DECEMBER 2005

# Petroleum review

## EI AWARD WINNERS...

## AUSTRALASIA

- Expanding frontier opportunities

## SHIPPING

- New ships for old
- LNG carrier fleet expansion

## CANADA

- Oil sands – a sticky dilemma

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

energy INSTITUTE

www.energyinst.org.uk


Think of us as an extension of your team
We'll fit right in
We don't just offer professional advice. Our uniquely collaborative approach means we work with you to maximise your business opportunities.
We offer a broad range of fully integrated solutions across audit, tax, corporate finance and consulting. Each of our services gives you the depth, dimension and experience to create and innovate.
Talk to our Energy, Infrastructure and Utilities Group and find out more:
Carl D. Hughes
UK Head: Energy, Infrastructure and Utilities
Telephone: +44 (0) 20 7007 0858
Don Kinnersley
Head of Business Development:
Energy, Infrastructure and Utilities
Telephone: +44 (0) 20 7007 0693
Deloitte.
Audit.Tax.Consulting.Corporate Finance.
Hill House, 1 Little New Street, London EC4A 3TR. Tel: +44 (0) 20 7936 3000.
© Deloitte & Touche LLP 2005.

Petroleum review

DECEMBER 2005 VOLUME 59 NUMBER 707
SINGLE ISSUE £15.00 SUBSCRIPTIONS (INLAND) £215.00
AIRMAIL £358.00

PUBLISHER

energy INSTITUTE

61 New Cavendish Street, London W1G 7AR, UK

**Chief Executive:** Louise Kingham, FEI

**General Enquiries:**
**t: +44 (0)20 7467 7100**
**f: +44 (0)20 7255 1472**

**Editor:** Chris Skrebowski FEI

**Associate Editor:** Kim Jackson MEI

**Design and Print Manager:** Emma Parsons MEI

***Editorial enquiries only:***
***t: +44 (0)20 7467 7118***
***f: +44 (0)20 7637 0086***

e: petrev@energyinst.org.uk

www.energyinst.org.uk

ADVERTISING

**Advertising Manager: Chris Bean**
**McMillan-Scott plc**
**10 Savoy Street, London WC2E 7HR**

t: +44 (0)20 7878 2415 f: +44 (0)20 7379 7155
e: cbean@mcmslondon.co.uk
www.mcmillan-scott.co.uk

SUBSCRIPTIONS

Journal subscriptions: Chris Baker t: +44 (0)20 7467 7114, f: +44 (0)20 7252 1472 e: **cbaker@energyinst.org.uk**

MEMBERSHIP

Sheila Wallace t: +44 (0)20 7467 7120
e: **swallace@energyinst.org.uk**

ABC Printed by Thanet Press Ltd, Margate

MEMBER OF THE AUDIT BUREAU OF CIRCULATION

## 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 picture: Chevron's Lufkin field, Barrow Island, Australia (see p41)**
***Photo: Chevron***



# CONTENTS

## NEWS



## SPECIAL FEATURES



## FEATURES



## EXTRAS



## REGULARS

# ¿Apertura ahora clausura?

The last month has produced the usual mix of good and bad news, as well as some where it is not clear if it is good or bad. The month's good news is that – to the surprise of many – the global refining system has proved more flexible and more adaptable in the face of the loss of sophisticated US Gulf Coast refining capacity after Hurricanes Katrina and Rita.

Refinery utilisation in OECD Europe and the Pacific rose by more than 1mn b/d in September, more than compensating for the loss of capacity in the US. The slight sting in the tail was that this was only possible because of high gasoline and distillate prices in the US providing the incentive – and as these have eased back, so marginal topping capacity has been turned off.

On p42 we look at the impact of the hurricanes on the oil and gas industry in the Gulf region. The latest International Energy Agency (IEA) monthly report (10 November 2005) shows that, as of 8 November, 740,000 b/d of crude capacity and 4.1bn cf/d of natural gas capacity remained shut in. It notes that BP's Thunder Horse development has been delayed to 2H2006, that Shell's Mars field production will not restart before July 2006, and that Chevron may abandon the Typhoon field TLP (tension leg platform) and reinstate production with alternative facilities. It is clear that the industry has been hit hard and the IEA's conclusion is that 'regional production next year could now struggle to regain the 1.5mn b/d seen before the storm season in 2005' is hard to gainsay.

Over the last year or so, a number of producer countries have tightened the financial and operational terms on which oil companies are allowed to operate (see *Petroleum Review*, February 2005). In this respect, the two most aggressive producers are probably Russia and Venezuela.

Russia's mix of fines and aggressive bureaucracy, amounting to virtual confiscation, effectively renationalised Yukos while purchase rationalised Sibneft. As a direct consequence, all other Russian oil companies – whether state-owned or not – are now reluctant to take any major decision without receiving tacit state sanction. Taxation has been raised to the point where 80% to 90% of all revenues above $25/b now go to the state.

Venezuela appears to be following where Russia has led. In the mid-1990s, the so-called Apertura (opening) – in which Venezuela opened up to foreign investment – now seems to be closing (clausura) amid tax hikes and the imposition of majority holding by PdVSA. President Chavez's latest demand is that companies operating in Venezuela accede to tax rates of 50% and royalties of 30% (which amounts to at least 82.5% of profits, according to Energy Minister Rafael Ramirez) and PdVSA holdings of between 60% to 90%, with PdVSA operational control, by the end of the year or quit the country. Many of the smaller companies have reportedly already accedeed. It remains to be seen whether the largest companies will attempt to resist the impositions.

The omens, however, are not good. The hurricane-induced capacity losses in the Gulf of Mexico are still running at 740,000 b/d – and in a tight market with little spare capacity.

In these circumstances, the companies are likely to find it difficult to resist Venezuelan demands. But, if they do concede, it is possible that it will attract imitation by other producers.

A lottery win will free a man or woman from the necessity of going to work in order to pay the mortgage. For oil producers, high oil prices have allowed them to pay off debts and freed them from the obligation to produce oil to service debts. Just how dramatic is the turnaround in oil producer fortunes is well documented in the latest issue of the *Economist* magazine (10 November 2005). This shows that, according to various sources (the US Department of Energy, the International Monetary Fund and the *Economist* magazine) oil exporters' surpluses are expected to run at $400bn in 2005, a level that in real terms is double the previous peak years of 1974 and 1980. As if that wasn't dramatic enough, the surplus is expected to expand to $500bn in 2006.

The oil exporters' surpluses overtook those of the Asian economies in 2004 and, by 2006, will be twice the surpluses of China, Japan, South Korea and the rest. How the oil producers will elect to use these surpluses remains to be seen. They are certainly in a position to accede to Fatih Birol's (the IEA's Chief Economist) recent suggestion that they should invest in order to expand oil production to meet growing world requirements. But will they? Absent the stimulus of debt servicing and with more military hardware than they have men to operate, there is no immediate stimulus for them to invest and possibly weaken prices.

Much analysis after the first two oil crises was based on the idea that the Opec producers would ration out production in order to save it for future generations. In the event, debt, arms purchases and rising populations have ensured that they kept expanding production. Now, for the first time, they have a real choice and, given most Opec oil producers' notable failure to diversify their economies away from oil and gas, they may chose to hold production steady rather than expand it further.

*Chris Skrebowski*

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

# E-DATA

The Defra website now details the steps taken by the UK government and the private sector to offset carbon dioxide emissions as well as offering basic explanations of different approaches being taken in the offsetting sector. It contains details of the UK government's commitment to offset carbon dioxide emissions from central government air travel from April 2006 as well as the offsetting of the UK Presidency of the G8 and EU. The new website will also offer (non-endorsing) links to a number of companies operating in this sector. The intention is that this website will act as a central portal and bring together offsetting companies with firms seeking to take voluntary measures to reduce their emissions. There is also a frequently asked questions section on carbon offsetting. It can be accessed at: **www.defra.gov.uk/environment/climatechange/carbon-offsetting/index.htm**

OILspace, the provider of energy market information, content management tools and supply chain management solutions to downstream energy companies, together with C1 Energy, a leading publisher of China's energy market pricing and news, have announced an agreement to deliver C1 Energy market news, reports, and pricing data via the OILwatch website **www.oilspace.com** Information will be available in both English and simplified Chinese languages.

*Oil & Gas Journal* has launched two electronic newsletters – *Oil & Gas Journal Daily Update* and *Oil & Gas Journal Weekly E&D Report* – joining *Oil & Gas Journal Online This Week*. For more details, visit **www.ogjonline.com**

A new web-based berth scheduling tool has been developed by the UK's Cirrus Logistics. The product, called SEABERTH, has been created to enable users to plan terminal activity to help reduce demurrage costs on an on-going basis quickly and easily as well as to meet business priorities. A product extension, SEABERTH Simulation, acts as a strategic decision support tool in the management of change in terminal operations.

## UK

***Nigel Griffiths, MP for Edinburgh*** *South and Deputy Leader of the House of Commons opened the new British Geological Survey (BGS) National Geoscience Data Centre Gilmerton Corestore on 12 October 2005. The archives include everything from the latest satellite images and rock samples to hand-drawn maps from the 18th century and are a unique record of UK Continental Shelf hydrocarbon exploration.*

***Oil production has commenced from*** *the Statoil-operated Urd field in the Norne area of the Norwegian Sea. The Urd subsea development comprises the Stær and Svale satellites. A total of five oil producers and three water injectors are due to be drilled on Urd, with gas lift planned for the production wells. Gas from the Norne ship will be injected in the wells in order to reduce well-stream density and increase production. Recoverable reserves in Urd are put at 70mn barrels of oil and a small amount of gas. Statoil has a 50% stake in the project, partnered by Petoro (25%), Hydro (13.5%) and Eni (11.5%).*

***Lundin Petroleum has announced the*** *successful completion of the Broom field Phase 2 drilling campaign in the UK North Sea, with both new development wells in production. Lundin has a 55% working interest in the Broom field complex and a 100% working interest in the Heather field and platform facilities. Lundin Petroleum is operator of both fields. Current gross production from the Broom field complex is approximately 32,000 b/d, restricted by Heather platform facility constraints.*

### Complete news update

The 'In Brief' news items in *Petroleum Review* represent just a fraction of the news we regularly publish on the EI website **www.energyinst.org.uk** via the 'News in Brief Service' link from the ***'Petroleum Review'*** drop-down menu. Covering all sectors of the international oil and gas industry, the News in Brief Service is a fully searchable news database for EI Members.

Why not visit the site to find out more about the latest developments and trends in your industry?

**www.energyinst.org.uk**

# IEA revises down world oil demand growth forecast

**The International Energy Agency (IEA) has revised down its forecast for world oil and gas demand growth over the next 25 years, citing the impact of higher energy prices on consumption. In its latest annual *World Energy Outlook*, which covers the period to 2030, the IEA has cut its baseline oil demand expectation ('reference scenario') by 6% (some 6mn b/d) to 115.4mn b/d, compared with its estimate a year ago.**

**Oil demand growth over the period is expected to fall to 1.3%/y from its previous forecast of 1.6%. Natural gas consumption over the same period is revised down by more than 2% to 4,789bn cm/d by 2030, an annual growth rate of 2.1% in contrast with its previous estimate of 2.3%.**

**The IEA has also increased its baseline crude import price estimate to 2030, with the inflation-adjusted nominal price climbing from $36/b last year to $65/b by 2030.**

**Despite the easing of outright demand, the expected growth between 2003 and 2030 stays robust, with oil demand over the period climbing 46% and gas consumption surging 77%, outstripping coal as the world's second-largest energy source. Coal consumption is expected to climb 1.4%/y to 2030, up from 5,200mn tonnes in 2003 to almost 7,300mn tonnes in 2030.**

**The agency also expects the share of crude oil supplies from Opec members to rise 11 percentage points from 39% in 2004 to 50% in 2030, with output of 50.2mn b/d. This contrasts a forecast decline in non-Opec supplies of 1.3% over the period, to marginally more than 46mn b/d in 2030.**

# Mittelplate oil pipeline commissioned

RWE Dea (50%, operator) and Wintershall (50%) have commissioned the new crude oil pipeline system for Germany's Mittelplate field. Compared with the previous method of moving the crude off the Mittelplate drilling and production island by barge – a method that was subject to tidal and meteorological restrictions – the increased transport capacity of the new pipeline link will allow oil production on Mittelplate island to be increased from the current 900,000 t/y to 1.6mn t/y. The combined annual production volume of the onshore and offshore operations at Mittelplate will be about 2.5mn tonnes of crude (50,000 b/d).

***Aker Kvaerner has been awarded a*** *NKr100mn contract for front-end engineering design (FEED) for BP's Skarv and Idun fields in the Norwegian sector of the North Sea, which are to be developed via a new floating production facility. Skarv and Idun are combined oil and gas developments, with 75% of the reserves held as gas and 25% liquids. Gas export will be through the Åsgard transport system (ÅTS) to the onshore Kårstø facility. Skarv is operated by BP (30%), partnered by Statoil (30%), Shell (25%) and ExxonMobil (15%). The Idun field is operated by Statoil (50%), partnered by Shell (40%) and Hydro (10%).*

### EUROPE

***Dong has sold 60% of licence PL274 in*** *the southern part of the Norwegian North Sea to PA Resources and Reveus Energy, each taking 30%. Dong will retain the remaining 40% and continue as operator. In addition, a small part of the southern part of the licence will be hived off into a separate licence, in which BG Norge will take an 80% stake and operatorship. Licence PL274 includes the Oselvar discovery.*

***Proposals have been drawn up by*** *Statoil to extract some 35mn extra barrels from its Tordis field in the North Sea with the aid of new technology for improved oil recovery (IOR). By installing a full-scale subsea separation facility, Statoil expects to improve the field's recovery factor from 49% to 55% at a cost of NKr1.8bn. The Tordis IOR subsea separation facility is due to come onstream in October 2007.*

### NORTH AMERICA

***BP is planning to invest up to $2.2bn*** *to double production from its acreage in the Wamsutter gas field in the US Rockies region. The multi-year drilling programme is expected to increase BP's share of ultimate recovery from the field by 450mn boe and increase BP's daily net production from 125mn to 250mn cf/d by the end of the decade. The $2.2bn outlay includes the drilling of 2,000 wells over the next 15 years and a two-year, $120mn technology field trial programme that could lead to additional field development in the future.*

***The Alberta Energy and Utilities Board*** *(AEUB) has rejected appeals from gas producers and ruled that 917 gas wells must be shut in as they threaten future oil sands development that could pro-*

# Faster drilling and reduced downtime

ExxonMobil reports that it has developed an optimisation process that is claimed to consistently reduce the time required to drill oil and gas wells by up to 35%. 'The Fast Drill Process (FDP) achieves this by using real-time, computer analysis of the drilling system's energy consumption. This analysis, in turn, helps improve the management of the factors that determine drilling rate, such as weight on the drill bit, rotary speed and torque,' explains the company. The result is significantly faster drilling rates and reduced downtime.

The company reports that it has used FDP in many of its operating areas, and the process has improved performance in a broad range of conditions – hard and soft rock, deep and shallow wells, high- and low-angle wells in a variety of mud weights. It is also understood to have shown comparable success in exploration, delineation and production wells.

'A key benefit of the FDP is that it quantifies the hidden cost of slow drilling,' states ExxonMobil. 'Drill rates have historically been evaluated by comparing performance to other wells in the same area. However, there has been no method to confirm that the comparison well was itself a high performing well. FDP allows ExxonMobil to make design changes to achieve the objective theoretical performance in a given well. Much of the performance improvement achieved has come from this ability to objectively justify design changes needed to extend previous performance limits.'

# Decommissioning partnership

**Aker Kvaerner, SBS Logistics, Onyx UK and Shetland Decommissioning Company have signed an agreement to jointly tender, develop and carry out decommissioning projects in the future, using SBS Logistics' Greenhead base in Lerwick, Shetland, as the main UK decommissioning yard.**

**The agreement is a development of the partnership between the group of companies, led by Norway's Aker Kvaerner, which in October 2004 bid for and won the £250mn decommissioning contract to break up Total's Frigg field gas installations in the North Sea, which straddle the boundary between the UK and Norwegian sectors.**

**'The expertise we will gain on the Frigg decommissioning project and the recent expansion of our Shetland hub with the lease of the Holmsgarth quayside and warehousing facility in Lerwick Harbour facility, will strengthen our position in this marketplace when bidding for further decommissioning contracts,' commented Harald Gulaker, Managing Director of Aker Kvaerner Offshore Partner.**

**SBS is constructing a decommissioning pad and controlled discharge area at its Greenhead base, which has large new concrete quaysides that, along with ample open laydown and storage facilities, make it particularly suitable for the offloading and onshore dismantling of offshore structures.**

**Onyx is heavily involved in offshore activities in both the UK and Norway and under a PPC (pollution, prevention and control) permit will operate the new facility and provide specific waste separation and recycling services. It is anticipated that more than 20,000 tonnes of steel and other materials will be shipped from the six Frigg platforms to Lerwick for processing at the new facility, with a target of achieving a recycling recovery rate of 98%.**

# *Repsol YPF targets Brazilian E&P sector*

Repsol YPF has been awarded 16 offshore exploration areas in the Campos, Espírito Santo and Santos basins under Brazil's latest licensing round. It will be operator of 11 areas, and partnered by international oil companies such as Statoil, Amerada Hess, BG Energy and Petrobras in the other five.

Repsol YPF already owns concessions on another eight offshore exploration blocks in Brazil. These latest additions bring the total to 24 blocks, making Repsol YPF the second largest oil company after state-owned Petrobras in terms of the number of exploration blocks in Brazil.

The areas awarded, all at water depths of between 100 and 2,500 metres, are as follows: one block in the Campos basin (50% Repsol YPF, 50% Statoil); two blocks in the Espírito Santo basin (one operated 100% by Repsol YPF and the other belonging 40% to Repsol YPF and 60% to Amerada Hess); 13 blocks in the Santos basin (nine with Repsol YPF as operator and the other four in association with Petrobras and BG Energy).

*duce some 25.5bn barrels of bitumen. The policy shuts in about 280bn cf of gas, or seven-tenths of 1% of Alberta's total gas reserves. Nearly 15% of the province's bitumen reserves are involved in the case.*

***Chevron and partner Kerr-McGee have*** *awarded Aker Kvaerner the $120mn semi-submersible hull and mooring system contract for their Blind Faith project in the Gulf of Mexico's Mississippi Canyon 650 block.*

***Norsk Hydro is planning to acquire*** *Spinnaker Exploration in an all-cash transaction for $2.45bn.*

***Kerr-McGee has signed a sales*** *agreement with Encore Acquisition for selected oil and natural gas properties in the Permian basin in western Texas and the Anadarko basin in Oklahoma, for $104mn in cash.*

## MIDDLE EAST

***The Independent Inquiry Committee*** *into financial irregularities bedevilling the UN Iraq oil-for-food programme has published details of illicit surcharges demanded of oil companies by the Saddam regime to participate in the scheme, writes* Keith Nuthall. *Its investigators show how, for instance, from September 2000 to August 2002, some $228.8mn in illegal surcharges were demanded from oil exporters, which were paid to Iraqi controlled bank accounts in Jordan or Lebanon and to Iraqi embassies.*

## RUSSIA & CENTRAL ASIA

***Rosneft is to acquire Interros' 25.94%*** *stake in Verkhnechonskneftegaz, which holds the licence to develop the Verkhnechonsk oil and gas condensate deposit in the Katangsky region of the Irkutsk Oblast. The Verkhnechonsk deposit is reported to be one of the largest in Eastern Siberia, with 83% of the Irkutsk Oblast's oil reserves. Its C1+C2 recoverable reserves total 201.8mn tonnes of oil and 3.4mn tonnes of gas condensate. Natural gas reserves are estimated at 129.2bn cm. TNK-BP holds a 62.7% stake in Verkhnechonskneftegaz, and the Irkutsk Oblast State Property Management Committee an 11.3% interest.*

## ASIA-PACIFIC

***Chevron has signed a heads of agree-*** *ment (HoA) with Tokyo Gas covering the purchase of 1.2mn t/y of Gorgon*



# UK oil and gas production

**The latest (October 2005) Royal Bank of Scotland *Oil and Gas Index* shows a marked decline in combined oil and gas output for July – at 3,072,088 boe/d – compared to the previous month (3,156,055 boe/d). August recorded another drop in oil production, down from 1,650,720 b/d to 1,325,144 b/d, while natural gas rebounded from 8,073mn cf/d to 10,043mn cf/d.**

**'While there is an underlying trend of diminishing potential in the North Sea as existing oil fields are maturing, the measurable decline in oil production recorded for July and August is due to one-off annual scheduled maintenance activity, which continued through August,' comments Andrew McLaughlin, Royal Bank of Scotland Chief Economist. 'Therefore, we expect production to resume its trend in September. Prices for oil and gas remain supportive of future investment into the sector, although prices have retreated from their all-time highs recorded in the wake of Hurricanes Katrina and Rita.'**

| Year Month | Oil production (av. b/d) | Gas production (av. mn cf/d) | Av. oil price ($/b) |
|---|---|---|---|
| Aug 2004 | 1,621,582 | 8,585 | 42.99 |
| Sep | 1,526,692 | 8,716 | 42.92 |
| Oct | 1,630,230 | 9,677 | 49.66 |
| Nov | 1,748,744 | 10,385 | 42.88 |
| Dec | 1,800,309 | 10,823 | 39.55 |
| Jan 2005 | 1,725,929 | 10,444 | 44.24 |
| Feb | 1,742,295 | 9,759 | 45.40 |
| Mar | 1,703,744 | 10,514 | 52.95 |
| Apr | 1,749,773 | 10,261 | 51.83 |
| May | 1,723,598 | 9,549 | 52.95 |
| Jun | 1,606,794 | 8,800 | 54.45 |
| Jul | 1,650,720 | 8,073 | 57.59 |
| Aug | 1,325,144 | 10,043 | 64.08 |

*Source: The Royal Bank of Scotland* Oil and Gas Index, *October 2005*

North Sea oil and gas production

# *Dana and GdF exchange assets*

Dana Petroleum has acquired from Gaz de France (GdF) a 15% working interest in the production sharing contract for blocks 352a and 353, located in the prolific Sbaa basin onshore south-west Algeria, for $93mn. An estimated 2.6tn cf of recoverable gas has been discovered on these blocks to date, within seven main accumulations, of which the largest (containing approximately half this volume) is the Oued Zine field. Although commerciality has not yet been formally declared, a development plan is under preparation, with first gas expected in 2010 at rates of 560mn cf/d.

In addition, Dana and GdF have executed an exchange agreement under which Dana will gain a 25% interest in the producing Anglia gas field and associated UK North Sea blocks 48/18b, 48/19b and 48/19e. The company will also receive an additional 22.113% interest in the producing Johnston gas field (together with a 30% interest in associated UK North Sea block 43/27a), taking the group's total interest in Johnston to approximately 50%. Dana is also to acquire a 30% stake in the recently awarded production sharing contract for the West El Burullus concession in the Nile Delta, offshore Egypt.

In exchange for the above assets, Dana has agreed to transfer to GdF a 24% interest in block 1 offshore Mauritania, a 27.85% stake in block 7 and a 17.5% interest in block 8. Dana will retain a 36% interest in blocks 1 and 7, and a 24% stake in block 8, and will remain as operator of all three blocks. In addition, GdF will pay all of Dana's costs associated with the next three deepwater exploration wells offshore Mauritania – one well is planned on each of the blocks – up to a cumulative cap of $30mn. The company will also pay for an additional 30% of costs associated with the first exploration well in the West El Burullus concession, up to a cap of $3mn.

*LNG, beginning in 2010, over a 25-year period. The parties are also discussing the potential sale and purchase of an equity interest in the Gorgon project.*

***ConocoPhillips is reported to be*** *looking to swap its 50% stake in block A in Aceh province with another field in Indonesia, while ExxonMobil plans to sell its 50% stake in the block. Block A reserves are put at 500bn cf of gas.*

## LATIN AMERICA

***Mexico has lost its appeal against a*** *refusal by a World Trade Organisation (WTO) disputes panel to order the US to immediately scrap anti-dumping duties on Mexican oil country tubular goods, writes* Keith Nuthall.

***Kerr-McGee has acquired a 25%*** *interest in the southern part of block 2(c) retained exploration area (REA) and a 30% interest in block 3(a) offshore Trinidad and Tobago. The two blocks are contiguous with block 3(b) and adjacent to the Angostura field.*

***Shell has acquired interests in five*** *blocks in the shallow water areas of the Espírito Santo basin, offshore Brazil. Shell will operate block ESM 438 with a 100% share, and partner with Brazil's national oil company Petrobras, who will operate blocks ESM 411, 436 and 437. Shell has also acquired a deepwater area in Santos block SM 518.*

## AFRICA

***OMV has announced oil discoveries in*** *block NC186, in Libya's Murzuq basin, and in block S2 (Al Uqlah) in the Shabwa province of Yemen.*

***Candax Energy has signed an agree-*** *ment with Mitsubishi for the farm-out of a 20% working interest in the Chaal permit onshore Tunisia. Candax will retain a 60% stake and continue as operator. SMIP, a Tunisian company, holds the remaining 20%. In a separate agreement, Candax and Mitsubishi have formed a 50:50 joint venture to evaluate a major gas development project in the Middle East.*

***The Ugandan government has signed*** *a production sharing agreement (PSA) with UK company Neptune Petroleum for petroleum exploration and development on Exploration Area 5, reports* Stella Zenkovich.



# Boosting Indonesian field production

SatCon Technology has sold to Chevron a medium-voltage static transfer switch (STS) and related equipment that will increase output from two oil fields in Indonesia by virtually eliminating power interruptions. The power reliability project – the first known application of STS technology for oil production – was developed through Chevron Energy Solutions.

Storms, lightning strikes and other factors frequently cause power outages that disrupt island-based oil field operations, resulting in many hours of lost production. In the event of an electrical disturbance at CPI's Kelok and Tilan oil fields on Sumatra, the STS will automatically switch the power to a secondary line in a fraction of a voltage cycle – less than one-sixtieth of a second – ensuring continuous power to the fields' pumping equipment.

It is expected that the STS will prevent 20 to 30 power disturbances each year, which translates to 30,000 additional barrels of oil that can be produced annually.

Over the past decade, the medium-voltage STS has enhanced reliability in semiconductor and semiconductor tools manufacturing facilities. If successful, this new application for improving oil production operations could open up a new market for the technology. 'There is growing demand for solutions to increase production in upstream oil operations,' said Jim Davis, President of Chevron Energy Solutions. 'This type of application may hold promise for remote oil fields that are interconnected to a power grid but are facing reliability issues. Over time, we hope to be able to offer similar solutions to other upstream operations.'

# Kristin field comes onstream

**Statoil's high-pressure/high-temperature (900 bar/170°C) Kristin field offshore Norway has come onstream. Production is via four subsea templates tied back to a floating platform, with a planned total of 12 wells. Gas is piped via the Åsgard pipeline to the Kårstø processing plant north of Stavanger, while the condensate goes to the Åsgard C storage ship for export. Eight of the wells will be highly deviated – the first of their kind to be drilled as subsea completions in a field with high temperature and pressure.**

**Due to reach plateau production next summer, Kristin contains estimated recoverable reserves of 43bn cm of gas and 240mn barrels of condensate.**

**Statoil's Tyrihans field, due onstream in 2009, is to be tied back to the Kristin platform once the facilities have spare capacity.**

**Kristin partners are Statoil (41.3%), Petoro (19.6%), Hydro (14%), ExxonMobil (10.8%), Eni (8.3%) and Total (6%).**

# World oil demand estimate revised down

Opec has revised downward its world oil demand estimate for 2005 by 40,000 b/d in its August *Oil Market Report*, based on lower than expected consumption reported in the first and second preliminary data for some major oil consuming countries such as the US and China. However, it also said that world oil demand growth was projected to rise by 1.58mn b/d to average 83.6mn b/d of oil production.

Giving its forecasts for 2006, the report predicts that average growth for world oil demand will be 1.9%, to average 85.2mn b/d.

On supply, the Opec report revised down projections for non-Opec supply growth by 17,000 b/d. It noted that non-Opec production in 2005 is expected now to average 50.5mn b/d, representing a 0.7mn b/d increase over the previous year. For 2006, non-Opec production is expected to now average 51.5mn b/d, an increase of almost 1mn b/d over 2005, and a downward revision of 148,000 b/d from the previous month's report.

While highlighting the demand and supply situation in the short to medium term, the report also emphasises the need to improve investment in the refining sector, stating that constraints due to refinery bottlenecks as well as geopolitical developments have had considerable impact on the oil market.

The report noted, however, that it will take several years to deliver the projects needed to ease current bottlenecks and prepare the appropriate refining capacity to meet expected demand.

Furthermore, any delays will only continue the current mismatch between the installed refinery capacity and crude type, and undermine the efforts of Opec and other producers on the upstream side to reduce volatility in the oil market.

## UK

*The UK government has announced £30mn of funding over three years for a new renewable energy programme and pledged to put schools at the forefront of the scheme. The Low Carbon Buildings programme (LCBP), which will come into effect in April 2006, will fund small-scale household and community projects, replacing two existing schemes – Clear Skies and the Major Photovoltaic (PV) programme – which both came to an end in November 2005. Some £1.5mn will be set aside to fund projects in the interim.*

*BP has posted a 16% increase in profits as record energy prices have more than compensated for losses at its hurricane-damaged rigs and refineries. Earnings rose to $4.41bn in the third quarter, up from $3.79bn a year earlier. Net earnings rose to $6.46bn, up from $4.82bn. Oil and gas production in the quarter declined 2.1% to 3.82mn b/d. Sales of oil products such as gasoline fell 9.4% to 6.1mn b/d as refining availability declined to 92.6% in the quarter, compared with 95.1% a year earlier.*

*BG Group is planning to carry out a £1bn share buy-back plan, after announcing a 44% rise in 3Q2005 profits to £308mn.*

## EUROPE

*Odd Roger Enoksen was recently appointed Norwegian Minister of Petroleum and Energy, representing the Centre Party in the coalition government headed by Jens Stoltenberg. Following the change of government, Anne Tingelstad Wøien has taken over as Political Adviser, while Anita Utseth is the new State Secretary of the Ministry.*

*Shell has reported a 68% increase in 3Q2005 income to $9.03bn compared with $5.4bn in 3Q2004. E&P earnings of $4.9bn were 112% higher than a year ago. Hydrocarbon production was 3.2mn boe/d, including the loss of 160,000 b/d due to hurricanes in the Gulf of Mexico.*

## NORTH AMERICA

*EnCana is to sell its natural gas liquids business to Provident Energy Trust for approximately $586mn (C$697mn).*

*ExxonMobil has posted a 3Q2005 net income of $9.9bn, compared to $5.7bn*



# Call for debate on UK nuclear

**Gordon Masterton, the new President of the Institution of Civil Engineers (ICE), took up office at the beginning of November with a call for a government-led debate on the future of the UK's nuclear energy policy. A recent ICE public opinion survey found that only one in four people want new nuclear stations built. The research also discovered that 71% of those against nuclear newbuild were concerned about safety issues.**

**Masterton commented: 'The majority of the public still regard nuclear as a dirty word. It's time government bit the bullet and encouraged a wider national debate so that the public have the facts about all our energy options. The biggest threat to the planet is global warming. An added benefit of re-investing in nuclear generation is that it has negligible carbon dioxide emissions. From that perspective, it is a globally green solution to the UK's energy generation gap.'**

**Nuclear power stations, which currently produce 22% of the UK's electricity, are closing down at a rapid rate – by 2023, 11 will have shut down, leaving just one generating electricity. With no current plans for replacements, and a five- to 10-year wait from drawing board to completion, ICE has been asking how the gap in generating UK electricity will be filled.**

**Masterton played a key role in fronting ICE's *State of the Nation 2005* infrastructure report, launched in October 2005. The energy section of the report stated that: 'another year has gone by without any new generating capacity being built' and that 'it may not be a case of the lights going out, but they are beginning to flicker'.**

**ICE believes that the government's target for 10% of the UK's energy to come from renewables by 2010 is unlikely to be achieved. The Institution estimates that between 5% and 7% is a more realistic figure. Masterton is also concerned about the UK's dependency on gas, stating: 'We've become over-reliant on gas. Indeed, this year the UK became a net importer. It is only sensible that we maintain a diverse mix of energy sources. With the general election behind them, the government needs to tackle an issue they seem in fear of confronting – and give the go-ahead for a new generation of nuclear stations before the threat of blackouts becomes more frequent.'**

# *OMV unveils new market targets*

OMV has set new targets for company growth until 2010, after achieving its 2008 goals ahead of schedule. It is now aiming for a production volume of 500,000 boe/d by 2010 and for further expansion of its refining and marketing business in the EU accession area.

In addition, OMV plans to be operating an international gas business marketing 20bn cm of gas by 2010.

OMV is the largest oil and gas group in Central Europe, with oil and gas reserves of some 1.4bn boe and daily production of 340,000 boe. Annual refining capacity currently stands at 26.4mn tonnes. The company also has 2,457 service stations in 13 countries and a market share of 18% in the Danube region.

# Chevron signs key pipeline deal

Chevron has signed a binding agreement with Kinder Morgan Energy Partners to be one of the anchor shippers in a 3.2bn cf/d pipeline system to be connected to the Sabine Pass LNG terminal in Cameron Parish, Louisiana. Under the agreement, Chevron has obtained up to 1bn cf/d capacity in a newbuild pipeline and 0.6tn cf/d interconnect capacity to the existing pipeline operated by Natural Gas Pipeline Company of America (NGPL), a subsidiary of Kinder Morgan, located adjacent to the Sabine Pass LNG terminal site. Combined, the newbuild pipeline and interconnect capacity with NGPL will provide important take-away options for Chevron's capacity at the Sabine Pass LNG terminal. The new pipeline system will provide access to Chevron's Sabine and Bridgeline pipelines, which connect to Henry Hub.

'This agreement is key to advancing Chevron's effort to provide the US market with new sources of natural gas, and is a significant step forward in our overall strategy of building complete gas value chains,' said John Gass, President of Chevron Global Gas. 'This pipeline, combined with our capacity in the Sabine Pass LNG terminal, will allow us the unique opportunity to flexibly link all key consuming markets east of the Rockies with Chevron's LNG projects,' commented Randy Curry, President of Chevron Natural Gas.

The new pipeline is planned to be in service in 2009, coinciding with Chevron's Sabine Pass terminal commitments.

*in 3Q2004 – including a special gain from the restructuring of the company's interest in the Dutch gas transport operator Gasunie. Third quarter 2005 results were reported to have been adversely impacted by the Hurricanes Katrina and Rita, with US production volumes down 50,000 boe/d and additional costs of approximately $45mn before tax. ConocoPhillips reported 3Q2005 net income of $3.8bn (3Q2004: $2.06bn), while Chevron posted a net income of $3.6bn (3Q2004: $3.2bn). Hurricanes Katrina and Rita are estimated to have reduced Chevron's quarterly results by more than $600mn. Marathon Oil reported a net income of $770mn for the period, also reporting a loss of 20,000 boe/d shut-in due to the Gulf of Mexico hurricanes. Anadarko Petroleum posted a 3Q2005 net income of $596mn on revenues of $1.76bn, while Apache posted a 60% rise in third-quarter earnings to a record $686mn.*

***The Lawrence Livermore National*** *Laboratory, California, US, has warned that global warming could be much higher than expected, releasing new models suggesting average temperatures worldwide could rise by 7.8°C by 2300 if fossil fuel consumption continues unchecked. Polar ice caps would melt and sea levels rise seven metres, it claims.*

## MIDDLE EAST

***The World Bank is to lend $325mn to*** *Turkey for state pipeline company Botas to build a 1.5bn cm capacity gas storage facility – the country's first – next to Salt Lake, writes* Stella Zenkovich.

***The World Trade Organisation (WTO)*** *has admitted Saudi Arabia as a member, a move forcing Riyadh to remove rules preventing overseas oil and gas companies from serving its wealthy petroleum sector, reports* Keith Nuthall.

## WORLD

***Global investment in renewable energy*** *hit a record $30bn in 2004, accounting for between 20% and 25% of all investment in the power industry, according to a recently published Worldwatch Institute report. Solar power was reported to be the fastest-growing renewable energy technology. The Worldwatch Institute – a Washington-based organisation working for environmental sustainability – also said that the renewables sector was growing as a result of government support and increasing private sector investment.*

# Georgian section of BTC pipe commissioned

The Georgian section of the Baku-Tbilisi-Ceyhan (BTC) oil pipeline has been officially inaugurated. Once completed, the 1,768-km pipeline will carry 1mn b/d of oil from the BP-operated Azeri-Chirag-Gunashli (ACG) field in the Azeri sector of the Caspian Sea to the eastern Mediterranean port of Ceyhan, bypassing the sensitive and heavily used Bosporus Straits.

Staged filling of the pipeline is a gradual process over a period of several months, involving more than 10mn barrels of oil. The oil is currently on its way towards the Georgia/Turkish border, and the loading of the first tanker at Ceyhan is expected around the end of the year.

The BTC partners are BP (30.1%), AzBTC (25%), Chevron (8.90%), Statoil (8.71%), TPAO (6.53%), Eni (5%), Total (5%), Itochu (3.40%), Inpex (2.50%), ConocoPhillips (2.50%) and Amerada Hess (2.36%).

The BTC pipeline is buried for its entire length and, following construction, land is being fully re-instated. The Georgian section is 249 km long, with a diameter of 42 inches. It crosses seven regions of Georgia, with a peak altitude of 2,400 metres. There are two pump stations through which the oil passes – one at Gardabani and one at Tetritskaro.

The South Caucasus gas pipeline (SCP) will carry Shakh Deniz gas from the Caspian to Georgia and Turkey and runs in parallel to the BTC line. It is currently 60% complete and on schedule to deliver first gas in the winter of 2006.

# Latest European Union developments

**The first ever multilateral treaty covering the Balkans has been signed in Athens, creating a European Energy Community, linking the gas and electricity policies of south-eastern Europe with those of the European Union (EU), writes *Keith Nuthall*. Under the treaty, Croatia, Bosnia & Herzegovina, Serbia, Montenegro, Macedonia, Albania, Romania, Bulgaria and Kosovo must apply EU energy legislation, including related environmental and competition laws. Anticipated cooperation is expected to expand natural gas infrastructure to create an intermediate market between the Caspian Sea and the EU. There are also commitments to reform gas tariffs. A ministerial council and a treaty secretariat will be established in Vienna. This extra-EU cooperation may continue in northern Europe, with Latvian EU Energy Commissioner Andris Piebalgs supporting strengthening work carried out by the 11-country BASREC (Baltic Sea Region Energy Co-operation), at a ministerial conference of the group. Agreeing a two-year extension for the project, he said sharing of good practice was 'an ideal starting point for regional co-operation'.**

**In other EU news:**

- **The European Commission (EC) has announced plans to simplify EU rules on a range of oil and gas topics, under a major overhaul of EU legislation to make European laws more user-friendly. Brussels will simplify legislation on maintaining minimum oil stocks, and repeal the waste-oil directive that insists member states prioritise regenerating waste oil rather than incineration, for instance.**
- **EU Energy Commissioner Andris Piebalgs has called for the oil industry to use profits earned from high oil prices to boost production and refining capacity. 'Oil prices remain too high. This is hurting EU citizens and business,' he said.**
- **French regional governments have been given the power to lower excise duty charged locally on diesel and unleaded petrol – a derogation from EU excise laws – provided cuts are no greater than 35.40 per 1,000 litres of unleaded or 23 per 1,000 litres of diesel.**
- **The EC has launched another competition inquiry over gas-electricity mergers in Denmark, which may lead to it blocking state-owned gas incumbent Dong's plans to control generators Elsam and Energi E2, and suppliers Københavns Energi Holding and Frederiksberg Elnet.**
- **The European Investment Bank wants to lend 200mn to Spain-Italy-owned Eurosviluppo Elettrica to design, construct and operate a large-scale natural gas-fired co-generation plant with a capacity of 800 MWe.**
- **An EU-supported research project is developing an electricity storage system based on hydrogen fuel cells. The HELPS (Hydrogen-based Electrical energy system for Local Power Storage) project is aiming to create emergency back-up and storage facilities for renewable generators and consumers.**
- **Estonia, Latvia and Lithuania have called for EU involvement in the planned construction of a natural gas pipeline connecting Russia and Germany due to environmental concerns.**
- **The European Bank for Reconstruction and Development is planning to support the creation of an LPG transfer facility at Ukraine's Kerch port, operated by Kazakh-owned AEGas Terminal.**

## UK

***UK Defra is proposing to introduce*** *Stage II gasoline vapour recovery controls at large service stations – the consultation document can be found at* **www.defra.gov.uk/corporate/consult/current.htm** *Defra says that the proposed measures would reduce VOC (volatile organic compounds) emissions from services stations by 16,000 t/y, or around half of the sector's contribution. Emissions from service stations are reported to account for about 3% of the UK's total VOC emissions.*

***Inter Pipeline Fund subsidiary Simon*** *Storage is understood to have entered into a 20-year fuel storage contract with Greenergy. Simon will invest £4.9mn in modifying existing facilities at its UK Immingham West terminal to accommodate production from Greenergy's new 750,000 b/y biodiesel production plant.*

***Star Energy reports that its 10bn cf*** *Humbly Grove gas storage facility in Hampshire – claimed to be the third largest gas storage facility in the UK – has commenced injection operations. The facility will have the ability to fill in 45 days and empty in 90 days. Humbly Grove's entire capacity has been contracted to Vitol, a major oil and gas trading company, for a firm period of three and a half years, with options to extend.*

***Centrica is to release additional gas*** *storage capacity to the market ahead of this winter, helping to enhance peak deliverability at the UK's largest gas storage facility. Up to 30mn therms of indigenous gas at the Rough gas storage facility – equivalent to an additional 3% of the facility's standard working capacity – will be available for storage customers to use during the winter, with deliverability rights in proportion to the gas purchased. The release of gas is in addition to historically high levels of customer gas already in store at Rough, with the additional quantity equating to supplying 65,000 homes every day over the peak winter period.*

***Aker Kvaerner has secured a contract*** *for the turnkey delivery of a biofuel-fired power station in Scotland in a consortium with Siemens. Claimed to be the largest dedicated biomass power plant in the UK, the new facility will be built in Lockerbie by E.ON at a cost of some 130mn. With 44 MW electricity production capacity, E.ON's new station will provide some 70,000 homes with power. The use of biomass*

# UK Forest Commission goes green


Waste cooking oil is being used as motor fuel as part of the UK Forestry Commission's continuing drive to develop more sustainable, environmentally friendly ways of caring for the nation's forests. The Commission currently has 160 vehicles using the biodiesel fuel, which has been refined from vegetable oil, including used cooking oil, and then blended with conventional mineral diesel. In the case of one forestry van being used in a trial in northern Scotland, ordinary diesel does not enter the equation at all – the vehicle is being fuelled on 100% used cooking oil that has not been refined and blended into biodiesel first.

As a government department, the Commission is committed to meeting the European Union's targets for use of carbon-neutral biological fuels, or biofuels – and it is already well ahead of the target. The target for the use of renewable road fuels derived from organic sources was 2% by the end of 2005, and 5.75% by the end of 2010.* However, biodiesel already comprises about 15% of the total road fuel bought by the Commission in southern Scotland, 8% over the whole of Scotland, and 5% over the whole of Great Britain.

Richard Earle, the Sustainability Development Officer with the Commission's Business Units, which include its Mechanical Engineering Services, reports that: 'All our biodiesel-powered vehicles are running well, with no sign of it doing any harm to our engines, and we're delighted to be making this contribution to the "Greening Government" programme. Vegetable oils are a sustainable fuel because they can continually be replaced by growing more of the plants that we get them from, such as oilseed rape. We can't do that with fossil fuels such as mineral oil. And for the same reason, they are "carbon-neutral". In other words, they don't increase the amount of carbon dioxide in the atmosphere. That's because this year's crop of oil-producing plants reabsorbs the same amount of carbon from the atmosphere as last year's crop released, in a perpetual, carbon-neutral cycle – just as our forests do when we replant them after harvesting. They are also more environmentally friendly, because they release fewer particulates (minute particles of soot), unburned hydrocarbons, oxides of sulphur and carbon monoxide into the air. And, by using waste oil as a fuel, we solve the problem of disposing of it after it's been used for cooking.'

The vegetable oil used in biodiesel comes from both 'virgin' (fresh-from-the-plant) sources and used cooking oil. The used cooking oil is supplied to bulk distributors by restaurants, chip shops and large industrial cooking establishments, such as those that make microwave-ready chips. The bulk distributors refine it into biodiesel and sell it on to customers such as the Forestry Commission.

Most of the Commission's biodiesel-powered vehicles run on a blend of 95% of the usual ultra-low-sulphur mineral diesel and 5% biodiesel. However, car-maker Citroen – which supplies many of the Commission's small vehicles – recently turned up the heat on mineral fuels when it agreed to honour its warranties on Commission vehicles if blends containing up to 30% biodiesel are used. The Commission is now trialling 23 vehicles in Perthshire on a 25% biodiesel blend, with no problems being experienced.

**See p11 for latest figures*

*instead of fossil fuels will avoid approximately 140,000 tonnes of greenhouse gases every year. The power station will be commissioned at the end of 2007.*

## EUROPE

***Vopak is to take over full ownership of*** *Tank-Terminal Deutsch-Ueberseeische Petroleum (DUPEG), after acquiring Lehnkering's 50% stake in the Hamburg facility. The terminal – which will be renamed Vopak DUPEG Hamburg – handles chemical products and has 120 tanks with a combined capacity of 137,000cm. It has two deep-sea jetties and a number of loading stations for road tankers and rail tank cars.*

## NORTH AMERICA

***Chevron Global Gas has filed an appli-*** *cation with the US Federal Energy Regulatory Commission (FERC) as part of the permitting process to build an underground natural gas storage facility to provide critical infrastructure necessary to meet the growing demand for natural gas in the US. The project, named Windy Hill, includes the construction and operation of an underground natural gas storage facility in north-eastern Colorado near the town of Brush in Morgan County. Windy Hill will include four salt storage caverns with a total working natural gas capacity of 6bn cf. Construction of the first two storage caverns is anticipated to start as early as 2006. The company anticipates providing service from the first two storage caverns beginning in 2008, and the third and fourth storage caverns in 2010.*

***The US's O2Diesel Corporation is to*** *work with Spain's Abengoa Bioenergy to sell O2Diesel's ethanol diesel fuel blend in Belgium, France, Germany, Netherlands, Portugal, and Spain, writes* Keith Nuthall. *Abengoa will buy more than 10% of O2 stock at a cost of some 3mn.*

## MIDDLE EAST

***In a bid to dilute the economic impact*** *of the hike in regulated gas prices, the Bulgarian Energy Ministry has proposed to allow state-owned gas supplier Bulgargaz to retain in full the BGN Lev 45mn ($27.8mn) in revenues it is expected to be paid in 2006 by Russia's Gazexport for the transit of gas to Turkey, Greece and Macedonia. At present, the company is allowed to pocket only 30% of the transit fees,*

# Drax concludes sulphur trade first

**Drax Power reports that it has successfully concluded what is believed to be the UK's first sulphur trade based on trading standards developed by Drax Power. 'The trade represents an important step in discovering the value of flue gas desulphurisation (FGD) technology at power stations,' states the company.**

**The regulatory framework for tradeable sulphur dioxide ($SO_2$) allowances from England and Wales' coal and oil-fired power generators came into effect on 1 October 2005. The scheme has evolved from a permit-based regime and paves the way for cost effective and efficient approaches to emissions abatement.**

**Drax Power has long been an advocate of a market that values environmental performance. It views this latest development as 'an important step in delivering against the country's environmental objectives whilst maintaining the benefits of security of supply and affordability so crucially delivered by coal-fired power stations'.**

**Drax Power also reports that it has signed a contract with EDF Trading for the supply of 300 MW of power, the delivery of 2.1mn tonnes of coal and 1mn tonnes of carbon dioxide over the next two years, starting April 2006. The Drax power station is claimed to be the largest, cleanest and most efficient coal-fired power station in the UK. The output capacity from the station's six generators is 4,000 MW. At current output levels, Drax supplies some 7% of the UK's electricity needs.**

**The company has also recently signed a contract with Sempra Energy Europe for the supply of 150 MW of power and delivery of 1mn tonnes of coal over the next two years, also commencing in April 2006. This is the second contract to be signed with Sempra this year and brings the contracted supply to a total of approximately 300 MW, including coal and an allocation of carbon.**

# *New, single pan-European spot carbon exchange launched*

A new, single pan-European spot carbon exchange for the trading of carbon emissions certificates within the EU's Emissions Trading Scheme (EU ETS) was launched in November 2005. The Climex Alliance is currently comprised of six European regional partners, including New Values (a Dutch-based European emissions exchange), SENDECO2 (the Spanish carbon dioxide ($CO_2$) exchange), STX Services (based in the Netherlands), Vertis Environmental Finance (Hungary), and UKPX (UK) and APX (the Netherlands) – both part of the APX Group that will act as the clearing counterparties.

The Climex Alliance brings together a number of the important European trading centres for carbon, including the UK, the Netherlands, Spain and southern Europe, Germany, the Czech Republic, Hungary, Poland, Slovakia and Slovenia, which – once all of the registries are open – will provide even greater carbon trading opportunities. Each partner focuses on a particular region, leveraging their expertise and customer base to deliver a bespoke spot carbon solution suitable for that particular market. The Climex platform will be in local languages where appropriate and each member of the Climex Alliance will provide access to the fully fungible spot carbon contract on the Climex platform – creating a single pan-European pool of liquidity.

Axel Posthumus, CEO of New Values – which developed the Climex platform – said: 'We believe that the Climex platform bridges the gap that may exist between the professional traders, such as the large energy producers, and the smaller players that may be new to trading, such as the energy intensive users, who fall into the industry categories within the National Allocation Plans for the EU. Both segments may trade on our platform and therefore, we have the potential to really unite European carbon liquidity and provide excellent trading opportunities from member companies in the Czech Republic right through to the UK and down to Spain.'

The nature of the contract also lends itself to being traded by companies who are more risk averse, explains Jeremy Hall, Director UK, APX Group: 'Because it is an exchange traded and cleared spot carbon contract, this means that the carbon allocation certificates are "delivered" within a short time period to the buyer and that cash settlement is cleared within the same time period for the seller. APX and UKPX act as the central counterparties, which means that in the UK, the contracts are cleared under UK law. We believe this will be an important benefit to both our members as well as the energy intensive users, and will greatly reduce the risk for the trading counterparties.'

*reports* Stella Zenkovich. *Meanwhile, Bulgarian domestic fuel prices have risen 35% in 2005. Heeding calls from the government, Russia's Lukoil – which controls 8% of the Bulgarian fuel retail market – has already slashed prices twice by 5%. It has also been asked by Energy Minister Rumen Ovcharov to help further by holding back prices at its Bourgas-based refinery.*

### ASIA PACIFIC

***Amec has been awarded a multi-million*** *dollar contract by PetroChina for consultancy services on the $3.5bn Dushanzi petrochemical expansion project in western China. The contract is reportedly the first ever awarded by PetroChina to a foreign project management company. Under the contract, which is scheduled for completion in 2008, Amec will provide project management, process engineering, planning, cost management, safety, health and environmental, quality assurance and other related services, together with its proprietary project management software, Convero, for the revamp of an existing refinery and development of a new petrochemical facility, including a 1.2mn t/y ethylene cracker.*

***BP and Hindustan Petroleum*** *Corporation Limited (HPCL) have signed a letter of intent to form a 50:50 strategic joint venture covering the refining and marketing sector in India. One of the joint venture's first major projects will be the construction of a $3bn refinery, with an annual capacity of at least 9mn tonnes (180,000 b/d), at Bhatinda, in Punjab, India. At the same time, the partners will begin to develop a joint marketing activity, including the establishment of a retail service station network, in preparation for the refinery coming onstream in 2009.*

### AFRICA

***Foster Wheeler has been awarded an*** *engineering, procurement and construction management contract by Sasol Technology (Sastech) for a new research and development (R&D) facility associated with Sasol's Fischer-Tropsch process. Foster Wheeler will design and manage the construction of the new plant, which will be integrated into Sasol's extensive R&D facility at Sasolburg, South Africa. The FTDR project is scheduled for completion by the end of 2006.*

# Meeting GHG emissions targets

Natsource – a leading global provider of asset management services, transaction services and advisory and research services in emissions and renewable energy markets – has announced that its wholly owned subsidiary Natsource Asset Management Corporation (NAMC) has closed the Greenhouse Gas Credit Aggregation Pool (GG-CAP), with total commitments of $550mn from 26 participants. The GG-CAP is reported to be the first private-sector initiative to provide a cost-effective means for companies to meet requirements to reduce their greenhouse gas emissions under the European Union Emissions Trading Scheme (EU ETS) and the Kyoto Protocol.

The 26 participants in the programme are among the largest consumer product, manufacturing, energy and utility companies in Europe, Japan, and North America, and have a combined market capitalisation of more than $300bn. Participants include Chugoku Electric Power, Cosmo Oil, Electricity Supply Board (Ireland), Endesa, E.ON UK, Hokuriku Electric Power, Iberdrola, Norsk Hydro, Repsol YPF and Tokyo Gas.

The GG-CAP is a 'buyers pool' that will combine the purchasing power of the 26 participants to acquire and manage the delivery of a large volume of compliance instruments created by the project-based mechanisms included in the Kyoto Protocol. These instruments – formally known as Certified Emission Reductions (CERs), created by Clean Development Mechanism (CDM) projects; and Emission Reduction Units (ERUs), created by Joint Implementation (JI) projects – can be used by participants to comply with emission reduction requirements from 2005–2012 imposed by the European Union Emissions Trading Scheme and by nations such as Canada and Japan seeking to comply with their obligations under the Kyoto Protocol from 2008–2012. According to Natsource estimates, these countries will be approximately 3.75bn tonnes short of their Kyoto Protocol emissions-reduction obligations from 2008–2012, based on current emissions trends.

NAMC will identify, evaluate, purchase, and manage delivery of reductions that buyers can use for compliance. Through the GG-CAP, companies will benefit from pooling large-scale demand to secure cost-effective compliance. They will also gain from GG-CAP's ability to use active risk management techniques to guard against under-delivery of contracted volumes. These techniques include diversification, reserve margins, risk management contracts and insurance products. They will facilitate the development of a highly-valued portfolio of compliance instruments that participants can use as a component of their overall compliance strategies. Importantly, the use of these instruments for compliance is supplemental to the participants' domestic efforts to reduce their emissions.

# New Central European gas hub

On 1 October 2005, Central European Gas Hub (CEGH), a wholly-owned subsidiary of OMV Gas, launched a new, customer-friendly hub concept for the European gas market. According to Werner Auli, Managing Director of OMV Gas: 'This new concept will enable traders to conduct short-term transactions based on standard agreements, which will simplify access to gas trading. It will now be sufficient to register only once during trading, rather than drawing up agreements for every transaction.'

The CEGH concept includes a one-time framework agreement with CEGH for title tracking (logging of transactions) and wheeling (transferring the gas between individual pipeline systems), guaranteed processing of new or expanded transactions with five days lead time. Agreements and prices are published on the Internet.

# *New UK targets for renewable fuels*

**UK Secretary of State for Transport, Alistair Darling, has announced that the UK government is calling for 5% of all UK fuel sold on UK forecourts to come from a renewable source by 2010 under a new Renewable Transport Fuels Obligation (RTFO). According to Darling, the RTFO will save around 1mn tonnes of carbon dioxide emissions in 2010 – the equivalent of taking 1mn cars off the road. The UK government currently supports biofuels through a 20 p/l duty incentive, which has stimulated sales of around 10mn litres a month – about 0.25% of all road fuel sales.**

**The RTFO will work through a system of certification. Oil companies will receive certificates from an administrator to demonstrate how much biofuel it has sold. If the company sells more than its 5% obligation, it would then be able to sell those certificates to other companies who need more to meet the obligation.**

# Expanding frontier opportunities

*In a global environment of rising oil and energy prices, the Australian petroleum industry is experiencing an increase in activity. New developments have come onstream in 2005, new companies (including several national oil companies) have invested in Australian projects and the footprint of exploration acreage has expanded, writes* Dr Marita Bradshaw *of Geoscience Australia.*

There will soon be two LNG production hubs in Australia. The original facilities on the Burrup Peninsula, inboard of the Carnarvon basin in Western Australia, will be joined in 2006 by a new LNG processing plant now under construction at Wickham Point in Darwin Harbour, Northern Territory. The Wickham Point LNG plant will be a 3.52mn t/y facility processing gas from the ConocoPhillips-operated Bayu-Undan field in the Timor Sea, in the Joint Petroleum Development Area (JPDA) shared by Australia and Timor Leste.

Recent discoveries in the Timor Sea's Bonaparte basin are the Katandra oil discovery in the Vulcan sub-basin by OMV in January 2005 and the Caldita gas discovery made by ConocoPhillips, further to the east in the Calder graben, in September 2005. New entrants to the Australian E&P scene have also been drawn to the Timor Sea. Avery Resources, a junior Canadian company, participated in the drilling of Katandra. Meanwhile,


**Map of Australia showing producing hydrocarbon fields, pipelines and potential producers**

UK-based Paladin Resources has bought into the Laminaria and Corallina oil fields; and Sinopec, the Chinese oil and gas giant, has also taken up acreage in the Timor Sea, participating with Eni in the drilling of the Vesta-1 exploration well.

There are major gas and condensate resources – 26tn cf and 540mn barrels, respectively, according to Geoscience Australia's *Oil and Gas Resources of Australia 2003* – in the Browse basin and a possible third hub for gas processing may eventually be established here, midway between the already producing Carnarvon and Bonaparte basins. Woodside is undertaking appraisal drilling on the Brecknock field and Inpex Browse is considering various options for the development of its giant Ichthys gas/condensate field, looking not only towards LNG, but also new technologies associated with gas-to-liquids (GTL) and dimethyl ether (DME) production. Small Australian explorers are also active in the Browse basin area – Karoon Gas is planning to acquire a 3D seismic survey in exploration permits to the east of the Scott Reef, while Nexus Energy has purchased the Crux gas/condensate field.

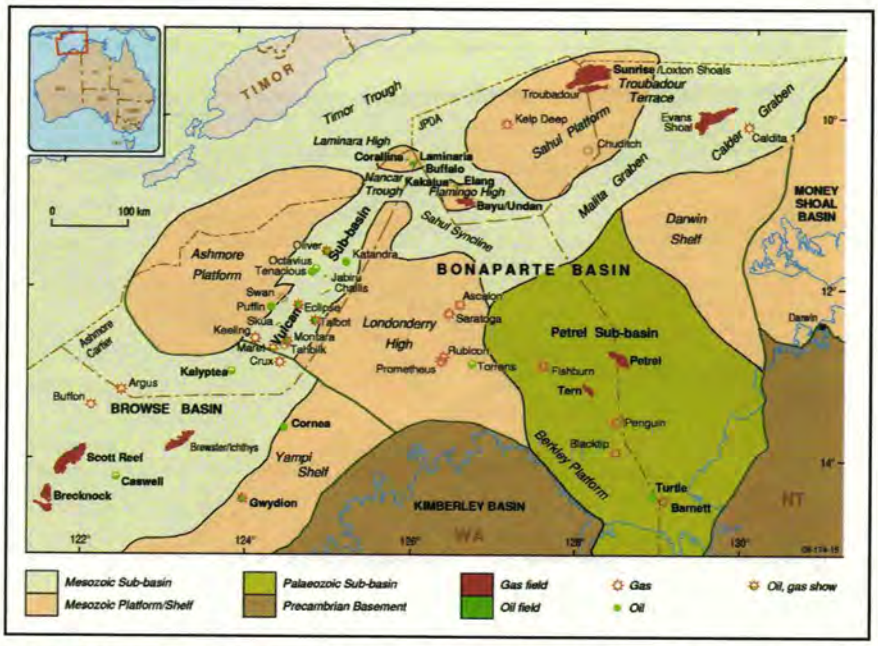
Despite the accelerating pace of activity to the north, the Carnarvon basin remains the premier hydrocarbon producing basin in Australia. Developments that have come onstream in the past 12 months include the fourth LNG train on the Burrup Peninsula for the North West Shelf Venture, the Apache Energy/Santos John Brookes gas field and the Santos group's Mutineer/Exeter oil fields. The Enfield oil development in the Exmouth sub-basin is under construction, with first production expected in late 2006.

Other projects committed or under active consideration include:

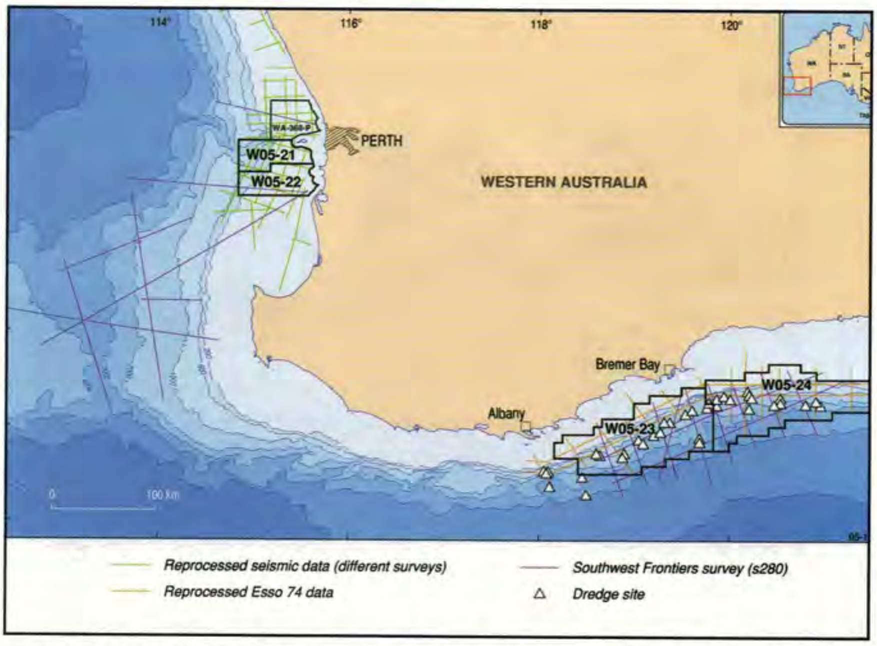
- The fifth LNG train for the NWS Venture.
- Chevron group's Greater Gorgon project (see p41).
- BHP Billiton's Pilbara LNG project, which plans to pipe Scarborough gas ashore from the Exmouth Plateau.
- Woodside's Pluto LNG development. The giant Pluto gas field was discovered in March 2005 and has been granted major project facilitation status by the federal government.

In this environment of bringing more gas to development, Chevron and Shell have been awarded a large tract of deepwater frontier exploration acreage on the Exmouth Plateau to continue the search for more hydrocarbon resources. In the Barrow sub-basin there have been a number of small oil discoveries – Apache Energy's Albert-1, Remus-1, Mohave-1 and Artreus-1; and OMV's Lauda-1. Vermilion Energy of Canada has purchased an interest in the Wandoo oil field and ONGC of India has farmed into Carnarvon basin acreage.

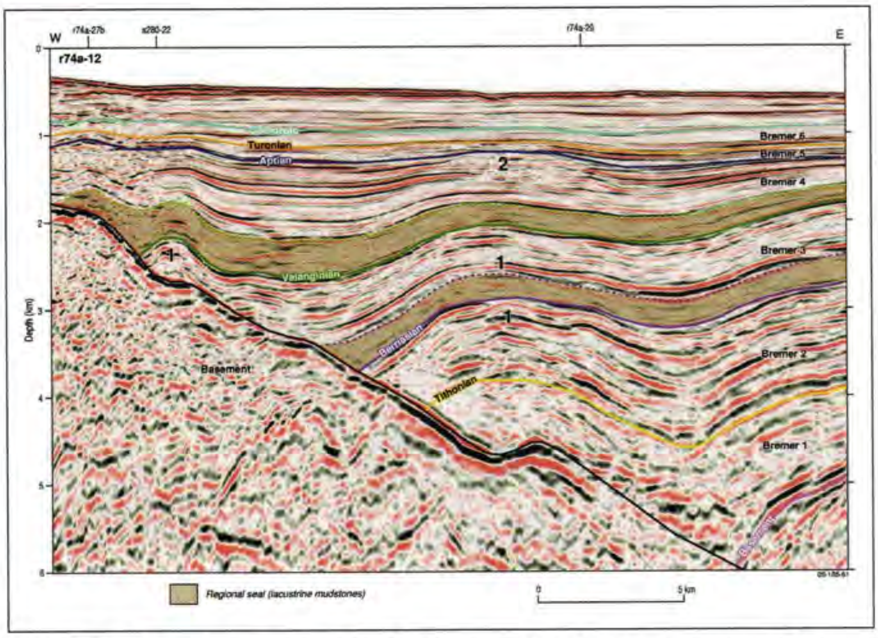
Further south along the western margin, there have been important developments in the Perth basin, where small- to medium-sized Australian companies are leading the way. First production from the offshore part of the basin is expected in early 2006, from the Cliff Head oil field discovered at year-end 2001 by Roc Oil. South of Cliff Head, new acreage has been recently awarded to Nexus Energy and partners in the offshore Vlaming sub-basin, an area that has seen no active exploration since the early 1990s. The renaissance in the offshore has been more than matched in the onshore Perth basin, where Arc Energy and Origin Energy have brought a number of recent oil and gas discoveries in to production.



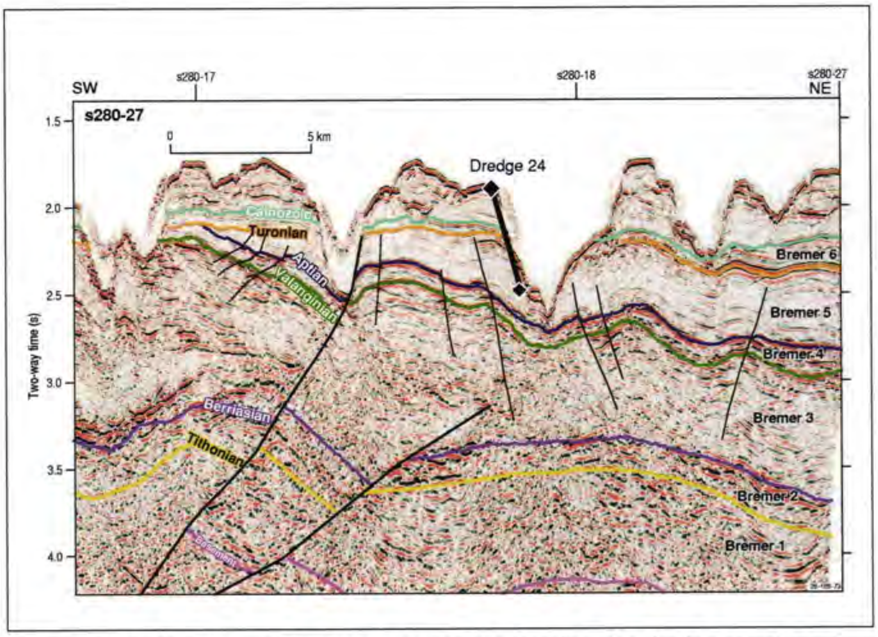

**Map of Bonaparte and Browse basins showing hydrocarbon fields, discoveries and geological features**




**Map showing location of dredge samples, new seismic acquisition and re-processed seismic in south-western Australia. Bidding for acreage release areas W05-21 to 24 closes on 20 April 2006**




**Seismic line through an anticlinal lead in the Jurassic-Cretaceous sequence of the Bremer sub-basin**




**Seismic line in the Bremer sub-basin showing the location of a dredge sample and the potential to link age-dated samples to seismic packages in this un-drilled frontier province**

In south-eastern Australia, BHP Billiton's Minerva gas field in the Otway basin came onstream in January 2005, with a pipeline linking the offshore field into the domestic gas grid. Other developments close to completion include Origin Energy's Yolla gas field in the Bass basin and Anzon Australia's Basker/Manta oil project in the offshore Gippsland basin. Nexus Energy, with partners KNOC and Seoul City Gas, has taken an acreage position in the Gippsland basin. Santos' Henry-1 gas discovery in the offshore Otway basin has been the largest discovery in the south-east this year.

## New government initiatives

Over the past five years, the Australian government has implemented a number of policies designed to encourage investment in oil and gas exploration. These include:

- 2001 – Access to offshore data, collected under the Petroleum Submerged Lands Act (PSLA), is available at cost of transfer, or free via the web.
- 2003 – Funding (A$61mn over four years) to Geoscience Australia for seismic data remastering and new data acquisition in the search for a new offshore oil province.
- 2004 – Tax incentives (150% uplift) for eligible exploration costs offset against petroleum resource rent tax (PRRT) in designated frontier areas.
- 2005 – Changes to PRRT to reduce compliance costs, improve administration and remove inconsistencies.

The positive influence these initiatives have had on encouraging exploration in Australia is being magnified by the current dramatic rise in oil price. This is particularly evident in the increased borrowings of seismic data from the Geoscience Australia archive, which is a lead indicator of company interest in exploration opportunities.

Public access to exploration and production data in Australia, including digital seismic tapes and core and cuttings samples from wells, results from legislation that initially subsidised exploration in return for lodgement and public availability of the data. When the subsidy was removed, the requirement that data be lodged with government and made available for future exploration continued, as enacted in the PSLA (1967), which applies to the Australian Marine Jurisdiction. In state waters and onshore, state legislation often mirrors these same data lodgement requirements. In 2001, this historical legacy was further enhanced with the Australian government's Spatial Information and Data Access Policy, so that company data are publicly available at the cost of transfer, after a relatively brief confidentiality period.

The 2003 Australian government's budget provided funds to preserve the seismic data archive by transcribing it onto high-density stable media. Apart from the benefits of saving any data previously stored on deteriorating magnetic tapes, the borrowing of data is now cheaper, quicker and easier. Indeed, in comparison to the same three-month period in 2004, there has been a three-fold increase in seismic data volumes borrowed by companies following the annual release of offshore acreage.

Apart from preserving and facilitating the access of explorers to seismic data, the funding has also has enabled Geoscience Australia to re-process selected seismic and collect new industry standard data in frontier basins. The initial focus of these endeavours has been in offshore south-western Australia; and already the impact can be seen in the take-up of exploration acreage and increased industry interest in the area.

*continued on p44...*

# An Australian first for Antrim

Alan Breadmore, *HSE Manager, and* Stewart McGregor, *Well Engineer, The Peak Group; and* Dwayne Warkentin, *Chief Operations Officer, Antrim Energy, report on the drilling of Antrim Energy's first Australian offshore well, which came in under budget.*

Calgary-based Antrim Energy is a fairly typical junior explorer, in that it has assembled a clutch of assets spread across the globe – in the UK, Tanzania, Argentina and Australia – with the aim of proving up at least one of these opportunities. Having an ambitious exploration programme but limited human resources, the Canadian company needed to conduct its Australian operations without establishing an Australian office. As a result, Antrim awarded the contract to plan and manage its first Australian offshore well to Peak Well Management (Asia-Pacific).

Conscious of the impact that Charles Darwin's South Galapagos Islands discoveries made on the world, Antrim Energy's first Australian offshore well was named South Galapagos-1. The Peak Group's optimisation software package P1™ was used throughout the planning phase for the well, with Peak's resident Australian staff continuing the optimisation process throughout the drilling phase.

South Galapagos-1 was drilled in 344 metres of water with a final TD (total depth) of 3,636 metres, at a location 278 km north-west of Broome, Western Australia. Designed to penetrate the early Cretaceous to mid-Jurassic formations below a four-way dip enclosed structure, the well took 32 days (planned duration was 34 days) to drill and abandon, from the Transocean semi-submersible *Sedco 703*. Given that the nearest offset data was from a 35-km distant well, the well site was considered 'wildcat' territory due to the different geological setting. Unfortunately, no hydrocarbons were discovered.

## Regional record

A gross measurement of well performance is 'metres drilled per day', from time of spud to time TD. This metric is used internationally by almost all major operators and is an accepted yardstick for measuring performance, relative to the peer group, of a drilling and/or completion operation. South Galapagos-1 was drilled in 157.7 metres/day.

For comparison, the most relevant offset wells to South Galapagos-1 in terms of drilling date and proximity are Trochus-1 (drilled in 1991, offset 35 km) and Sheherazade-1 (drilled in 1993, offset 69 km). Trochus-1 recorded 95.9 metres/day and Sheherazade-1 was benchmarked at 100.1 metres/day.

## Getting it right

In terms of logistics and materials supply, the remote location of the

*continued on p22...*

# Exploration moving to a more dynamic level

*Exploration drilling and seismic activity is at record levels in New Zealand, with four offshore oil and gas fields currently under development and large areas of prospective offshore exploration acreage being made available for investment.*

Lindsay Clark *reports.*

Significantly higher domestic gas prices, high oil prices and a strong demand for energy have underpinned the changes. Together with government investment into data acquisition to support block offers, the changed environment for exploration is attracting new explorers and investors to New Zealand.

The government agency responsible for petroleum – Crown Minerals, which was restructured two years ago – has put a new focus on making data freely and easily available to exploration companies, and to promoting more block offers outside of the current single producing basin of Taranaki.

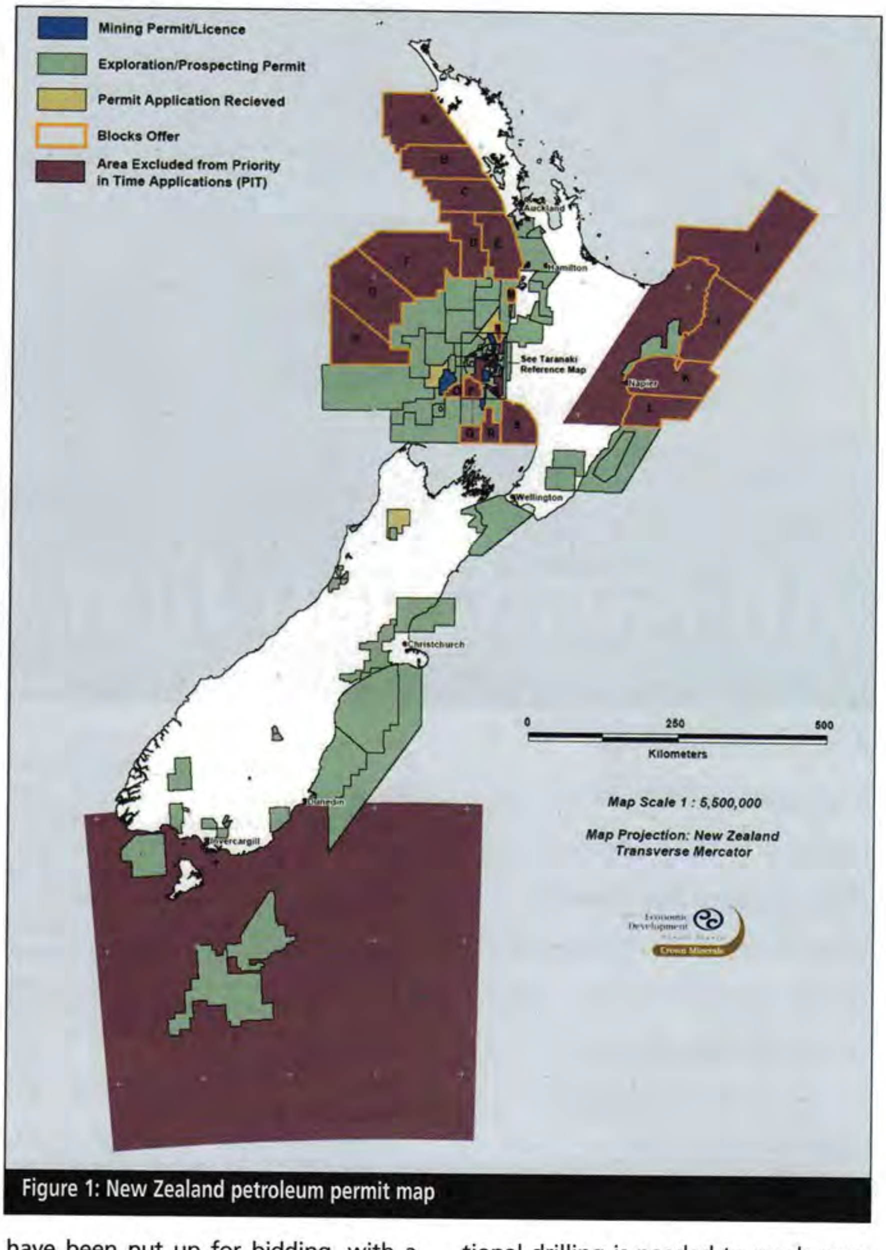



Figure 1: New Zealand petroleum permit map

To maximise the potential for new exploration investment, five offshore block offers over four different petroleum basins are currently being marketed (see **Figure 1**). Meanwhile, two block offers have just closed (on 2 December 2005) – on the undrilled offshore Outer Taranaki basin and on the offshore Northland basin, which runs north and south of New Zealand's largest city of Auckland.

Two more block offers will close on 17 February 2006 – under which four, lightly-explored blocks covering 43,000 sq km offshore the East Coast basin have been put up for bidding, with a further seven blocks on offer offshore Taranaki. In the East Coast, the government acquired almost 3,000 km of new 2D seismic data over the northern half of the basin, processed other seismic, and then made this freely available to explorers as part of the offer. Only three offshore wells have been drilled in the whole of the East Coast basin to date – all revealed an active petroleum system with plentiful hydrocarbons. Multiple potential reservoirs and trapping styles have been indicated, although additional drilling is needed to reach more detailed geological understanding.

A fifth block offer over the Great South basin – one of New Zealand's most prospective frontier basins – is also to be announced before the end of 2005.

## Field development

The first two oil-only fields offshore New Zealand – Tui and Maari – were about to be given the final investment go-ahead at the time of writing (see **Table 1**). Perhaps the most encouraging development is the Tui area fields, consisting of three adjacent oil fields – Tui, Amokura, and Pateke – to the northwest of the Maui field. The 20–30mn barrel project, scheduled to be in production by 2007, indicates an oil-bearing fairway in the large Western Platform area of the offshore Taranaki basin. Recent discoveries were made in the Kapuni sands, a geological formation that contains New Zealand's largest crude oil discovery, Maui B, which is now almost depleted. More wells are to be drilled near the Tui area in 2006 by the Houston-based operator Transworld Oil, which could be linked to the same FPSO (floating production, storage and offloading) vessel that will develop the Tui field.

The largest new oil field is Maari, to the south of the Maui field, which is based mainly on the relatively shallow Moki formation. Maari contains some 50mn barrels of oil reserves and is operated by Austrian company OMV, which has made substantial investments in New Zealand. The oil will also be accessed via an FPSO.

The largest and most significant new gas project currently under development in New Zealand is the Pohokura field, offshore Taranaki, near New Plymouth – the operational centre of New Zealand's oil industry. Due onstream by mid-2006, field reserves are put at 700bn cf of natural gas, with a further 43mn barrels of condensate. Pohokura partners are Shell, OMV, and local exploration company Todd Energy. Initial gas production is expected to be in the region of 50bn cf/y – about 25% of New Zealand's total annual gas production – with an additional 3mn b/y of condensate.

Construction of the onshore Pohokura production station was well underway at the end of 2005. Two of the three planned production wells drilled from onshore have reached over 6 km under one end of the fields. Six more production wells are to be drilled in 2006 by an offshore rig and linked to a single unmanned offshore platform.

A second offshore gas-condensate field – Kupe – to be operated by Australia's Origin Energy off the south Taranaki coast, is also being developed. The field contains reserves of about 300bn cf of natural gas and 16mn barrels of condensate, and has the possibility of more production from nearby prospects. Kupe is expected to begin flowing in 2008, with production of about 20bn cf/y of gas and 1.6mn b/y of condensate.

Once onstream, the four new offshore fields will more than triple New Zealand oil reserves by 2008 – reaching 130mn barrels, up from the current low figure of 40mn barrels (as at January 2005). Oil output, too, is expected to triple – to approximately 20mn b/y during the early phase of production. The country's self-sufficiency in oil, which slipped to 18% by early 2005, is forecast to rise to over 50% by 2008.

| Field | Reserves (estimate) | Peak output per year (est.) | Final investment decision | Date onstream |
|---|---|---|---|---|
| Pohokura (offshore) | Gas: 700bn cf<br>Condensate: 43mn barrels | Gas: 50bn cf<br>Oil: 3mn barrels | Approved July 2004 | June 2006 |
| Maari (offshore) | Oil: 50mn barrels | na | Due late 2005 | 2007 |
| Tui area (offshore) | Oil: 20–30mn barrels | na | Due late 2005 | 2007 |
| Kupe (offshore) | Gas: 300bn cf<br>Condensate: 15mn barrels<br>LPG: 627,000 tonnes | Gas: 20bn cf<br>Oil: 1.7mn barrels | Due early 2006 | 2008 |
| **Total new reserves** | **Gas: 1tn cf**<br>**Oil: 128–138 mn barrels** | | | |

Table 1: New oil and gas field developments

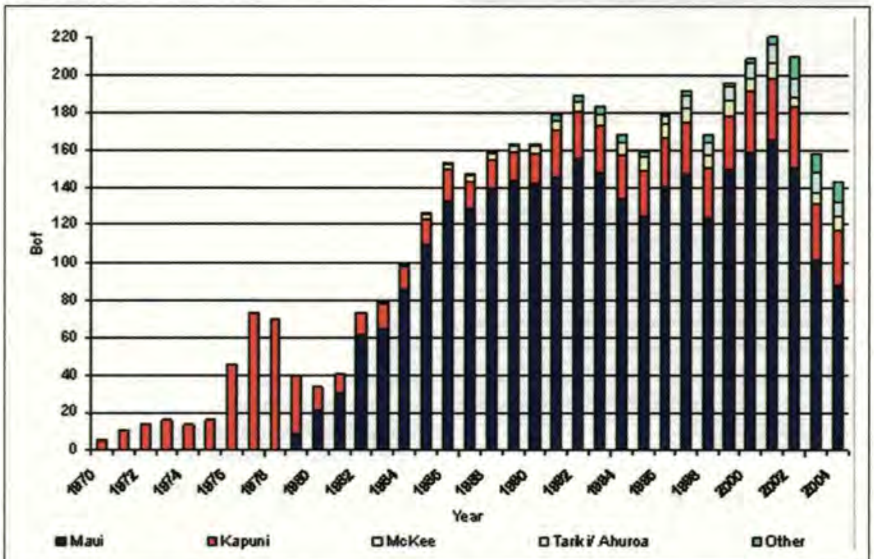



Figure 2: Annual (net) gas production 1970–2004

The new Pohokura and Kupe gas fields will together add around 1tn cf to New Zealand's natural gas reserves, more than doubling the current low remaining reserves figure of 870bn cf at the start of 2005. However, with the Maui gas field (which had original reserves of 3.4tn cf) about to run out of gas in the next few years, there is still a great need to find more gas to feed growing energy industry demands.

## Exploration activity

As a result, exploration activity was stepped up another gear in 2004 and, while continuing at a high level in 2005, is likely to increase to a higher level again in 2006.

In 2004, a record 33 wells were drilled – twice that of the previous year and including seven offshore holes. The length of 2D seismic acquired in 2004 more than doubled from 2003, to 5,466 km, while the amount of reprocessed 2D rose to 23,800 km in 2004, up from 10,800 km. Total exploration and development expenditure was NZ$279mn in 2004, a 76% rise from the $120mn spent in the previous year.

In 1H2005, some 2,881 sq km of offshore 3D seismic data was acquired – almost as much as the total previously acquired in the country. Over one-third of this 3D was shot by Texas new entrant Pogo Producing. A large programme of 2D and 3D seismic is planned for the 2005–2006 summer, following the drilling of close to 30 onshore wells by the end of 2005. Indeed, the demand for onshore rigs has been so great that many operators are reporting long delays in obtaining drill slots. No exploration wells were drilled offshore in 2005. In 2006, however, offshore drilling is likely to reach record levels, with over 12 wells being

Kapuni Group sands are targets for new Taranaki gas and oil prospects

drilled, including production wells for the Pohokura and Tui fields.

Furthermore, existing exploration work programmes and likely work programme commitments arising from current bidding rounds will result in drilling and seismic survey services in New Zealand being a hot commodity over the next year.

## Energy and gas demand growth

New Zealand is currently experiencing its longest and strongest period of sustained economic growth for 40 years, with an unemployment rate of 3.7% being the lowest among OECD countries. Although economic activity is now showing signs of slowing, the demand for energy continues unabated (see **Table 2**).

The demand for electricity has been growing at over 2%/y over a long-term average, with consumption in the industrial and residential sectors growing at twice that rate. Until recently much of the increased demand has been met by gas-fired power stations. However, with gas in short supply, power generation companies are increasingly turning to geothermal and wind power, and, to a lesser extent, coal. If new sources of gas were found they would have a ready market.

The decline in available gas from Maui (see **Figure 2**) has already forced two methanol plants operated by Methanex Corporation in Taranaki to suspend operations and wait for more gas to come to market.

The era of cheap plentiful Maui gas, which kept other companies from exploring for gas is now over and new sources of gas are now selling at over three times the price of gas sold on the original Maui contract of NZ$2/GJ.

This new pricing era now provides explorers with the incentive to reappraise previous discoveries and explore near field prospects.

Despite depletion of the Maui field, the operators are planning to drill near field exploration wells, to test areas of interest from previous work, and are analysing reprocessed seismic data. While it is not expected that any additional discovery of gas reserves will substantially change the life of Maui itself, any new gas would have an impact on any future New Zealand decision to meet gas demands by importing LNG.

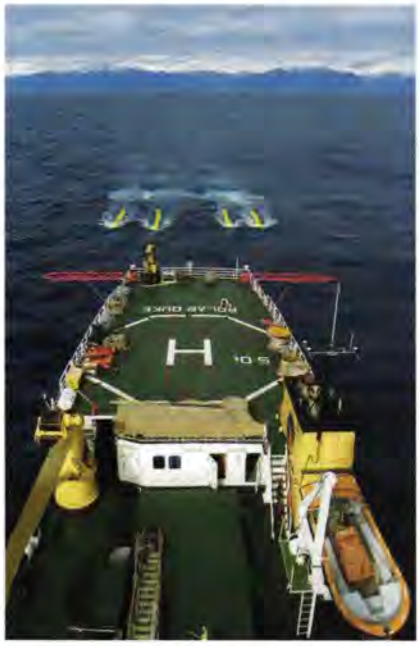
Understandably, the increased gas price is encouraging exploration companies to look for more gas. The deep (3,000+ metres) Kapuni sands – which have provided much of New Zealand's oil and gas resources – are being targetted, particularly in onshore or nearshore Taranaki. Downstream generator Mighty River Power has formed a partnership with the most active onshore Taranaki explorer, Swift Energy, to drill three deep gas wells. Two other downstream gas users, power companies Contact Energy and Genesis Energy, have also decided to invest in exploration.

The government has also provided incentives for gas exploration by way of a package of measures including a five-year reduction of royalties for new gas well targets, reducing tax obstacles for longer stays in New Zealand waters by offshore rigs and seismic boats, and acquiring seismic data supported by various geotechnical studies, and giving this data away free to industry to support block offers.

## Easy place to do business

New Zealand provides a positive economic environment where exploration and production companies can operate with confidence in a politically stable and advanced western economy. Within this environment, the government administers rights to explore and develop petroleum resources via a transparent process of allocation.

The World Bank *Doing Business in 2006* report ranked New Zealand as No 1 in the world as the 'easiest place in the world to do business' out of 155 countries surveyed. This placed it ahead of Singapore, the US, Canada and Norway. Of 10 business criteria used to compile the World Bank survey, New Zealand ranked No 1 in both protecting investors and in registering property. New Zealand was ranked second in dealing with licences.



Seismic work on New Zealand's many coastal basins paves the way for more offshore wells

Crown Minerals plans to continue this 'easy to do business' approach for exploration companies around the world, by making freely available online permitting and geotechnical data during 2006.

## Good future prospects

The sedimentary basins in the east and south of New Zealand's South Island are likely to offer some of the most attractive frontier petroleum prospects in the future. Substantial flows and shows of oil and gas have been detected and tested in both the Canterbury and Great South basins when both areas were drilled some 20 years ago.

The offshore Canterbury basin has attracted the most interest, with Australian companies Tap Oil and AWE now joined by fellow Australian companies Beach Petroleum and Claire Energy for exploration of a permit north of

*continued on p31...*

| Key indicators | 2004 | 2005 | 2006* |
|---|---|---|---|
| GDP growth | 3.6% | 4.2% | 2.25% |
| Interest (90-day bills) | 5.3% | 6.5% | 7.25% |
| Inflation | 3% | 2.8% | 4.0% |
| Unemployment | 4.3% | 3.9% | 3.7% |

*forecast

Table 2: A robust economy

*Source: Reserve Bank of NZ, September 2005*

| Country/Field | Operator | Oil or gas output | Start-up date | Oil res. (mn b) | Gas res. (bn cf) | Capex ($mn) | Production system |
|---|---|---|---|---|---|---|---|
| **AUSTRALIA** | | | | | | | |
| Angel | Woodside | gas/cond | 4Q2008 | | 1,800 | | NNM platform + 3 subsea |
| Bambra | Apache | gas/cond | 2004 | 0.7 | 30 | | wellhead plat via Harriet |
| Blacktip (Bonaparte Gulf) | Woodside | gas | 2007 | | 1,100 | | potential 2.53mn cm/d |
| Brecknock/Scott Reef | Woodside | gas/cond | 2010+ | 228 | 18,400 | | poss LNG development |
| Chrysaor/Dionysus* | Wapet | gas | 2010/2012 | 75 (cond) | 3,988 | 150 | *part of A$10 bn project |
| Cliff Head | Roc Oil | oil | 2005 | 20–30 | | | |
| Crosby (Exmouth) | BHP Billiton | oil | 2006 | 112ft column | | | |
| Dixon/Castor | Woodside | gas/cond | 2005/2010 | | | | FPSO, gas to Echo-Yodel |
| Dockrell/Keast | Woodside | gas/cond/oil | 2005/2010 | | | | to Echo-Yodel or Goodwyn |
| East Pilchard | Esso Australia/BHP | gas | 2005+ | | | | |
| Echo/Yodel | Woodside | gas/cond | mid-2002 | 37 (cond) | 400 | 200 | 2 subsea via Goodwyn A |
| Enfield (WA-271-P) | Woodside | oil/gas | 4Q2006 | 125–146 | | 1,480 | FPSO (900,000 barrels) |
| Evans Shoal | Shell Australia | gas | 2005/2009 | | 10,500 | | poss supply to Darwin LNG, 7.5mn t/y? |
| Geryon* | Chevron | gas | | 103 (cond) | 3,320 | | |
| Gypsy/Rose/Lee | Apache | oil/gas | 2002, 2005, 2003 | 7 | 150 | | wellhead platform to Varanus Island |
| Golden Beach | Santos | gas | 2005+ | | 50 | | |
| Gorgon* | Chevron | gas | 2010 | 316 (cond) | 18,379 | | 10mn t/y LNG, Barrow Island |
| Iago* | Chevron | | | 89 (cond) | 977 | | |
| John Brookes | Apache | gas/cond | Sep-2005 | | 450 | 300 | wellhead platform to Varanus Island |
| Kipper (Gippsl'nd basin) | ExxonMobil | oil/gas | 2009 | 30 (cond/LPG) | 620 | 263 | subsea development |
| Laminaria Ph2 | Woodside | oil | 2002 | 21 | | 130 | 2 horizontal wells, 65,000 b/d peak |
| Laverda | Woodside | oil | 2006 | 56.3 | | | via Enfield facilities |
| Loxton Shoals/Sunrise/Troubador | Woodside | gas | 2005/2009 | | 5,000 | | Darwin LNG, 7.5mn t/y? |
| Macedon/Pyrennes | BHP Billiton | gas | under eval | | | | |
| Manta/Basker/Gummy | Woodside | oil/gas | 2003/2006 | 26 | 260 | | FPSO and subsea |
| Minerva/La Bella (Otway) | BHP Billiton | gas | Jan-2005 | 1 | 301 | | subsea or monotower |
| Monet (nr Varanus Island) | Apache | oil | 2004 | | | | |
| Mutineer-Exeter (Cnvrn basin) | Santos | oil/gas | Mar-2005 | 100 | | 283 | Modec FPSO |
| Nappamerri trough | Santos | gas | end-2003 | | | | |
| Nasutus | Apache | oil | under eval | | | | |
| Orthrus/Maenah* | Chevron | gas | | 31 (cond) | 1,199 | | |
| Patricia Baleen (Bass Straits) | Santos | gas | 2004? | | 70 | 52 | subsea |
| Perseus/Athena | Woodside | gas/cond | 1999 on | | 7,600 | | North Rankin and subsea |
| Petrel/Tern | Santos | gas | under eval | | 2,700 | | |
| Ramillies | BHP Billiton | oil | 2002+ | 2 | | | |
| Rankin-Sculptor | Woodside | gas/cond | 2005–2010 | | | | subsea to Echo-Yodel |
| Ravensworth (Exmouth basin) | BHP Billiton | oil/gas | 2006 | 121ft column | 26ft column | | |
| Reindeer | Apache | gas | under eval | | 350 | | |
| Scarborough (Exmouth basin) | ExxonMobil | gas | 2010+ | | 8,000 | $4.7bn? | supply Pilbarra LNG |
| Searipple | Woodside | gas/cond | 2005+ | | 50 | | with Perseus via N Rankin |
| Sole (off Victoria) | Santos | gas | 2005 | | 277 | | 2 subsea production wells |
| Spar* | Chevron/Ampol/Shell | gas | 2012 | 11 (cond) | 350 | | |
| Stickle | | oil | 2006 | | | | |
| Sybarrow (Exmouth basin) | Woodside | oil | 2007 | 90 | | | |
| Tenacious | OMV | oil | under eval | 5 | | 42 | tie-back to Jabiru |
| Tern/Petrel B'nap'te Glf | Santos | gas | 2008+ | | 3,000 | | platform or FPS |
| Tidepole | Woodside | cond/gas | 2013 | 14 cond | 420 | | |
| Thylacine – Otway Gas Project | Woodside | gas | mid-2006 | | 436 | 170 | wellhead plat + 5 subsea |
| Geographe — Otway Gas Prjt | Woodside | gas | mid-2006 | | 364 | 170 | 3 subsea manifold |
| Urania* | Chevron | gas | | 8 (cond) | 266 | | |
| Vincent (WA-271-P) | Woodside | oil | 2006+ | 117.4 | | | via Enfield facilities |
| West Tyral Rocks* | Wapet | gas | 2010 | 98 (cond) | 3,513 | | |
| White Ibis (Bass gas project) | Origin Energy (ex Boral) | gas | 2005 | | | | |
| Wilcox | Woodside | gas/cond | 2010 | | 300 | | to Goodwyn or Echo-Yodel |
| Yolla (Bass gas project) | Origin Energy (ex Boral) | oil/gas/cond | 2005 | 45 cond | 300 | 240 | platform 49mn cf/d, 5,000 b/d |
| Woolybutt | Eni | oil | Mar-2003 | 25 | | 70 | 2 subsea to FPSO |
| **KEY DISCOVERIES** | | | | | | | |
| Lynx/Vega | Woodside | gas | | | | | |
| Casino Otway basin | Santos | gas | | | 300 | | |
| Jacaranda Otway basin | Boral Energy | oil | | | | | |
| Tregony (PEP 153) | Santos | gas | | | | | potential 10–15 mn cf/d |
| Io/Jansz* | ExxonMobil | gas | | 120 (cond) | 20,000 | | joint development Gorgon |
| Titanichthys | Inspex Browse | gas/cond | | 700mn boe | | | |
| Gorgonichthys | Inspex Browse | gas/cond | | 2,339mn boe | | | |
| Brecknock South | Woodside | gas/cond | | 88 | 3,900 | | |
| Wheatstone-1 | Chevron | gas | | | test 54mn cf/d | | |
| Pluto | Woodside | gas | LNG in 2010 | | | | |
| Katandra (Bonaparte basin) | OMV | oil | | | | | |
| Caldita (Bonaparte basin) | ConocoPhillips | gas | | | | | |
| **TIMOR GAP-ZOCA** | | | | | | | |
| Greater Sunrise** | Shell | cond/gas | 2006/2007? | 300 | 9,160 | | with Bayu Undan/float LNG |
| Laminaria East | BHP Billiton | oil | | | | | close to Buffalo field |
| Bayu/Undan | Phillips | cond/gas | Feb-2004 | 404 | | 1,696 | 3 platforms, Ph1 liquids |
| Bayu/Undan | Phillips | gas/LNG | 2H2006 | | 3,400 | | Ph2 LNG |
| Jahal | BHP Billiton | oil | | | | | |
| **NEW ZEALAND** | | | | | | | |
| Kahili | Indo-Pacific | oil/gas | mid-2004 | | | | |
| Kauhauroa | Westech | gas | uncommercial at present | | 170 | | |
| Kauri | Swift Energy | oil/gas/cond | 2004 | | | | |
| Kupe | Origin Energy (ex Boral) | gas/oil | 2008 | 15 (cond) | 300 | 250 | platform |
| Maari | OMV New Zealand | oil | 2007 | 50 | | 170–300 | FPSO + subsea |
| Pohokura | Shell | gas/cond | Jun-2006 | 43 (cond) | 700 | 170–300 | 6 s'sea wells to NNM plat +3 ext'd rch |
| Rimu | Swift Energy | oil/cond | 1Q2002 | 27 (boe) | | | |
| Tui, Amokura, Pateke area | Transworld Oil | oil | 2007 | 20–30 | | | FPSO + subsea |

*Greater Gorgon comprises 850mn barrels of condensates and 52tn cf of gas in 10 accumulations
**Greater Sunrise comprises Sunrise, Sunset and Troubadour

Table 1: Planned field developments in Australasia


# New ships for old

*Steadily rising oil prices may well be behind the high level of earnings that tanker operators have enjoyed this year, but they have also pushed up costs.*

After the hectic period of business that was enjoyed by tanker operators in 4Q2004, this year has been something of a comedown. That should not be construed as suggesting that tanker operators have had a hard time of it during 2005 – freight rates are still good by historic standards, even if they are broadly lower than last year. However, a longer than normal summer lull, occasional disruptions to trade and, worst of all, record high bunker fuel prices have made 2005 feel a little dispiriting.

Moreover, while there is clearly optimism that the enforced phase-out of older, single-hull tankers from the world fleet over the next few years will provide a further boost to the freight market by squeezing the supply side, owners are facing rising prices for replacement tonnage as the yards respond to high steel prices and a lack of newbuilding slots by hiking their quotes. Partly as a result of this, the pace of scrapping has slowed.

Operators' hopes of an upturn in fortunes in the fourth quarter along the lines of that experienced in 2004 were, in fact, answered a month early when Hurricane Katrina hit the US Gulf of Mexico, knocking out a sizeable portion of crude oil production and causing several refineries to be closed. As a result – and despite signs that US consumers were responding to calls for restraint in energy use – there was an extra demand placed on the world tanker fleet for additional imports both of crude oil and refined products into the US.

## Market reaction

In October this year, the International Energy Agency (IEA) revised downwards its forecast in oil demand growth for 2005 to just 1.4%, citing the dampening effects of rising oil prices. However, product demand is increasingly dislocated from oil production and the impact on trade is much greater. IEA figures for the mid-point of 2005 show imports into OECD countries running 6% higher than at the same time a year earlier – crude oil imports were 4% up, at 24.96mn b/d, and product imports were up 11%, at 8.39mn b/d. These figures also hide the effect of growing levels of oil demand in non-OECD countries, most notably China and India.

Moreover, the impact on tonne-mile demand for tanker capacity has clearly been higher still. The most rapid increases in demand have been recorded in North America, generating substantial additional demand for long-haul tanker shipments, both of crude oil and of refined products.

As a result of this, the markets have been able to accommodate the new tonnage arriving this year in the global tanker fleet without threatening to weaken freight rates. For example, spot rates for very large crude carriers (VLCCs) – tankers of 200,000 dwt or more – fell dramatically in January 2005 from the extraordinary highs of the last quarter 2004, but only to levels in line with those recorded a year earlier, remaining around that level through the rest of the first quarter. Thereafter, rates for Middle East stems heading east were below year earlier levels, although westbound rates were firmer on the back of rising US demand.

Occasional periods of weakness were experienced, certainly around June and again in early August, as Iraqi exports were cut and US refineries underwent extended maintenance. During these periods, double-hull VLCCs were competing with single-hull ships on eastbound trades.

Freight rates for Suezmax (120,000 dwt to 200,000 dwt) tankers experienced a slow and steady decline from the end of 2004 until September of this year. Spot rates for West Africa to US Gulf movements declined from

Worldscale* (WS) 350 around the turn of the year to a low of WS 130 by the end of August. However, they had more than doubled by the first week of October as charterers picked up additional cargoes to replace US output shut in after Hurricane Katrina.

The Aframax (80,000 dwt to 120,000 dwt) sector began 2005 on a similar trend, but the market was buoyed in April and May, partly as a result of increased demand for lightering services in the US Gulf with the arrival of a large number of VLCCs from the Middle East, and partly due to congestion in the eastern Mediterranean after a collision in the Dardanelles and a grounding in the Bosporus that reduced available tonnage. In addition, there was a surge in exports from Russia in May to avoid an increase in crude oil export duty introduced on 1 June.

Rates for Panamax (60,000 dwt to 80,000 dwt) tankers followed a similar pattern to those in the Aframax sector. The Atlantic market in particular was supported by several factors – rising imports of crude oil and residual fuel oil into the US, partly to offset adjustments to refinery runs in favour of lighter products; and the move of single-hull vessels into the Asian market.

Any improvements in income have, however, been largely eaten up by rising bunker costs, which have tracked crude oil prices on a largely upward trend – so much so, in fact, that by the end of October 2005 prices for all grades of fuel were roughly twice what they had been 18 months earlier. Indeed, some analysts have calculated that many shipowners are actually making less money than they were two years ago, despite the higher level of freight rates.

## Threats to capacity

Behind these market fundamentals lies the threat of a squeeze on tanker capacity resulting from amendments to international conventions agreed by the International Maritime Organisation (IMO) in December 2003. In particular, the changes to Annex I of the International Convention for the Prevention of Pollution by Ships (Marpol) 1973/78 came into effect in April this year, revising the existing Regulation 13G and introducing a new Regulation 13H for tankers carrying heavy grade oils as cargo.

Regulation 13G, which established a phase-out schedule for single-hull tankers in 1992 and was revised in 2001, now contains an accelerated deadline – as of 5 April this year, so-called 'pre-Marpol' tankers built before 5 April 1982 were to be taken out of service or converted to double-hull configuration. 'Marpol' tankers, which are fitted with protectively located segregated ballast tanks, can trade longer but, again, those built prior to 5 April 1977 were to be retired from 5 April this year. There is a rolling retirement schedule for vessels built after that date. A new category of ships comes into scope of Regulation 13G, which has so far been restricted to tankers of 20,000 dwt and more. It now applies to those as small as 5,000 dwt.

Flag states were given the option of permitting 'Marpol' ships to continue to trade after their scheduled retirement date, so long as inspections under the Condition Assessment Scheme (CAS) are satisfactory, and with an ultimate deadline in 2015.

Regulation 13H prohibits the carriage of heavy grade oil (certain crude oils and fuel oils, and bitumen, tar and their emulsions) in single-hull tankers of 5,000 dwt or more after 5 April this year and in single-hull oil tankers of between 600 dwt and 5,000 dwt after 2008. Again, flag state administrations have some leeway to permit the continued trading of such vessels, up to a limit of 25 years of age.

There were fears that the global capacity for shipbreaking would be insufficient to cope with the number of ships expected to be retired. However, more than six months after these new provisions came into effect, there has been no rush to scrap older ships. Fears of under-capacity across the tanker sector encouraged many flag states to issue permits for older ships to continue trading, with certain restrictions, and firm earnings have ensured that owners were willing to take advantage, despite very high scrap prices being offered by breakers in the Indian sub-continent.

According to shipbroker EA Gibson, the volume of tanker tonnage sold for scrap has declined sharply since mid-2004 – 18.9mm dwt was scrapped in 2002, 17.9mn dwt in 2003, 7.9mn dwt in 2004 and only 2.7mn dwt in the first three quarters of 2005. Then again, Gibson's analysis of the fleet age highlights the fact that there is very little VLCC and Suezmax tonnage over 20 years of age still trading – the oldest ships are predominantly in the smaller size ranges.

Gibson expects additions to the 'dirty' tanker fleet to total 19.8mn dwt this year, with 13.9mn dwt scheduled to be delivered in 2006. In addition, the 'clean' tanker delivery schedule points to 8.6mn dwt of new tankers arriving in the fleet this year and 9.6mn dwt next year.

The product and chemical tanker sectors are further threatened by changes to Annex II of Marpol that come into effect on 1 January 2007. The amend-

## New fleet record for ABS

ABS reports that it has broken through the 120mn gross tonne (gt) mark to establish a new all time fleet record. The classification society states that it has benefitted from the current active newbuilding market and a steady inflow of existing vessels changing class. With more than 1,400 vessels of almost 25mn gt currently on order to ABS class, the fleet is expected to grow further in the short term.

The recent strong interest in new mobile offshore drilling units (MODUs), which include jack-ups and semisubmersibles, has also boosted the ABS orderbook. The society has maintained its dominant position as the leading provider of classification services to the offshore sector, with 50 MODUs (43 jack-ups and seven semi-submersibles) currently on order to ABS class at yards in Singapore, China and the US, with several more contracts pending.

ABS passed its historic fleet record, originally set in 1981, during 2004. Since that time the ABS-classed fleet has established new highs every month until reaching the 120mn gt mark in late September.

Within the newbuilding sector, ABS has continued its traditional strength in classing tankers, with 166 vessels aggregating more than 9mn gt on order.

This includes particular strength in the Suezmax and Panamax sectors, with a 34% and 36% share respectively of these vessels on order to ABS class. It has also continued its recent successes in the containership sector, with 112 vessels approaching 5mn gt that will be built to ABS class for European and Asian owners.

Within the offshore sector, the strong MODU orderbook is supplemented by contracts for various production units, including the Agbami field's FPSO (floating, production, storage and offloading vessel). The $1bn project will deliver what is claimed will be the world's largest and most sophisticated FPSO.

Furthermore, ABS claims that it currently has one of the largest LNG orderbooks, with 35 LNG carriers currently on order to ABS class at yards in Korea, Japan and China. ●


ments have altered the requirements for the carriage of certain cargoes deemed to be hazardous and noxious in chemicals tankers and, in particular, will require vegetable oils to be carried in IMO II tanks. This change is likely to have a significant impact on the overall level of demand for IMO II tonnage, while at the same time freeing up some capacity in the IMO III chemical tanker and single-hull product tanker sectors.

At a recent conference on chemical and product tankers in London there was considerable discussion as to the exact impact these changes will have. Consultant Fred Doll expressed his belief that it would add between 3% and 4% to annual IMO II tonnage demand, numbers that are well within the range of annual variation due to product demand growth or shifts in demand location.

## Where to now?

Indeed, there is a considerable level of uncertainty about the short-term outlook for the tanker industry as a whole. Brokers' reports show that the past three northern hemisphere winters have produced sharp spikes in spot freight rates for most sizes of vessel – the 2004/2005 spike was particularly high – and, as this issue of *Petroleum Review* went to press, there was every sign that the 2005/2006 winter will see yet another spike.

Such a marked seasonal variation in spot earnings suggests that there is not a lot of slack in the system. Whatever the consultants might deduce from their analyses of tanker supply and demand, the market clearly believes that the position is tight. Although the fleet continues to grow, there is a lot of scrapping to come in the smaller size ranges and additional demand is constantly emerging.

A gambler (or a shipowner – there is little difference!) might say that this is a good time to get involved in the tanker business. However, as things stand, it could be a frustrating move to attempt. Secondhand values tend to track the spot market quite closely and this upturn has been no different – going the newbuilding route would be equally problematic, given yard congestion and rising prices.

Getting into the market would be an expensive business but, given the cost of fuel, so is staying there. Tanker owners are going to want to see some return on the efforts they are having to make to keep the world's oil market working. •

**Worldscale (WS) is a rating system that allows charterers and owners to compare rates on different routes. Every year the Worldscale Committee publishes a comprehensive list of what WS 100 is in $/t for every conceivable journey around the world. WS 45=45% of the WS 100 value.*


*...continued from p15*

South Galapagos-1 well resulted in supply boat trips of over 40 hours (one-way). This was further complicated by a supply line initially split between two ports. Helicopter one-way flight times of one hour and 40 minutes placed critical importance on accurate scheduling. The challenge was met with no NPT (non productive time) assigned to factors involving logistics and materials supply.

The Antrim permits are located within the northern migration boundaries of the Southern Humpback Whale, an endangered and protected species. With drilling occurring during the latter part of the calving season in the bays of the Kimberly coast, utmost commitment to stringent environmental protection practices had to be honoured.

The regulatory approval process was conducted using Peak's own SHE (safety, health and environmental) management system. This required the development and implementation of an Emergency Response Plan, Operator Safety Case Bridging Document, Oil Spill Contingency Plan, Environment Plan, and a project-specific SHE Management Plan. A pre-spud was conducted with all parties followed by a rig acceptance audit to help ensure a common understanding of Peak Well Management's expected standards. The goals of Antrim and Peak were aligned with the use of a performance-based contract.

To satisfy the client that Peak project personnel always factored in the SHE impacts of their decisions and activities, a component of the final project fee was subject to SHE performance criteria benchmarking.

## The result

The true final performance measure for a company's project management capabilities lies in the answer to: 'Was the client pleased with the outcome?' Keith Skipper, Executive Vice President, Antrim Energy said: 'I want to convey my congratulations for a job well done on Antrim's behalf... Peak has demonstrated on the South Galapagos operation that it can provide a fully integrated service for the drilling of offshore wells – all we did was pick the location, raise the money and pay the bills!... I'm sure there were instances when you were stretched but these are significant and meaningful projects to conduct and the end result, albeit disappointing from an exploration point of view, was truly satisfying.' •

*For futher information, please visit* **www.peak-group.com**

# LNG carrier fleet expansion


Photo: ConocoPhillips

*The huge planned increase in LNG consumption over the next decade will require a rapid expansion of the world's LNG carrier fleet, writes* David Hayes. *Major shipyards are already booking a growing number of carrier orders as more countries plan to increase LNG use as part of wider efforts to expand clean energy consumption.*

At the end of July 2005 the world's fleet of LNG carriers numbered 183 vessels of all sizes. Currently, 115 LNG carriers are under design or construction at shipyards worldwide. Most of these are due for delivery by the end of 2008. The global LNG carrier fleet size will expand rapidly as a result over the next three years and will reach almost 300 vessels by the end of 2008.

'The LNG carrier market depends on LNG projects. We can forecast the LNG carrier market size based on projects,' commented Duck Yull Lee, Executive Director of the Basic Design Division in the Basic Performance Research Institute, which is run by Daewoo Shipbuilding & Marine Engineering (DSME) in South Korea. 'The LNG carrier market will double by 2010 due to the growth in LNG demand. We expect that probably 36 LNG tankers will be ordered worldwide this year, of which one third will be very large, exceeding 200,000 cm in capacity. At present, we are building LNG carriers up to 211,000 cm, while the Samsung and Hyundai shipyards are building vessels a little bigger, up to 216,0000 cm models are ordered and under construction. They are building to the same vessel dimensions as us.'

Daewoo expects 40 to 50 LNG carriers to be ordered and delivered worldwide each year for the next four to five years. With very few LNG carriers due to retire, the size of the world's LNG carrier fleet is expected to almost double in number to about 350 vessels by 2010. At the same time, the fleet's LNG carrying capacity will more than double in volume due to the large size of the new generation of carriers now being built.

New ships due to be ordered by LNG producers, importers and bulk cargo shipping companies will all contribute to the growing number of LNG carriers that will ply international sea routes in the future. Qatar, for example, will become a major LNG carrier fleet operator, with plans calling for about 70 LNG carriers – worth about $15bn – to be ordered from South Korean shipbuilders by 2010 as part of plans to develop the QatarGas II project (see *Petroleum Review*, July 2005).

The unprecedented growth in the global LNG carrier fleet will be accompanied by technical innovation in LNG carrier design. The average size of LNG carriers is due to grow, while technical developments in ship propulsion and LNG cargo containment also are planned.

'This is the start of the very large LNG carrier newbuild era. Superflex LNG carriers for ConocoPhilips and Shell are 240,000 cm [in capacity],' Lee said. 'For Qatar, the ship capacity depends on the propulsion system for Q-Max vessels over 260,000 cm. For gas turbine engines it will be 269,000 cm and for conventional two-

# Propulsion guidance from ABS

The surge in LNG carrier newbuildings and the accompanying development of a new generation of these specialised ships has generated interest in alternative propulsion systems to the traditional gas-fired steam plant.

These alternatives are addressed in the new ABS *Guide for Propulsion Systems for LNG Carriers*, reportedly the first such comprehensive set of standards to have been issued by a classification society.

Currently, several types of propulsion configurations are being ordered, with others planned. At the heart of the differing propulsion systems debate is economics together with safety concerns over the manner in which boil off gas (BOG) is treated.

'There are over 40 ships that have been contracted with propulsion systems other than steam,' says Mumtaz Mahmood, Director, Technology & Business Development, ABS Europe and primary author of the new guide. 'This is a clear indication that gas-fired boilers with steam turbines are no longer the most favoured choice for the main propulsion plant on standard or large LNG ships.'

Mahmood notes that dual fuel diesel electric and direct drive, slow speed diesel plants, coupled with an onboard re-liquefaction plant to handle the cargo boil off, appear to offer operational efficiencies for these new designs.

'However, there is no single obvious propulsion system of choice,' he added. 'The choice depends on numerous factors such as gas price or trade route, among others.'

The new ABS Guide provides comprehensive criteria for the various propulsion systems currently on offer from shipyards – dual fuel gas turbine/steam turbine combined cycle with electrical propulsion, dual fuel diesel electrical propulsion and slow speed diesel direct drive, as well as conventional steam turbines.

In terms of BOG there are two ways it can be handled, explains Mahmood. One is to use it as fuel for propulsion or secondly to re-liquefy and return it back to the tanks. The second alternative requires an onboard re-liquefaction plant. The ABS Guide includes detailed criteria for the plant design, piping, electrical systems, construction materials, compressors, pumps and separators.

In addition, the document offers guidance with regard to the placement of propulsion systems in the overall vessel arrangement scheme, as well as refrigeration systems and redundancy systems required if there is an equipment failure.

Currently, ABS has 35 newbuilding LNG carriers on order. ●

stroke diesel engines it will be 261,000 cm to 262,000 cm. The propulsion system has not been decided yet by Qatar Gas.'

Various factors are taken into account by LNG carrier operators when deciding ship engine design and the vessel carrying capacity. Where purchase and operation costs for different propulsion systems are equal, some companies may give more value to low emission engines. In this case, gas turbine propulsion generally is preferred due to low emissions.

'We, as shipbuilders, estimate the ship price, not the ship operating cost,' Lee pointed out. 'We think the building costs will be similar, but a gas turbine engine is a little more expensive. Oil prices now are very high, at over $70/b. If this high price continues, then it may affect engine selection decisions and gas propulsion will be more beneficial.'

He continued: 'Propulsion is the main issue for ship buyers. Already, apart from the conventional system, there are some ships with 2-stroke diesel engines. Also, duel-fuel electrical propulsion is in use. Now we are studying gas turbine electric propulsion. Four propulsion systems will be enough.'

## Reaching the max

While LNG carrier sizes are growing, a point will come when the maximum optimum LNG carrier size is reached. Where this point lies is still a matter for debate.

'As shipbuilders, we are not limited in our ability to increase the ship's size, but by the port terminals to be served. Theoretically we can build very large gas carriers if we add more cargo tanks,' Lee commented. 'It is possible both technically and practically. It is just the cost of the extra tanks. Q-Max 270,000 cm vessels have five tanks. For 300,000 cm-plus carriers it should be six or more tanks. I think the maximum practical size is 270,000 cm to 300,000 cm for LNG carriers when considering terminal facilities and draught limitations, although we can build larger ships. If a deeper draught is possible then it is better as the ship is more stable, but many LNG terminals have a 12 metre to 12.5 metre draught limit.'

Talking about large bulk vessel design in general, Lee pointed out that oil tankers have a more suitable hydrodynamic shape for sailing than LNG carriers. Oil tankers are better balanced and more manoeuverable compared with LNG carriers. Increasing the width of a gas carrier is not regarded as a good solution unless the vessel has a deeper draught, which will improve its operating efficiency.

'Maybe we are coming to the limit in LNG carrier size. It might be that some owners are interested in very big sizes but no one has mentioned it yet,' Lee said. 'Maybe there will be some larger LNG carriers, but demand is very limited and it is the same case as demand for ULCC [ultra large crude carriers] oil tankers. Since ship design is subject to the port and terminals facilities, all shipowners want their vessels to trade freely at any terminal.'

## Far East interest

Although LNG importers' main business interest in LNG usually begins when the gas arrives at their receiving terminal, in recent years a number of Far Eastern importers have started to become involved in LNG shipping operations as a way of diversifying their business activities and generating new profits.

State-run Korea Gas Corporation, for example, and four South Korean shipping lines plan to establish a new shipping company to transport LNG for Korea Gas that will be purchased under future gas import contracts. So far, no name has been decided for the company which will be established by Korea Gas, Hanjin Shipping, Korea Line, SK Group and Hyundai Merchant Marine. Plans call for the new company initially to operate four 145,000 cm capacity LNG carriers. The vessels will be used to transport LNG from Yemen to South Korea, and from Sakhalin to South Korea. All four carriers are planned for delivery in 2008.

In late October, Korea Gas announced that contracts to build the four carriers had been awarded to three South Korean shipbuilding consortia. DSME and Korea Line Corporation were awarded a contract to build two LNG carriers, while Hanjin Heavy Industries and STX Pan Ocean will build one vessel, and Hyundai Heavy Industries and sister company Hyundai Merchant Marine will build the fourth vessel.

For DSME, the contract award lifted the number of LNG carrier contracts signed in 2005 to eight, including a recent contract signed with Bergesen Worldwide of Norway for two 156,100 cm LNG carriers.

Although the Korea Gas-led consortium awarded contracts for the first four vessels to an all-Korean shortlist of six shipyards, the consortium's second round of LNG carrier bidding is likely to attract international interest as the new company is expected to specify that an under-development, Korean-designed LNG cargo containment system is used for the first time.

'Cargo containment is an important issue. There are several systems now – the spherical ball shape design, the conventional membrane-type, "Gaz Transport (GT) No 96" system and the "Technigas (TG) Mark III",' Lee said. 'Also, the GTT CS1 membrane system is being used for the first time in French shipyards, but there have been failures and problems during ship construction, so ship delivery will be delayed and the CS1 system still is not proven.'

For the past three years, Korea Gas' R&D Division – in cooperation with three major South Korean shipyards: DSME, Samsung Heavy Industries and Hyundai Heavy Industries – have been developing the KC1 containment system, which, according to Lee, is similar to the GTT Mark III containment system. South Korean shipyards are sharing the various R&D tasks involved in developing the KC1 system, while Korea Gas has taken the coordinating role. Government support is being given to the project due to Korea Gas' status as a state-run enterprise.

'The first round bidding for four LNG carriers are due for delivery in 2008,' Lee commented. 'The new shipping company will need four or five more vessels for delivery in 2010, so probably they will specify KC1 containment technology for the second round bid in 2007 or 2008. That will have a great effect on GTT, the French membrane technical licensee. Their royalty fee policy will have to change. But now there is no competitor to them.'

'Currently, most LNG carriers favour the membrane containment system and GTT holds the licenses for both membrane system types,' explains Lee. 'If the KCI technology design is proven it will become a strong competitor to the GTT design and will affect GTT's design royalties significantly. As all South Korean shipyards pay a high royalty fee to GTT, they want to reduce the royalty amount; but it is difficult because now there is no competitor to GTT.'

## South Korea consolidates position

Meanwhile, South Korea is expected to consolidate its position as a major supplier of LNG carriers to the global gas-carrier fleet in the future. DSME, Samsung Heavy Industries and Hyundai Heavy Industries have the capacity to build nine or ten LNG carriers a year each at present. Both DSME and Samsung have announced plans to increase their production capacity to 14 LNG carriers annually.

By 2008, South Korean shipyards are expected to have expanded their LNG carrier building capacity to produce about 40 LNG vessels per year in total, of which half will be very large carriers over 200,000 cm in capacity.

South Korean shipyards will win about 80% of the total LNG carrier capacity ordered until 2010, Lee forecast, while others will be built in Japan, Spain, France, China and other countries.

Daewoo's Okpo shipyard is located on Koje island, which lies 40 km south-west of Pusan, off the south-eastern tip of the Korean peninsular. Facilities include two dry docks for building new vessels and three floating docks, mainly for repair work, but which also can be used to build new ships. DSME employs 11,000 staff, including 1,400 engineers and 6,200 skilled workers. In addition, the company uses a number of subcontractors who employ about 6,000 workers. While some subcontractors supply equipment, others help DSME fabricate parts of the ship's structure or provide various services such as painting ships. Some subcontractors work onsite at Okpo shipyard, others offsite.

'We have no expansion plans for our shipyard, but we are trying to increase our LNG carrier construction productivity,' Lee noted. 'As long as we maintain qualified engineers in South Korean shipyards and we are flexible to meet client demands we can continue to compete against foreign shipyards. There could be a threat from China in the future, but there is no big threat for our core business. LNG carriers are needed in China and they already build two to three vessels annually for domestic clients.'

Meanwhile, South Korean shipyards also are receiving a growing number of orders for LPG/ammonia gas carriers as global LPG consumption continues to rise. DSME, for example, has received firm orders for seven large LPG/ammonia carriers in 2005, with some more options. 'Our LPG carrier business is growing as well because where there is LNG production there is LPG production, especially in the Middle East,' Lee commented. 'There could be 30 to 40 very big 84,000 cm LPG carriers ordered in the future to carry QatarGas LPG. Also, other LPG shipping companies are looking for newbuild LPG vessels.'

DSME is currently building 17 LPG carriers for various clients, including Bergesen Worldwide of Norway, AP Moller of Denmark, Exmar of Belgium, K-Line of Japan, Gulf Marine of Greece and Geogas of Switzerland.

'LPG carriers of 40,000 cm to 45,000 cm will be demanded in the future, but we still get inquiries for 38,000 cm size carriers,' Lee said. 'Most of our orders are from owner operators.'

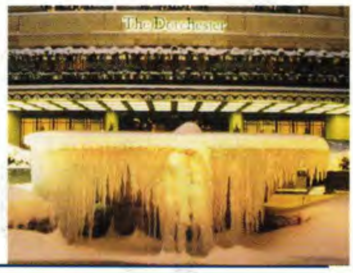
Date: **Tuesday 14 February**

Venue: **Dorchester Hotel Park Lane, London**

Time: **12.30 for 13.00 – 14.45**

Sponsored by

platts



# *IP Week Lunch*

### Guest of Honour and Speaker: Paolo Scaroni, CEO, Eni

**The *IP Week Lunch* once again promises to be a key event in the petroleum industry calendar. This year we are pleased to welcome a key industry leader from Europe, *Paolo Scaroni*, CEO, Eni. Mr Scaroni became CEO of Eni in June 2005. A graduate of economics and commerce, Paolo Scaroni has held a number of executive positions in Italy and abroad.**

**TICKET APPLICATION FORM**

energy INSTITUTE

Please send the completed form to Arabella Dick, Energy Institute, 61 New Cavendish Street, London W1G 7AR, UK t: +44 (0)20 7467 7106 f: +44 (0)20 7580 2230

I wish to order ticket(s) ....................@ £149.00 (£175.08 inc VAT) each = Total £ ....................

Title:.................. Forename:.................................... Surname:....................................

Company:.................................................... Address: ....................................................

....................................................................................................

Postcode: .................................................... Country:....................................................

e: .................................... t: .................................... f: ....................................

I will pay the total amount by: ☐ Sterling Cheque or Draft on a bank in the UK, and I enclose my remittance, made payable to the Energy Institute, for £..........................................

☐ Visa ☐ MasterCard ☐ Euro Card ☐ Diners Club ☐ Amex

Card Number: ☐☐☐☐ ☐☐☐☐ ☐☐☐☐ ☐☐☐☐

Valid from: ☐☐ / ☐☐ Expiry: ☐☐ / ☐☐

Credit card holder's name and address (if different from above):

Forename: .................................................... Surname:....................................................

Billing Address:....................................................................................................

....................................................................................................

Postcode:.................................................... Country: ....................................................

Signature: .................................................... Date:....................................................

**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 ☐

a) Tickets can be purchased by members and non-members of the Energy Institute.
b) The cost of one ticket is £149.00 plus VAT at £26.08 and includes pre-lunch drinks and wine. Liqueurs are not included in the ticket price. VAT is payable by all UK and overseas purchasers. Full payment must be received before tickets can be guaranteed.
c) 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.
d) Special dietary requirements will be accommodated if the EI is notified by 26 January 2006. An additional charge will be levied by the venue to delegates requesting a special meal on the day.
e) Guests' names should be submitted in writing to the EI before 26 January 2006 at the latest for inclusion in the printed guest list. Name changes or additions submitted after this date cannot be included in the printed guest list.
f) This event is included in the *IP Week Pass* as well as the *Tuesday Morning Pass* and *Tuesday Afternoon Pass*.
g) If you cancel your order after it has been processed, a refund less a 20% administration charge of the total monies paid will be made provided that notice of cancellation is received in writing by 13 January 2006. No refunds will be paid or invoices cancelled after this date.
h) Upon 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.
i) Dress is lounge suit. Please adhere to the dress code.
j) The EI and The Dorchester Hotel reserve the right to refuse admission. Admission is strictly by ticket only.

**Photocopies of this form are acceptable**

# Going digital – a question of integration

*The ultimate aim of the 'digital oil company' is to deploy web-based technology that links operational and business applications from end-to-end, both upstream and downstream. There's still a long way to go, but significant initiatives are underway to integrate diverse silos of information globally, for more informed decision-making, production optimisation and efficient resource allocation, writes* Brian Davis.

The digital oil company is taking shape, with the oil majors several years down the line in adopting e-procurement, e-logistics, real-time 3D visualisation, advanced information management, e-transactional processing and integrated supply chain management. Unfortunately, however, there's no silver bullet in terms of software solutions or common data exchange standards in the search for world-class best practice.

The oil and gas industry lags behind integrated supply chain initiatives in the automotive industry, electronics sector and banking. However, oil companies, software suppliers and consultants are working hand-in-hand to develop the vision – aiming to provide management and operational teams with visibility online from smart wells and intelligent completions, through to onshore refineries and along the supply chain.

## Tackling the integration stack

Shell is one of the leading players targeting commercial integration of its digital E&P (exploration and production) business, with ten 'Smart Fields' programmes underway, mostly in the Asia-Pacific region, covering operations in Brunei and Sarawak, Malaysia, with E&P operations in the US, Europe and the Middle East to follow.

The key aspect of the Smart Fields programme is development of an 'integration stack', which, as Erik van Kuijk, Principal Workflow Consultant at Shell International E&P, explains, includes people, processes, knowledge and information, and software tools. 'The key to success is not at the software portfolio level, but to take a close look at the process level,' he insists.

Traditionally, companies have focused on software systems and have tried to tie them together to provide an interface for data exchange. 'Considering that data supports business and operational processes, it is more important to decide what knowledge, information and data is required to make processes work effectively. Then to address the "plumbing" and IT infrastructure network,' van Kuijk suggests.

Much of the technology is in place. The current emphasis is on rationalising a mountain of diverse software, optimising systems and integration. Shell's Portfolio Management and Integration (PMI) team is working with third parties and strategic partners to rationalise systems, targeted at providing a uniform platform for applications used by a highly mobile workforce, and economies of scale.

These systems will be integrated in five portfolios – sub-surface, wells, facilities, production and business administration. 'This means eliminating the silo mentality. For example, subsurface engineers were happy to operate in an environment which didn't talk to business administration,' remarks van Kuijk.

Security is a key issue of concern, and the Smart Fields team has developed Data Acquisition and Control Architecture (DACA) to keep the infrastructure separate from an office environment that is regularly bombarded by viruses and trojans. As new Smart Fields are brought onstream, the DACA architecture will be coupled with the 'collaboration stack' to identify gaps and priorities in people skills, communications, data management, processes, software and IT security.

The collaboration environment is being built in standard building blocks – 'like Lego', quips van Kuijk – to deliver a collaboration portal environment with a generic process engine and standardised business processes that can be con-

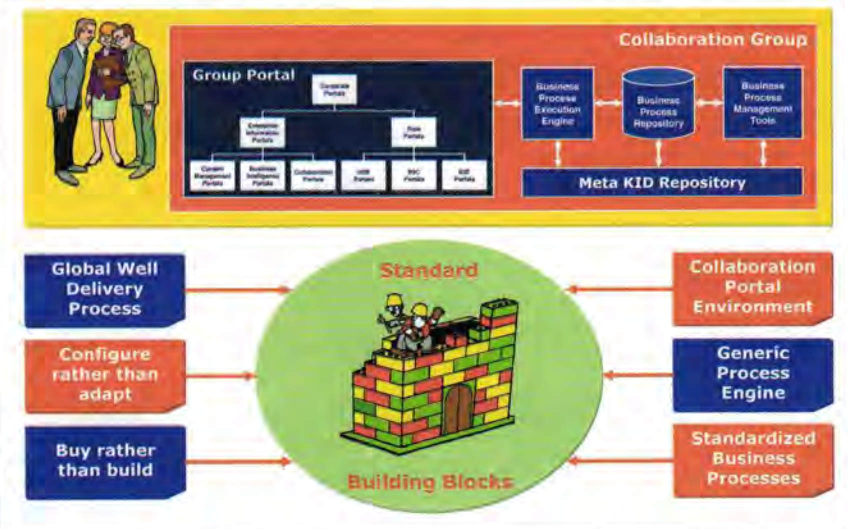



Figure 1: Collaboration environment *Source: Shell International*

figured to meet different portfolio requirements.

The first process to be automated in this way is Global Well Delivery. Traditionally, well engineers rely on disparate systems, data and processes to piece together proper work management and decision support (including work management, personnel management, drilling information, process guides, documents, planning and knowledge management). 'These systems are increasingly large and complex, and rationalisation will undoubtedly require changes to existing applications, work processes and user capabilities,' remarks van Kuijk.

In partnership with SAP and Accenture, Shell has created a Wells Portal, which incorporates the Global Well Delivery Process with an automated component called xIEP – x (for variable) Integrated Exploration and Production. Put simply, xIEP is a black box business process engine that translates the Global Well Delivery Process into an automated system.

SAP is releasing xIEP with several business scenarios, including procurement. The Wells Portal portfolio will be rolled out from January 2006 to address greenfield and brownfield developments in Europe initially. As a collaborative tool, the multi-discipline E&P team can use multiple information sources to decide which drilling programme is appropriate for different wells, in concert with geoscientists, engineers, contractors, the asset manager, financial and business managers, each with individual portal views.

The Wells Portal interfaces seamlessly with Shell's document management system LiveLink, for access to geotechnical applications, and a variety of enterprise and third-party systems, such as Landmark's Engineers Data Model (EDM) infrastructure. The Wells Portal can be used for sharing knowledge round the group. The user can drill down to find relevant knowledge quickly which is exactly fine-tuned to their process needs.

'Well Delivery definition is a relatively simple and well organised process,' admits van Kuijk. 'This is only the first step to automate the E&P process. The ultimate dream is to automate end-to-end processes. The beauty of the system is that it is all web-based – client server architecture that will be very familiar to people and easy to navigate.'

System integration means keeping the big picture in mind. Both the PMI team and the Smart Fields group are in Shell International's Research Directorate. The key objective is termed 'Enterprise First', considering what's of benefit to the company as a whole. Consequently, a number of global processes have been identified, which are new candidates for address in the collaboration stack.

Interestingly, 80% of the Well Portal delivery process is generic and just 20% Shell specific. Shell has reached agreement with SAP to market the generic version to competitors and partners. 'It's like building Lego blocks, through the SAP system, and developing a number of interfaces with underlying systems called "iViews", which will grow over time to address the next scenario or portal,' says van Kuijk.

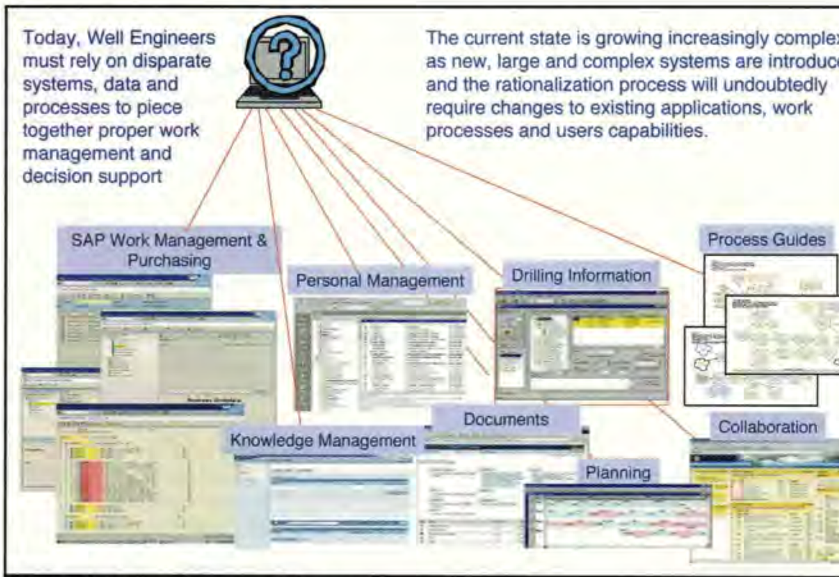



Figure 2: Well engineers – challenges

*Source: Shell International*

## From information portal to business apps

The entry point for most companies to the digital business environment is the information portal. There's a wide choice of 'best of breed' portal solutions on the market, from the likes of SAP, Plumtree, Hummingbird and others. Most handle a combination of structured and unstructured information. Structured information is well-documented process information, managed using systems like Documentum and SAP Knowledge Management. Whereas unstructured information, such as market news, can be drawn from the web or systems like Oilwatch from Oilspace.

'Today, more and more companies are starting to integrate their business processes into the portal,' explains Holger Kisker, Programme Director, Oil and Gas, at SAP. The first applications to be integrated are employee self-service systems for HR (human resources) and office administration, followed by manager self-service for performance reviews and information on teams.

Now the emphasis is on integration of business processes such as procurement, sales order processes and maintenance. Many oil companies have projects in this area. For example, Statoil is in the process of transformation from an information portal to an integrated business application portal, addressing generic business support processes.

Shell's xIEP is a composite application which stands on top of multiple applications in an integrated business process model for asset maintenance of wells, ongoing workplan, materials and services procurement, tracking and settlement activities. There is also a pilot for planning, budgeting and construction of new wells up to hand-over of the production unit. Similar projects are under development with BHP Billiton, ConocoPhillips and Anadarko.

The underlying assumption is the ability to roll out portal applications for adopting best practice in different scenarios speedily, because the business process application is outside the underlying application coding. Consequently, Shell – in partnership with business development partner Accenture – can make changes to the asset maintenance process in a day that would previously have taken a few months.

'The major drivers of oil company adoption of business application portals is the need for standardisation and harmonisation in global operations,' says Kisker. The goal is to integrate the E&P upstream business end-to-end, linking all people, information and processes from asset maintenance and delivery, to production management and optimisation, exploration and appraisal. Discussions are underway with several oil majors about their priorities.

## Improving asset management

BHP Billiton is also scoping the digital oil field of the future. Work is underway in the Gulf of Mexico and there are plans to roll out the digital approach with all new assets, according to Katya Casey, Global Geoscience Applications and Information Management Lead.

The company is also looking to optimise plant maintenance processes using the xIEP module in partnership with SAP and Accenture, following a pilot project in the US. 'Our main focus is on portal technology and related areas, including 3D visualisation and integration,' says Casey. BHP Billiton is already using a SAP Enterprise Portal version6 and Schlumberger's Decision Point software for dynamic production reports, well tests and other petroleum specific data. Plans are in hand to integrate the petroleum data with back-end office systems for HR and financial reporting.

The Application Information Management (AIM) team was formed in 2002 to handle common data management issues, eliminating data redundancy, developing new data models, and increasing knowledge management in the face of rapid business focus changes. The AIM team has a principle to 'buy not build' systems, integrate wherever possible, minimise application functionality duplication, and aims to adopt global/local data standards where appropriate.

'Our ultimate goal is a single data repository for each data type, with rich metadata for each database; to enable narrowly focused searches for information/data to deliver measurable results,' explains Casey. The portal is a major component of the digital strategy, with a focus on integrated information and knowledge management, including the 'Get Knowledge' programme for technical specialists.

Casey recognises that integration of silos of information is a difficult task. 'The industry has struggled with this issue and different approaches, like using unique identifiers. We are now focused on metadata integration to build a catalogue of information across the silos,' she says. Metadata offers a summary about the quality and trustworthiness of data, and the team is currently identifying keywords that would be critical across different systems. The foundation of the project will be POSC-developed data models for technical data and standards related taxonomies, to map into the technical structured and unstructured data stores.

The main objective of the integration programme is to make better decisions faster. The portal will handle volume-based, visual integration of high density data on advanced seismic and petrophysical applications, with grid- and point-based analytical and visual integration where geophysical 3D data is dense but sparse. Middleware has yet to be chosen.

The digital model approach promises significant benefits when developing new assets. Initially, the Global AIM web-based information portal delivers a one-stop location for data mining and dynamic reporting. The portal has two components – a horizontal layer that connects to financials, employees and administrative services; and a vertical component specific to petroleum-related reports and applications.

'The portal is designed to bypass some complex desktop applications, to produce quick summaries for petroleum asset-specific applications via a web browser,' says Casey. The portal serves 1,600 people in BHP Billiton's petroleum operations and has just been linked to the BHP-wide enterprise portal, so employees can gain access to health and safety reports, and other information for corporate aggregation. There is also a supplier portal, developed in partnership with external bodies.

Knowledge preservation archiving is a priority given the ageing profile of the workforce in the oil and gas sector. And new business processes are now based on toll-gate milestones.

A key objective is to establish information management foundations and to plan a move into a 3D earth model.

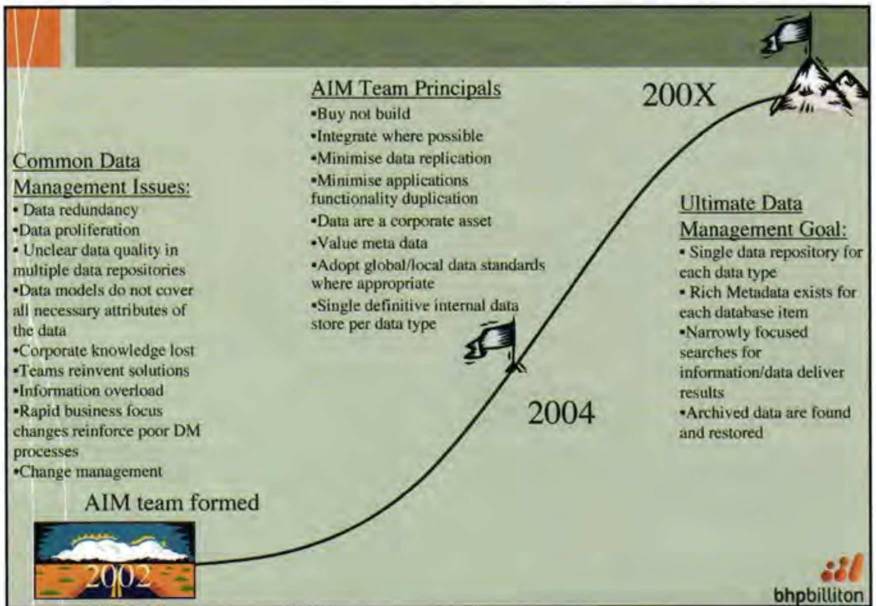



Figure 3: Technical data management strategy

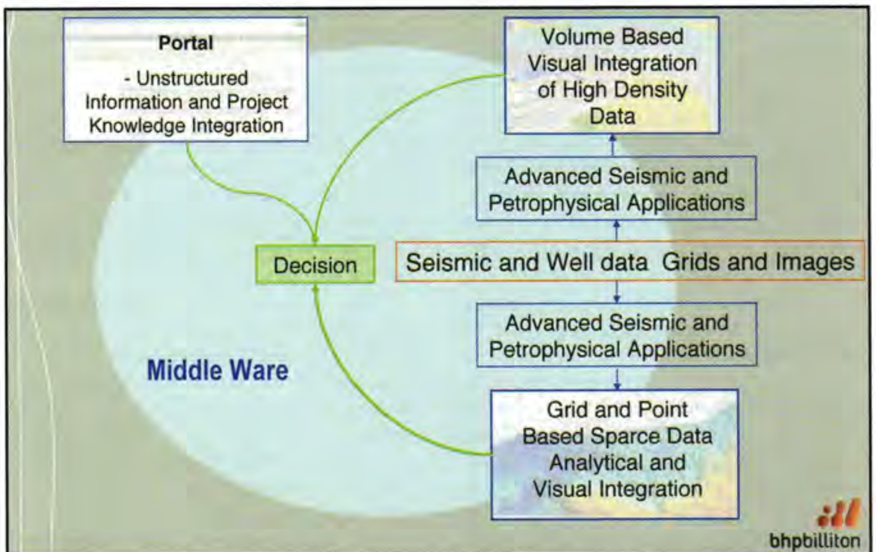



Figure 4: Support all interpretations of 'integration' concept to make better decisions faster

BHP Billiton has created integrated mapping workflows, using ArcSDE (a spatial data engine) as a single culture database for mapping applications. The GIS (geographical information system) strategy is being developed by the Minerals Exploration and Petroleum teams.

Casey makes the point that technology is not the crucial issue, but working with people to encourage adoption is. 'You have to work on your processes and people, you can't work on one without the other,' she remarks. Early benefits of having a portal were exposure of data that needed clean up, and processes that required correction. 'The portal exposes data and processes which have to be taken care of, to make the business more efficient. It also allows the user to watch information more dynamically in an onscreen dashboard, so you can spot problems before they occur.'

Finally, the portal will help the workforce find information faster. Casey admits: 'We're not there yet, because you still need to put the right processes in place. It's all very well trying to implement technology and assume everything will fit. But, in reality, the organisation is often not integrated enough itself to enjoy the full benefit of this technology.'

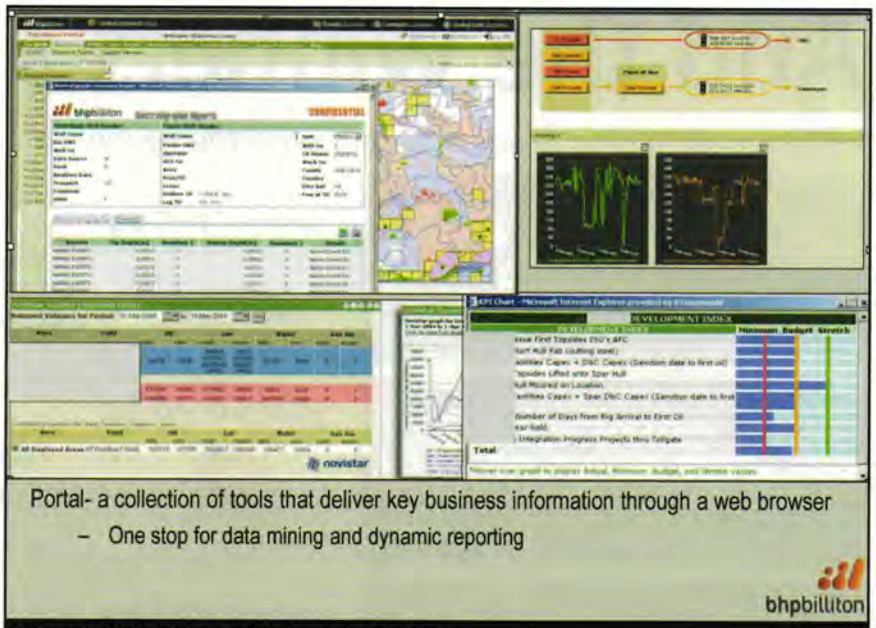



Figure 5: Global AIM – web information delivery

## Cisco tackles security fears

Stuart Robinson, Business Development Manager at Cisco Systems EMEA, believes a key driver for digital oil fields is the need to extract between 10% and 20% more from new and existing fields. He claims: 'Nobody has yet cracked all the issues around collecting data from intelligent devices on wellheads, extracting the data, correlating and aggregating it, then bringing the data into a secure enterprise data environment.'

Cisco recognises that oil and gas exploration, production and processing relies heavily on mechanical checks and controls rather than complex software systems, due to security concerns. Consequently, engineers favour simple, hardware-based methods for monitoring the status of a given process.

'While this ensures that work environments can remain relatively safe, it has drawbacks from both a business and process engineering perspective,' claims Robinson. 'Oil and gas companies are less flexible and responsive, and take longer to adapt to changing circumstances because of the difficulty of integrating operational data into enterprise management systems. This problem is acute given the wide and rapid fluctuation of product prices. An inability to respond swiftly to changing market conditions means companies risk missing out on opportunities.'

Cisco – in partnership with OSIsoft and WiredCity – has developed an Intelligent Information Network, which allows IP (Internet Protocol) systems to be integrated into process control functions. The aim is to avoid compromising safety and security, while creating improved flexibility and responsiveness. Together, they have created an Industrial Data Centre solution that sits between the enterprise data network and the process control network.

Pilot projects are in place in the Gulf of Mexico, monitoring production of offshore oil fields. Information is captured at data centres in Houston, using an OSIsoft platform called PI (Plant Information), a time and datastamp flatbed text historian with 350 different interfaces, to capture data from analogue and digital interfaces into the database. Using the IP network, data can be connected from various geographical locations to provide a secure, holistic view of the network at an operational centre across the globe. The IP network is open and standards-based, so new applications can be introduced with ease. ●

*...continued from p18*

Dunedin. The permit contains a number of known structures – including the Galleon-1 well drilled by BP in the 1980s, which flowed gas at 10mn cf/d and condensate at the high rate of 2,240 b/d. At the time, the find was regarded as uncommercial. The partners plan to target several large structures, including the deeper water Barque prospect with a potential of 5–6tn cf of gas plus 500mn barrels of condensate.

Other companies have staked an interest in the Canterbury basin, including the substantial Australian-based explorer Origin Energy, which has been awarded large offshore acreage from Banks Peninsula (near Christchurch) to the south of Dunedin.

At the far south of the South Island, the Great South basin is regarded as one of New Zealand's most prospective areas for both oil and gas. Eight wells were drilled in the 1970s and 1980s, which proved there was an active petroleum system with some very large structures. However, since then the Great South basin has largely been overlooked.

That is set to change, with Crown Minerals setting aside a large area of the Great South basin for a future blocks offer to be announced by the end of this year. It also has plans to acquire additional seismic to support this, and subsequent, offers. Recent geological analysis indicates very large quantities of source rock in the basin, with modelling suggesting that 1,800bn barrels of oil and 180tn cf of gas have been expelled.

The technical characteristics of New Zealand's offshore basins offer explorers the chance to discover petroleum resources of significant size and value to have material impact. ●

*For more details on New Zealand exploration, visit the Crown Minerals website* **www.crownminerals.govt.nz**

# And the winners are...

Petroleum Review *is pleased to announce the winners of the EI Awards 2005*

| | | |
|---|---|---|
| communication award | sponsored by amec | winner The Hearts and Minds programme – Shell, Leiden University, The University of Manchester and University of Aberdeen |
| community initiative award | sponsored by TOTAL | winner Empowering Guiria fishermen to become enterpreneurs – ConocoPhillips, Venezuela |
| environment award | sponsored by KPMG | winner Improving the safety and environment operational standards on the Volga – TNK-BP |
| innovation award | sponsored by ExxonMobil | winner CHRP combined heating refrigeration and power – Doug Marriott Associates |
| international platinum award | sponsored by TNK-BP | winner ExxonMobil link school programme – ExxonMobil |
| outstanding individual achievement award | sponsored by NORMAN BROADBENT Measurably Different | winner Sanjay Kaul |
| safety award | sponsored by | winner Airside defence driver testing – ExxonMobil Aviation International |
| technology award | sponsored by BG GROUP | winner The Trident monotower gas production platform – Shell |

**EI Awards 2005 sponsored by** Deloitte.

# Cutting fugitive emissions

*From October 2007 all existing UK processing plants and power stations will have to comply with the European Union's (EU) IPPC Directive 96/61/EU, which aims to improve the management of industrial processes and ensure a higher level of protection for the environment. An important part of this legislation is reducing fugitive emissions, which will have significant consequences for all processes in any factory, reports* Peter Childs (right), *Managing Director, Beldam Burgmann, a UK packing and static seals company.*

The directive has applied to new-build factories since 1996, but, crucially, it becomes applicable to all existing sites in October 2007. This date will be a turning-point for the way in which EU industry operates – all plants and factories which fail to comply with the standards set by the directive may be closed from this point. Therefore it is imperative that industry starts acting now.

To put the problem into perspective, a typical European refinery loses between 600 tonnes and 10,000 tonnes of volatile organic compounds (VOCs) per year. It is estimated that 72% of this is attributable to plant equipment such as pipe flanges, pumps, valves and vessels. The consequences of these losses are far reaching. However, the loss of product is only the tip of the iceberg in terms of total cost of fugitive emissions – there are clean-up costs, loss of production time, labour costs to repair leaks, environmental fines and more. In this way, reducing fugitive emissions not only protects the environment, but can also save companies a lot of money.

The directive compels process plants to reduce dramatically the loss of these materials through unanticipated leaks, evaporation, flaring, or spills, and, as such, the next few years will be vital – everything possible must be done in order to bring plants up to standard.

The new legislation is wide-ranging and introduces a concept of 'Best Available Technique' (BAT), urging plants to find the best available solution for reducing fugitive emissions right the way along the process, from areas such as design, product selection, fitting and fitter training, to maintenance, site monitoring, and so on. As such, it requires companies to change the way they operate – industry must begin to make decisions on the basis of what is the best available product and operating method, and move away from its current cost-orientated framework.

According to BASF, 28% of its emissions come from flanges, so improving flange connections will be a priority. Whilst it is true that all gaskets leak, the variation between gaskets is enormous, and therefore choosing the best available gaskets is critical.

Traditionally, a gasket or seal has been selected according to the particular fluid being sealed and on the grounds of temperature, pressure and available bolting. However, from now on, a new specification will have to be considered – all plants and factories will have to ask themselves how much the gasket will leak. Many gasket suppliers will not be able to answer this question, indicating the huge changes industry will have to undergo in the next two years.

So, what can be done to solve this problem? It is important to start acting now. Several high quality products are currently being introduced to the UK market, such as the Novaphit SSTC-TAL

*continued on p38...*

# A sticky dilemma

*Making money from Canada's oil sands, it would seem, is like shooting fish in a barrel. About 175bn barrels of the black, gooey stuff lies just beneath the surface of north-east Alberta, well within mining distance. Exploration risk is nil, the regulatory and political climate is cheery, demand for crude has never been brisker, and returns on investment are at an all time high, writes* Gordon Cope.

**Oil sands mining and refining – turning muck into black gold**

Small wonder, then, that investment is pouring in. The region has 47 initiatives, worth C$90bn, either recently completed, under construction or scheduled to begin in the next two years. They include Imperial Oil's $6.5bn Kearl project, Syncrude's C$7.8bn expansion programme and Canadian Natural Resources' C$30bn Horizon development. The Canadian Association of Petroleum Producers (CAPP) estimates that mining and in-situ capacity, which was 1.2mn b/d at the end of 2004, will rise to over 3mn b/d by 2015.

However, oil sands face growing pains, any number of which could derail the multi-billion juggernaut. Is the greasy wheel starting to squeak?

## Woe is me

While overall capacity continues to climb, actual output from the mining portion has hit a bit of a speed bump recently. It dropped from an average of 608,000 b/d in 2004 to an expected 566,000 b/d in 2005. A fire at the Suncor facility in January almost halved production from the project for the first nine months, from 225,000 b/d to less than 130,000 b/d (no one was injured). At Syncrude, a hydrogen unit failed in January, knocking off 25% of production for that quarter. Athabasca oil sands also had unscheduled maintenance at its Muskeg River mine that also temporarily reduced production by 30%.

Those seeking to build new projects face their own problems. In an area where moose outnumber men by a wide margin, Alberta's Construction Labour Relations association released a forecasting report that oil sands projects would need 18,600 workers in 2005 and 24,000 by 2008. According to the report, there is a dire need for pipefitters, industrial electricians, boilermakers, ironworkers and crane operators. 'Currently, projects are constrained in the pace of growth by labour and infrastructure,' says Onno Devries, CAPP's General Manager of Oil Sands. 'Some projects are having a difficult time.' In the past, labour issues have contributed to numerous cost overruns – for example, Syncrude's Stage 3 expansion, which was originally budgeted at C$4.1bn in 2001, is expected to reach C$8.2bn before it is finished in 2006.

Even if they can round up sufficient workers to build the mines, upgraders and other facilities, getting equipment to the remote region poses its own logistics nightmare. The region is serviced by one, two-lane highway that stretches 400 km from Edmonton to Fort McMurray – it is clogged with trucks moving immense boilers. A multiparty task force recently concluded that streamlining access into the region would cost in the neighbourhood of C$1.7bn. 'Some of the huge vessels move up the two-lane highway at 10 mph,' notes Devries. 'Government needs to expand infrastructure and make sure roads are adequate to handle the transport of equipment.'

When oil sands projects come onstream, they must face the rising cost of natural gas. Separating a barrel of mined bitumen from its sand and clay matrix requires about 250 cf of gas, then another 500 cf or so for upgrading into synthetic crude. In-situ mining is even more intensive, requiring about 1,000 cf of gas to steam it out of the ground. The region uses approximately 600mn cf/d now – Ziff, a consultancy, calculates that by 2015, that figure could rise to 1.5bn cf/d.

The sheer scale of the industry has a profound environmental impact and, although plant facilities are designed to meet strict emission controls, overall greenhouse gases (GHGs) continue to climb as each project enters production. Water, which is in seemingly great abundance in the region, is also reaching alarming limits. According to oilfield consultant Bruce Peachey, the oil sands use around one barrel of water for every barrel of bitumen produced. 'The Athabasca River has a summertime low flow rate of 3,000mn cm/y, and allocations now stand at 360mn cm/y – over 10% of that rate. Shutting down a mega-project for four months because of lack of water would not be popular.'

Even then, output faces the problem of transport to refineries in Canada and the US. Bitumen is a thick, viscous liquid that resists movement. Diluent, usually a thin condensate stripped from natural

Photos: Suncor

gas production, is normally used to thin it out sufficiently to flow through pipes. However, Alberta's condensate production has been flat at around 160,000 b/d for the last several years, and is beginning to decline. As a result, the condensate premium in Alberta, which has traditionally sat at around 2%–4% above WTI, has risen to 45% or more.

Production itself is facing a further constraint – pipeline capacity. Any increase in Canada's consumption will be minor in comparison to the expected expansion of oil sands output over the next decade – CAPP says that 600,000 b/d of new export pipe capacity will be needed by 2015. A potential crunch could emerge by 2008, creating a bottleneck that could significantly decrease producer prices.

## Relief in sight

Although the sector may seem to be in dire straits, there's nothing like the prospect of hundreds of billions in revenues over the next 20 years to sharpen the sense of self-preservation. Suncor announced that the majority of its fire damage, pegged at C$250mn, is largely repaired. It was back to 225,000 b/d output by September, and expects to increase output to 260,000 b/d this month with planned streamlining. Further expansions are also on track at other projects – mining output from the three existing plants is expected to hit almost 800,000 b/d by the end of 2006.

The shortage of skilled manpower, a key component of construction costs, is being mitigated through a number of initiatives. Major components for CNRL's Horizon project, for instance, are being manufactured everywhere from Italy to California. The Northern Alberta Institute of Technology, a trades college, announced its goal of training 160,000 skilled workers over the next decade – it recently established a facility near Fort McMurray to train First Nations members as welders and millwrights. 'The Alberta and federal governments appear to have recognised this and are looking at ways to address the shortfall through increasing opportunities for local employment, apprenticeships with unions, and immigration from other parts of Canada and outside Canada,' says Devries.

Getting goods and people to Fort McMurray is also being untangled by the Athabasca Regional Issue Working Group (RIG), a roundtable of industry, government and community representatives. The province has earmarked funds to improve road and rail access, and local government is improving housing, hospitals and other infrastructure for inhabitants. CNRL is constructing an airstrip capable of handling Boeing 737s at its Horizon project, so that crews can be flown directly in and out.

Meanwhile, cost overruns have been rectified on several levels. Projects are being scaled down to smaller, more manageable steps in order to control labour needs and timelines. Engineering and planning are being finalised as much as possible before the first shovel of dirt is turned in order to avoid costly changes in mid-construction. A large-projects database is being compiled by industry and government in order to establish realistic construction timelines for the cold, remote region.

## Doing it right

Long Lake, a C$3.5bn steam assisted gravity drainage (SAGD) joint venture between Nexen and OPTI Canada, is a study in how to do things right. When the 70,000 b/d facility comes onstream in 2007, it is expected to be on time and on budget. Long Lake has been able to stick to the script because a lot of energy and planning was put into the project. 'There were lots of issues, but they identified them and developed solutions,' comments David Coll, a spokesman for the project. In addition to doing the majority of front-end engineering before construction, Nexen and OPTI took a hands-on approach. 'There's a high degree of owner involvement in the design to start-up phase. They make decisions, as opposed to contractors,' notes Coll. The project is an open site where union and non-union trades work when needed, which controls labour costs. 'We're also assembling as much as we can offsite, we have over 700 modules.'

The rising cost of natural gas is largely outside the oil sands sector's control – fortunately, alternatives exist. Without a doubt, the most intriguing suggestion has been to build specially designed nuclear reactors to provide heat and power. Atomic Energy of Canada (AEC) says its CANDU reactor, which can be scaled to suit a 200,000 b/d SAGD project, could shave 20% off input costs in the form of lower gas usage. Ralph Klein, Premier of Alberta, expressed reservations, however: 'If the environmentalists go nuts over building a dam, can you imagine how they would react to a nuclear power plant?' he said.

More likely are various schemes to reduce energy inputs, such as lowering the temperature of water in separators, as well as seeking alternative fuels. Coke gasification is a process in which low-grade bitumen residuals are put into a high-temperature, high-pressure gasifier along with steam and oxygen to create synthetic gas, (mostly carbon monoxide (CO) and hydrogen (H)). While capital outlay is significant, operating costs are low. In addition to producing a fuel source, the hydrogen can be used for upgrading bitumen to synthetic crude, and for co-generating electricity and steam for SAGD. Long Lake has opted for such a system – it will use synthetic gas made from its own bitumen production to upgrade output to 60,000 b/d of sweet, 39° API synthetic crude.

Meanwhile, environmental concerns are being addressed through consultations with stakeholders and the adoption of sustainability programmes. Suncor, for instance, has managed a 32% decrease in GHG intensity since 1990, and a 43% decrease in water intensity withdrawal since 2000. It has cleaned up the water quality in its reclaimed ponds to the point where the Canadian toad has made a comeback (researchers put radio transmitter belts on some to see where they hopped to). Imperial will reduce emissions at its Kearl Lake project by installing three 85-MW cogeneration facilities. 'If companies are not seen as good environmental stewards, it could show up in the investment market,' comments Devries.

For pipelines, the expected shortfall in export capacity is being addressed. 'There are smaller projects on the go to meet tight export predictions in 2008,' notes Devries. Longer term needs are being met with a number of different proposals:

- Terasen proposes to expand its Trans Mountain system capacity from the current 242,000 b/d to 500,000 b/d crude and a further 250,000 b/d refined with a C$2.5bn looping scheme, entering full operation by 2009.
- TransCanada wants to spend C$1.7bn to ship 400,000 b/d south to the US Midwest. The Keystone project would involve conversion of 1,200 km of existing gas lines and 1,800 km of new, 30-inch line to Wood River, Illinois. The line could be in operation by 2009.
- Enbridge is continuing with its efforts to move 400,000 b/d more Canadian crude into the US Midwest with an open season on C$1.3bn worth of expansions and extensions to its Southern Access system. The reversal of the Spearhead line, which runs from Cushing, Oklahoma, to Chicago, is expected to be completed in 1Q2006. This will move Canadian crude closer to the huge Gulf coast market.
- Enbridge is also hoping to build Gateway, a C$2.5bn, 1,120 km, 30-inch line that would move 400,000 b/d from the Edmonton area over the Rocky Mountains to a deepwater port in Kitimat, British Columbia. A memorandum of understanding has been signed between Enbridge and PetroChina regarding commitments to take 200,000 b/d.

The Gateway plan could also include a 150,000 b/d return line to deliver much needed condensate from the coast to heavy oil producers in Alberta. Enbridge hopes to begin construction in 2008, and service by 2010. However, if the lack of condensate is still restricting bitumen transportation, a trend toward more at-site upgrading may accelerate. Currently, about 560,000 b/d of the 1.2mn b/d mining and in-situ production is upgraded to synthetic oil. While CAPP predicts that number to rise to 890,000 b/d in 2015 (on total production of 3mn b/d), it could easily be 20% higher.

Although serious constraints still remain, industry participants predict a bright future. 'What's constraining projects right now is labour and infrastructure, but we were optimistic for the region when crude was in the \$25–\$30/b range,' says Devries. 'Now, from an investment perspective, the economics are very favourable. We're very optimistic.'

...continued from p34

gasket, designed and manufactured by Frenzelit in Germany. This graphite gasket meets the stringent German 'TA Luft' emission standard, which is set to become the benchmark across Europe for determining gasket performance.

The SSTC-TAL is tested by a complex procedure that involves sealing helium at 300°C, and is extremely difficult to meet. SSTC-TAL is rated for use from –240°C up to +550°C and has excellent resistance to hydrocarbons, steam and many chemicals. Easily meeting the German blow-out test VDI2200 at 60 bar, this new Frenzelit gasket can be seen to offer a viable solution for plants to adopt over the next two years.

Following the ban on asbestos, reinforced graphite is now the most common gasket material in the chemical and petrochemical industries, with the tang metal reinforced version being the most prevalent. However, this grade will not meet the TA Luft standard for leakage and is unlikely to become the best available technique.

The SSTC-TAL is very soft, and therefore is suitable for sealing even imperfect flanges. It is cut from sheet, ensuring rapid delivery, and is suitable for most metal flanges in most applications. However, for sealing oxidising acids, food applications, glass lined and plastic flanges, a different gasket is available.

The Universal Pipe Gasket (UPG) from W L Gore also easily meets the TA Luft standard. It is a moulded gasket comprising 100% expanded PTFE, and is already in stock in the UK. Rated for use from –240°C to +270°C, the gasket has very wide chemical resistance and is FDA approved for use in contact with food, with the lowest creep of any PTFE gasket. It has no binders or fillers, and so will not harden in service, and has very low minimum gasket stress to seal.

However, choosing the best gasket is only half the story – it is crucial to fit the gasket correctly in order to ensure a long, trouble-free service life with the lowest possible fugitive emissions. Some suppliers now offer an on-site fitter training course, which details and explains best practice. These courses also offer certification as part of the audit trail to prove that the best available techniques are being used by the plant concerned.

To conclude, while stressing the impact that the directive will have, industry should not fear this new legislation. Gaskets have been developed and are now available, which significantly reduce fugitive emissions. The small extra cost involved will be quickly regained by the savings achieved from reduced product loss. October 2007 is not far away and action is recommended now.

Date: **Wednesday 15 February**

Venue: **Grosvenor House Hotel**
**Park Lane, London**

Time: **18.45 for 19.30**

# *IP Week Dinner*

**Guest of Honour and Speaker:**
***Lord Browne of Madingley, HonFEI*, Group Chief Executive, BP**

**After dinner speaker: *John Sergeant*, former BBC Political Correspondent**

## TICKET APPLICATION FORM

energy INSTITUTE

Please send the completed form to Jacqueline Warner, Energy Institute, 61 New Cavendish Street, London W1G 7AR, UK t: +44 (0)20 7467 7116 f: +44 (0)20 7580 2230

I wish to order ticket(s) ....................@ £195.00 (£229.13 inc VAT) each = Total £ ....................

Title:.......................... Forename: .................................... Surname: ....................................

Company:.................. .................................... Address: ....................................

....................................................................................................

Postcode: .................................... Country: ....................................

e: .................................... t: .................................... f: ....................................

I will pay the total amount by: ☐ Sterling Cheque or Draft on a bank in the UK, and I enclose my remittance, made payable to the Energy Institute, for £........................................

☐ Visa ☐ MasterCard ☐ Euro Card ☐ Diners Club ☐ Amex

Card Number: ☐☐☐☐ ☐☐☐☐ ☐☐☐☐ ☐☐☐☐

Valid from: ☐☐ / ☐☐ Expiry: ☐☐ / ☐☐

Credit card holder's name and address (if different from above):

Forename: .................................... Surname: ....................................

Billing Address: ....................................................................................................

....................................................................................................

Postcode: .................................... Country: ....................................

Signature: .................................... Date: ....................................

**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 ☐

a) All tables seat 10. Purchasers of less than 10 tickets will be seated with other guests.
b) Ticket purchasers wishing to share tables with named individuals or companies must state this when completing the application form, as changes cannot be made after tickets have been allocated.
c) Applications should be made by completing this form and sending it to Energy Institute, with the full remittance including VAT. Orders received by 25 November 2005 will be included in the primary table allocation. Applications received after this date will then be considered on a first-come, first-served basis.
d) The cost of one ticket is £195 plus VAT at £34.12. VAT is payable by all UK and overseas purchasers. No additional charges will be incurred for credit card payments. Full payment must be received before tickets can be guaranteed. All tickets are the same price, whether or not your guests are EI Members.
e) Upon 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.
f) Tickets for tables in the primary allocation will be mailed December 2005. Please note that the EI may be unable to meet requirements in full, and we suggest therefore that you do not invite guests until you have received your tickets. In the event that the Dinner is oversubscribed, allocation of tickets will depend on the degree of the applicant's involvement in EI affairs, and a waiting list will operate. Full refunds will be made as appropriate.
g) If you cancel your order after it has been processed, a refund less a 20% administration charge of the total monies paid will be made provided that notice of cancellation is received in writing by 13 January 2006. No refunds will be paid or invoices cancelled after this date.
h) Successful applicants should submit their guests' names, in writing, to the EI before 26 January 2006 at the latest. Name changes or additions submitted after this date cannot be included in the printed guest list. Further information regarding the guest list will be provided with the tickets.
i) Special dietary requirements will be accommodated if the EI is notified by 26 January 2006. An additional charge will be levied by the venue to delegates requesting a special meal on the day.
j) Dress is black tie with decorations. PLease adhere to the dress code.
k) The EI and the Grosvenor House Hotel reserve the right to refuse admission. Admission is

**Photocopies of this form are acceptable**

# Economic impact of reserve revenues

*For developing countries that are rich in oil, gas and minerals, one of the key challenges is to convert the revenues from these resources into sustainable economic development. The failure of many countries to overcome this challenge has led to the concept of the 'resource curse', which describes the distorting and negative effects of large resource revenues on economies and societies. However, the resource curse is not inevitable and some countries have demonstrated that large resource revenues and sustainable economic development can indeed be complementary, writes* Sarah McNaught, *Head of Oil & Gas, KPMG.*

In recent years, the quality of governance has been seen as a key to whether a country succumbs to the resource curse. Good governance, both of the resources sector itself and of the overall process of development, allows large oil, gas and mining revenues to reinforce sustainable development.

A crucial element of good governance is transparency in the operation of public accounts and public sector entities. Transparency helps to reduce the potential for corruption, and to reinforce government accountability. In countries with large oil, gas and mining revenues, a particular focus on the revenues from these extractive industries is warranted. The large rents that such industries often generate can create incentives for misappropriation of revenues, and for wasteful expenditure. Moreover, the size of these industries in small or low-income countries means that they often come to dominate the economy, making transparency in the extractive industries a critical element in the overall quality of governance.

A lack of transparency, coupled with inadequate governance, has been associated with the failure of some countries – particularly in sub-Saharan Africa – to translate large revenues from oil, metals and diamonds into sustainable development and poverty reduction. In some cases, revenues from these industries have been misappropriated directly by corrupt governments, so that they could never reach the economy. In many cases, there has been a huge economic loss in the course of government expenditure, due to corruption in procurement and execution of contracts, and poor planning. The opportunities for gains from extractive industries have also fomented and sustained some civil conflicts.

An additional argument for giving special attention to the governance of revenues from extractive industries is their transient nature. Petroleum and mineral resources are exhaustible and provide revenues for a limited period. There is only one chance to capture the rents from these resources and put them to good use. Good governance later will not bring back wasted resource earnings.

Not all resource rich countries have suffered acute problems. However, large revenue flows often make such countries vulnerable to corruption, instability and policy failures if the fabric of governance weakens. Transparency of revenues can lessen such vulnerability and helps to institutionalise good governance at the sector and aggregate economic levels.

## Taking the initiative

One scheme aimed at improving transparency is the Extractive Industries Transparency Initiative (EITI), which was announced by UK Prime Minister Tony Blair at the Johannesburg World Summit on Sustainable Development in September 2002. The primary emphasis of the EITI is for governments of resource rich countries to bring about transparency and to do so voluntarily (see **Figure 1**).

The primary motives of countries implementing the EITI vary and may range from:

- Implementation of a wide-ranging

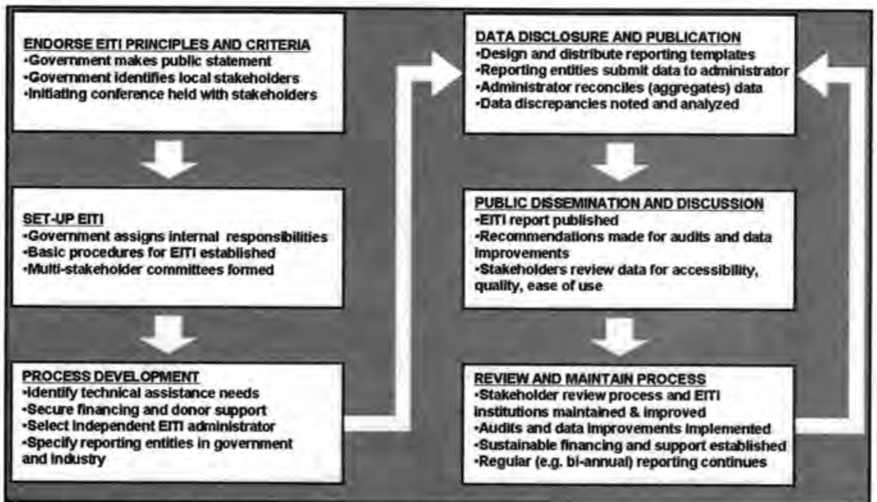



Figure 1: EITI establishment, development and maintenance

anti-corruption agenda, of which the EITI forms a key part (eg Nigeria).

- An ability to demonstrate a high level of transparency already attained through oil funds or similar policies (eg Azerbaijan).
- Policy recommendations of the IMF (International Monetary Fund) and World Bank relating to the reporting and use of extractive industries' revenues (eg Kyrgyz Republic).
- Participation in broader transparency initiatives such as the G8 Transparency Compacts (eg Peru).
- The need to consolidate governance following a period of political instability or conflict (eg Timor Leste).

Naturally, the motives of a country can influence the speed and manner in which it implements the EITI.

Countries that are implementing the EITI are keen to stop 'free riders' from benefitting from the 'EITI brand'. Free-riding countries might announce implementation of the EITI, but make limited efforts to implement it in practice, whilst claiming that they have improved governance. To avoid this, some entity may need to validate, or measure, countries' implementation of the EITI. However, most attempts to measure the quality of governance (eg corruption, openness to private investment, rule of law, etc) between countries suffer from difficulties of absolute measurement, and also from absence of a suitable approved international measuring authority.

For example, it could be argued that the proper measurement of relative progress with the EITI should take account not only of whether specific benchmarks have been achieved (eg timely publication of data in a suitable form), but also of broader challenges – a low income country with little capacity and many problems can be expected to make slower progress towards transparency than a middle income country with strong government capacity. A suitable process for evaluating EITI implementation is to be agreed by stakeholders ahead of the next EITI Conference in 2006.

At the time of writing, the EITI is still in its initial stages of implementation. The evidence from the first countries to begin implementation, including Nigeria, Azerbaijan, Kyrgyz Republic and Ghana, is that establishing a process that meets all of the EITI criteria can take several years. Factors that can slow down implementation include limited government capacity, the need to reach consensus on processes among stakeholders, formulation of legislation to support the EITI process, establishment of independently audited information for state companies and government agencies, and broader developments in the political and economic sphere (such as political transitions and new policy priorities).

## Governance reform

Although implementation of the EITI in a wide range of countries will require considerable attention from governments, companies and the international community over the next few years, it is important not to lose sight of its role within the broader context of helping to improve governance.

The EITI is not an end in itself, but one step along the path to good governance of oil, gas and mining production. The EITI process, and improvements in the transparency of revenues, can help to build trust in governments and to help improve understanding of the economic role of the extractive industries. It should also lessen opportunities for misappropriation of revenues and corruption.

However, in order to help ensure that oil, gas and mining development contribute to sustainable development, a far wider process of governance reform is needed. This includes increasing accountability for the allocation and spending of extractive industries' revenues by government at both central and regional levels, strengthening the rule of law, and improving the management of the technical, environmental and social issues raised by the extractive industries. Hence, the long-term future of the EITI lies in its integration into a broader process of eliminating the resource curse by improving governance in resource-rich countries.

# Chevron's Australian operations

Chevron operates the Barrow Island and Thevenard Island oil fields, which still present exciting opportunities for continuing production and development despite being mature operations. In particular, Barrow Island has been a world-class example of sustainable development with the island's oil exploration and production operations having coexisted for more than 40 years within an 'A' class nature reserve. Since production commenced on Barrow Island in April 1969, more than 300mn barrels of oil have been produced. (See front cover photo.) Production from the Thevenard area is processed through nine unmanned offshore facilities located around the island – since operations began in 1989, more than 140mn barrels of oil have been processed through these facilities.

Chevron's Australian operations also include the Gorgon project off Australia's north-west coast, in which it holds a 50% interest and acts as operator. Partners are Shell (25%) and ExxonMobil (25%). Development will be via a two train (10mn t/y) LNG facility and domestic gas plant on Barrow Island. The greater Gorgon area represents Australia's largest undeveloped gas resource, estimated at 40tn cf and equivalent to 25% of the country's total known gas resources.

In April 2005, Shell allocated capacity from the Energia Costa Azul terminal in Mexico to provide market access for up to 2.5mn t/y of Gorgon LNG into North America. In October, Chevron Australia announced an agreement with Tokyo Gas for the sale of 1.2mn t/y of LNG over 25 years from its share of Gorgon gas. Marketing for other customers is continuing. During July 2005, the project entered a 12-month front-end engineering and design (FEED), awarding more than $A100mn in contracts. The downstream contract, which includes the LNG facility on Barrow Island, was awarded to the Kellogg joint venture (which includes KBR, JGC Corporation of Japan, and Australian-based partners Clough Projects Australia and Hatch Associates). The upstream contract, which includes all subsea production facilities and pipelines, was awarded to a joint venture involving JP Kenny and Technip.

The Gorgon project has the potential to be a significant contributor to the Australian and Western Australian economies, creating 6,000 jobs and generating more than A$17bn in taxes and royalties. A final investment decision in Gorgon is anticipated during 2H2006, with first gas sales slated for 2010.

Chevron also holds a one-sixth interest in the A$12bn North West Shelf Venture, located on the Burrup Peninsula, 1,500 km north of Perth in Western Australia. The most significant phase of development involved the construction of Australia's first LNG plant, with exports to Japan beginning in 1989.

Facilities on the North West Shelf include two of the world's largest offshore gas production platforms – North Rankin 'A' and Goodwyn 'A' – and extensive onshore processing facilities incorporating four LNG trains, storage facilities and load-out jetties, domestic gas processing facilities and LPG and condensate production facilities. Following the start up of the fourth train in mid-2004, a fifth train is now under construction with completion scheduled for 2008. The *Cossack Pioneer* floating production storage and offtake (FPSO) vessel produces over 100,000 b/d of high quality oil for export and domestic refining.

The North West Shelf Venture supplies about 15% of Japan's LNG demand under long-term contracts. In addition, sales of LNG have been made to customers in Spain, South Korea, Turkey and the US.

# The stakes are rising

*The Gulf of Mexico is playing an increasingly important role in helping the US meet its ever-growing demand for energy. However, following the devastating effects of Hurricanes Katrina and Rita in 3Q2005, does the US government need to reassess its energy strategy, which is heavily dependent on oil and gas?* Mojgan Djamarani *reports.*

The current US energy crisis is the unavoidable consequence of not having diversified domestic sources of fuel and having a large part of its oil and gas industry concentrated in an area which is prone to hurricanes. That seems to be the general consensus reached on the Capitol Hill. Prior to Hurricane Katrina, Louisiana and the adjacent areas of the Gulf of Mexico (GoM) accounted for 29% of US oil output and 24% of its natural gas production. Louisiana is also a major hub for the transport of oil, gas and refined products.

Although there are other significant reserves of oil and gas elsewhere in the US, in some regions stringent environmental protection regulations (in areas such as the Arctic National Wildlife Reserve (ANWR) and the Rockies) and fierce NIMBY ('not in my back yard') attitudes (in federal and state waters off the Pacific and Atlantic coasts) have prevented any suggestions that they be opened up to oil and gas exploration. Hence the importance of Louisiana and the GoM to the US energy structure on the one hand, and the risks associated with it on the other – and the stakes are rising.

Speaking before the US House Energy and Commerce Committee hearing on the impact of Hurricane Katrina, Scott Angelle, the Louisiana Department of Natural Resources Secretary, warned that as more of the protection provided by Louisiana's barrier islands and central wetlands washes away, increasingly more onshore and near-offshore production will be damaged or destroyed by even less powerful storms than the recent hurricanes – especially by storms whose paths, like Katrina, directly pass through the producing areas off the coast.

While production has been declining everywhere else in the US, it has been increasing in the GoM. Spurred by the Bush administration's 2001 energy strategy and a friendly state legislature, the energy companies invested billions of dollars into offshore deepwater production facilities. By March 2005, there were reported to be 107 producing projects. Each year, from 1997 to 2002, deepwater production rates have risen by well over 100,000 b/d for oil and 400mn cf/d for natural gas. By the end of 2005 – and prior to Katrina – these offshore facilities were expected to supply more than 12% of US Lower-48 oil output.

## Growing dependence

US dependence on the Gulf could only grow as new oil and gas discoveries were made in deeper waters and plans for LNG import terminals were approved. The widening natural gas supply/demand gap and the high gas prices have had detrimental effects on the large industrial gas users – particularly the chemical sector, which has gone from being an exporter to an importer of products.

The GoM was increasingly expected to open the way for greater US LNG imports that would lead to supply and price stability. In 2004, the US imported 700bn cf of LNG (3% of total US consumption). Louisiana is the home of the largest throughput facility – Southern Union in Lake Charles – out of the four existing LNG import terminals in the US. It is also undergoing a more than doubling of capacity from 1bn cf/d to 2.5bn cf/d. Of the 32 projects announced by the industry prior to Hurricane Katrina, two-thirds (66.66%) were slated for the Gulf coast, where extensive support facilities already exist, while some 73% of new approved terminals are located onshore or offshore in Texas and Louisiana. Last February, the Gulf Gateway Energy Bridge LNG project was completed. In March 2005, it hosted what was the world's first offshore offloading of an LNG carrier.

## Impact of Katrina and Rita

However, Hurricanes Katrina and Rita may have challenged these assumptions. Katrina was the first major hurricane to hit the area and its impact both onshore and offshore was devastating. For comparison, the impact of Hurricane Ivan – which struck two states in September 2004 – was largely confined to the offshore, with most of the resulting damage to subsea pipelines; although it also destroyed seven platforms and damaged a further 26. Katrina, on the other hand, destroyed 46 platforms and severely damaged a further 16. With the subsequent flooding, Katrina, however, wreaked havoc onshore, destroying production support facilities and two major pipelines that carried petroleum products to the south-east and the mid-Atlantic regions, damaging port facilities and knocking out eight refineries. Hurricane Rita which followed on the heels of Katrina, inflicted even more substantial damage to the offshore facilities than Katrina, according to the US Interior Department – managing to capsize Chevron's deepwater, 28,000 b/d Typhoon drilling platform.

In spite of the much smaller scale of Hurricane Ivan, some 7.42% of daily oil output and 1.19% of the daily gas production in the GoM was still shut in by February 2005, according to the US Minerals Management Service (MMS). Given the much larger scale of destruction caused by Katrina and Rita, the recovery time will be considerably longer – and the longer it takes, the more pressing the US energy crisis will become. According to the US MMS, as of 6 October 2005, some 80% of oil output and 66% of natural gas production in the Gulf remained shut in.

| | Katrina | Rita |
|---|---|---|
| Platforms destroyed | 46 | 63 |
| Platforms damaged | 20 | 30 |
| Rigs destroyed | 4 | 1 |
| Rigs adrift | 6 | 13 |
| Rigs damaged | 9 | 10 |
| Rigs unaccounted for | 0 | 3 |
| **Total** | **85** | **120** |

**Table 1: Damage to oil and gas structures in the Gulf of Mexico from Hurricanes Katrina and Rita**

*Source: US Minerals Management Service*

All three hurricanes – Ivan, Katrina and Rita – tore drilling rigs from their moorings and set them adrift. This has raised considerable concern about the viability of the billion dollar deepwater rigs and the prospects of the GoM to act as a lever on the increasing US oil import dependency.

According to the US Interior Secretary, Gale Norton, 108 older design and small drilling platforms that were destroyed by the hurricanes will not be rebuilt. They represented 1.5% of the Gulf's oil output and 0.7% of its gas production, and were located close to the onshore. Of the deepwater facilities, Marathon Oil, Chevron and Shell's projects in the Gulf seem to have suffered most damage. Marathon suffered loss in production of 36,000 boe/d out of a total of 60,000 boe/d, while Shell's net production from the GoM is down almost by two-thirds to 160,000 boe/d.

The Congressional Budget Office estimates that capital losses in the energy producing industries range from between $18bn to $31bn – roughly 25% of the total losses from the Hurricanes Katrina and Rita. Insurers who specialise in coverage for offshore oil rigs and platforms are already considering increases in premium prices. According to John Coomber, CEO of Swiss Re – whose own claims are expected to be in the range of $1.2bn before tax – price levels in the upcoming renewals must be adjusted to reflect the higher frequency and severity of natural catastrophes. The company is reviewing the basis on which it writes offshore energy risks, primarily with a view to segregating and pricing natural perils distinctly from operating perils, and also by addressing the form of Business Interruption Coverage.

Prior to Katrina, there were 17 refineries – representing 16.2% of total US refining capacity of 17.1mn b/d – operating in the coastal area around the GoM. Katrina knocked out eight of these, cutting processing capacity by some 2mn b/d. However, according to Bob Slaughter of the National Petrochemical and Refiners Association – speaking before the House Energy and Commerce Committee hearing – the hurricanes removed some 3.4mn b/d, or about 20% of total US refining capacity, as refineries in Alabama, Tennessee and Texas also had to reduce runs while Midwestern plants lost feedstock due to the closure of the Shell-operated, 1.2mn b/d Capline crude oil pipeline. Soaring gasoline prices – reaching between $4 and $5 per gallon in some areas – followed immediately, as petrol wholesalers and retailers strove to meet demand.

The current fuel shortages in the US will have their strongest impact on the world refining and refined products markets. Before Hurricanes Katrina and Rita, the US was consuming 20.4mn b/d of oil – 44% of which was gasoline. However, the storms hit at a time of already tight domestic, as well as global, refining capacity, coupled with the peak summer driving season. As a result, the US was caught with very low gasoline stocks – at 194mn barrels. The crunch in the US refining sector has been particularly acute, as demand for gasoline has been rising while refining capacity has been declining. There are currently 148 refineries in the US, with 17.1mn b/d capacity, compared to 325 facilities with 18.6mn b/d capacity in 1981 – striving to meet a 20% rise in gasoline demand since 1995, with half of that rise taking place since 2000. Gasoline demand currently stands at 9mn b/d – 10% of which is imported.

Thus, any increase in demand can only be met by either increasing imports or building new refineries. However, not one new grassroots refinery has been built in the US in the last 30 years. Additions to production capacity have been achieved by debottlenecking and extending the existing facilities to take advantage of economies of scale on a limited number of sites.

To meet the shortfalls, the US has begun importing more refined products – originally destined for the relatively cheaper European and Latin American markets – although this has tended to drive prices up.

## Drive to reduce dependence

Although the recent hurricanes highlight the flaws in the US energy policy, they also provide the country with an opportunity to reassess an energy strategy that relies heavily on oil and natural gas.

No new changes in strategy have emerged so far. The immediate response of the Republican-dominated congress was to blame the crisis on decades of environmental and clean air legislation that has closed off several oil and gas rich areas to exploration. However, a bill sponsored by the Texas Republican Congressman, Joe Barton, head of the House Energy and Commerce Committee, was passed by the House on 7 October 2005, that gets rid of a whole range of fuel blends required by anti-pollution regulations and places strict limitations on the use of clean vehicle fuels and biofuels to encourage the construction of new refineries in order to increase the supply of gasoline. Already a number of clean air and environmental safety measures have been waived to help the energy companies restart their operations in the affected area and calls have been made for more coal to be used in power generation in order to release natural gas for use in the chemical industry.

The Republican Senator, Pete Domenici, head of the Senate Energy Committee, has gone one step further and asked for the opening up of the ANWR (which was left out of the recent energy bill) as well as the banned Outer Continental Shelf waters off Florida and California, in the eastern Gulf and the east coast. Currently, federal offshore drilling is allowed only in four states – Alaska, Louisiana, Texas and Alabama.

Even if the ANWR and other currently off-limit regions were opened up, it is unlikely that their impact will make any difference to the US energy situation in the short to medium term. According to a 2002 EIA report – *Potential Oil Production from the Coastal Plain of the Arctic National Wild life Refuge: Updated Assessment* – between seven and 12 years will be required from an approval to explore and develop, to first production from the coastal region of ANWR. The study further noted that the time to first production could vary significantly, based on the time required for petroleum leasing once approval to develop the ANWR is given. Environmental considerations and the possibility of drilling restrictions could also significantly affect projected schedules.

The nuclear industry is also gearing itself up to seize on the current crisis to build new power plants. In September, Areva of France and the US nuclear power producer Constellation Energy formed a joint company, UNiStar Nuclear, that has plans to build four plants that could be up and running by 2015. NuStart Energy – another consortium, comprising eight companies with substantial government financing – has announced that it is spending $100mn to prepare applications to build two new reactors in Alabama and Mississippi.

## Short-term solutions

Even if implemented, the measures discussed above can only provide a long-term solution. In the shorter term, although many see greater room for conservation measures, their prescriptions remain largely limited to calling for higher minimum fuel efficiency requirements for all vehicles, which in recent times has fallen to a 20-year low. No calls have yet been made for higher petrol taxes and improved public transport along the lines of those in Europe that corresponded to a reduced dependence on oil.

In 2004, Western Europe consumed 2.8mn b/d of gasoline compared to 9.3mn b/d in the US. Put another way, per capita consumption of gasoline in the US is over three times greater than West Europe. The federal gasoline tax of 18.4 cents/gallon was last raised in 1993, by just over 4 cents/gallon to its current level – which, if adjusted for inflation, has actually fallen by 25% in real terms. The gasoline taxes in the various states range from 10 cents to 35 cents, with an average of about 22 cents/gallon. Compare this to $3.13/gallon, or 83 cents/litre, in the UK for ultra-low sulphur unleaded petrol, or 89 cents/litre for conventional unleaded petrol.

The most that President Bush's administration could come up with in the aftermath of Katrina and Rita was new rules calling for a slight increase in fuel economy standards for mini-vans, pick-up trucks and SUVs, starting in 2008. However, the regulation is riddled with loopholes – for example, rating 'Hummers' as commercial vehicles and therefore exempt – which will do little to stop vehicle manufacturers continuing to build large gas guzzlers.

Relative consumption and tax statistics such as these are not routinely discussed around the watercoolers of US offices and factories. Therefore, any US politician that tries to curb gasoline consumption is unlikely to see his or her approval ratings improve.

At the time of writing, Hurricane Wilma was reported as the strongest ever recorded Atlantic storm. It missed the Louisiana and Texas coasts – so will anything change between now and next year's Hurricane season?

**A month after Rita, the US Minerals Management Service (MMS) reported that 1mn b/d – nearly two-thirds of the industry's oil production in the Gulf – and 5.6bn cf/d – more than half of the gas – was still shut in.**

*... continued from p14*

The Vlaming sub-basin of the Perth basin is one of the areas where the market's perception of petroleum prospectivity has changed with the increased access to data. Previous exploration had been unsuccessful in locating commercial reserves of hydrocarbons, with the last well in the Vlaming sub-basin having been drilled in 1993. No bids were received for offshore acreage offered in 2000 and 2003, and the poor quality of seismic data remained a major barrier to understanding the petroleum potential of the sub-basin.

The new funding initiative enabled the re-processing of 2,000 km of seismic data as well as the collection of 300 km of new data to support the 2004 acreage release in the Vlaming sub-basin. Following a competitive bidding round, during which explorers had ready access to the improved re-processed seismic data, a new exploration lease (WA-368-P) has been awarded with a guaranteed work programme that includes the drilling of a well.

Apart from the Vlaming data, Geoscience Australia's 2004 south-west frontiers seismic survey also collected data in the Mentelle basin and the Bremer sub-basin of the western Bight basin. This was the first seismic data to be acquired from the Bremer sub-basin since 1974. The seismic data has been integrated with dredge information from a geological sampling survey to unravel the sedimentary succession within this un-drilled frontier basin. The results of this study were presented to Australian and international explorers at a recent workshop in Canberra. Bremer was offered for release in the 2005 offshore acreage round, it is a designated frontier area for tax purposes. Bidding closes on 20 April 2006.

The programme of developing new investment opportunities in Australian frontier basins and delivering them to the market via the annual offshore acreage release is continuing. New data sets are being acquired in the Arafura and Mentelle basins and on the central North West Shelf.

# Emissions Management

**Tactics :** the first day of reckoning approaches – pay up or roll forward?
**Strategy:** a new dynamic? Implications of the G8, the APP and COP 11

The Energy Institute (EI) and the Consilience Energy Advisory Group (CEAG) are pleased to invite you to a half-day seminar on:
**Monday 12 December 2005, Energy Institute, 61 New Cavendish Street, London W1G 7AR, UK**

## The background

The first year of the European Emissions Trading Scheme is drawing to a close and some key compliance deadlines are approaching. This seminar will summarise the emissions 'story so far' and review the events of November and December and what they mean for the further development of climate change regulation.

## Seminar objectives

1. To provide a clear summary of developments so far in the climate change industry both in Europe and worldwide;
2. To explain the compliance options still available to European installations faced with March/April 2006 deadlines;
3. To analyse the performance of the European market in its first year of operation;
4. To interpret the events and the three meetings of international leaders in November;
5. To review the likely future development of the climate change industry.

## Programme

**13.30** *Coffee and registration*
**14.00** *Liz Bossley*, CEAG – The story so far
**15.00** *Tea*
**15.30** Delegate workgroups assisted by CEAG facilitators
1. Meeting the March and April deadlines – practical scenarios.
2. The market instruments – pitfalls for the unwary and optimisation options.
3. Kyoto, the APP and the EU ETS- what next?
**16.30** CEAG facilitators Workgroup reports
**17.00** *Liz Bossley*, CEAG – Closing remarks

## BOOKING FORM

To book attendance at this conference, please complete this form in BLOCK CAPITALS and return it to the address below, together with payment in full. **Arabella Dick, Energy Institute, 61 New Cavendish Street, London W1G 7AR, UK.**
**t: + 44 (0)20 7467 7106, f: + 44 (0)20 7580 2230, e:** arabella@energyinst.org.uk

Title : .......... Forename(s): .............................. Surname: ..............................

Organisation: .............................. Job title: ..............................

Mailing Address: ..............................

.............................. Postcode: .............................. Country: ..............................

e: .............................. t: .............................. f: ..............................

The course fee is £250.00 (£293.75 inc VAT) for the first delegate from each company. In the event that more then one delegate from a company wishes to attend the event, the fee for each delegate from that company will be reduced to £200.00 (£235.00 inc VAT).

I will pay the total amount by (please tick appropriate box):

☐ Sterling Cheque or Draft drawn on a bank in the UK
I enclose my remittance, made payable to Energy Institute, for £ ..............................

☐ Credit Card (Visa, Mastercard, Eurocard, Diners Club, Amex ONLY)

☐ Visa ☐ Mastercard ☐ Eurocard ☐ Diners Club ☐ Amex

Card No: ☐☐☐☐ ☐☐☐☐ ☐☐☐☐ ☐☐☐☐

Valid From: ☐☐☐☐ Expiry: ☐☐☐☐

Credit card holder's name and address: ..............................

..............................

Signature: .............................. Date: ..............................

Photocopies of this form are acceptable

### TERMS AND CONDITIONS

When completing and sending the booking form, the purchaser is liable for full payment of the event fee. Full payment must be received before place(s) can be guaranteed. Under UK Excise Regulations delegates from all countries are required to pay VAT on any event taking place in the UK. The Energy Institute. Registered in England No. 1097899 at 61 New Cavendish Street, London W1G 7AR, UK.

In the event of cancellation of attendance by ticket purchaser a refund, less 20% administration charge of the total monies due, will be made provided that notice of cancellation is received in writing on or before 5 December 2005. No refunds will be paid, or invoices cancelled after this date.

### 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 ☐


Photo: Jim Four

*Speaking at the EI Autumn Lunch held at The Berkeley, London, on 17 October 2005,* Joan MacNaughton, *(above) Director General – Energy, DTI, outlined the progress that has been made as part of the energy policy review and the climate change programme, and work being undertaken by the UK government during its presidencies of both the G8 and European Union. She also reviewed some of the challenges that lie ahead.*

She began by noting that the UK Department of Trade and Industry (DTI) had 'very good working relations with the Energy Institute', stating that it had been of 'tremendous' help in achieving a 'more innovative approach to consultation'. This particularly had been the case in the climate change programme review, where the EI had helped to 'synthesise different views' and 'add value'. Furthermore, considered 'an enormously valuable resource', the EI was expected to be 'very busy' in helping the DTI 'get the flesh on the bones of energy policy over the next few years'.

MacNaughton went on to note the UK Prime Minister's remarks at the Labour Party Conference at the end of September, where he stated that: 'Next year, building on Britain's Kyoto commitment, we will publish proposals on energy policy... Climate change is too important to ignore; too serious for us to split into opposing factions on it... How much longer can countries such as ours allow the security of our energy supply to be dependent on some of the most unstable parts of the world? The G8 agreement must be made to work, so we develop together the technology of the most prosperous nations to allow them to adapt and emerging ones to grow sustainably – and that means an assessment of all options, including civil nuclear power.'

She stressed, however, that while the mention of nuclear was a 'significant place-marker', UK energy policy was 'not going to be just about nuclear... it is going to be about the whole issue of climate change – on which the Prime Minister has personally taken such a lead – and the whole issue of security of supply.' She also noted that the UK government had been quite 'radical' in bringing both these issues together at the heart of energy policy as outlined in its Energy White Paper that was presented two years ago. 'I am still convinced that it is the right thing to do, as it means you get a more coherent and sustainable approach', she said.

## The nuclear question

Continuing with the topic of nuclear, she commented that: 'It is now a long time since we commissioned a nuclear power station in this country – the last one was Sizewell – and we have never built a nuclear power station except in the public sector. Yet we now have a market-led approach to the provision of generation and, indeed, to the delivery of energy policy generally. Will the market provide if given the right regulatory framework for nuclear, or will there be issues of support to be addressed?... If there are, is that going to be a matter for business, the tax payer or the consumer?'

She then posed a number of questions: 'How does this sit with the rest of energy policy and the general approach to the provision of security of supply? What might the impact be on investment generally? And how does it fit with other options trying to address climate change?'

She noted that it was not a question of nuclear versus renewables, or nuclear versus energy efficiency, stating that: 'We are probably going to need them all.' She appreciated that industry wanted certainty on this issue, but stressed that it needed to be 'the right kind of certainty' – and that was what UK government ministers were currently mulling over in the run up to the energy policy review.

## Climate change

MacNaughton then went on to discuss the climate change programme review, 'which is looking at progress towards those Kyoto commitments and our domestic target of a 20% reduction in $CO_2$ [carbon dioxide] emissions by 2010, and also whether we are on course for our longer-term targets for 2020 and 2050 as set out in the Energy White Paper'. She stated that there was a commitment to make an announcement on this by the end of the year.

She also noted that Sir Nick Stern of the UK Treasury had been asked to 'look at the economics of climate change, both nationally and internationally', and that that review would 'cover quite a range of issues that will be relevant to the energy policy review'.

## The importance of G8

Moving on to the recent G8 summit at Gleneagles, she pointed out that there had been 'a very strong emphasis on climate change' as part of the discussions. Out of this had come a 'programme of action', much of which would address the issues of energy efficiency, renewables, cleaner fossil fuels, the more effective generation and distribution of power, and R&D.

'This is all set in the context of the G8 countries and the five big emerging economies that are actually going to be emitting far, far more than we are and who need support if they are going to prosper and have sustainable growth in a way that doesn't dwarf our attempts to reduce emissions,' she said.

She re-emphasised the Prime Minister's message that 'the G8 agreement must be made to work', noting that on 1 November 2005 (see p48) there would be 'an important announcement' in London to 'carry forward the dialogue and set the scene for when everybody goes off to Montreal for the next UN discussions on targets and everything else surrounding Kyoto'.

She continued: 'There has been some speculation that the G8 programme of action was actually a default to technology, that it was about technology being the only solution. Actually it is not. If you read it there is a very strong emphasis on the market as well, on demand and the role it has to play... Market mechanisms are crucial and paramount among them is the EU emissions trading scheme [EU ETS].'

Briefly commenting on the EU ETS and the carbon price – noting that the gas price has an important link to the carbon price because of the substitution effect of coal – MacNaughton stressed that 'you cannot predict the future'. She believed it was better to 'give a number of scenarios and think about these, rather than give false precision'.

She stated that the DTI and government knew that industry was 'crying out for certainty' on the emissions trading scheme and on the size of the next phase of allocations. 'We know that you would like something that actually reflects the reality of the investment cycle beyond 2012 and know you want that partly because of the issues of relative competitiveness here, but also in order that you can do business in an orderly way.'

She stated that: 'We are working very hard on our analysis of that, and working hard to understand what other member states and the [European] Commission are going to be doing. The Commission has promised that it will publish guidance before the end of the year on methodology and on what their expectations are of individual member states.'

She went on to note that the UK government was keen for this issue to be 'managed effectively on a multilateral, decision making forum' and that industry input on the risks and opportunities were very much welcomed. She called on those present to become 'involved in the consultation process', which was 'trying to narrow the parameters of uncertainty'.

Looking to the issue of security of supply, MacNaughton felt that there was now, in general, 'a more informed debate about what is going to happen and less alarmist comment regarding the lights going out'.

She noted that while there were 'some price differences with the Continent', these were 'not really against [the general consumer], with many retail prices lower than the EU median'. However, she believed that 'the real pain' was 'being felt in the wholesale forward gas market – particularly at the middle and larger industrial user level'. As a result, the government had commissioned a joint working group to look at the way in which the UK gas market works, the way it works in the Continent and what that means for policy.

'And that takes me in to the EU Presidency, because we are preparing for the meeting of Energy Ministers in December which will be our opportunity to try to make a bit of a difference and leave a platform behind for others to make progress on this whole issue of market opening', she said.

She also noted that a report following an enquiry by the Energy Directorate (DG Tren) on 'the functioning of the market, market structure, access to infrastructure, third-party access, independence of regulation... those sorts of issues', would be ready in time for the December meeting.

MacNaughton then went on to stress that the UK had the advantage of being seen 'as a good place to invest'. 'We have a lot of infrastructure actually coming forward and we are already seeing the benefits in terms of the first new LNG terminal operating in the Isle of Grain since the summer, and the doubling of capacity in the Interconnector to Belgium which is due to come onstream a month early in November. Both of those will help with getting through the winter and calming down anybody who thinks that the lights might go out.'

'We have also been working hard at government level – we have a treaty with Norway and negotiated a treaty with Holland, both of those have helped with pipeline infrastructure. The first phase of the Norwegian pipeline comes on next November and a year or two after that the big pipeline bringing Ormen Lange gas, which will be capable of supplying 20% of our needs, will be commissioned.'


## EI Award of Council

Dr Roger Cairns FEI received an Award of Council from EI President Sir John Collins at the Autumn Lunch. The Award was made in recognition of his 'outstanding contribution' to the work of the EI. Roger has had a long association with the Institute, having been a Member of Council of the former Institute of Petroleum for five years, until the merger. He also chaired a Discussion Group Committee for many years. Outside of the Institute, Roger was Managing Director of Hardy Oil & Gas from 1989 to 1997, Chairman and Chief Executive of Cedar International from 1998 to 2005, Director of Technip from 2001 and is presently a consultant.

On accepting his award, Roger said that his work with the EI over the years had helped him 'give something back' to an industry that had been 'extremely good' to him. He stated that organisations such the EI needed 'the support of professionals' and urged those present to 'become involved'. He noted that: 'Institutes in this country play a really serious role in balancing all those other forces that are governed, if you like, with an element of self interest.'

## Role of the DTI

Coming to the close of her speech, MacNaughton asked: 'What is it that will make these markets work best, so that we can deliver on our own agenda of prosperity and looking after the environment?'

'The challenge really is to get the right quality of analysis so that we can give ministers the best possible basis for addressing these difficult decisions and to consult properly. I am hopeful that between now and publication of the energy policy proposals, many of you will have been involved in the process.'

# Solving climate change on a sustainable basis

UK Prime Minister Tony Blair concluded an international conference on climate change on 1 November 2005, saying that the world needed to solve the problem 'on a sustainable basis'. The meeting took place under the new Gleneagles dialogue that includes the G8 countries as well as China, India, Brazil, Mexico and South Africa. Blair said the evidence of climate change was getting stronger and even those who doubted it accepted there were concerns over energy security and supply. He acknowledged that the Kyoto protocol had been important and added that the world needed to combine the need for growth with 'a proper and responsible attitude' towards the environment.

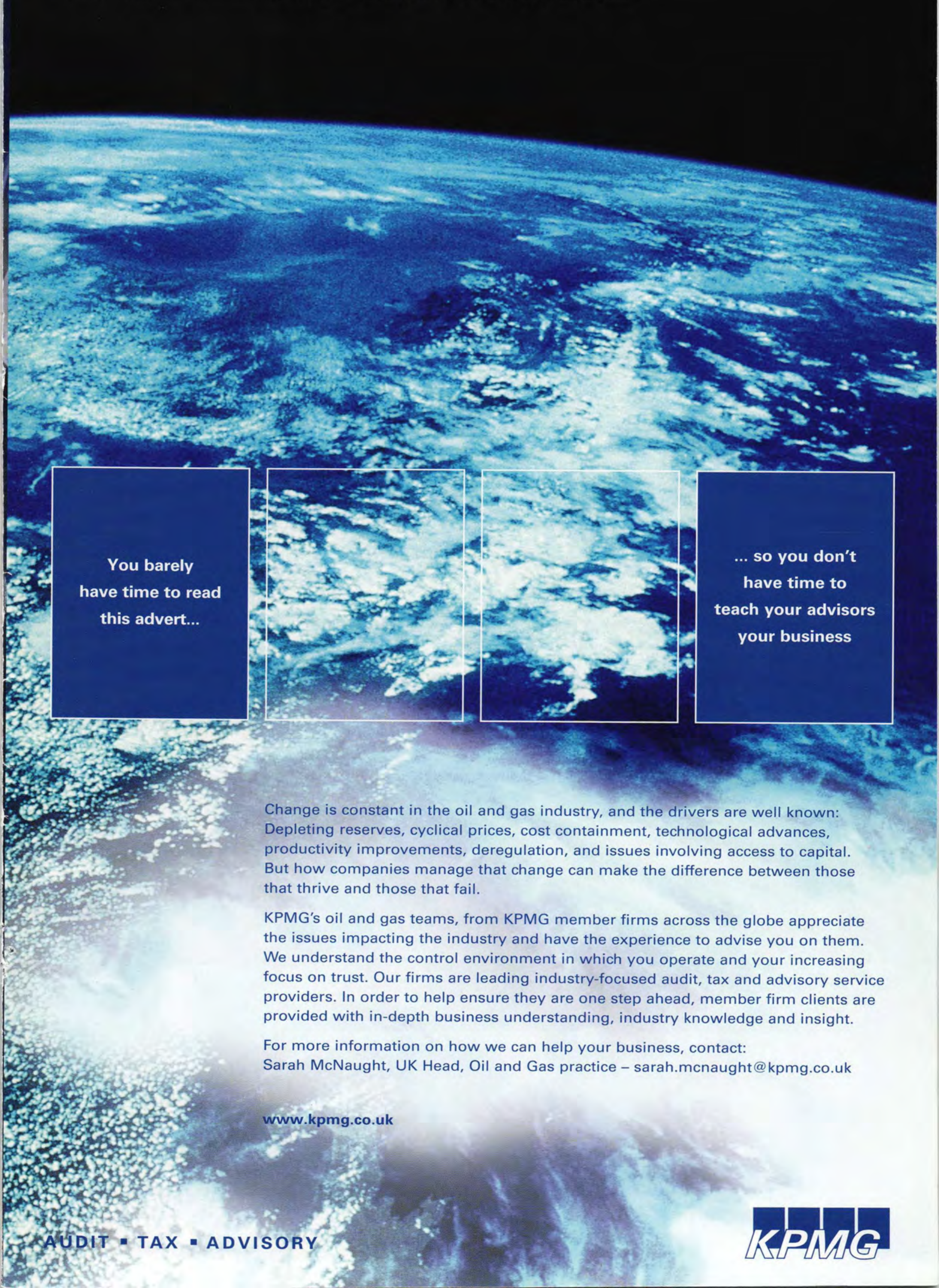
'The blunt truth about the politics of climate change is that no country will want to sacrifice its economy in order to meet this challenge,' Blair commented. 'But all economies know that the only sensible, long-term way to develop is to do it on a sustainable basis.' He added that solutions would come in part through the private sector in developing the technology and science.

The conference agreed to work together on cleaner, low carbon technologies and looked ahead to further discussions lin Montreal.

Speaking earlier in the day, Trade and Industry Secretary Alan Johnson said the meeting underlined the broad consensus needed to tackle climate change, yet maintain economic growth. 'We now need to identify priorities for cooperation, in both the short and long term. And we need to set a clear context for the private sector to invest in low carbon technologies with signals that are "loud, long and legal".'

When later asked what was the key thing the Prime Minister wanted to achieve from the talks, the Prime Minister's Official Spokesperson (PMOS) replied that it was important to recognise what had been achieved since Gleneagles. The EU had already agreed to work with China to capture and store carbon dioxide emissions, and these talks were going well. There was new work into efficiency in buildings, appliances and transport, including work with the US, the EU, Russia, China and India and the rest of the +5 Group. There was dialogue with America and China on low carbon investment strategies, and there was consultation on a World Bank Energy Investment framework which would allow the World Bank to invest in large scale projects such as low carbon heating systems in Russia, and clean coal facilities in China.

The government was also reported to be looking at when key technologies could be deployed, and how it could be made to happen by developing strategies for key sectors such as the automobile industry, or technologies to reach zero carbon emissions. ●


You barely have time to read this advert...
... so you don't have time to teach your advisors your business
Change is constant in the oil and gas industry, and the drivers are well known: Depleting reserves, cyclical prices, cost containment, technological advances, productivity improvements, deregulation, and issues involving access to capital. But how companies manage that change can make the difference between those that thrive and those that fail.
KPMG's oil and gas teams, from KPMG member firms across the globe appreciate the issues impacting the industry and have the experience to advise you on them. We understand the control environment in which you operate and your increasing focus on trust. Our firms are leading industry-focused audit, tax and advisory service providers. In order to help ensure they are one step ahead, member firm clients are provided with in-depth business understanding, industry knowledge and insight.
For more information on how we can help your business, contact:
Sarah McNaught, UK Head, Oil and Gas practice – sarah.mcnaught@kpmg.co.uk
www.kpmg.co.uk
AUDIT ▪ TAX ▪ ADVISORY
KPMG


E & P Technical Specialists Wanted
Visit www.shell.com/careers/ep
Always looking
Petroleum, Well, Project, Process, Discipline and Production engineering, & Petro/Geophysicists
At Shell, we never stop looking to the future, or for the people that will make it happen. Take now for instance. We're looking for the world's top Exploration & Production talent to join us in building a business capable of real and sustainable growth. If that's you, and you're interested in exploring your potential in an environment characterised by opportunity, flexibility and reward, why not look to your own future at:
www.shell.com/careers/ep
Shell is an Equal Opportunity Employer