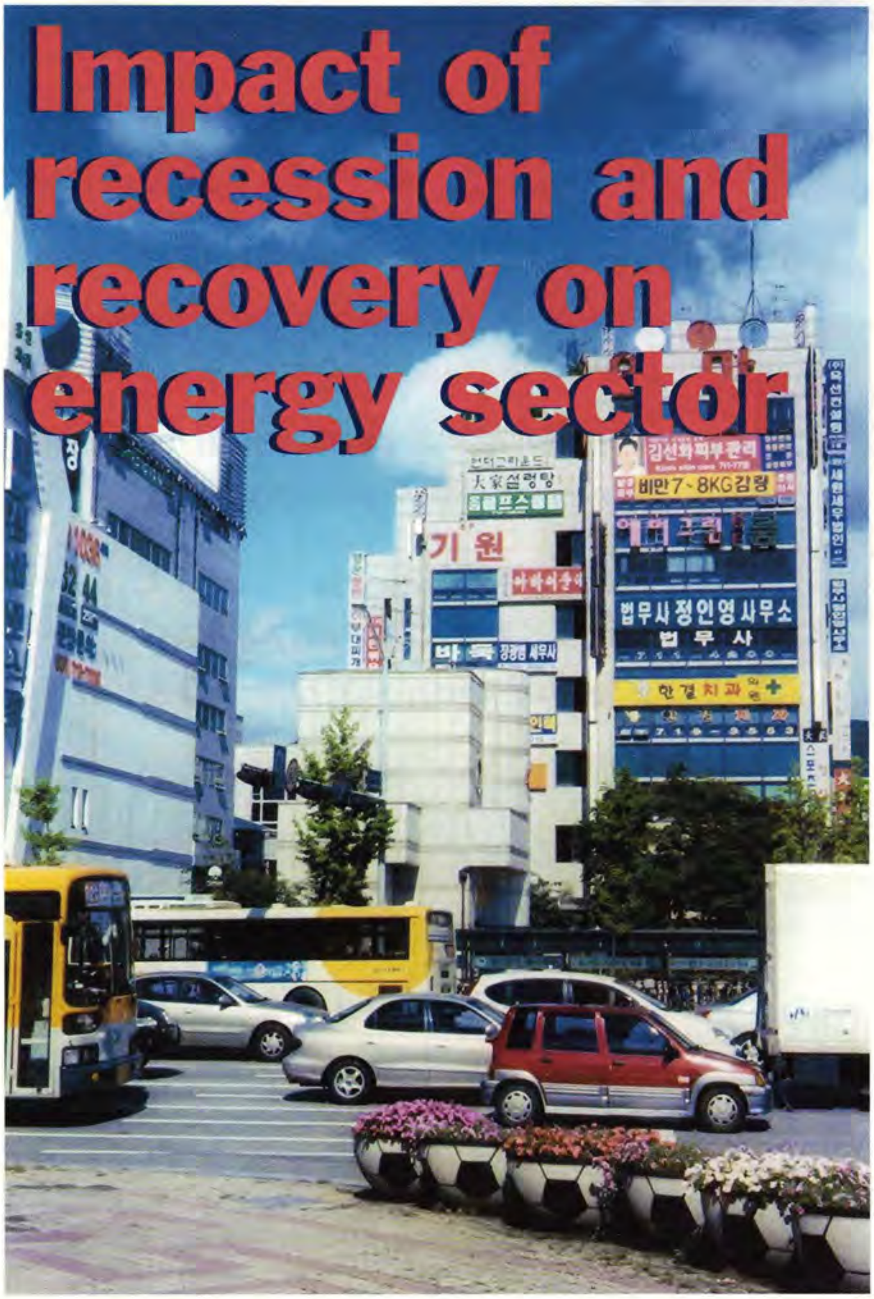
Impact of recession and recovery on energy sector



South Korea has come a long way since the 1997 financial crisis marked the end of a long economic boom. Forced to call in the International Monetary Fund to help solve its massive financial problems largely through a wide-ranging corporate debt restructuring programme, South Korea's economy achieved a recovery within a few years, helping restore the nation's pride once again. *David Hayes* looks at how the 1997 economic crisis and subsequent recovery have had important repercussions for South Korea's energy sector.

The streets of Seoul *All photos: David Hayes*

South Korea's economy is expected to grow by 3% to 3.5% in 2003 following a first-half growth performance of 2.8%. While the government is forecasting that the nation's economic growth performance should improve to 5% in 2004, this year's performance is just half the 6% growth rate achieved in 2002 when the summer World Cup jointly staged by South Korea and Japan helped in buoying economic growth and the boosting of consumer spending.

However, 2003 has turned out to be a more difficult year. With the World Cup football circus long departed, South Korea is facing a slump in consumer confidence as the recent severe acute respiratory syndrome (SARS) epidemic in Asia, the war in Iraq and public concerns over North Korea's nuclear ambitions have contributed to the current economic downturn.

The 1997 economic crisis and subsequent recovery have had important repercussions for South Korea's energy sector. After energy consumption dropped sharply in 1998 due to the financial crisis, primary energy demand began recovering the following year and has continued to grow, reaching 209mn toe in 2002, up 5% compared with 198.5 toe in 2001.

The reorganisation of the energy sector

While energy demand has risen once again due to an increase in vehicle numbers and the growth in residential and industrial energy use, the energy sector itself has undergone a reorganisation. South Korea's privately owned oil refining industry underwent several rounds of restructuring in the late 1990s due to the impact of the financial crisis. This was followed by the dismantling of Korea Electric Power Corporation (Kepco) in 2001 and a reorganisation of the electricity industry after Kepco was broken up into six state-run generation companies, of which five await privatisation.

Now it is the turn of South Korea's natural gas import and transmission industry to be restructured. After the government's original proposals were rejected by Parliament last year, plans to reorganise and privatise Korea Gas Corporation (Kogas) are currently under review as part of the government's overall policy of instituting competition in the gas industry.

In spite of South Korea's rapid economic growth over the past two decades, the country has few indigenous energy resources and has to rely on imported energy for the bulk of its needs. All crude oil and natural gas supplies are imported, along with about

Kogas headquarters, Seoul

20% of petroleum products and most of the country's coal requirements.

Domestic energy production provides just 16% of South Korea's total primary energy needs. Nuclear power is the main domestic source, accounting for 79% of domestic energy production, followed by locally mined anthracite, representing about 10.5%, hydropower 3.4% and renewable energy the rest.

Nuclear power and natural gas have been the two important new energy sources to be developed over the past two decades. Nuclear power generation, for example, accounted for less than 1% of energy consumption in 1980, but by 2002 had reached 29.7mn toe, representing 14.35% of total energy consumption.

Liquefied natural gas (LNG) first began to be imported in 1986. LNG imports have grown to 23.5mn toe/y and now represent about 11.25% of total energy consumption.

Coal and oil traditionally have been South Korea's most important energy sources. Since the 1980s coal consumption has grown almost three-fold to reach 49mn toe in 2002. Coal accounts for about 23% of total annual primary energy consumption, compared with about 33% in 1980, due to rising petroleum use by vehicles and the development of nuclear power.

The use of petroleum products, meanwhile, has grown about three-fold since 1980 to reach 102.7mn toe, or 765mn barrels, in 2002 and today accounts for about 49% of total energy consumption. Naphtha is the largest item, representing about one-third of total petroleum consumption. Used mainly by the petrochemicals industry, some 245mn barrels were used in 2002, the highest annual figure on record and 5% up on the previous year. Diesel accounts for almost 20% of petroleum use. Some 139mn barrels were used in 2002 representing a 5% increase on 2001. Bunker-C oil consumption fell to about 7% to 117mn barrels in 2002, representing almost 15% of petroleum use. During the same period kerosene use dropped 4.5% to 58.8mn barrels. LPG use grew about 8.5% last year to reach 91.4mn barrels, accounting for 11.5% of petroleum use, while gasoline consumption rose 2% to 64.3mn barrels, representing about 7.5% of petroleum use.

Tough times for refiners

Although energy demand is growing, South Korea's oil refining industry has faced a tough time during the past three years. Refining overcapacity that plagues the industry caused losses among refiners in 2000 and 2001 as domestic demand for petroleum products remained flat.

Although domestic consumption of petroleum products grew 3% in 2002 to reach 765mn barrels, refineries were forced to reduce their refining volumes due to a 20% fall in refined product exports, which dropped to 238mn barrels last year after total export volumes previously had been remained largely unchanged since 1998.

'The operating environment for oil refiners is not bright in this economic situation,' commented a spokesman at Korea Petroleum Association (KPA). 'Last year refineries recorded profits as the result of changes in the exchange rate after losses in 2000 and 2001. This year the same situation is continuing, with refiners earning profits from exchange rate profits.'

South Korea is the fourth largest importer of crude oil and sixth largest consumer of petroleum products in the world. While the local refining industry is suffering from overcapacity, petroleum product imports have been increasing since the domestic market was liberalised in 2000. About 43 import companies initially registered to import petroleum products, although only about 18 are operating now.


Service station in Seoul

In 2002 South Korea imported 228mn barrels of petroleum products. Diesel imports have doubled since the domestic market opened, while kerosene imports have grown 32%. Naphtha imports have risen 10%, while LPG imports have stayed flat.

The Middle East is the main source of the country's crude oil supplies. Since 1990 between 72% to 78% of South Korea's oil imports have come from the Middle East and about 10% from Southeast Asia. The remaining volume is sourced from other major oil producing countries worldwide. 'Crude oil imports were down in 2002 as refinery operations slowed down,' said the KPA spokesman. 'This year we expect oil imports will stay at the same level as 2002 and that demand will show a very slow increase. At the end of 2002 the oil stockpile was 101 days, which is above the government target of 90 days.'

South Korea's refining industry consists of five refining companies with the combined capacity to refine 2,438,000 b/d of oil. In spite of restructuring that took place within the industry in 1999, the nation's refining capacity has remained unchanged since the financial crisis struck in 1997. Further restructuring is due, however, as Inchon refinery is bankrupt and under court administration until a new owner can be found.

In 2002 the overall operational rate for South Korea's entire refining capacity was 88.6%, down 8.3% compared with 96.6% in 2001 and well below 99.78% recorded in 2000. The present international economic slump has meant that South Korean petroleum product exporters are finding business more difficult this year. Until 2002 refineries mainly exported their excess capacity to Japan and China, shipping a record 306mn barrels in 2000.

However, Japan and China are now facing their own economic slowdown. Consequently, South Korea's exports of petroleum products have dropped, sliding to 238mn barrels in 2002, and resulting in a correspondingly lower refinery capacity utilisation ratio.

In spite of the slowdown in local and overseas petroleum product demand, no refineries have been forced to shut down production capacity so far. However, a number of refineries have delayed completing their government-backed desulphurisation programmes, which originally were due for completion in May 2003.

SK Corporation is South Korea's largest refiner with facilities to refine 810,000 b/d of crude, accounting for 33% of local refining capacity, plus process equipment to upgrade 90,000 b/d of heavy oil. In second place is LG-Caltex, which can refine 610,000 b/d, accounting for 24.6% of local capacity, and can upgrade 70,000 b/d of heavy oil. S-Oil (formerly Ssangyong Oil) can refine 443,000 b/d, equivalent to 18.2% of local capacity, and has facilities to upgrade 130,000 b/d of heavy oil. Hyundai Oil became the fourth largest of South Korea's five oil refineries – with facilities to refine 310,000 b/d, accounting for 12.7% of the country's refining capacity, and upgrade 42,000 b/d of heavy oil – following its divestment of Inchon Oil after suffering a financial loss in 2001. Inchon Oil is the smallest refiner, capable of refining 275,000 b/d and accounting for 11.3% of the nation's refining capacity. The company was declared bankrupt soon after being sold by Hyundai, and is currently under court administration while a new owner is sought.

Slowdown in gas demand

Meanwhile, natural gas is expected to remain an important source of energy in the future, although the rate of gas demand growth is expected to slow from now until 2010 due to a forecast reduction in gas-fired power generation growth.

'The gas industry is growing at 7% to 8% annually, but we think from now until 2010 it will grow a little bit slower at 4% as electricity companies' use of gas will be slower,' explained Kogas Strategic Planning Team Manager, Jong-Kook Lim. 'The peak time for electricity demand is summer and winter. The peak time for LNG is winter. Summer demand is very low. We have a big problem with seasonal gas demand fluctuations. We have used spot orders from Qatar and other countries for winter for the past five years.'

In 2002 Kogas imported 17.8mn tonnes of LNG at a cost of $3.9bn, representing a 10.5% increase in volume compared with 16.2mn tonnes in 2001. LNG consumption has risen 70% since South Korea's financial crisis caused gas use to drop for the first time in 1998 before returning to the growth path the following year.

South Korea's winter season runs from October to March, with February usually being the coldest month of the year. The number of spot cargoes has recently increased as Kogas needs to use more spot cargoes in winter as regular long-term LNG contracts require regular shipments throughout the year. Kogas plans to import 29 spot LNG cargoes this winter after importing 43 spot cargoes of 56,000 tonnes last winter from Qatar, Oman and Indonesia. According to Lim, Kogas will import 19mn tonnes in 2003, representing a 6.7% increase in imports. The slowdown in import growth has been caused by slower growth in gas-fired power generation.

City gas companies are Kogas' largest customers. South Korea is served by 33 city gas companies, of which 29 distribute natural gas. In 2002 city gas companies purchased 11.1mn tonnes, up 7.8% compared with 10.3mn tonnes the previous year. Some 61% of South Korea's total LNG imports are used as city gas feedstocks, while power generation uses 36.5% of LNG imports.

In 2002 some 6.5mn tonnes was used for power generation, up 23% compared with 5.3mn tonnes the previous year. The five thermal power generation companies (gencos) formerly belonging to Kepco used 4.7mn tonnes in 2002, while independent power plants (IPPs) used a further 1.2mn tonnes, the remaining 525,000 tonnes being used for captive power generation.

Government legislation

In 2002 the government submitted three deregulation laws for ratification that proposed changes to the natural gas import and transmission industry. The proposals were rejected by Parliament, which considered that some of the new legislation could create problems in implementation. The proposals remain pending while the government tries to revise the draft laws, incorporating ideas gained by studying gas industries in other countries.

One proposed piece of legislation that Parliament did not approve would involve splitting the Kogas gas marketing department into three competing LNG suppliers. The idea was that the three LNG companies would compete to sell gas to the Kogas pipeline transmission company, rather like power companies competing to supply electricity to a pool or to an independent customer.

City gas companies that buy their natural gas feedstocks from Kogas are among those opposing gas industry deregulation as they fear the proposals could threaten their current gas supply monopolies within their exclusive geographical supply areas. City gas utilities believe they may be forced to open their distribution networks to other companies wanting to supply gas if deregulation is introduced.

Since plans to privatise Kogas and restructure the gas industry first began the government has instructed Kogas not to sign any more long-term LNG supply contracts. To meet the country's growing gas consumption requirements, Kogas is restricted to signing mid- and short-term contracts or placing spot market orders. In mid-2002 the company signed two mid-term contracts. One was a seven-year mid-term contract with the Australian North West Shelf project partners for the supply of 500,000 t/y of LNG. The other was a seven-year mid-term contract with Malaysia's LNG Tiga plant for 2mn t/y. Both contracts started in May 2003.

Kogas expects gas demand to reach almost 20mn tonnes by 2005, rising to 21.65mn tonnes in 2010 and reaching 28.2mn tonnes in 2015. By 2015 city gas companies would provide 80% of demand and power generation 20%.

South Korea's gas supply sources are expected to diversify while gas demand continues to rise. A small offshore gas deposit – Donghae – is due to be tapped and could supply the equivalent of 400,000 t/y of LNG from 2005 to 2010 before production starts to decline.

Pipeline plans

Meanwhile, Kogas is planning to import 7mn t/y of gas by pipeline from Irkutsk in Russia. The first supplies are due to arrive between 2008 to 2010. At present the pipeline construction consortium including Kogas is reviewing construction plans. Two routes from northern China to South Korea have been proposed after the original route was changed at China's request to avoid passing through Mongolia and paying transit fees. One pipeline route passes through North Korea from China en route to South Korea, while a second route runs south to China's Shandong Province and then crosses by submarine pipeline to landfall on South Korea's west coast near Incheon and Seoul.

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Middle East struggles to sell gas

The Middle East holds a substantial percentage of the world's gas reserves, yet only a fraction is currently being produced. In a bid to encourage domestic production several Middle Eastern countries are now promoting gas-fired power generation in the hope of creating large, new markets for their gas. *Dr Paul McDonald*, Managing Director of Pearl Oil, an oil and energy consultancy based in the UK and Hong Kong, reports.

Natural gas is the poor relation of oil across much of the Middle East. Although the region holds 36% of the world's proved gas reserves, it accounts for only 9% of global production – and only four countries export gas outside the region. Several Middle Eastern countries are trying to encourage gas production by promoting gas-fired power generation, in the hope of creating large, new markets for their gas. Progress has often been slow, however, and gas remains under-utilised compared with most other regions of the world.

Middle Eastern interest in gas-fired power generation has arisen largely as a result of rapidly rising electricity demand and a looming shortage of generating capacity. In most parts of the region the electricity sector has been a long way behind the oil industry in the allocation of state funds. Over the past few years, however, some countries have tried to bridge the gap in funding by opening their generating sectors to private investment.

At the same time there has been a move amongst the principal oil exporting countries to rein-in the high growth in domestic petroleum demand in order to maximise the volumes of oil available for export. Gas-fired power generation has therefore been promoted not only as a means of oil substitution but also as a way of monetising some of the large, undeveloped gas reserves in the region.

The policy has not, however, been an unqualified success, with the result that neither the gas nor the electricity industries are developing as rapidly as desired or, indeed, as needed.

Preventing power shortages

Electricity consumption in the Middle East has risen at over 8% a year since 1990. On the other hand, generating capacity has risen annually by only 3% over the same period. Only the cushion provided by the high level of overcapacity in the early 1990s has prevented shortages today – and in some countries, notably Iraq and Lebanon, capacity is already inadequate, owing to the fact that much of their capacity is unusable because of war damage. In other countries, including Saudi Arabia, peak electricity demand is now uncomfortably close to the total usable generating capacity, and both gas and power sectors have been finding it difficult to attract investors. In the UAE, by contrast, independent power producers (IPPs) are developing several gas-fired power stations – although it is the gas producers of Qatar more than those of the Emirates who stand to benefit.

Middle Eastern gas reserves, on the other hand, are not particularly well-developed, apart from in Qatar and, to a lesser extent, Egypt, Oman, the UAE and Iran. Gas production has often struggled to obtain investment because of the difficulty in finding secure, long-term outlets for the gas. Gas prices have also been kept low by many governments across the region. In the UAE, for example, wholesale gas prices generally range between \$1 and \$1.30/mn Btu.

Saudi Arabia has kept domestic prices at \$0.50/mn Btu for many years before allowing them to be raised to \$0.75/mn Btu in January 1998. Later that year, the Saudis approached seven US oil companies and asked them to submit 'recommendations and suggestions' about the possible involvement of foreign companies in the Kingdom's gas sector. Subsequently, three major integrated projects involving gas, power and other developments were formally offered to international oil companies. The companies, however, were unwilling to invest until several changes had been made, including the removal of the power generation schemes from the projects. One effect of including the power schemes as part of the gas packages was to delay a number of planned power stations whilst the negotiations dragged on. The Saudis have begun to re-tender the power schemes as separate packages since July this year.

Some of the Saudi range of generating schemes, however, will be needed before the giant gas projects that are now on offer actually enter production. According to the state-owned Saudi Electricity Company (SEC), the Kingdom needs at least 1.5 GW/y of new generating capacity between now and 2010 in order to keep pace with the growth in electricity demand. Of necessity, some of the new capacity will therefore be oil-fired. Two new power plants of 700 MW each, at Shuaiba and Shuqaiq, on the Red Sea, are to be run on crude oil.

Gas and power developments stall

Another country struggling to develop its gas and electricity sectors in parallel is Iran. As in Saudi Arabia, foreign companies have complained about what they see as inadequate rates of return on upstream gas ventures. The situation in

Iran is further complicated by the fact that the government has been trying to develop the main gas field, South Pars, in up to 26 separate phases. Delays to some of the phases and the consequent uncertainties about future supplies of gas are making some investors wary of committing to schemes to build new gas-fired power stations.

Israel also has ambitious plans to switch its power stations to gas. Here, there is the added complication that two of the three main sources of gas for power stations are outside Israeli territory – one source is offshore from the Palestinian enclave of Gaza; the other is Egypt. Israel has expressed some reservations about buying gas from the former, while the Egyptian Government has indicated its reluctance to supply Israel while the Palestinian question remains unresolved. Eventually, commercial pressures may outweigh political sensitivities. In the meantime, however, further delays are occurring to the gas-to-power programme as a result of Israel's inability to agree the financing and construction of a gas transmission grid.

The most severe problems concerning gas and power are, not surprisingly, to be found in Iraq. Before the latest conflict Iraq had ambitious plans to raise its gas production. The main incentive to developing a number of the fields was the prospect of a new generation of gas-fired power stations to provide markets for the gas. Gas turbines were ordered for a new station near Baghdad and there was even talk of exporting gas-generated electricity to neighbouring countries. Such schemes must now be put on hold as the priority must be to repair war-damaged generating, transmission and distribution assets before any new, integrated gas-to-power schemes can be seriously contemplated.

Country	Generating capacity (in GW, as at 1 Jan 2002)
Iran	28.0
Saudi Arabia	26.4
Egypt	15.7
Israel	9.7
Kuwait	9.3
UAE	9.0
Syria	7.7
Iraq	4.6
Oman	2.3
Qatar	2.3
Lebanon	2.0
Others	3.7
Total	**120.7**

Sources: Arab Fund for Economic and Social Development (AFSED), Israel Electric Corporation (IEC) and author's estimates.

Table 1: Middle East generating capacity, 2002

And the good news?

A few countries have managed to make progress with their gas and power plans. The UAE has attracted both gas and power companies, and several IPP schemes are under way. As in other parts of the Arabian peninsula, these are often combined with water desalination plants. The Taweelah A-1 station, which is jointly owned by the Abu Dhabi Water and Electricity Authority (ADWEA), Total and Belgian utility Tractebel, is one of the largest cogeneration plants in the world, with a capacity of 1.4 GW. An even larger facility is planned at Umm al-Nar, where an 805 MW unit is to be expanded to 1.6 GW.

One reason for Abu Dhabi's success in developing gas-to-power schemes is the Emirate's enthusiasm for privatisation. Whilst Iran and Saudi Arabia have solicited private participation in their electricity sectors, they have been slow to firm-up projects. Investors have also been discouraged by political opposition inside both countries to private investment in power.

While the UAE may be making the most progress in gas-to-power schemes, the gas involved is not only the UAE's but Qatar's as well, and, in the case of a power development in Fujairah, the gas is to come initially from Oman. With its large reserves and small home market, Qatar is obliged to stretch its gas chain into neighbouring countries. It plans to start delivering gas from its Dolphin field to Abu Dhabi in 2006 and there are further plans to supply gas by subsea pipeline to power stations in Kuwait from the same year, with a possible spur line to Bahrain.

Egypt, too, is trying to integrate its gas production with power plants outside the country. In July this year a pipeline was opened linking Egypt's offshore al-Arish field with the 650 MW Aqaba power station in Jordan, where it will replace heavy fuel oil as the feedstock. This is planned to be the first of a series of gas-to-power developments using Egyptian gas.

The Aqaba pipeline is to be extended northwards through Jordan to serve three power stations, at Rihab, Samra and Hussain, near Amman, which are due to be commissioned in 2005. The pipeline's developers are optimistically hoping to build an extension shortly afterwards to Syria, followed by two further extensions serving power stations and other users in Cyprus and Turkey. The whole project is known as the Arab Gas Pipeline (AGP). Its intended capacity of nearly 1bn cf/d means that it will almost certainly need to be extended northwards from Jordan.

The northern extension, however, may be put in doubt by Syrian plans to supply Cyprus with gas. The island plans to convert its power stations from oil to gas by 2006, which may be too soon to enable AGP to build a line there.

Syria, meanwhile, has plans of its own to use domestic gas for new power station projects. At present it is converting the 680-MW station at Banias from oil to burning gas from Syria's Palmyra gas field.

Turkey disappoints gas exporters

Turkey's burgeoning electricity generating market has attracted offers of gas from a number of other Middle Eastern gas producers – including Iran, Iraq, Yemen, Qatar and Oman – to the extent that it faces a potential oversupply unless it can persuade some suppliers to deliver less than they have contracted for. While gas demand continues to grow strongly in Turkey, earlier forecasts of demand from the power sector have proved massively over-optimistic. Gas demand for 2005 is now forecast around 2.2bn cf/d, compared with earlier Turkish forecasts of 4.4bn cf/d. Power generation accounts for nearly 70% of Turkey's gas consumption.

Last year Turkey stopped importing gas from Iran, citing quality problems, and called for its 22-year contract to be renegotiated. This year it is trying to reduce contracted flows from Russia. Several future supply deals appear to be in doubt, including one to import LNG from Egypt.

The Turkish gas glut is a particular blow to Iraq, which had ambitious plans to develop a series of gas fields in the north of the country to serve power and other developments in both Iraq and Turkey. There is almost certainly insufficient demand in Iraq alone to make the project financeable in the foreseeable future.

Leader or laggard – IT and telecommunications in oil and gas

The oil and gas industries have become highly dependent on sophisticated information and communications technology (ICT) to achieve their business goals. Whether it is the complex analysis of seismic data below a salt dome, or global integration of procurement of goods and services, ICT has become key to business success. *Tim Aikens*, Managing Consultant at Syntegra*, reports.

In this, oil and gas companies are not alone – global businesses across all sectors look to their ICT systems to enable them to operate on a truly international scale. As the business world gets closer to operating in real time, the speed at which raw data can be translated into business intelligence has become a key differentiator. Industry is increasingly relying on sophisticated in-country and trans-border communications networks to transport voice and data seamlessly to all four corners of the globe.

Taking advantage of these networks means that businesses are readily able to disseminate data to and from remote locations, the rationalising of personnel, reducing transportation costs and leveraging the expertise of the workforce, whatever their location. For an oil company this means that an offshore worker in Angola, for example, can view and respond to downhole data in real time from a well in Azerbaijan.

Driving global business

In fact, technology has become not only a tool to aid global business, but a driver towards it. Increasingly sophisticated technology has encouraged the realisation of the concept of the 'virtual company' with a resilient ICT infrastructure as its backbone. Rather than replicating the roles of non-core personnel and creating a miniature version of the company in each country, a virtual company has these functions located centrally, or in a limited number of key locations, while the local outposts focus on core business activity.

This concept has been gaining ground in other sectors, such as manufacturing and pharmaceuticals for example, and is gaining an increasing foothold in the oil and gas industry. The concept of the virtual oil company can be illustrated by the contrast between oil production in Siberia under the Soviet Union, where whole towns were built around oil fields to house oil company workers, and the increasing trend for unmanned facilities and 'lean production' in the West.

Oil and gas issues

However, unique factors within the oil and gas sector raise particular issues, which impact upon the deployment of ICT. The first of these is location. Global manufacturing and pharmaceutical companies have, to an extent, a degree of choice about where they are located, enabling them to take advantage of favourable labour costs, stable political and meteorological environments and proven fixed, mobile and satellite telecommunications networks.

The oil and gas industries on the other hand are significantly constrained by where the raw material is located. Remote areas, like Azerbaijan, Angola or Siberia, tend to have major technology infrastructure gaps, as do areas of political conflict and developing nations. This places extra pressure on an oil company's ICT department to maintain, and in some cases even create, a robust and secure infrastructure. Not only do the huge volumes of data relating to upstream operations need to be supported, but also downstream activity such as transportation, logistics and marketing, and even basic office functions such as word processing, email and voice calls.

The oil and gas sector is extraordinarily capital intensive. Increasing spend on ICT could be seen as adding a further burden to capital budgets that are already stretched. This creates a dilemma for the industry. On the one hand the effective use of ICT can contribute significantly to a reduction in costs associated with running a global oil business. For example, through advances in seismic acquisition and interpretation, intelligent and real-time drilling and data processing and analysis, drilling success has been improved and finding costs associated with remote exploration are kept as low as possible. On the other hand the purchase, deployment and maintenance of complex information and communications technology infrastructures reduces the amount of capital available for core E&P and downstream development. With the full array of ICT spend from global networks to local desktops and specialised software, it's an expensive shopping list!

In most industries the complex and constantly evolving nature of ICT has resulted in a gradual shift towards outsourcing this technology to specialist service companies. Oil, with its history of outsourcing and innovation, is no exception. Oil companies have already adopted a range of policies on outsourcing. Some merely lease the communications infrastructure and handle the rest of the IT facility in house. Others contract out the running of existing systems or work with services firms to modernise or replace systems with customised solutions that have been developed collaboratively in order to optimise specific operations.

Self-evident logic

The logic of outsourcing non-core functions is self-evident – it allows companies to concentrate their efforts on their core competencies, while the ICT experts concentrate on the systems required to support the increasingly complex oil business processes and the inherent changes and developments in technology. Outsourcing can also lead to cost savings due to reduced overheads. Equally attractive to a company trying to reduce capital expenditure, the cost of ICT is transferred to the operational expenditure budget.

Historically there have been various reasons why companies in all industries have been cautious in their approach to outsourcing their ICT functions. Data is commercially sensitive – increasingly it is the lifeblood of any organisation – which raises concerns about the reliability and integrity of third-party suppliers. The ability of those third parties to provide sufficient guarantees of reliability and to provide a satisfactory level of technical performance is also not certain.

However specialist suppliers are increasingly winning customers' trust. Contracts in other sectors, including local and national government, where organisations arguably have the most sensitive data and most stringent reliability requirements, bear witness to this. This suggests that third parties are indeed capable of handling the most confidential information in a secure manner and that, as a result, outsourcing of ICT to specialist contractors will increase.

The ultimate level to which ICT is outsourced will largely depend on two factors – firstly, on the oil company's assessment of the commercial business benefits and, secondly, its appetite for risk. Most companies do not own their own telecommunication backbone such as IP networks or satellite, as the cost is prohibitive and there is little commercial benefit in doing so. Instead, they lease them from telecoms companies. When it comes to data centres there is a decision to be made between cost and risk. Oil companies are split between those who run their own, and those who outsource, again from specialist providers.

In the software arena there are already a number of commercial off-the-shelf (COTS) products, such as financial and human resources applications, which can be implemented using common, proven web-service-based architectures that are widely used throughout a number of industries. The risk associated with using these kinds of products is minimal. However, if the shift towards ICT outsourcing continues then it is likely that a number of niche applications that are much closer to core operations, such as 3D seismic modelling, may also become available on a similar basis. This is where the risk – for both oil company and supplier – increases, but is also where the most attractive margins will be found as a consequence.

Standardisation and consolidation

Whatever the outsourced model chosen, it seems clear that a degree of standardisation and consolidation is inevitable. Looking at the convergent IT and telecommunications industries, the market is maturing and settling and there is increasingly little to choose between the functionality of different products in the same field. High profile mergers and acquisitions, as well as the everyday level of collaboration going on, are strong indicators that this trend is sure to continue.

The differentiating factors are now the way that ICT is implemented, the choice of system integrator and the manner in which it is paid for. This may be where ICT can now deliver the competitive advantage, by making the entire infrastructure available to be purchased on a usage-based model. So far the oil industry has resisted this 'pay as you go' approach to ICT, which is the logical destination on the outsourcing journey. However, it may be that the current cost pressures and focus on efficiency will drive the industry to adopting this model.

Radical re-focus

Certainly it will require a radical re-focus in the way the IT department is managed and staffed. A shift in skill sets would be required, moving away from the full breadth of ICT to focus more on commercial skills and the ability to match business and technology needs with the services offered. There are already calls, most recently at the IDC European Technology Forum, for the Chief Information Officer to be more ready to align technology to business benefit, to demonstrate the overall value to the company, and to be more commercially and politically aware. The growth of outsourcing and usage-based procurement certainly adds impetus to this call.

ICT outsourcing is becoming an important tool in the enablement of the virtual oil company, but the issue is complicated by the fact that ICT itself is the enabler of the virtual company, and that certain IT functions are inherently bound up in the company's core competencies.

Further transformation

As the oil and gas industries continue their search for even greater cost-effectiveness, together with a desire to increase recovery rates or refinery margin, the pressure on ICT departments will also increase. This could be the start of a further transformation in this part of the industry.

Applications and infrastructure outsourced on a usage-only basis would reduce the need for capital investment in ICT. The need for internal ICT competence in the oil companies would mostly be at the strategic and procurement levels, together with some specialist skills. But this would demand an equal transformation in relationships with ICT suppliers, who would need to be seen as technically competent, reliable as well as flexible enough to deliver.

The opportunity for ICT to play a major role in transformation is there. The question is whether the risk is considered too high at this stage.

**Syntegra is part of BT Group, playing a key role in the company's ICT strategy as an expert in business transformation and change management. Syntegra helps organisations transform the way they operate by applying business knowledge and technology to make possible new and better ways of working. Its primary activity is the provision of consultancy and systems integration services including business consultancy, complex programme management and custom systems design, development and operation.*

Images courtesy of BT IRIS ©BT IRIS

Gulf of Mexico moves in deepwater floaters

Permanently moored, semi-submersible floating production units (FPUs) now offer an alternative to tension leg platforms (TLPs) and spars for development of large, deepwater oil and gas fields in the Gulf of Mexico. The deployment of the Na Kika FPU marks the start of this new trend, with further units of this type to be deployed in Thunder Horse and Atlantis. *Jeff Crook* reports.

Reel for Thunder Horse coiled tubing system *Photo: Halliburton*

The Gulf of Mexico gained a new lease of life with the advent of deepwater production solutions such as diverless subsea wells, TLPs and spars during the 1990s. As a result, oil production in depths greater than 1,000 ft began to exceed shallow water production, for the first time, in March 2000. This trend is set to continue with deepwater oil production likely to account for 69% of daily production by 2007, according to the US Mineral Management Service (MMS).

Thunder Horse is the largest field found so far in the Gulf of Mexico, with recoverable reserves of more than 1bn boe. It is located around 150 miles southeast of New Orleans in water depths ranging from 5,800 ft to 6,500 ft, and is due to come into production in 2005. Thunder Horse reserves surpass those of Mars, the previous largest field, whose 700mn barrels of reserves are being recovered by means of a TLP installed by Shell in 2,940 ft of water during 1996.

BP is operator of Thunder Horse, holding a 75% equity interest; the remaining 25% stake is owned by ExxonMobil. BP also claims to be the largest acreage holder in the deepwater Gulf of Mexico with around one-third of all deepwater reserves discovered to date. The importance of these reserves was recently highlighted by BP Chief Executive Officer Lord Browne of Madingley, who stated that spending on the company's deepwater Gulf operations should reach at least $15bn during the next decade.

In addition to Thunder Horse, BP has major stakes in the Atlantis, Holstein, Horn Mountain, Mad Dog and Na Kika deepwater developments. It operates all these projects with the exception of Na Kika, which is operated by Shell during the pre-operation phase. BP is then set to take over as operator from the onset of production. The company is also undertaking the development of the Mardi Gras Transportation System to transport oil and gas from these deepwater fields to shore (see *Petroleum Review*, August 2003).

Na Kika development

The Na Kika FPU is to be installed by the end of 2003 as part of a $1.4bn oil and gas development 140 miles southeast of New Orleans. In the first phase the host facility will be connected by 10 subsea wells in water depths ranging from 5,800 ft to 7,000 ft, to develop the Kepler, Ariel, Fourier, Herschel and East Anstey fields. Two further wells in a sixth field, Coulomb, lying in a water depth of 7,600 ft of water, will be tied back to the host facility at a later date.

Na Kika's gross ultimate recoverable reserves are put at over 300mn boe. The Kepler, Ariel and Herschel fields are primarily oil, while the Fourier and East Anstey fields are primarily gas.

The facilities are designed to process 425mn cf/d of gas and 110,000 b/d of oil. The FPU has a length and width of 81.2 metres (266.4 ft) and a height of 55 metres (180.4 ft). Its hull comprises a pair of rectangular steel pontoons, each measuring 41 ft wide and 35 ft high, with a deck supported by four square steel columns measuring 56 ft wide and 142 ft high. The 64,000 tonnes of buoyancy provided by the hull (displacement) will support the risers, umbilicals and mooring lines, in addition to the weight of the FPU itself.

The problem of flow assurance for the project is complicated because some of the produced fluids will flow downhill in their path along the seabed to the host facility. This consideration has prompted the operator to give careful thought to insulation and heating of flowlines. The overall scheme therefore includes electrically-heated and pipe-in-pipe flowlines and risers.

Dockwise Shipping transported the 31,500-tonne host facility from Hyundai Heavy Industries' (HHI) Ulsan yard to Corpus Christi onboard the heavy transport vessel *Mighty Servant 1* on 13 April 2003. After final checks at the Kiewit Offshore Services yard, the unit will be towed to its field position where it will be anchored by a 16-leg catenary mooring system. Each leg of the mooring system comprises chain, wire rope, and a suction pile.

Sonsub's *HOS Dominator*, a newly-built 240-ft long dynamically positioned vessel has been contracted for long-term subsea support for Na Kika. The vessel is equipped with a 3,000 metre *Innovator* remotely operated vehicle (ROV), allowing it to undertake a range of construction support activities and other subsea tasks, such as well intervention.

Thunder Horse and Atlantis

Thunder Horse will be developed by the what is reported to be world's largest steel semi-submersible FPU with a displacement of 140,000 tonnes. The unit will have a production capacity of 250,000 b/d of oil and 200mn cf/d of gas, together with living quarters, utilities and drilling facilities. In addition, the FPU will have the capacity to inject 300,000 b/d of water into the reservoir to maintain production.

The water injection pumps for this project are claimed to have the highest pressure ever used for the purpose and thus needed to be specially developed. Sulzer built a 12-stage prototype capable of producing a 5,600 metre head at 6,000 rpm. This pump was powered by a 10-MW

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Injector frame for Thunder Horse coiled tubing system ***Photo: Halliburton***

Rotor for what is claimed to be world's highest pressure injection pump
Photo: Sulzer Pumps

Murphy establishing Asia-Pacific hub

As part of our series of feature 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 *Murphy Oil.***

Murphy Oil Corporation is a worldwide oil and gas exploration and production company with refining and marketing operations in the US and UK. Its principal E&P activities are located in the politically secure basins of the US Gulf Coast, Canada and the UK North Sea. It also has a major presence in Malaysia.

Highlights in 2002

Although lower oil and gas prices at the beginning of 2002, depressed downstream results throughout the year and lower gains on asset dispositions led to a fall in Murphy's net income to $111.5mn from $330.9mn in 2001, this was partially offset by an average production of 125,800 boe/d – a record that is expected to be surpassed in 2003 and again in 2004. (See **Figure 1**.)

Driving this rise in output was the coming onstream of the Terra Nova field offshore eastern Canada, in which Murphy holds a 12% interest, and peaking natural gas production rates at the Murphy-operated Ladyfern field in western Canada. The trend is set to continue in 2003 with the coming onstream of West Patricia (85%) in shallow-water Malaysia in the second quarter and as two new fields in the deepwater Gulf of Mexico – Medusa (60%) and Habanero (33.75%) – enter production. In 2004 the Murphy-operated Front Runner field (37.5%) will come onstream, driving Murphy's average production on a worldwide basis above 160,000 boe/d.

The company's interest in the 136mn barrel Syncrude (5%) project in northern Alberta and block 16 (20%) in Ecuador will also add to its production portfolio in coming years.

One of the most significant events in 2002 was the Kikeh discovery (80%) in block K – Malaysia's first deepwater oil discovery. Reserves are put in the range of 400 mn to 700mn barrels. An additional well is to be drilled on the Kikeh structure in 2003 in order to help further define both reserves and oil flow characteristics. First production is expected in 2007.

Murphy now holds a substantial acreage position in the Sabah Trough – a virtually undrilled geological province with only 13 wells that have yielded seven discoveries. The company plans to drill a minimum of five wildcats in deepwater Malaysia during 2003.

Other developments during the year included the sale of the Ship Shoal block 113 unit (50–70%) in the Gulf of Mexico and in early 2003 the signing of a Letter of Intent to sell Murphy's 13.82% interest in the UK North Sea Ninian field. The company also accumulated an acreage position in 154 blocks in the deepwater Gulf of Mexico and has three major discoveries currently under development.

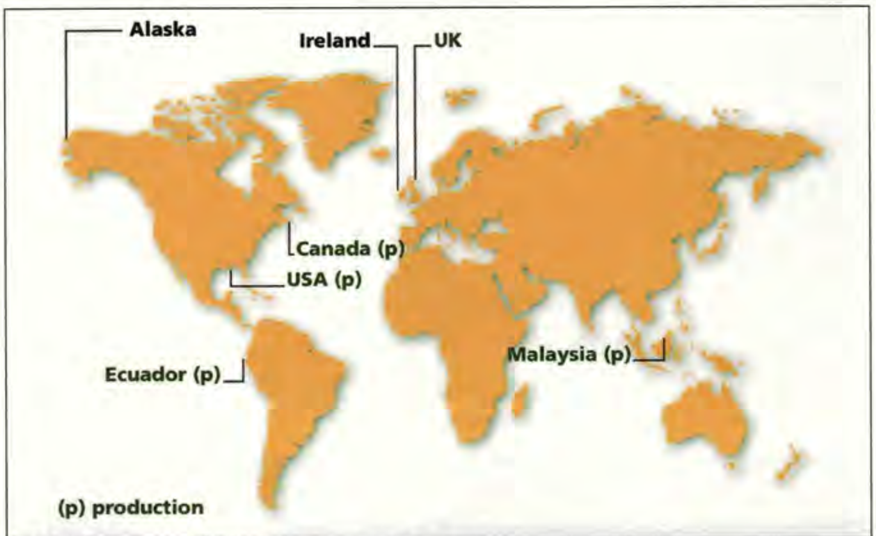

Figure 1: Areas of Murphy's international E&P activity

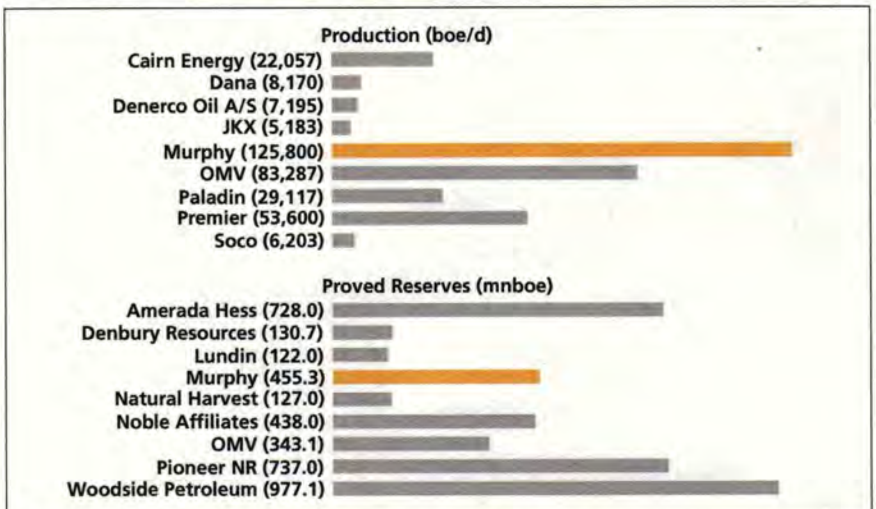

Figure 2: Production and reserves comparison data (2002 year-end)

Malaysian presence

Murphy became the third largest acreage holder in Malaysia with its acquisition of three offshore blocks in 1999. Since then it has continued to add to its acreage position and the country is expected to serve as a platform for future growth in Southeast Asia as a whole.

Success continues in Murphy's 85%-owned shallow-water blocks. During 2002 the company confirmed the commercial viability of this acreage by sanctioning a development at West Patricia, located approximately 25 miles from the coastal port of Bintulu, Sarawak, Malaysia. The establishment of a production centre will allow Murphy to fully develop its surrounding acreage.

West Patricia is currently producing 10,000 b/d from a well jacket to a floating storage facility. A number of untested structures have been identified nearby that, if successful, could tie into the field infrastructure. The company has already had success at the nearby Congkak discovery and recently discovered a new oil field in block SK 309 offshore Sarawak.

Murphy continues to expand its presence in Malaysia, with the recent addition of an acreage position in Peninsular Malaysia and the award of acreage in deepwater. The company signed production sharing contracts covering blocks L (60%) and M (70%), located adjacent to block K, in January 2003, followed by a contract in July 2003 giving the company a 75% working interest in PM blocks 311/312. These blocks represent an exploitation position similar to shallow-water blocks SK 309/311 as reserves have already been identified. Murphy plans to shoot 3D seismic surveys during 2003 in preparation for a drilling programme in 2004.

UK interest

Murphy has been an active player in the North Sea for 35 years. However, the inevitable maturing of the basin has caused the company to redirect its resources to the thriving growth centres such as Malaysia. Nevertheless, Murphy continues to harvest its existing assets – including Ninian (13.8%), T-Block (11.3%), Columba B, D & E (3.7%–5.8%) and Amethyst (12%). Total UK production is around 15,000 boe net to Murphy. Despite the mature nature of the basin, Murphy continues to consider the North Sea a core area of operations.

*Visit **www.oilvoice.com** to view over 300 continually updated oil company profiles.
Alternatively, you can e: **cp@online-data.co.uk**

...continued from p33

variable-frequency electric drive motor and was tested up to pressures of 957 bar (65% higher than the required operating pressure) whilst installed within the safe confines of a test pit. The photograph on p33 shows one six-stage rotor, with the overall pump having two six-stage rotors mounted 'back-to-back' in a configuration that assists the hydraulic balance.

The FPU will be able to perform drilling operations on 20 subsea wells located directly beneath it. The provision of these drilling facilities is one reason for the huge scale of the unit – its deck measures 123 metres long and 105 metres wide (big enough for two soccer fields) and the height up to the deck is 58 metres (equivalent to the height of a 20-story building). Compensation equipment and guide sheaves are being supplied by Aker Kvaerner as part of a $11mn contract for advanced drilling and mooring equipment.

A coiled tubing system, supplied by Halliburton, is to be installed on the deck of the FPU to allow intervention operations to be performed on the wells located beneath it. This system is designed for high pressure/high temperature (HP/HT) operations and includes a 135,000-pound injector and 750-tonne lift frame. It features what are claimed to be the largest, most powerful and strongest components ever deployed for this purpose, including Halliburton's V135HP coiled tubing injector and a reel capable of handling 36,000 ft of $2^3/_8$-inch coiled tubing. The 750-tonne capacity tension lift frame is said to be twice the size of normal lift frames.

Halliburton says that it will be used primarily during the completion phase of the wells for operations such as fill removal, fluid swap, milling, backup for e-line perforating, fishing, jetting, plug retrieval, and tubing cuts. To add to the efficiency of intervention operations the tension lift frame is equipped with a track that enables the injector to be moved without completely rigging down in order to quickly change to wireline operations.

Drilling in these water depths continues to present a challenge and not all has gone to plan – a drilling riser was lost from Transocean's *Discoverer Enterprise* in April. Fortunately no injuries occurred and no hydrocarbons were released as a result of this incident, and a visual inspection of the wellhead with a remote-operated vehicle showed no wellhead damage. However, drilling operations were suspended while an investigation was undertaken into risers of similar design.

The 55,000-tonne steel hull for the FPU is being fabricated by the Daiwoo Ship and Marine Engineering company in South Korea, under a $200mn contract. The company also received a second order from BP for the hull of a FPU to be installed in the Atlantis field. Atlantis is the third largest field so far found in the Gulf of Mexico. The field is located in the Atwater Foldbelt, approximately 125 miles south of New Orleans, in water depths ranging from 4,400 ft to 7,100 ft.

The Atlantis FPU will have a capacity of 150,000 b/d of oil and 180mn cf/d of natural gas. The recoverable reserves, which were previously put at 635mn boe, were upgraded by 200mn barrels in February 2003 following a successful appraisal well. *[Ed: The 635mn boe figure represents a proved plus probable (2P) estimate from the operator BP. Although the successful appraisal well is likely to have increased recoverable reserves, the companies do not intend to publicly revise the reserve estimate for the field prior to its startup in 2006.]*

Sonsub was awarded a contract to supply five *Innovator* ROVs to cover the Thunder Horse and Atlantis developments, together with the Mad Dog and Holstein fields, which are being developed by permanently moored spars. In addition to supply of the ROVs this contract covers operation, maintenance and the supply of tooling packages.

Mardi Gras system

The Thunder Horse and Atlantis FPUs will export their oil and gas via steel catenary risers (SCRs) through the Mardi Gras subsea system to shallow water platforms, for onward transmission to the shore. This transport system will also handle the production from spar production facilities that are to be installed in the Holstein and Mad Dog fields. See *Petroleum Review*, August 2003, for more information about this subsea pipeline system that is claimed by Intec Engineering of Houston to be 'pushing the envelope of subsea pipeline design'.

Deep gas reservoirs

Although deepwater production has been growing strongly in the Gulf of Mexico, output will only partially offset the US' large energy deficit. In a bid to help source additional supplies to meet demand, operators are now being offered royalty incentives to drill for deeper gas reservoirs from existing shallow-water facilities in the region.

While the shallow waters of the Gulf of Mexico have been actively explored to date, relatively few wells have penetrated depths below 15,000 ft because of the high cost and risk associated with such wells. The US MMS holds the view that since shallow water infrastructure is already in place – in terms of platforms and pipelines – any newly discovered deep gas reservoir production could come online relatively quickly.

Oil and gas discovery, seismic and wildcats all fall in 2002

IHS Energy **has just released its** ***World Petroleum Trends (WPT) 2003 Report*****, which highlights and examines petroleum trends in over 180 countries during the year 2002. It also presents key oil and gas E&P data for the preceding decade (1993–2002).**

In 2002 just two giant oil discoveries (over 500mn boe) were reported while gas discovery failed to replace annual production for the second year running.

This year's report marks the 11th successive year that IHS Energy has assembled country, regional and global estimates of oil and gas resources and production and presented them in a comparable manner, allowing a 10-year perspective to be shown.

The report highlights a number of 10-year trends:

- The cumulative effect of liquids-reserves revisions and new discoveries has more than kept pace with liquids consumption during the past decade.
- In 2003, confirmed liquid resources discovered at the end of 1992 were 416bn barrels, or 26% higher reserves than estimated at the time.
- In 2003, confirmed gas resources discovered at the end of 1992 were 2,300tn cf, or 36% greater resources than estimated at the time.
- Upwards revisions to the previous global-reserves estimates account for approximately 75% of all additions and only 25% of new discoveries.

Discoveries and production

In the world (excluding North America), the number of new-field wildcat wells (NFW) completed in 2002 decreased in number by 191, compared to 2001. In 2002 the number of global oil and gas discoveries reported fell by 16 (to 397), giving totals of 234 new oil discoveries and 163 new gas discoveries for the year. Figures for North America show a similar pronounced decline in new-field wildcat wells (NFW) with the US' share of global NFWs in 2002 being the lowest in a decade. However, at over 39% of the global total for 2002, US offshore drilling reached its highest percentage for the period 1993–2002.

Estimates of volumes of new hydrocarbon discoveries made in 2002 for the world less North America was almost 6.6bn barrels of liquids and 30tn cf of gas. Re-estimated figures for 2001 were 10.1bn barrels of liquids and 48tn cf of gas. ***[Ed: Original estimates were 8.9bn barrels and 42.2tn cf. So the revision involves uplift of 13.5% and 13.7% respectively.]***

Total world production of liquids in 2002 decreased by 0.7% at 26.7bn barrels (73.2mn b/d) while gas production continued to increase to 97.6tn cf (267.4bn cf/d), or 2.5% above 2001 production. And 2002 marked the second year in a row when new discoveries of gas failed to replace annual production. The North American share of natural gas production (26.1%) was at its lowest for the entire decade, down

	Country	Replacement (%) 1998–2002	Replacement (%) 1993–2002	Production (,000 b/d) 2002	Production (mn b/y) 2002
1	Russia	17	14	7,698	2,810
2	Mexico	11	14	3,585	1,309
3	China	60	64	3,387	1,236
4	Norway*	23	28	3,330	1,215
5	UK*	17	25	2,463	899
6	Brazil	129	202	1,500	548
7	Kazakhstan	788	482	989	361
8	Angola	525	424	905	330
9	Oman*	38	31	902	329
10	Egypt*	37	32	751	274
11	Argentina*	13	24	800	292
12	Australia*	136	103	730	266
13	India	33	22	793	289
14	Malaysia	77	50	833	304
15	Colombia*	20	23	601	219

Note these figures represent IHS Energy Group's estimate of volumes found in new-field discoveries and exclude any revisions made to fields discovered before 1993.

The production figures are from the BP Statistical Review of World Energy 2003.

** Production in decline (see* Petroleum Review *August 2003)*

Table 1: Top 15 non-Opec producers (excluding North America) in 2002, liquid reserve replacements from new field wildcat discoveries 1993–2002

	2002–oil new discovery (bn b)	2002* oil production (bn b)	2002** reserves replacement ratio	2002–gas new discovery (tn cf)	2002* gas production (tn cf)	2002** reserves replacement ratio
Latin America	1.51 (1.4)	3.74	40.40%	5.55 (4.0)	4.86	114.2%
Europe	0.15 (0.8)	2.50	6.00%	2.18 (2.7)	11.02	19.8%
Africa	2.28 (2.6)	2.89	78.90%	6.72 (5.2)	4.70	143.0%
Middle East	0.35 (1.4)	7.66	4.60%	0.84 (6.7)	8.32	10%
Asia-Pacific	1.98 (2.0)	2.92	67.80%	13.27 (22.8)	10.65	124.6%
CIS	0.29 (0.7)	3.41	8.50%	1.86 (0.8)	23.70	7.8%
World excl. N. America,	6.56 (8.9)	23.12	28.40%	30.42 (42.2)	63.41	48.0%
of which Opec	1.88 (3.0)	10.31	18.20%	7.23 (10.9)	14.35	50.4%

* BP Statistical Review of World Energy *June 2003*
** Petroleum Review *calculation*

Table 2: IHS Group estimates of 2002 new discovery volume by region and *Petroleum Review* calculation of replacement ratios (2001 unrevised)

from a high of 29.4% in 1997. This is almost entirely due to the decline in offshore gas production, down from 29.9% of the global total in 1993 to 20.8% in 2002. However, in absolute terms offshore natural gas production in North America in 2002 was at its highest since 1997.

US onshore gas production has risen fairly steadily throughout the decade but fell by 1.7bn cf/d in 2002 (–3%).

Changes in liquid production in 2002 varied from region to region. North America, Saharan Africa, Far East and Australasia and the CIS all showed slight production increases while Latin America, Europe, Central and Southern Africa and the Middle East were down slightly. In particular, the US showed a modest production increase above 2001 figures – up slightly to 16.4% of the global total, and Russia, for the fourth year in a row, also expanded production 6% during the period. Compared with 2001, gas production in 2002 increased in all regions with the exception of Central and Southern Africa and the Middle East.

In 2002, there were only two giant discoveries (ie exceeding 500mn boe). These were Kikeh – an oil discovery offshore Sabah in east Malaysia, and Tomoporo 9, an oil and gas discovery in Venezuela's Maracaibo Basin. Eight other discoveries are likely to exceed 200mn boe: Dhirubai 1 and 3 (gas) in India; Dorado (gas and condensate) in Venezuela; Cachalote (oil and gas) in Brazil; Usan, Doa and Bolia (all oil and gas) in Nigeria; and Ca Ngu Van (oil and gas) in Vietnam.

Significantly, the liquids discovered in Malaysia and Venezuela accounted for 9% and 8%, respectively, of the total global liquids reserves added in 2002. Gas discoveries in India and Indonesia accounted for 17% and 10%, respectively, of the total global gas reserves added in 2002.

Remaining reserves

IHS Energy estimates that, in 2002, remaining global reserves of liquids and gas (conventional gas only) stood at 1,153bn barrels and 6,662tn cf, respectively. In 2002, reserves to production ratios (R/P) for liquids and gas now stand at 43 years and 68 years, respectively.

Opec reserves of liquids are almost double those of non-Opec countries, 739bn barrels compared to 414bn barrels, giving R/P ratios of 71 years and 25 years, respectively. Opec and non-Opec reserves of gas are almost the same (approximately 3,300tn cf) but their respective R/P ratios are 193 years and 42 years.

Reserves replacement

Table 1 gives the percentage of liquids produced that were replaced by new-field discoveries in the decade. The countries chosen are the top-15 non-Opec liquids producing countries in 2002. Canada and the US are excluded because comparable data is not available. Estimates of volumes of new discoveries for 2002 are listed in **Table 2**.

Exploration performance

The number of new-field wildcat wells completed in the world, excluding North America, fell from 1,147 in 2001, to 956 in 2002. The number of oil and gas discoveries reported fell from 413 to 397, hence the success rate increased from 36% to 42%. The number of these discoveries likely to be deemed commercial is not known at this time.

For North America, in terms of absolute numbers, fewer wildcat wells were drilled in than at any time in the previous nine years, while internationally only 1999 saw less wells drilled.

Other activities

In the world, less North America, both 2D and 3D seismic activity decreased in 2002 by 37% and 16%, respectively, compared with 2001. Also in 2002, the numbers of new licence awards made decreased by 5% compared with 2001. The number of licences active during 2002 was comparable to that in 2001.

* *The* WPT 2003 *report is available as part of IHS Energy's Petroleum Economics and Policy Solutions (PEPS) online subscription service. The entire report is available for purchase from IHS Energy. For more information, please contact e:* **sales@ihsenergy.com**

'Our data shows that even though the number of international discoveries has declined, the combination of reserve revisions and new discoveries have exceeded global oil demand over the past ten years. This partly explains the paradox of the petroleum industry's ability to generate excess oil supplies even though new oil discoveries have not come close to replacing demand,' said Pete Stark, Vice President, Industry Relations, IHS Energy.

Cutting costs with global benchmarking

A global benchmarking programme developed by strategy consultant PIMS Associates* is reported to have helped cut costs in the lubricants sector by as much as 30%. Here, Managing Director *Keith Roberts* explains why members of the programme are 'one step ahead' of the competition as benchmarking enables them to regularly assess their internal performance and learn from others in the industry.

Benchmarking allows managers to undertake qualitative analysis of the reasons for existing differences in cost, complexity and performance position of companies, business units and processes. By getting a clear understanding of position, strengths and weaknesses, managers can ensure that robust numbers underpin future business strategy and that difficult management decisions are backed up by objective evidence. If, like most of the major lubricants companies, you are reducing headcounts or closing plants, benchmarking also helps provide objective evidence that such actions are necessary in order to remain competitive.

Lubricants study

The methodology developed by PIMS Associates enables competing businesses to work alongside one another to learn best practice without compromising their own competitiveness. Our study of the global lubricants market began in 1992. To date it has investigated the performance of 133 plants in 46 countries. Most of the major players in the industry are represented in the study, including ExxonMobil, Shell, BP, Eni and Idemitsu, as well as independents such as H&R in Germany as well as Rhinopak in the US.

The impetus to benchmark came from economic uncertainty coupled with increasing competitive pressure which forced producers to re-examine all areas of their operations. In the current climate of uncertainty, benchmarking helps managers to gain more control and understand where they can (and need to) implement radical improvements.

Each participating plant inputs data every two years to provide a detailed analysis of, amongst other things, its production efficiency, plant configuration, manning levels, service levels and error rates. The process takes pains to ensure consistent and accurate data input. First there is a kick-off meeting with the people involved in data assembly, to introduce the aims of the project and to go through the data form and glossary of definitions, highlighting the areas of potential inconsistency or inaccuracy. Then the participants typically take five person-days (over an elapsed month) to complete the two-page data sheet. This is followed by a face-to-face data review with PIMS consultants to check for problem areas. Once the final data set is agreed to be correct, PIMS produces extensive data reports showing the results, and presents these along with an Executive Summary displaying the evidence, pinpointing the improvement opportunities, and suggesting priority areas for corrective action.

Problems with previous studies

Other benchmarking studies often present their output as a spreadsheet of performance metrics down the rows, with one column per participant (labelled 'You', 'Competitor A', 'Competitor B', etc.). This is unwise in many ways:

- It converts benchmarking from an exercise in 'learning from appropriate comparisons' into one of competitor intelligence – who is 'Competitor D' and what are their weaknesses? This compromises confidentiality and is illegal under European competition law.
- It draws you naturally into simplistic 'league tables' for each metric across the whole sample, without correcting for inherent structural differences between players.
- It does not show how different metrics relate to each other – for example, how manning levels per filling line relate to tonnes packed per head.
- It does not quantify the prize for moving to best practice, and hence help prioritise among actions for change.

Cost waterfalls

In contrast, the PIMS approach uses a framework of 'cost waterfalls' that start at the headline level (cost per tonne) and then systematically drill down via algebraic relationships to drivers such as articles per tonne packed, number of lab tests per blend batch, manning levels per line, etc (see **Figure 1**). As well as comparing against direct local competitors, PIMS compares each plant to the average of several anonymous 'look-alike' plants with the same scale, complexity and labour cost environment (see **Figure 2**).

Kuwait Petroleum International Lubricants has participated in every European benchmarking round since the project began. Managing Director Alessandro Gilotti comments: 'The PIMS analysis provides a clear understanding of relative competitive positioning and the results are a key input into our ongoing strategic planning processes. The lubricants industry is in constant flux and regular review of, and focus on, efficiency and effectiveness is critical to future success.'

The project has recently been expanded to include distribution and grease production. Participating plants range in size from 5,000 tonnes to 500,000 tonnes. Results show that the cost advantages of scale are limited – at any level of scale it is possible to be a lean, low-cost performer as long as complexity is managed appropriately.

In-depth focus

Benchmarking has evolved in the last decade. While companies were once happy to just see how production costs could be reduced, the process has changed over time, leading companies to ask more complex questions about the whole supply chain.

The PIMS benchmarking is 'unique' as it looks further than the technical and production issues to the complexities of the industry and focuses on the appropriate comparators. (See **Figure 2**.) The methodology allows each participant to rapidly identify which aspects of its supply chain are out of sync by a meticulous 'drilling down' into problem areas. It also allows participants to evaluate alternative scenarios for change, by performing 'what-if?' analyses against anonymous plants that have already made the proposed changes. As a result, many companies use the bi-annual results and our independent advice to set the company's strategy for the future, with a tremendous impact on the bottom line.

The wealth of time-series and cross-sectional evidence now available in the benchmarking database has had an interesting side effect. For the first time, it is now possible to empirically examine questions that previously were only the subject of theoretical speculation. For example, configuration issues – when is it a good idea to:

- have lots of finished product holding tanks?
- hold more inventory of packed products to increase average batch sizes?
- have automated drum filling lines?
- operate a distribution 'milk round'?
- use more bulk additive?
- operate secondary warehouses?
- blend in-line?
- invest in pigging to reduce the amount of flushing oils that need to be recycled?

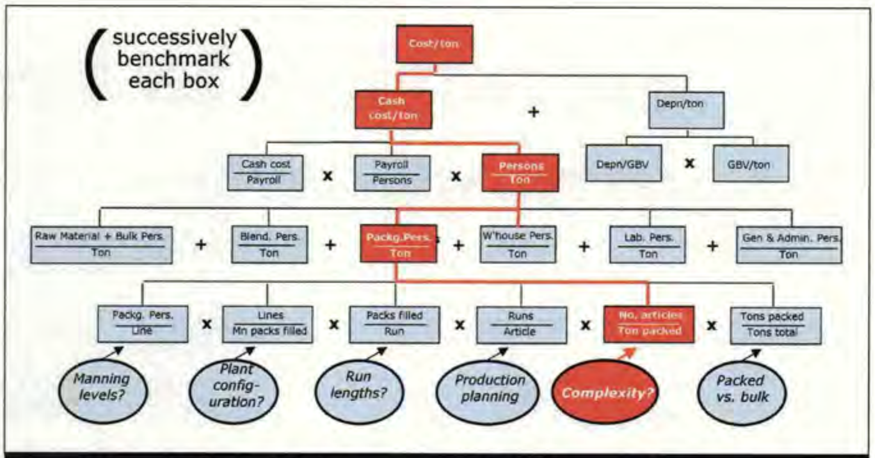

Figure 1: Example of waterfall of cost components for lubricants production

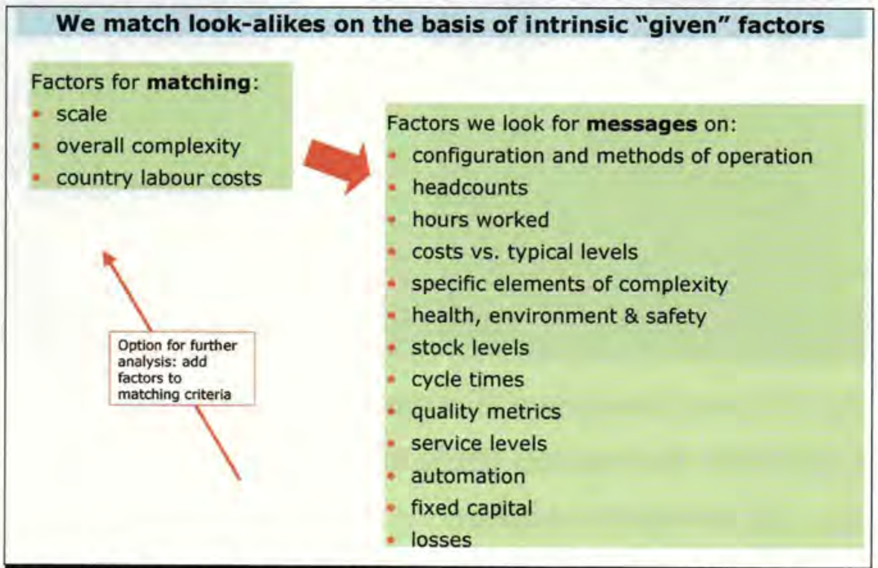

Figure 2: PIMS compares each plant to the average of several anonymous 'look-alike' plants with the same scale, complexity and labour cost environment

Key question

One key question for players contemplating production rationalisation is the interaction between scale, complexity, capital intensity and cost. For example, a plant planning to reduce complexity discovered that it was already in the best quartile for articles per tonne, pack footprints etc – its real opportunity lay in improved production planning to ensure bigger batch sizes while simultaneously reducing finished product inventory. Another plant planned to invest heavily in automation and new equipment to reduce headcount – the PIMS evidence warned that the plan would produce a worse result, as the productivity gains would be worth less than the increased maintenance and depreciation would cost. The plant scaled back its investment to address two key areas (packing lines and product holding tanks) which had a much better benefit/cost ratio.

It even has implications for areas such as health and safety – do some types of plant (batch blenders, automated filling lines, low percentage of contract labour) have fewer accidents than others? These are questions that require a large database of different plants to generate statistically robust answers.

The way forward

The PIMS 'look-alikes' and quartile charts give benchmarks for specific plants, while cross-sectional modelling adds statistical rigour.

Following the success of the lubricant industry benchmarking, we have introduced similar new programmes for other markets, including the petroleum industry. All industries can benefit from benchmarking – the identification of areas of improvement and learning from best practice 'look-alikes' can reduce costs and provide management with an objective insight into the best way forward.

For more information, please log onto **www.pimsconsulting.com**

EU expansion to provide new opportunities for UK lubes

***Rod Parker*, Executive Director of the British Lubricants Federation (BLF), takes a closer look at the UK lubricants market.**

To many observers the gradual decline in the number of UK lubricant manufacturing plants might suggest that the sector was in some sort of crisis. This trend developed over the last 75 years and will continue – however, while manufacturing numbers have reduced over this period, total UK market demand has produced a different picture.

The decline in plant numbers has resulted from market forces that ensure companies have sufficient operational efficiency and size – sometimes called critical mass – to remain afloat and profitable. Lubricant industry manufacturing over-capacity and survival of the fittest have been the main factors that have driven the reduction in numbers. During my time in the UK market I have witnessed the minimum viable tonnage/turnover continually move upwards. Many oil/grease blenders and compounders have merged, amalgamated or just sold up over the years. The same forces have also affected raw material suppliers and integrated oil companies.

However, despite this consolidation there has been a continual stream of new entrants – although the numerical losses have exceeded new start-ups, so overall the numerical decline continued. From over 700+ UK lubricant sector companies in the 1920s (including blenders, chemical suppliers, raw material suppliers, distributors, specialist freight companies etc) there are currently less than 100 core UK lubricant sector companies. Those sector companies that survived are stronger by a sort of Darwinian natural selection process.

Market size

Total UK market demand has not aligned with the number of market players. The highest tonnage/ litres into UK consumption occurred in 1973 – when the market reached just over 1.1mn tonnes. In 2002 consumption was down to around 840,000 tonnes. UK consumption has remained around this level for some years and we should expect a continued small overall decline in consumption, year on year, into the future.

The high levels of lubricant demand in the 1960s and 1970s were driven by heavy industries such as steel, shipbuilding and coal mining. Today, these industries have all but vanished in terms of lubricant consumption – apart from the steel industry where consumption has been drastically reduced. In contrast, UK vehicle numbers are at their highest ever levels and, as a result, automotive lubricant sales into both the commercial vehicle and passenger car sectors have increased their share of the overall lubricants market to around 50%. However, all sectors have and will continue to experience the consumption reducing effects of efficiency and environmental factors which hit sales volumes.

Lube exports

UK lubricant manufacturers have been in business for a long time, longer than in most other countries. Many UK lubricant companies are well over 100 years old and one actually goes back some 250+ years. The western world's 'Industrial Revolution' started in the UK and would have faltered without suitable lubricants to reduce friction and wear. As market conditions changed and the industrial revolution spread to other countries, many of the UK's lubricant companies become quite expert at growing their businesses via exports.

The UK lubricant companies, both small- and medium-sized enterprises (SMEs) and the major oil companies, continue to export their products all over the world. Branded lubricating oils and greases made in Great Britain are still in considerable demand overseas.

Having become fairly dependent on

exports, the health of the UK lubricant sector is driven by the combined economic activity of both the home and export markets.

Home market situation

For the home market the available data for 2003 indicates a positive change is beginning to happen. The UK is doing fairly well and recently UK equity markets have sensed a gradual recovery. Many of the western world's stock markets also sense better times around the corner. US recovery is coming into view with GDP growth showing improvements year on year. US fiscal stimulus is due to a combination of previous measures, GDP growth and 2003/2004 tax cuts, with no really negative news. Together these factors are helping US business and consumer confidence to climb steadily again. US economic activity helps drive many potential lubricant markets around the globe.

The UK economy had a poor start in the first half of 2003. However, GDP recovered in the second quarter and manufacturing continues its year-on-year increases, having just moved into positive figures. The concern is will this be sustained? Retail sales seem to be holding up fairly well. UK consumers continue to spend, but there are some concerns that household debt is getting out of control. A major stimulus to the economy is government spending and this will continue until the next election and maybe beyond. Sterling's trade weighted average indices are currently below the 1990 100% indexed level and are down around 7% compared to last year, potentially benefitting exporters' margins.

UK lubricant demand is unlikely to ever get back to steady growth and the highly competitive market will continue. Gains to companyies bottom lines will be dependent on innovation, maintaining or growing penetration in new markets, the development of higher margin niche products, increased penetration of fluid management schemes into the market and the continuation of acquisitions/ mergers. Innovation and possibly more consolidation are likely. The state of the UK economy, which improved during 2H2003 won't have much immediate impact on lubricants sales as there is a long lag that follows any move out of a period of economic downturn. It's all to do with a phenomenon of running stocks down when going into an economic downturn and the slow stock build-up when coming out of one.

European situation

In the rest of the European arena many economies are stagnating and GDP growth for the region as a whole is near to zero, although just positive. During the first three months of 2003 the three major European economies of France, Germany and Italy had negative GDP growth.

A recent EU survey of European industrial confidence showed very poor results and in consequence exporting opportunities to the region have been negatively affected.

Raw material supplies

The other side to any company's profit and loss account is the cost of raw materials. Most lubricants are blended from mineral base oils and the current supply/demand situation for one of the major lubricant constituents – base oils – is difficult. Group I base oil producers are stretched and, as a result, supplies are tight despite European demand being patchy. Weak demand in Germany, France and Italy has created an opportunity for base oil sellers to move products to other world markets, especially the US and the Singapore area where base oil prices are higher. In the short-term European base oil prices are likely to move up rather than reduce in price. This could bring more pressures on finished product prices or margins.

At the lower volume speciality end of the market, manufacturers using higher priced Group II and III base oils will find production capacity is also tight. This is due to an earlier than scheduled refinery maintenance programme at one supplier and tighter availability in North America following an explosion in a refinery hydrogen unit.

EU enlargement

European Union enlargement will also provide new opportunities for UK lubricant manufacturers.

The current 15 European Union (EU) Member States' population grew last year by almost 1mn to 379.4 mn. During 2004 the EU will be expanded to 25 Member States following the inclusion of Cyprus, the Czech Republic, Estonia, Hungary, Latvia, Lithuania, Malta, Poland, Slovakia and Slovenia. This enlargement will result in a 75.1mn-population increase in the EU, bringing it to a new total of 454.5mn. In addition to the 25 Member States there are also three applicant countries – Bulgaria, Romania and Turkey – who wish to join the EU. A further 17 European countries are not part of the EU.

If demand were population driven, the EU would become a significantly larger market for all goods than the US, whose 2001 population was 285.9mn. It is expected that the new EU countries will have a big appetite for domestic goods such as cars and other domestic appliances as their economies improve and the local populations prosper. Therefore, we should see increased demand for lubricants in these countries as they progressively move from their existing standard of living towards the higher EU average.

Looking back at last year's statistics, EU lubricant demand during 2002 bucked the previous few years' trend by recording a small increase. The overall picture was made up of automotive oil continuing its decline, mainly due to efficiency factors, offset by some industrial lubricants sectors which provided better news with a number reporting increased demand.

The existing 15 EU countries are mature markets in terms of lubricants demand. They are expected to show a gradual progressive decline in local consumption of lubricant products over the medium to longer term. This is in response to environmental and efficiency factors such as longer drain periods, smaller sump sizes, low friction products, more sophisticated products and more efficient industrial use.

Market developments

Regulator, manufacturer and end-user concerns for the environment are driving lubricant formulation changes to achieve cleaner and more efficient use of lubricating oils and greases. Good examples are the improved auto-oils that help engine manufacturers meet the latest emission standards and improvements to industrial oil formulations to ensure oil mist is minimised.

The latest vehicles, both cars and trucks, have extended service intervals. Increased drain periods for petrol engines means that 15,000–20,000-mile oil changes are becoming the norm, while one range of engines can go 30,000 km to 50,000 km between oil changes for petrol and diesel engines respectively.

In the industrial lubricants sector, members of the BLF have been very active, recently forming a Task Group – the Metalworking Fluids (MWF) Product Stewardship. The Group brings together those companies that have a commitment to the development, manufacture and marketing of safe and effective MWF products. It intends to assist in the education of end-users, enhance the health and safety provision to both the members and their customers' employees, consider the protection of the environment and ensure the provision of qualified, reviewed information to industry, trade unions, government and the general public.

Lukoil: undervalued and underestimated?

Over recent years Lukoil has often been criticised by analysts for its international activities, including upstream operations. According to *Oktay Movsumov* (right), Vice President for Finance Lukoil Overseas, this has been mainly due to a lack of information about the company's international activities.

To address this Lukoil Overseas Holding Ltd and its parent company have developed a special communications programme and plan of action for shareholders, investors and analysts.

In June and August of this year investors and analysts visited the Perm Region and Kazakhstan, where they were shown the production facilities and the latest developments at the Shershnevskoye and Karachaganak fields. Movsumov claims that the visitors were suitably impressed – particularly by Karachaganak, which is clearly a world-class project. He noted that, after having visited the fields, analysts from ATON Capital reported in their research materials (dated September 2003) that investors had underestimated the international production assets of the company and their contribution to the valuation of Lukoil in general.

Profitable production

Movsumov indicated that the international upstream assets of the company were highly profitable and production was expanding fast. Noting that Lukoil's main aim in international projects is to secure production-sharing agreements (PSA) that are subject to the laws of the country in which money is invested, he went onto point out that PSAs are not subject to export restrictions and local tax regimes, and there are no restrictions as to investment cash flows.

He explained that, in 2002, the lifting costs for the Karachaganak project amounted to $1.30/b. Those of Kumkol, another Lukoil Overseas project in Kazakhstan, reached $1.25/b, with EBITDA of $6.52/b. This, Movsumov claims, confirms the merit of the recent $1.375bn sale of Lukoil's 10% stake in the Azeri-Chirag-Guneshli project, at the equivalent of $6.15/b of proven reserves.

Lukoil Overseas current portfolio whic includes the operation of all exploration and production outside Russia, comprises 12 international projects located in Azerbaijan, Kazakhstan, Egypt, Iran, Iraq and Colombia with proven hydrocarbon reserves (excluding the Iraqi field Western Qurna-2) of 634mn boe and production of 68,000 boe/d in 2002. The company is the operator of seven projects.

The development plan anticipates annual production increases for the company of 25%, the same increase as seen in 2002. Movsumov anticipates that production from international projects should reach 15% of Lukoil's total production.

Since its establishment in 1997 the Lukoil Overseas Group has undergone significant changes. In 2001, Lukoil-Perm, one of Lukoil's largest oil producing divisions, was incorporated into Lukoil Overseas Holding Ltd thus financing the company's international projects and providing financial stability to the Lukoil Overseas Group.

New projects

Over the last two years a number of new projects have been added to the portfolio – the production project WEEM (Egypt) and the exploration projects Condor (Colombia), Northeast and West Geisum (Egypt), and Anaran (Iran). According to Movsumov the next step will be joining the Kandym-Khauzak-Shady (Uzbekistan) and Dostyk (Kazakhstan) projects and the development of West Qurna.

In order to staff its international projects Lukoil has assembled a manpower reserve of 300 people that are being trained in large internationally recognised petroleum institutes. The annual training and development budget is around $2mn. Already over 100 company employees have worked or been working on international projects in Kazakhstan, Azerbaijan, Egypt and Colombia.

Currently Lukoil's upstream activities are concentrated in three key regions – CIS countries (Caspian region), the Middle East and Latin America. According to Movsumov the company is following the pattern of the international oil majors in using the cash flows generated in their core regions to expand and diversify their business.

Starting from the CIS countries (Azerbaijan, Kazakhstan), where Lukoil has obvious competitive advantages, it has established a position in the Caspian region and has moved on to the Middle East and Latin America.

According to Movsumov around 85% of the current, and 76% of the prospective, global oil reserves are concentrated in these regions of the company's operations. The situation with gas is similar – 78% of current and 72% of prospective reserves (according to US Geological Survey in 2002). Average lifting costs of the existing international production projects of Lukoil amount to $1.5/boe (2002). The average production rate per well is high in these regions, he claims. In the Karachaganak project it amounts to 3,124 b/d; and for the WEEM project, 728 b/d. For 2002, Lukoil Overseas claims an exploration success ratio of 67%.

International activities are becoming increasingly important in the development of the company and the integration of the Caspian, and ultimately the South American, assets will increase efficiency and hence profitability, according to Movsumov. He noted that crude from the Karachaganak and Kumkol fields flowing via the Caspian Pipeline Consortium system, could supply up to 15% of Lukoil's refining capacity in Eastern Europe. Assuming successful exploration operations in Colombia starting from 2005 the company is expected to be able to supply the US markets with up to 1.5mn boe/y. And over the six years to 2010, this figure could reach 60mn boe, he claimed. In addition to this, Lukoil, in line with its strategic objectives, intends to increase the share of gas projects in the company portfolio to 30–40% by 2010.

As a final observation Movsumov noted that international diversification of the business gives the company access to cheaper sources of financing, which reduces capital costs and improves profitability. There is also a political benefit, as development of international assets helps in the creation of strategic hydrocarbon reserves for Russia.

Knowing who you are dealing with on the Internet

A major barrier to realising the benefits of online business transactions has been a lack of trust that the people you are doing business with really are who they claim to be. *TrustAssured* from The Royal Bank of Scotland aims to provide the systems and the assurance companies need to enable them to commit to net-based transactions. *Chris Skrebowski* reports.

The Royal Bank of Scotland noticed that companies were reluctant to move critical business processes online largely because of the insecurity of not knowing who they were dealing with. The Bank recognised that this was a historic banking problem, which it had expertise in overcoming, and initiated an internal project around four years ago to develop systems for use over the Internet. The passage of legislation giving legal force to digital signatures opened the way for a complete security/authentication system over the web.

George Evers, the Head of Sales, at TrustAssured, told *Petroleum Review* that, although initially seen as an internal project, the size of the possibilities led to the formation of TrustAssured to provide a commercial service to business. These services are already in successful use by the UK's Ministry of Defence (MoD) and by Lombard Financial Services. Evers explained that the TrustAssured solution should be particularly attractive to the oil and gas industry where there had been an understandable reluctance to exchange high value data over the Internet. A similar reluctance was seen in terms of payments and contract confirmation. He reported that increasing interest in their solution was now being seen with Schlumberger, Indigo Pool and the DTI making enquiries. The increasing interest, he felt, was coming as a result of the good reports from those already using the system.

He noted that the transaction security and the audit trails it offers would enable companies to gain economies from reduced transaction times and the elimination of paperwork and documentation. An area he felt that was of particular interest to the oil and gas industry was the ability to reduce the cost of operating joint ventures by transferring data flows securely to the web.

He also noted that the requirement by the UK Government to interact via the web for processes such as statutory reporting, patent applications, licence applications and consents was a move likely to be followed by other governments and regulatory agents would give companies an incentive to take up the system.

Financial services

Lombard, which claims to be the largest asset financier in the UK, is using the Sign & Store application to share documents electronically with its customers, amend them with a full audit trail and then create legally binding contracts online using digital signatures. Alison Doherty, Product Manager for Lombard, confirmed to *Petroleum Review* that the new system had cut the time taken to process a standard contract from days to hours. She explained that the customers typically started with a small or limited trial, but rapidly adopted it for all their transactions as confidence built up. She also believed it was a business driver, claiming that its ease and speed had actually helped to increase the amount of business concluded.

Brian Duffy of the MoD was similarly enthusiastic when he explained the UK Government's MoD is using TrustAssured's managed service to control access to the Defence Electronic Commerce Service, a secure portal which allows suppliers to bid for contracts and make use of a collaborative environment that is supportive of joint working on specific programmes.

TrustAssured's white-label PKI service is also being used by a leading high street bank to provide its business customers with the smartcard-based certificates needed to access the new IP-based BACS payment services. The Payment Strategy and Solutions Manager claimed that the white-label service has been implemented more cost effectively, much more quickly and with far less risk or management effort than would have been possible if the bank had developed its own infrastructure.

Public key infrastructure

Mark Robinson, Senior Manager–E-Commerce, explained that the system being sold by TrustAssured is based on public key infrastructure (PKI). This allows individuals to:

- Authenticate themselves when connecting to online systems, enabling access to commercially sensitive data and applications to be controlled.
- Create, share, amend and sign documents with legally binding digital signatures, allowing contracts with suppliers and joint venture partners to be concluded online.
- Sign documents that include legally binding signatures, allowing statutory reports to be submitted to regulators and applications to be made electronically to consent bidders and patent offices.
- Participate in online collaboration environments – such as deal rooms – with confidence in the identity of the other participants and their authority to act on behalf of their companies.

According to Evers there are other vendors of individual elements of a PKI solution, but TrustAssured offers a complete package providing an end-to-end solution that can be up and running within as little as three months. He noted that as a neutral third party, TrustAssured was particularly well placed to meet the needs of a multi-organisation project. The company was also able to provide a 'white-label' version that would allow services to joint ventures to be under the joint venture's own branding.

Package integration

The integration of these PKI solutions into existing packages (packaged or bespoke) was not a problem, according to Robinson, as TrustAssured was working directly with leading application vendors to PKI-enable their offerings to the oil and gas industry. He noted that TrustAssured had a number of its own PKI-enabled applications such as its Sign & Store solution which supports the secure sharing and signing of electronic documents. This, he explained, is needed to create and agree contracts online, and to submit data to government services. He also noted that the company was working closely with leading systems integration companies on the 'trust components' of its solutions for the oil and gas industry.

The Royal Bank of Scotland is a founder member and board member of Identrus, the global standard for the provision and management of identity credentials.

Letter to the Editor

The ageing of oil

Dear Sir,

The September 2003 issue of *Petroleum Review* carried a thought-provoking table on p14, showing the extent to which giant North Sea fields had been depleted. The range was from 10% for Halfdan in Denmark (a surprise late discovery) to 95% for the venerable Forties and Ninian fields in the UK sector. By chance, the *Offshore* magazine at that time also carried an article on the new commercial opportunities arising from the work of dismantling the mammoth offshore structures of the North Sea. The exploitation of the North Sea has been a monument to engineering and efficiency but, by a strange irony, that has served simply to accelerate depletion. The ageing of fields is evidently as natural as it is for humans. They are born when their wildcats sire them and they die on abandonment, reaching their prime in middle age.

The information on these particular fields prompts a wider question about corresponding depletion for countries, regions and, eventually, the world as a whole. It is a much more difficult question to answer because many of them are reluctant to admit to their age. Think of an old troupe of music-hall dancers who look beautiful from the back of the theatre but are revealed from a seat in the front row to be applying make-up with a trowel. The make-up itself comes in many shades. Some countries under-report their reserves and let them 'grow' over time, giving the impression that they are younger than they are. Some exaggerate their potential for new encounters. Some mask their status by failing to properly distinguish the different types of oils, and others hide beneath an aroma of natural gas liquids belonging to the gas domain.

Revealing the wrinkles

ASPO (the Association for the Study of Peak Oil and Gas) unkindly tries to lift the veils of obfuscation and denial to reveal the wrinkles. The accompanying table, derived from the Association's website (**www.peakoil.net**), lists the producing countries by date of peak production, showing the status of depletion and discovery. It is surprising to find that, as of

Country Regular oil (As of end 2002)	Date peak production	% discovered	% depleted	Total production to 2075
Austria	1955	92%	80%	1.0
Germany	1966	95%	79%	2.4
Venezuela	1970	96%	48%	95.0
Libya	1970	94%	42%	55.0
Ukraine	1970	85%	65%	4.0
Kuwait	1971	93%	34%	90.0
US-48	1971	98%	88%	195.0
Canada	1973	95%	76%	25.0
Turkmenistan	1973	74%	48%	6.0
Iran	1974	94%	42%	130.0
Romania	1976	92%	76%	7.5
Indonesia	1977	93%	65%	31.0
Algeria	1978	86%	43%	28.0
Brunei	1978	98%	67%	4.5
Trinidad	1978	96%	71%	4.5
Nigeria	1979	95%	40%	55.0
Tunisia	1981	83%	55%	2.2
Hungary	1982	90%	70%	1.0
Chile	1982	89%	80%	0.5
Peru	1983	90%	61%	3.8
Albania	1983	86%	63%	0.8
Cameroon	1986	96%	71%	1.4
Russia	1987	94%	61%	200.0
Croatia	1988	82%	50%	1.0
France	1988	93%	70%	1.0
Netherlands	1989	85%	62%	1.3
Bahrain	1990	67%	67%	1.5
Dubai	1991	93%	77%	4.8
Pakistan	1992	84%	56%	0.9
Turkey	1991	87%	67%	1.2
Papua	1993	77%	33%	0.9
Egypt	1995	92%	67%	13.0
Syria	1995	91%	63%	6.0
Gabon	1996	97%	64%	4.5
India	1997	88%	47%	12.0
Brazil	1997	92%	75%	6.0
Italy	1997	88%	39%	2.3
Argentina	1998	95%	69%	12.0
Angola	1998	98%	46%	10.0
Sharjah	1998	74%	63%	0.8
UK	1999	94%	63%	32.0
Colombia	1999	94%	57%	10.0
Yemen	1999	84%	46%	3.5
Qatar	2000	98%	52%	13.0
Australia	2000	88%	53%	11.0
Norway	2001	93%	48%	33.0
Congo	2001	88%	54%	2.8
China	2002	93%	47%	57.0
Mexico	2002	94%	55%	55.0
Malaysia	2002	91%	53%	10.0
Denmark	2002	75%	43%	3.0
Oman	2003	96%	47%	15.0
Ecuador	2004	96%	39%	8.5
Neutral Zone	2004	77%	41%	16.0
Vietnam	2005	83%	27%	3.3
Sudan	2005	68%	10%	2.0
Thailand	2005	81%	27%	1.5
Uzbekistan	2009	83%	33%	3.0
Saudi Arabia	2013	96%	31%	300.0
Abu Dhabi	2014	94%	23%	78.0
Azerbaijan	2014	90%	35%	23.0
Bolivia	2016	66%	29%	1.4
Iraq	2019	87%	20%	135.0
Kazakhstan	2028	90%	15%	40.0
WORLD	2000	94%	47%	1900

Notes: Regular oil excludes heavy, deepwater and polar oils, and NGL from gas fields. It is usually accepted that once a country has depleted 50% of its reserves it is unable to maintain production flows which then start to decline. When flows are unconstrained, peak production will broadly coincide with 50% reserve depletion. The major exception is the Opec producers where production flows have been subject to controls. All estimates are generously rounded. Unit Gb.

The peak and depletion of regular oil

today, as many as 51 countries have already passed their peak.

In one sense, it is reassuring that the world has not quite reached middle age – meaning that it is definitely not about to run out of oil. But in another sense, it is cause for serious concern as a permanent and irreversible decline in production is evidently about to commence. Will oil age gracefully?

This recognition of depletion leads us to think about the future, remembering at the same time that the prosperity of the industrial age so far has been driven by energy derived from fossil fuels, none better than petroleum. The population has risen six-fold exactly in parallel with oil production. The future has to face the corresponding decline of this critical energy source, which cannot fail but have far-reaching impacts on almost all aspects of life, including agriculture, which means food. The importance of the Middle East is self-evident, simply because the five countries bordering the Persian Gulf control half of what is left. 'Control' is perhaps too strong a word after the invasion of Iraq, but irrespective of who ends up in command, the fact remains that these countries are in a position to profiteer from the growing shortage – and in the not too distant future.

'Profiteering' used to be a bad word, bringing memories of sinister and immoral individuals exploiting wartime shortages. Governments brought in legislation, such as Rent Acts, to curb their activities. Even free-wheeling New York frowns on racketeering by the Mafia. So, how can we prevent profiteering in oil?

The issue itself runs into conflict with classical economic theory that holds that there can be no shortage in a properly functioning open market, speaking also of seamless transitions to new resources as the need arises. The world has not previously faced the natural decline of a commodity as important as oil, so it is hardly surprising that depletion fails to comply with the precepts of past experience.

Depletion protocol

But a simple solution suggests itself. The countries of the world could sign a protocol to cut their production and imports to match the world depletion rate (annual production as a percentage of what is left to produce), which is currently running at about 2% a year. Few of the producers can exceed their depletion rate anyway and it should not be a great burden on the importers, given the massive waste of modern society that tolerates burning up precious fuel in traffic jams and subsidises air transport with tax-free supplies.

The importers could handle their allocation how they choose. They could auction it to the highest bidder, adopting the principles of globalism; they could tax it higher, making corresponding cuts on other taxes; they could ration it; or they could find a happy compromise.

Several notable benefits would flow from such an arrangement:

- the world price of oil would remain in reasonable relationship with actual production cost;
- poor countries would be able to afford their minimal needs;
- massive and destabilising financial transfers to the Middle East would be avoided; and
- determining depletion rate would call for much needed new information on current reserves.

More important yet, the world, including the people of the Middle East, would benefit hugely by learning gently how to face the reality of oil depletion, as imposed by Nature, giving them time to adjust and find better workable solutions. In particular, they could learn to reduce waste and turn to renewable energies – even nuclear if that could be made safe and deliver a satisfactory net energy return. They could dig up coals and tar-sands, retort oil shales and exploit the remaining deepwater and polar frontiers to help tide them over to supplement their conventional supply. They might even find that the concerns about climate change would recede in parallel with oil depletion.

In the real world, not every country would sign the protocol – and some of those that did might cheat. The non-compliers would likely reap short-term benefits by their failure to cooperate, but it would not really matter because they would suffer in the longer term, being rapidly overtaken by the more efficient and prepared compliers.

There are two ways to descend the depletion slope. One is to jump blindly off the cliff-top with fingers crossed. The other is to deliberately search for the path between the crags to be sure of reaching the valley below, safe and sound. The valley itself might even prove to be an attractive place, free of much of the violence and excess that has marked the highlands.

C.J.Campbell

Largest accounting change in 25 years

Launching PricewaterhouseCoopers' 'Crunch Time' report *Manfred Wiegand,* Global Utilities Leader, explained that the requirement to adopt IFRS (International Financial Reporting Standards) by the end of 2005 represented the biggest accounting change in 25 years for companies, particularly for companies reporting under national accounting standards. Implementation needs to be started immediately if the deadline is to be met. *Chris Skrebowski* reports.

Wiegand went on to explain that there was a need to embed the new requirements across the whole organisation as the changes will force a closer management of various areas. One notable change will be the requirement to identify and document all derivatives embedded. There is also a need for accounting of deferred tax effects and the need to reconcile the requirements of tax accounting and financial accounting.

Costs will be involved in meeting the new requirements, principally in terms of systems and people, but also in terms of aligning internal and external reporting.

He explained that the new requirements applied to all listed companies and that no derogations were allowed. The aim was for a common European capital market reporting to global standards by 2005. A particular cause for concern, in terms of timing, was the comparability requirement that meant 2005 accounts had to include 2004 numbers, which, according to Wiegand, meant that if work had not already started on the new reporting procedures companies could have difficulties meeting the deadline.

Oil and gas sector

For the oil and gas industry there were no industry specific rules in IFRS, although there was a paper on the extractive industries. The need was to meet framework rules that would apply to the 15 countries of the EU and also conform with US GAAP rules.

According to Wiegand, UK companies are already ahead of the rest of Europe because of the adoption of FRS 17. He also noted that companies using UK GAAP or US GAAP should have only limited problems with the new reporting standards. 'Life of/full cost' accounting was not in conformity with the new rules, while 'successful effort' was 'mainly OK' as the IFRS was based on 'fair value' accounting. He suggested companies needed to be involved with the IASB as they could then 'influence the setting of the standards', particularly as these 'have a significant impact on a company's business'.

Benefits of IFRS

Turning to the benefits of IFRS, Wiegand suggested that by providing a single set of accounts that would be fully comparable the cost of capital would be lowered and better chances for a common European capital market would emerge. He recognised that there may be a continuing requirement for local accounts, which could require some companies in some jurisdictions to produce two sets of accounts. The benefits of transparency and comparability were, however, pressures that would lead to common standards over a wider and wider area. It was notable that Russia, Australia and the Middle East are also planning to adopt IFRS. He suggested that a notable benefit was that analysts would find it very much easier to measure and compare company performance once the common reporting standards were in place.

Crunch time

The PricewaterhouseCoopers' report, entitled *Crunch Time – Embedding International Financial Reporting Standards in Energy and Utilities,* can be viewed at www.pwc.com/energy More information on IFRS can be found at **www.pwc.com/ifrs**

In summary, the Crunch Time report indicates:

- All EU listed companies are gearing up to adopt International Financial Reporting Standards (IFRS), and so are those in Russia and Australia.
- The transition to IFRS is the biggest change in financial reporting in 25 years and a major challenge for companies currently reporting under national accounting standards.
- Time is running out in which to prepare for moving to IFRS from 2005, with companies in need of comparative figures for 2004.

Wiegand explained that: 'Adopting IFRS is a bigger challenge than most businesses think and not simply a number-crunching exercise for the financial controller. While most companies recognise that conversion to IFRS can have an impact on their reported profits or net assets, they may not realise the substantial effect it may have on the whole organisation.

Estimating the time, cost and scope of the work involved can be one of the toughest issues companies face – it is not unusual for costs to run to several millions of euros for a single large company.'

Scale of the challenge

In a short time-frame, companies have a lengthy 'to do' list, including:

- Understanding and analysing the impact of IFRS on financial performance.
- Obtaining the new data required and adapting systems to provide it.
- Finding the resources and expertise needed to make the changes.
- Meeting employee training and knowledge sharing needs.
- Aligning systems for reporting for statutory, regulatory and internal purposes.
- Gaining shareholder and analyst understanding of the impact of changing to IFRS.

Wiegand explained that: 'The change to IFRS is expected to trigger larger swings in reported profits, reflecting fluctuations in derivatives values. Lack of awareness and understanding across the broader financial community could create investor concern and share price volatility.' He concluded by noting that: 'With IFRS in place stakeholders will be able to compare like with like and oil, gas and utility companies will be able to compete on equal terms when raising capital on the financial markets. The common application of IFRS is an important step towards a single global accounting language that will contribute positively to restoring public trust in financial reporting – I expect all sectors to benefit from this.'

Achieving a low carbon economy

The UK Government's policy for creating a low carbon economy requires a doubling of the rate of energy efficiency improvement as seen over the last 30 years, writes *Peter Jenner*, CEng FEI, William Battle Associates.

Energy efficiency is a proven means of saving money and reducing the environmental burdens of an organisation. This approach, however, is not enough.

At present energy remains a peripheral business issue to most organisations. The aim must now be to create a paradigm shift in the UK's energy performance – this is made more difficult during a cycle of cheap energy. Energy managers know the difficulty of engaging senior management to support energy efficiency and in many cases even the environmental agenda. The Climate Change Levy and the aims of corporate social responsibility provide a new opportunity for energy managers to integrate efficiency into every element of the organisation's business plan.

In the past many energy and environmental improvement programmes have been undertaken outside the context of the strategic direction of an organisation. The result is that the project will lack the backing of senior management. This creates a situation where the resultant benefits can be short lived.

Energy managers make a major contribution to the improved competitiveness and reduced costs of UK industry, largely accomplished through the use of technical innovations.

However, 'technical fix' solutions alone will not deliver the magnitude of savings required by government targets. Most energy managers will agree that senior management needs to be involved to help engage people to change behaviours.

All organisations, regardless of their size or business sector, can benefit from employing effective energy management. The best way of achieving maximum success is to ensure that the person with responsibility for making energy savings operates within the context of the overall business plan. For that, the organisation needs an 'Energy Leader'.

Energy leadership

Energy leadership is one of the critical factors in developing a successful energy programme. Energy Leaders set the pace and direction of their element of the business. They must think outside the box and challenge what currently exists.

The key characteristics of an effective Energy Leader are:

- Focuses on people rather than technology.
- Innovates new approaches and regularly re-appraises existing systems.
- Seeks to build enthusiastic partnerships for action.
- Challenges the way energy is used.
- Manages change so that energy efficiency becomes the norm rather than the exception.
- Long-sighted – knows where the organisation is going and looks for synergies for action.
- Builds an irresistible business case for action.
- Inspires others to act and empowers by explaining the end result.

Energy leadership requires not only knowledge and ingenuity, but also diligence, persistence and commitment. The new Energy Leader training course from the Energy Institute aims to link the energy/environmental agenda directly to business goals through the engagement and motivation of people.

*The Energy Institute and William Battle will be running the first Energy Leadership programme on Wednesday, 3 December 2003 in London. For further information please contact Nellie de la Monneraye on T: +44 (0)207 467 7178 or e:***ndlm@energyinst.org.uk**

Standard Test Methods

Quality control now available online

As the first step towards the online publication of all its codes and standards, the Energy Institute has launched its flagship title – *Standard Test Methods (STM)* – online at **www.energyinstpubs.org.uk**

STM – Standard Methods for Testing and Analysis of Petroleum and Related Products, 2003 – is a compilation of test methods based on traditional and modern instrumentation techniques (including joint methods with BSI, EN ISO and ASTM). These Standard Methods are an essential part of any quality control regime and are necessary for the national and international trading of petroleum and petroleum products.

For several years STM has been available as two printed hardback volumes, with an accompanying CD-Rom to assist searching. STM is used by refineries, laboratories, testing houses and individuals across the industry. The next hardback book edition will be published in February 2004 and can be ordered from Portland Customer Services, e: **sales@portland-services.com**

Online for the first time

The Energy Institute will continue to publish STM in book form. In addition, it has launched STM Online, which can be purchased in its entirety on an annual subscription basis or in the form of single copy sales. Global, Site and Individual Subscriptions are available. This means that individuals and companies can access the latest petroleum test methods from their desk or laptop anywhere in the world at any time.

Subscriptions start at £1,300 per annum. A 25% discount is offered to Energy Institute Members. More information is available at **www.energyinstpubs.org.uk** or e: **sfm@energyinst.org.uk**

More online

Also new online is the Energy Institute's Transport Fuels Technology (TFT) Update Service. Available quarterly, online or via email, the TFT Update Service delivers carefully selected abstracts from worldwide literature, including technical journals, conference proceedings, special reports, books and databases. Bibliographic and reference details are also provided to assist with further study where needed.

An online index is also provided for the accompanying textbook – *Transport Fuels Technology* – which is available from Portland Customer Services.

The service and textbook form an essential source of material for scientists and engineers interested in transport fuel science and technology, as well as librarians, information scientists, managers and planners. Subscriptions start at £195 per annum. A 25% discount is offered to Energy Institute Members. To subscribe, please e: **sfm@energyinst.org.uk**

Branch News

LONDON

Contact: *Ian Robinson, e: IRobin1040@aol.com*
T: +44 (0)1932 783774

9 December: 18.00: *Flammability – Regulation of Flammable Materials*, Dr Alan Brown, HSE

ABERDEEN

Contact: *Alan Higgins, T: +44 (0)1224 790389*

11 November: *Paladin's Role as an Operator with support from Petrofac & Helix RDS*, Paladin Resources

Discussion Groups

ENERGY, ECONOMICS, ENVIRONMENT

in association with BIEE

The World Energy Investment Outlook: Highlights from the 2003 IEA Report

Tuesday 4 November 17.00 for 17.30–19.00

Energy Institute, 61 New Cavendish Street, London W1G 7AR, UK *Refreshments provided*

Speaker: **DR FATIH BIROL, Chief Economist, Head, Economic Analysis Division, International Energy Agency**

Contact: **Laura Viscione**
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IFEG

Valuing Your Service: Securing your Future

This well-attended seminar took place on Thursday 2 October 2003 at the Energy Institute. All the delegates found the afternoon extremely informative. Thank you to the speakers: Emma McKenzie, Harwell Drying and Restoration Services; Sylvia James, Consultant; and Chris Porter and Mary McCall from Factiva. Our thanks are also extended to Harwell Drying and Restoration Services and Factiva for sponsoring the seminar and the buffet lunch.

Harwell Drying and Restorative Services
www.harwell-drying.demon.co.uk

Factiva, a Dow Jones & Reuters Company
www.factiva.com

For more information on IFEG, please contact Sally Ball, Secretary of IFEG, T: +44 (0)20 7467 7115
e: ifeg@energyinst.org.uk

Latest from the library

Copyright

The new rules for Copyright were due to enter into force on 31 October with the passing by Parliament of Statutory Instrument 2003 No 2498 – The Copyright and Related Rights Regulations 2003. At the time of writing the Copyright Licensing Agency was still finalising details for the licences which will allow us to supply you with copies of articles should you require them for a commercial purpose. Unfortunately an additional payment will be incurred. If your need for the copies is non-commercial, however, we can continue to supply them at our standard photocopy rates once you have completed a photocopy declaration form. Please talk to any member of LIS staff for further information.

Christmas opening hours

The library will close at 12.30 pm on Christmas Eve, Wednesday, 24 December 2003 and will reopen at 9.15 am on Monday, 5 January 2004.

New additions to library stock

Most of these items can be borrowed by Institute Members either by visiting the EI library in person or contacting us via e-mail, fax or phone. If we send the requested items to you through the post we just ask that you refund the cost of postage.

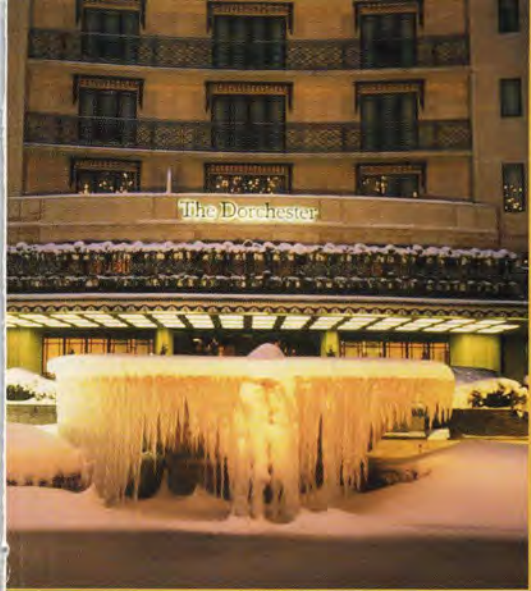
Before it closed at the end of September the Electricity Association Library kindly donated some very useful items to us – some of which are included in the list below.

- *Climate Alarmism Reconsidered.* Robert L Bradley Jr. 1st Edition. Institute of Economic Affairs, London, UK, 2003. ISBN 0255365411
- *Electricity and the Environment 2003.* Electricity Association, London, UK, 2003.
- *Guide to the New Electricity Legislation.* Electricity Association, London, UK, 2002.
- *International Exploration Economics, Risk, and Contract Analysis.* Daniel Johnston. 1st Edition. PennWell, Tulsa, Oklahoma, US, 2003. ISBN 0878148876.
- *Striking a Balance 2003: The Sustainability Strategy Update and Progress Report of the UK Offshore Oil and Gas Industry.* UKOOA, London, UK, 2003.

Contact Details

- **Information, careers and educational literature queries to:**
  Chris Baker, LIS Officer, +44 (0)20 7467 7114
  Sally Ball, LIS Officer, +44 (0)20 7467 7115
- **Library holdings and loans queries to:**
  Liliana El-Minyawi, LIS Officer, +44 (0)20 7467 7113
- **LIS management queries to:**
  Catherine Cosgrove, LIS Manager, +44 (0)20 7467 7111
- **IFEG queries to:**
  Sally Ball, IFEG Secretary, +44 (0)20 7467 7115

Fax any of the above on +44 (0)20 7255 1472 or
e: **lis@energyinst.org.uk**
Visit our website at **www.energyinst.org.uk**



IP WEEK 2004
16 – 19 FEBRUARY
LONDON

energy INSTITUTE

IP ANNUAL LUNCH

Tuesday 17 February 2004, 12.30 – 14.45
at the Dorchester Hotel, Park Lane, London

The IP Annual Lunch, held in the elegant surroundings of the Dorchester Hotel, provides an excellent opportunity to hear an international leading figure speak about the key issues affecting the petroleum industry today.

Guest of Honour and Speaker
Inge Ketil Hansen
Acting President and Chief Executive Officer, Statoil

Inge Ketil Hansen was appointed Acting Chief Executive in September 2003.

Hansen became Chief Financial Officer and Executive Vice President for Statoil's Corporate Centre and Services in March 2000. He joined Statoil from Orkla Finans where he was Managing Director.

After graduating from the Norwegian School of Economics and Business Administration in 1970 with an MSc in Business Economics, he joined the Research Institute for the Pulp & Paper Industry, and held a series of posts at Jiffy from 1973-80.

Hansen has also been President of Nor Independent Leasing and a General Manager with Bergen Bank/Den norske Bank.

Hansen is also a member of the board of directors of the Norwegian School of Management.

For more information on this and other IP Week 2004 events, please visit:

www.ipweek.co.uk

TICKET APPLICATION FORM

energy INSTITUTE

Please photocopy this page and send completed form to the Events Department,
Energy Institute, 61 New Cavendish Street, London W1G 7AR, UK F: +44 (0)20 7580 2230

I wish to order .... ticket(s) @ £149.00 + 17.5% VAT (£26.08) each = Total £ ....

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Data Protection Act
The EI will hold your personal data on its computer database. This information may be accessed, retrieved and used by the EI and its associates for normal administrative purposes. If you are based outside the European Economic Area (the "EEA"), information about you may be transferred outside the EEA. The EI may also periodically send you information on membership, training courses, events, conferences and publications in which you may be interested. If you do not wish to receive such information, please tick this box ☐
The EI would also like to share your personal information with carefully selected third parties in order to provide you with information on other events and benefits that may be of interest to you. Your data may be managed by a third party in the capacity of a list processor only and the data owner will at all times be the EI. If you are happy for your details to be used in this way, please tick this box ☐

Terms & Conditions:
- Tickets can be purchased by Members and Non-Members of the Energy Institute (EI)
- The cost of one ticket is £149 + VAT (£26.08) Total - £175.08 and includes pre-lunch drinks and wine. VAT is payable by UK and overseas purchasers. Liqueurs are not included in the ticket price. Full payment must be received before tickets can be guaranteed.
- Seating arrangements will be organised by the EI, bearing in mind guests' wishes. Companies or individuals wishing to share tables must state this when completing the application form, as changes cannot be made after tickets have been allocated.
- Special dietary requirement will be accommodated if notified to the EI by 6 February. An additional charge may be incurred.
- Guests' names should be submitted in writing to the EI by Wednesday 28 January 2004 for inclusion in the printed guest list. Name changes or additions submitted after this date cannot be included in the printed guest list.
- This event is included in the IP Week Pass, a well as the Tuesday morning and Tuesday afternoon passes.
- If you cancel the order, a refund, less a 20% administration charge of the total monies paid will be made provided notice of cancellation is received in writing on or before 5 January 2004. No refunds will be paid or invoices cancelled after this date.
- Dress is lounge suit.
- An application for tickets indicates your acceptance of the terms and conditions listed above. Upon the EI receiving your booking form (by fax, post or email) you become liable for full payment of the fee and you undertake to adhere to the terms and conditions as specified. This is not a tax invoice.

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