Petroleum review

APRIL 2004

Middle East

- Saudi Arabia – mixed messages
- UAE – oil and gas expansion plans

Company management

- Alleviating 'partner drag'

Fabrication

- Tough times ahead

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Wednesday 14 July 2004
Savoy Place, London

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ABBREVIATIONS

The following are used throughout *Petroleum Review*:

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

No single letter abbreviations are used.
Abbreviations go together eg. 100mn cf/y = 100 million cubic feet per year.

Front cover: Agip Gas' Sabratha jacket under construction at Intermare Sarda's Arbatax yard. The 23,000-tonne jacket is to be installed offshore Libya in 3Q2004.

Photo courtesy of Intermare Sarda

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ROUNDUP
From the Editor

Is depletion underpinning high oil prices?

With oil prices remaining firm and stocks generally on the low side, particularly for gasoline in the US, earlier confidence that oil prices will soon be weakening is starting to evaporate. Financial analysts are starting to hedge their bets and quietly raising their price targets, typically by $3–$4/b. Politicians no longer mention floods of cheap oil or cheap gasoline.

A whole series of factors are cited for the firmer price outlook. All have some merit, but none really explains what is going on. In no particular order, the usual favourites include Opec's reluctance to raise production even though prices are above their target range, but, as we show on p40, it is probably only Saudi Arabia that has any operable spare capacity. Speculative buying of crude futures by hedge funds is also blamed, as is the political and social unrest that is threatening production flows in Nigeria and Venezuela. Other factors are continuing high gas prices in the US and Canada boosting demand for oil products as substitutes; rapidly expanding demand in Asia, particularly China; and reviving economic activity in the US and Japan.

Depletion factor

The one factor rarely mentioned is the increasing impact of depletion. Depletion rates are not recorded or factored in. The IEA (International Energy Agency) or EIA (Energy Information Administration) have no standard procedure for recording depletion, and may not even recognise it as a significant factor. There is no qualification to growth projections to account for the impact of depletion. For many years this made little difference, the only major producer in decline was the US and the impact on world supply could be ignored.

However, depletion is now starting to have a significant impact – and one that can only grow. In the August 2003 issue of *Petroleum Review* it was shown, using the figures from the *BP Statistical Review*, that 21mn b/d came from producers already in decline. Total production in 2002 was 74mn b/d, so 29% of global production was already coming from areas where production was in decline.

Moving forward to 2004, demand is expected to reach 80mn b/d according to the latest (March) *Monthly Oil Market Report* from the IEA, with their latest demand growth projection now 1.6mn b/d. [Note: IEA figures are rather higher than those in the *BP Statistical Review.*]

In the absence of any reliable statistics a reasonable 'guesstimate' for average decline rates is 4%, which means the decliner group's production is going down by around 850,000 b/d a year but now only account for around 25% of total production.

The under-recognised impact of this is that, to meet this year's projected demand growth of 1.6mn b/d, the producers still able to expand production have to meet the 1.6mn b/d of recognised demand growth and make up for the largely unreported 850,000 b/d of decline. Thus, the required new production is 2.45mn b/d (1.6 + 0.85). But, as it all has to come from the producers with expansion potential, this means the real average growth rate required of them is not the overall 2.1% growth reported by the IEA but a rather more demanding 4.1% (2.45mn b/d on a production base of 60mn b/d). This would seem to be a key factor in the continuing strength of oil prices.

Over the last few months the IEA's monthly reports have been hinting that production decline is likely to overtake both China and Mexico by the end of 2004. If this happens, then, by early 2005, at least 27mn b/d of production will be in decline. This would be 33% of global production. At this point decline would be over 1mn b/d per year, so, to meet demand growth of 1.5mn b/d, the countries where production was still expanding would need to add 2.5mn b/d – or an average 4.5% growth.

Inbuilt bias

The conclusion is that slowing decline is as important as expanding production to meet future energy demand – but its importance will not be fully recognised until depletion is systematically reported by agencies such as the IEA and EIA. Until then there will an inbuilt bias to investments that expand production versus those that slow depletion.

Chris Skrebowski

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

(e)world

The Oxford Institute for Energy Studies has launched its new website at **www.oxfordenergy.org**

PetrolWorld recently added an 'International Convenience News Page' to its site at **www.petrolworld.com**

A significant step towards open market access has been achieved with the launch of the 'European Oil and Gas Directory' by UK's First Point Assessment and Norway's Achilles Joint Qualification System (JQS). Suppliers registered in either First Point or Achilles JQS now have a shop window to buyers across the world. The new public domain directory is free to view, shows high level details on suppliers registered in either of the two North Sea databases, and is quick and easy to search. The directory can be accessed at **www.fpal.com** or **www.achilles.no**

Foundation Energy, the independent new London-based, energy trading and marketing company, has announced that it is now ready to trade having closed a transaction with Ritchie Capital Management under which an affiliate of RCM has provided funding to Foundation Energy. For more information about the company, e: **breason@foundationenergy.co.uk**

Windpower is likely to be the dominant renewable technology until 2020, according to a new report from the UK Government. Both on-and offshore wind can deliver almost all of the required growth to meet the 2010 renewable energy target and wind is likely to be the dominant technology as far as 2020. However, the Renewables Innovation Review says that windpower alone will not have enough resource to achieve the estimated contribution that renewable energy will need to make in order to meet the government's 2050 carbon reduction aspirations. A report summary is available at **www.dti.gov.uk/energy/renewables/policy/renewables_innovation_review.shtml**

Transmission charges for generators of renewable energy in outlying areas of Scotland could be eased under proposals recently announced by the UK Department of Trade and Industry (DTI). The report on the conclusions can be viewed from the DTI website at **www.dti.gov.uk/energy/consultations/transcharging_doc.pdf**

Datamonitor has unveiled its new website at **www.datamonitor.com** The analyst reports that the new site has been designed so that users are 'never more than three clicks away from locating the exact search' required. For more information e: **filiopoulos@datamonitor.com**

In Brief

UK

UK Energy Minister Stephen Timms *announced in early March the 22nd Offshore and 12th Onshore Licensing Rounds – claimed to be the largest for almost 40 years. The new 'Frontier' licence – designed to increase the amount of oil and gas activity in the West of Shetland region – is made available for the first time in the latest offshore round. The round has opened all of the UK onshore area and 1,039 blocks and part blocks in the offshore area for oil and gas licensing opportunities. Full details of the acreage on offer are available at* **www.og.dti.gov.uk**

ChevronTexaco has received approval *from the UK Government to proceed with the second phase of the Alba Extreme South development. First oil is expected in November 2004.*

UK Energy Minister Stephen Timms has *offered an out of round licence covering North Sea block 43/20c to RWE Dea UK SNS.*

ChevronTexaco has reached farm-in *agreements with Statoil and DONG on licence P1026 in the UK Atlantic Margin, which includes the Rosebank and Lochnagar prospects.*

Europe

The Norwegian Ministry of Petroleum *and Energy has received applications from 18 qualified companies for the 18th licensing round on the Norwegian Continental Shelf. This is a substantial increase from the 13 companies that applied in the 17th licensing round. The Ministry aims to award new production licences in 2Q2004.*

Norway's Government Petroleum Fund *grew by 39% in 2003 to NKr845bn ($121bn), according to the central bank.*

Total (40%, operator) has announced *the start of production from the Skirne gas and condensate field in block 25/5 in the Norwegian sector of the North Sea. Planned plateau production is 150mn cf/d of gas and 6,900 b/d of condensate.*

Statoil has signed a contract to sell the *multipurpose shuttle tanker* MST Odin *to Marathon Petroleum and its Alvheim project partners for an undisclosed sum. The sale is contingent upon the partners' approval of the development of the North Sea Alvheim area, and following approval of a plan for*

NEWS Upstream

Developing stranded gas

Syntroleum and Sovereign Oil & Gas Company are to work together to acquire and develop stranded natural gas fields worldwide using Syntroleum's proprietary gas-to-liquids (GTL) synthetic fuels technology. The joint development agreement brings together the Tulsa and Houston-based companies to identify and licence proven gas fields in remote locations for use as feedstock to supply Syntroleum's GTL Barge. The GTL Barge will produce environmentally friendly synthetic fuels from natural gas at a competitive price to replace high-sulphur diesel and other conventional fuel.

Earlier in February 2004, Syntroleum announced the signing of a Memorandum of Understanding with Spanish engineering contractor Dragados Industrial and TI Capital, the finance arm of a Middle East-based crude oil transportation and marketing company, to finance, build, own and operate GTL Barge plants.

Syntroleum's GTL Barge consists of a nominal 19,000 b/d total liquids production plant mounted on an inland barge. Ideal for calm water conditions, the barge plant uses Syntroleum's proprietary air-based GTL technology, the Syntroleum Process, to convert natural gas into synthetic diesel and other clean fuels. The GTL Barge is designed to develop already discovered offshore and near-shore natural gas assets where there is currently no infrastructure to economically produce and transport the gas. The GTL Barge is claimed to be capable of producing about 130mn barrels of synthetic fuel from a 1.2tn cf field. The primary product is a high-quality, environmentally friendly synthetic diesel fuel that is biodegradable, non-toxic and as clear as water.

Syntroleum has already identified 40 stranded gas fields that would be a good fit for its GTL Barge plants, with potential reserves equivalent to 8bn barrels of synthetic diesel and clean fuels.

Tackling decline in Seven Heads gas output

Ramco Energy (86.5%, operator) reports that production from the Seven Heads gas field in the Celtic Sea has declined from 44.4mn cf/d in February to 40.4mn cf/d in March. Although the technical team reviewing the reservoir has not completed its work, it believes that water condensing from the gas and a small amount of formation water are building up in one or more of the well bores, thereby masking reservoir pressures and aggravating the decline in production.

In consultation with its partners – Island Petroleum Developments (12.5%) and Sunningdale Oils (1%) – and Marathon, Ramco is now developing plans to embark on a diagnostic 'blow-down' programme which will involve all five of the Seven Heads wells being shut in. A temporary connection to the compressors on Marathon's Kinsale A platform will then be used to reduce the pressure in the pipeline connecting Seven Heads to the platform. Once this has been done the Seven Heads wells will be re-opened. This should result in a surge of production that will quickly remove any water that has built up in the well bores.

The data obtained during this process should allow an improved measurement of reservoir pressures, and will be invaluable in helping to determine the future deliverability and recoverable reserves of the field, states Ramco.

Boulton H field comes onstream

The Boulton H field in the UK southern North Sea has come onstream with an initial production of nearly 140mn cf/d of gas. Boulton H is the last field to be commissioned as part of the five-field CMS III development programme, which has been developed using the production and transportation facilities of the Caister Murdoch System (CMS). Current combined production from the five fields – Murdoch K, Hawksley, McAdam, Watt, and now Boulton H – is 310mn cf/d.

In addition to production from Boulton H, the additional compressor unit installed as part of the CMS III development programme is fully operational on the Murdoch platform, doubling CMS compression capacity and boosting overall production by around 15%. The added compression also allows ample provision for handling future developments.

Partners in the CMS III development are: ConocoPhillips (59.5%), GdF Britain (26.4%) and Tullow Oil (14.1%).

NEWS Upstream

Boosting Alpine oil output

ConocoPhillips (78%, operator) and Anadarko Petroleum (22%) are planning to increase oil production capacity at the Alpine field on Alaska's North Slope to 140,000 b/d of oil. The field, which started production in November 2000, is currently producing about 100,000 b/d.

The Alpine Capacity Expansion Project Phase 2 (ACX2) will be completed by mid-2005. ACX2 will increase both the oil handling and seawater injection capacities of the Alpine oil field facilities. The $58mn ACX2 project follows the previously announced ACX1 project, which will start up later this year.

The two expansion projects are important for increasing oil production and maintaining reservoir pressure. To date, 81 wells – 39 production and 42 injection – of the planned 94 wells have been completed at the two Alpine drill sites. Alpine has been developed exclusively with horizontal well technology and employs enhanced oil recovery (EOR).

The 40,000-acre field was developed on just 97 acres, or two-tenths of 1% of the field area. In addition, Alpine is a near zero-discharge facility. The waste generated is reused, recycled or properly disposed. There is no permanent road to the field; in the winter, ice roads are constructed to allow transportation of equipment and drilling supplies to the site. These roads minimise environmental impact, because in the spring the ice roads melt, leaving no trace on the tundra. Small aircraft also provide services to the field.

Alpine is the largest onshore oil field discovered in the US in more than a decade. It also is the western-most producing oil field on Alaska's North Slope. The field is located in the Colville River area, 34 miles west of the Kuparuk River field, near the border of the National Petroleum Reserve.

Fabrication contract award for Constitution

Mustang Engineering, part of John Wood Group, has been selected by Kerr-McGee to provide engineering, procurement services and project management assistance for the topsides production facility on a truss spar for its recently announced Constitution field in Gulf of Mexico Green Canyon blocks 679 and 680. It will be similar to those previously designed for the Boomvang, Nansen and Gunnison spars. The Constitution truss spar, to be located in 5,000 ft of water offshore Louisiana, will have the capacity to process 40,000 b/d of oil and 200mn cf/d of gas. The field development plan includes five dry trees and one subsea tieback. First production is expected by mid-2006.

Harweel project

Amec has further strengthened its position in the Middle Eastern energy market by winning a front-end engineering design (FEED) contract from Petroleum Development Oman (PDO) for the development of the Harweel cluster of oil fields in southern Oman.

PDO recently embarked on a long-term strategy to sustain its oil production through enhanced oil recovery projects. Amec's FEED contract forms part of the Phase 2 development of the Harweel cluster, which is based on miscible gas injection. Intended to extend the life of the cluster, the project will provide an oil and gas field gathering system, gas injection facilities and transportation via pipelines to a central processing plant for separation and gas sweetening. The contract also includes a sweet gas export pipeline and a stabilised crude oil export pipeline. The new facilities should enable PDO to produce over 20,000 cm/d of oil and gas from early 2008.

Row over Sakhalin 3

United Financial Group (UFG) has reported that ExxonMobil's Sakhalin 3 project is at the centre of a row between the US and Russian Governments. Exxon and Texaco (together with Rosneft) were awarded the exploration rights to three blocks – Kirinsky, Ayashsky and East Odoptinsky – back in 1993. However, little progress has been made over the past decade, mainly because of the fruitless search for an acceptable progress production sharing agreement (PSA) framework under which the project could be developed. The tender was recently annulled on the grounds that without PSA status, the exploration and development of the project could be carried out through a standard auction.

Energy Minister Igor Yusufov said that the Russian Government wanted up to $1bn for the licence. The move has been described by US Ambassador to Russia Alexander Vershbow as potentially harmful to US-Russia ties.

In Brief

development and operation by the Norwegian authorities. Marathon intends to convert the vessel into an FPSO for use on the Alvheim field.

Eastern Europe

***Petreco of the UK is soon to commence** drilling operations in Bulgaria's Galata Cape gas deposit on the Black Sea coast. The company expects to pump 400mn cm of gas over the next three to four years, reports* Stella Zenkovich.

North America

***The ban on offshore drilling near the** Queen Charlotte Islands in British Columbia could be safely lifted according to a Canadian Government scientific panel, reports* Monica Dobie. *The report says environmental precautions would have to be taken, such as creating marine-protected areas and restricting drilling close to land.*

***Canada's Petroleum Technology** Research Centre has concluded that empty wells in the Weyburn oil field, Saskatchewan, can hold an estimated 21mn tonnes of carbon dioxide, writes* Monica Dobie.

***'HOT Ice No. 1', a US government-**industry collaboration looking for methane hydrates in Alaska, has wrapped up without any extraction of the otherwise abundant gas, writes* Philip Fine.

***Technip has secured a contract from** Kerr-McGee for the engineering and construction of a spar floating production platform hull as well as the engineering and delivery of the associated moorings and production riser system for the Constitution field in Gulf of Mexico Green Canyon blocks 679 and 680. Fabrication will be carried out by Technip's yard in Mantyluoto, Finland. Delivery is slated for 2005. First oil is expected in mid-2006.*

Middle East

***Anadarko Petroleum is selling its block** 30 gas concession in northern Oman. The concession is estimated to hold 300bn cf of gas.*

***Tanganyika Oil of Canada is to sell** 3mm shares for $18.9mn, writes* Stella Zenkovich. *The monies are to be invested in developing the 2.4bn*

In Brief

barrel Oudeh field in north-eastern Syria. Production is forecast to peak at 30,000 b/d of oil.

***A joint venture comprising Eni (50%),** Repsol-YPF (30%) and Saudi Aramco (20%) have signed a natural gas exploration and development agreement covering Section C in Saudi Arabia's Rub Al Khali Basin. Meanwhile, Sinopec and Saudi Aramco have signed an agreement covering Section B.*

Russia & Central Asia

***Rosneft is understood to be planning** to invest $1.2bn in the Vankor field in East Siberia over the next four years.*

***Yuri Trutnev has recently been** appointed Russia's new Minister of Natural Resources.*

***BP is to invest $5bn on developing the** Sakhalin-5 project. Rosneft and BP have signed a corresponding framework agreement under which each will retain their current stakes in the project – Rosneft 51%, BP 49%. Reserves are estimated at 700mn to 800mn tonnes of oil and 600bn cm of gas.*

Asia-Pacific

***ConocoPhillips' Belanak field in West** Natuna, South China Sea, is expected onstream in December 2004, at an initial production of 10,000 b/d, rising to around 40,000 b/d in 2005.*

***BG, together with partners Oil and** Natural Gas Corporation (ONGC) and Reliance Industries, is to invest $140mn in the Panna oil and gas field, offshore Mumbai, to target new reserves and to expand current production. The expansion programme is expected to result in gross incremental recovery of 18mn barrels of oil and 74bn cf of gas. First production is expected in 3Q2005.*

***The Pakistan Government is reported** to have granted two petroleum exploration licences to Pakistan Petroleum covering block 2766-1 (Khuzdar) in the Khuzdar district of the Balochistan Province and 2568-13 (Hala) in the Hyderabad and Sanghar districts of Sindh Province.*

***Cairn Energy's N-A-1 exploration well** in Rajasthan has flowed 1,225 b/d. Preliminary oil in place reserves are 130–470mn barrels, of which 20–80mn barrels are thought recoverable.*

NEWS Upstream

UK oil production remains low

UK oil production in December 2003 was down marginally on the month at 2,056,143 b/d, and down significantly (12.6%) on the year, according to the latest (February) *Oil and Gas Index* from the Royal Bank of Scotland. Gas production of 13,116mn cf/d was down on the month (November 2003: 13,145mn cf/d) and up on the year (December 2002: 12,582mn cf/d).

Commenting on the results the Bank's Senior Economist and energy specialist Tony Wood said: '2003 saw a significant decline in UK oil production, despite higher oil prices maintaining revenues. Many commentators expect oil prices to fall through 2004, which combined with the weaker dollar represents the key economic challenge for the competitiveness of North Sea oil production this year.'

Year Month	Oil production (av. b/d)	Gas production (av. mn cf/d)	Av. oil price ($/b)
Dec 2002	2,353,028	12,582	28.32
Jan 2003	2,274,870	12,890	31.17
Feb	2,215,831	13,599	32.23
Mar	2,251,714	12,420	29.92
Apr	2,092,765	10,868	27.50
May	1,948,620	9,659	25.59
Jun	1,940,265	9,221	27.31
Jul	1,957,888	9,250	28.43
Aug	1,858,409	9,842	29.51
Sep	1,966,800	9,546	26.81
Oct	2,018,972	9,934	28.93
Nov	2,036,012	13,145	28.76
Dec	2,056,143	13,116	29.84

Source: The Royal Bank of Scotland Oil and Gas Index

North Sea oil and gas production

Kashagan development plan approved

Kazmunaygaz (KMG), the petroleum authority for the Republic of Kazakhstan, and the consortium companies of the North Caspian production sharing agreement – currently* ExxonMobil (16.67%), Agip (16.67%), British Gas (16.67%), Shell (16.67%), Total (16.67%), ConocoPhillips (8.33%) and Inpex (8.33%) have announced approval for development plan for the Kashagan oil field.

Production start-up is now expected in 2008, with an initial output of 75,000 b/d of oil, ramping up to 450,000 b/d. Further development phases will raise full field production to a plateau level of 1.2mn b/d. Full field development is currently expected to cost some $30bn, with projected ultimate production of up to 13bn barrels of oil. (See p34) for more details on the project.)

Note: After completion of BG sale: ExxonMobil, Agip, Shell and Total (20.37% each), ConocoPhillips (10.19%), and Inpex (8.33%).

North Sea contract hat-trick for Technip

Technip has been awarded three contracts for key developments in the UK North Sea that represent a total value of over £35mn. The Shell Pierce project award involves the engineering, procurement, installation and commissioning of a dynamic water injection riser, water injection riser base, two water injection flow lines and two water injection manifolds. Co-venturers are Nippon Oil Exploration and Oranje-Nassau.

The Eni Stirling project involves the design, manufacture and installation of two flexible flow lines, installation of a free issue control umbilical and the design, fabrication and installation of a wellhead protection structure. Technip is also responsible for all associated tie-ins, pre-commissioning and testing.

The BP Rhum project is an engineering, procurement, installation and commissioning (EPIC) contract that involves the tie-back of new wells to an FPSO, including the installation of four steel tube umbilicals and three in-field pipe-in-pipe pipelines.

NEWS Upstream

Stratic Energy focuses onshore Morocco

Stratic Energy has acquired a 36% working interest in two large concessions located onshore north-western Morocco. The Moulay Bousselham and Mamora permits have only been lightly explored in the past.

However, a proven hydrocarbon system is present on the blocks, with exploration drilling in the 1920s confirming the existence of the Ain Hamra oil field at shallow depths in Tertiary reservoirs within the area now enclosed by the Moulay Bousselham concession. The field produced light oil sporadically until the late 1950s and was then abandoned. No material exploration activity has been undertaken since that time.

Existing seismic suggests the presence of both shallow Tertiary over-thrust and deeper Mesozoic sub-thrust objectives. A number of shallow gas anomalies have already been identified and the group is currently assessing the local industrial and domestic market for gas. Infrastructure exists with railway, gas pipelines and a refinery all located on or immediately adjacent to the company's blocks.

The work programme for the initial three-year term will consist of the acquisition of a regional airborne gravity and magnetic survey, reprocessing existing 2D seismic and the acquisition of at least 250 line-km of new 2D seismic. The group is committed to drill four exploration wells to test shallow Tertiary objectives or one deep exploration well to test the sub-thrust play. It is anticipated, however, that both objectives will be tested by wells in the initial term of the licence, with the first well expected to spud in late 2004/early 2005

The offshore area has been licenced in recent months with both Petronas and Repsol holding offshore concessions near the Stratic blocks. Offshore exploration drilling in Morocco will commence later this year with wells from both Shell and Vanco currently slated for early drilling.

Stratic's partners in the venture are Heyco International (39%) and Enercorp (25%). Upon commercial success, ONAREP, the Moroccan state oil company, has an option to back-in for a 25% interest in any development.

Fortuna on way to increased production

Fortuna Energy, a wholly-owned subsidiary of Talisman Energy, has completed the Reed Hz #1 and Hakes Hz #1 gas wells in the Appalachian Basin of New York State. Reed tested at 20.3mn cf/d of gas, while Hakes flowed 17.5mn cf/d.

The results come on the heels of the company's recent Andrews discovery. 'In the past four months we have tested five successful wells at combined rates of 69mn cf/d,' said Dr Jim Buckee, President and Chief Executive Officer of Talisman Energy. Pipeline construction is currently under way and both wells will be tied into an existing Fortuna gathering line. The Andrews well was expected to commence production in mid-March, at an initial production rate of 10mn cf/d, rising to 20mn cf/d over the course of the month.

Fortuna plans to drill a total of 11 horizontal Black River wells during 2004, three of which are currently drilling. It expects to spend C$85mn in 2004, increasing average production this year to over 80mn cf/d (69mn cf/d net of royalties), compared to 60mn cf/d in 2003 (52mn cf/d net of royalties).

Apache confirms Qasr reserves estimates

Apache reports that its Qasr-3X well on Egypt's Khalda concession has logged 448 ft of net pay in the Jurassic Lower Safa formation. The well results have helped confirm the company's original estimate of ultimate recoverable reserves in the range of 1tn to 3tn cf of natural gas and 20mn to 60mn barrels of condensate. Three additional Jurassic delineation wells and at least one shallower Alam El Bueb (AEB) Cretaceous well at Qasr are planned this year.

Facilities design and procurement are under way to develop an extensive pipeline system from Qasr. The field will be linked to a gas supply hub at Apache's Shams gas field, with the ability to transport gas to three existing gas processing plants, two of which are operated by Apache's Khalda Petroleum Company joint venture.

The Qasr-1X discovery well, completed in July 2003, tested at a daily rate of 51.8mn cf/d of gas and 2,688 b/d of condensate from two zones. Qasr-2X tested at 35.4mn cf/d of gas and 1,320 b/d of condensate in December 2003, and is currently producing at a restricted rate of 10mn cf/d of gas and 400 b/d of condensate.

In Brief

***Pertamina has signed a preliminary** agreement with ExxonMobil over development of Indonesia's largest oil find in three decades – Cepu. The two sides are understood to have agreed to split equally any gains from the field. Cepu has proven reserves of 600mn barrels, although some analysts estimate it has upward of 1bn barrels. Field development is considered by analysts to be crucial to Indonesia's efforts to remain a net oil exporter.*

***Burlington Resources is to develop** natural gas deposits at Bajiachang gas prospect in south-western China's Chuanzhong block. Chuanzhong has proven gas reserves of 30bn cm. First gas is expected to initially flow at 420mn cmly from 2005.*

***In order to improve its supply security,** China is establishing a 70- to 75-day strategic petroleum reserve in four locations. The first phase – to be built in Aoshan in Zhejiang Province on the coast south of Shanghai – is scheduled to complete in 2007. The remaining three phases will take place in Zhenhai (in Zhejiang Province), Huangdao (in Shandong Province) and Dalian (in Liaoning Province). China is expected to import 60% of its oil by 2020.*

***Woodside Energy is to sell its Bass** Strait exploration interests to Sydney-based oil and gas producer Anzon Energy Australia for A$65mn.*

***Unocal reports that the Gehem-2** appraisal well at the Gehem field offshore East Kalimantan, Indonesia, flowed at a daily rate of 31.3mn cf of gas and 1,917 barrels of condensate. The find is thought to have the potential to contain up to 1.5tn cf of recoverable gas.*

Latin America

***ChevronTexaco is to be awarded the** exploration licence for Plataforma Deltana block 3 offshore Venezuela's Atlantic Continental Shelf.*

***The Brazilian National Oil Agency** is reported to have announced an E&P licencing round in line with the country's objective of achieving energy self-sufficiency by 2006. Some 33 companies have been qualified to participate in the round, which will conclude in August with the auctioning of the new areas, most of which are located offshore in the Atlantic Ocean.*

In Brief

UK

Shell has announced a further downgrade *of its oil reserves and is to delay publication of its annual report, due on 19 March, to June 2004. The company said its reserves in Norway were 250mn barrels lower than previously thought.*

Europe

Inge K Hansen has been appointed *Group President and Chief Executive Officer (CEO) of the new Aker Kvaerner. Hansen's previous position was acting CEO with Statoil. He will be replaced by Helge Lund, who until now has been CEO in Aker Kvaerner.*

The European Commission is reported *to have approved the $925mn sale of the ABB oil and gas businesses to a private equity consortium.*

Eastern Europe

Mol of Hungary has sold its 35% *minority stake in Egaz and 27.2% in Degaz – two regional gas distributors – to Gaz de France for an undisclosed sum, reports* Stella Zenkovich.

North America

Statoil has signed a Letter of Intent *with Dominion regarding the proposed expansion of the Cove Point LNG facility.*

EnCana has sold its 53.3% interest in *heavy oil producer Petrovera Resources to Canadian Natural Resources for $285mn (C$374mn).*

Pacific Energy Partners is understood to *be paying C$156mn for BP's 1,300-km Rangeland pipeline system in Alberta. The company also plans to buy Imperial Oil's 222-km Mid-Alberta Pipeline.*

Middle East

The Bush administration is reportedly *expected to prohibit US oil and gas companies from future investments in Syria – although it will allow some already existing projects to continue – as part of new US sanctions to be unveiled in the near future.*

The US is reported to have awarded *$200mn worth of new contracts for supplying oil to Iraq, all of which rely on*

NEWS Industry

Management changes at Shell

Sir Philip Watts has stepped down as Chairman of the Board of The Shell Transport and Trading Company, and as Managing Director, by mutual consent. Jeroen van der Veer, the President of Royal Dutch Petroleum, will succeed him as Chairman of the Committee of Managing Directors.

Meanwhile, Lord Oxburgh has been appointed interim Non-Executive Chairman of The Shell Transport and Trading Company.

Malcolm Brinded has been appointed a Director and Managing Director of the Company and will serve as Vice Chairman of the Committee of Managing Directors. He will step down from the Board of Management of Royal Dutch Petroleum Company and offer himself for election by shareholders of The 'Shell' Transport and Trading Company at the forthcoming Annual General Meeting (AGM).

Walter van de Vijver has stepped down from the Board of Management of Royal Dutch Petroleum Company and as a Group Managing Director, by mutual consent. His duties as Chief Executive of Shell's Exploration and Production business will be assumed by Brinded, in addition to his current responsibilities for the Gas and Power business.

Rob Routs, currently a member of the Board of Management of Royal Dutch Petroleum Company, will assume van der Veer's responsibility for the Chemicals business in addition to his current responsibilities for the Oil Products business. Judith Boynton will continue as a Managing Director of the Shell Transport and Trading Company, and as Chief Financial Officer.

Scottish E&P 'Oscar' winners unveiled

The achievements of seven oil and gas industry companies were recognised on 4 March 2004 at a gala dinner in Aberdeen attended by senior government and industry figures to mark the 2004 Scottish Offshore Achievement Awards. The awards were organised by the Scottish Enterprise Energy Team in conjunction with industry sponsors.

The winners were:

- Export Achievement Award, sponsored by the *Press and Journal*: KCA Deutag.
- Innovative Technology Award, sponsored by the Department of Trade and Industry: Baker Oil Tools.
- Health, Safety and Environment Award, sponsored by BP: PSL Energy Services.
- Most Promising Company Award, sponsored by Ramco Energy: Petrotechnics.
- Small Company Award, sponsored by Offshore Europe Partnership: Integrated Subsea Services.
- Succeeding Through People Award, sponsored by ChevronTexaco: KBR Production Services.
- Rising Star Award, sponsored by KBR Production Services: John Donachie of Schlumberger Oilfield Services.
- The award for Overall Company Performance went to KCA Deutag.

The winning companies will receive a business development trip to Houston, Texas, during the world's largest oil and gas event this year, OTC 2004, including assistance with meeting key commercial contacts in the global energy industry from Scottish Development International, the Energy Team and the award sponsors.

Call for new Iraq National Oil Company

The US-led Coalition Provisional Authority (CPA) has reportedly proposed to have a reconstituted Iraq National Oil Company (INOC) in place before 30 June 2004, the scheduled date for the handover of administration to the Iraqis. It is hoped that such a move will help depoliticise the oil industry and make it easier for Iraq to attract the long-term investment it desperately needs.

CPA wants there to be clear separation of powers between a new INOC and the Iraqi Oil Ministry. The Ministry would act as a government agency and oversee critical matters such as Opec, but would have little or no say in day-to-day management of the industry. This would be left to INOC, which would have an experienced technocrat as director general or president, answerable to a board of directors free of political control and made up of industry experts.

NEWS Industry

Guidance on greenhouse gas reports

As the reporting of greenhouse gas (GHG) emissions has become more widespread within the oil and gas sector the need for guidance on how to account for and report these emissions has grown. Recognising this need, the International Petroleum Industry Environmental Conservation Association (IPIECA) – in collaboration with the American Petroleum Institute (API) and the International Association of Oil and Gas Producers (OGP) – initiated the development of 'Petroleum Industry Guidelines for Reporting Greenhouse Gas (GHG) Emissions' to promote credible, consistent, and reliable GHG accounting and reporting practices from oil and gas operations.

The finished product is the result of nearly a year's work and was developed with the broad participation of petroleum operators, including those already tracking GHG emissions from their operations. The Guidelines – which strike a balance between flexibility and cost-effectiveness in accounting and reporting, and the need for consistency and accuracy in the reported results – are now freely available at **www.ipieca.org/reporting/ghg.html**

Latest European Union developments

MEPs are heading off a move by European Union (EU) Ministers to agree without consultation pared-back legislation on guaranteeing the security of gas supplies during a European crisis, reports *Keith Nuthall*. The European Parliament's industry committee has voted narrowly to refuse an EU Council of Ministers bid to approve the heavily amended legislation without further input from MEPs. This move followed vigorous opposition to European Commission (EC) attempts to gather extra authority to direct gas flows around Europe during serious supply shortages. Because Ministers and MEPs subsequently amended out these proposed powers, the Council says Parliament has removed its own veto rights by erasing clauses affecting the single European market.

In other EU news:

- Russia has presented Brussels with a 14-point list of concerns about potential trade losses when the EU enlarges in May. Moscow is particularly seeking compensation for lost exports in Poland and Slovakia and has called on the Commission to give Russian energy imports more generous treatment. Meanwhile, the recently-resolved standoff between Belarus and Russia over gas supplies has raised concerns at the Commission that such an embargo could have starved neighbouring EU accession countries of gas.
- A 300mn loan could be paid to Italy's Eni by the European Investment Bank (EIB) to help it drill 85 wells in the Adriatic and Ionian seas, involving the installation of eight new platforms and about 125 km of subsea pipelines. Total reserves are estimated at 26bn cm.
- The Commission has also approved reductions in excise duty charged by the UK Government on bioethanol used for road transport from January 2005 until December 2010. It would be set at 20 pence below the duty for ultra-low sulphur petrol and sulphur-free fuel. It has also approved a total exemption until 2010 within Germany from excise duty on mineral oil for pure and blended biofuels.

Government changes in Faroe Islands

Following a general election in the Faroe Islands on 20 January 2004 the Ministry of Petroleum has been abolished and the responsibilities of the Ministry have been divided between the Ministry of Trade and Industry and the newly formed Ministry of the Interior. Petroleum affairs have been placed with the Ministry of Trade and Industry.

The new Minister of Petroleum, Bjarni Djurholm, has decided that petroleum affairs shall be organised as an administration under the Ministry. The former Permanent Secretary of the Ministry of Petroleum, Herálvur Joensen, has taken up position as Permanent Secretary at the Ministry of Fisheries and Maritime Affairs. Sigurdí Jákupsstovu has been appointed head of the new petroleum administration. Sigurdí Jákupsstovu is also Director of the Faroese Geological Survey and will function as director of both the Geological Survey and the Faroese Petroleum Administration.

The name of the new administration is 'Faroese Petroleum Administration'. It will be responsible for all administrative tasks related to petroleum exploration on the Faroe Shelf and will be the focal point of contact in these matters. For more details, visit www.ofs.fo

In Brief

supplies from Turkey. Six of the deals are with Turkish firms – Turcas Petrol, Opet Petrolcul, Petrol Ofisi, Delta Petrol Urunleri Ticaret, Iprgaz and Tefirom. The seventh contract went to Texas-based Refinery Associates.

Russia & Central Asia

***Roman Abramovich is reported to be in** discussions to sell half of his 92% stake in Sibneft, with ChevronTexaco, Total and Shell thought to be potential bidders.*

***Sakhalin Energy, operator of the** Sakhalin-2 project, is to supply up to 300,000 t/y of LNG to Japan's Toho Gas over 23 years, starting in 2010.*

***Azerbaijan is planning to buy 4bn cm** of gas from Kazakhstan through the KazRosGaz joint venture during 2004. The gas will be supplied from the Karachaganak field, with reserves put at more than 1.2bn tonnes of oil and condensate, and 1.35tn cm of gas.*

***Iran is reportedly planning to build a** terminal at the Caspian Sea port of Kiyanly in Turkmenistan for the export of liquefied Turkmen gas to the Middle East country. Construction is expected to complete in August 2005.*

***Irkutsk Region's Governor Boris** Govorin and TNK-BP Managing Director Viktor Wekseberg are reported to have sealed an agreement to establish the East Siberian Gas Company, which will implement a gas supply and gasification project based on gas feedstock from the Kovyktinsk gas condensate field. The partners aim to be supplying 300mn cm of gas by 2006, with further growth to 2.2bn cm in 2009.*

***Russia's Federal Energy Commission** (FEC) is reportedly insisting on the inclusion of the Caspian Pipeline Consortium (CPC) in the register of natural (infrastructure) monopolies. Should this happen, its oil transit rates could be raised. However, the decision to include CPC in the register can be taken only with the consent of all the consortium's shareholders. The structure of the stakes of the founding member states in the CPC is: Russia (24%), Kazakhstan (19%) and the Sultanate of Oman (7%). The consortium's private founding members include: Chevron Caspian Pipeline Consortium (15%), Lukarco (12.5%), Rosneft-Shell Caspian Ventures (7.5%), Mobile Caspian Pipeline Company (7.5%), Agip International (2%) and others.*

In Brief

Asia-Pacific

The Indian Government is understood *to be studying ways of having strategic gas reserves for 15 days in order to ensure uninterrupted supply once the market matures five years from now. The project is expected to cost some $100mn. India's gas consumption is projected to rise from 65mn cm/d to 300mn cm/d by 2025, while the share of gas in its domestic energy sector is expected to increase from 8% to 20%.*

Shell reports that it has disposed of *some 1.9bn shares in Sinopec via a bookbuilt placing of shares on public markets that raised about $742mn.*

PetroChina has signed a take-or-pay *natural gas agreement with Tianjin Gas Group for the second Shaanxi-Beijing gas pipeline, covering the delivery of 1.2bn cm/y of gas. The pipeline project is scheduled for completion in September 2005. Designed with an annual transmission capacity of 12bn cm, the same volume as the West-East pipeline, the second Shaanxi-Beijing pipeline covers the five provincial and municipal markets of Beijing, Tianjin, Shanxi, Hebei and Shandong.*

Canadian-based InterOil Corporation *is understood to be buying BP's Papua New Guinea (PNG) petroleum distribution assets and operations, including three terminals, seven depots and over 40 fuel retail sites, for $11.3mn.*

Shell is to sell a 26% stake in India's *Hazira LNG project to Total for an undisclosed sum. Shell will remain the majority owner and operator of Hazira, which is due to deliver first gas in 4Q2004.*

Japan National Oil Company (JNOC) *has merged with the Metal Mining Agency of Japan (MMAJ). The new organisation is to be known as the Japan Oil, Gas and Metals National Corporation (JOGMEC).*

Latin America

Marathon Oil is reported to have cancelled *its plans to build a 750mn cf/d LNG import terminal in Tijuana, Mexico. The action follows a decision by the Baja California state government to appropriate land Marathon had targeted for the terminal.*

NEWS Industry

Changes to fuel duty and PRT in UK budget

UK Chancellor of the Exchequer Gordon Brown announced a 1.9 p/l increase in fuel duty in his latest Budget. He also unveiled an incentive for the introduction of sulphur-free petrol and diesel (less than 10 ppm sulphur versus current 50ppm or less) which will carry a duty rate 0.5 p/l lower than that currently applied to ultra-low sulphur fuels. Rises will be delayed for six months, until September. Meanwhile, car tax is frozen, as is all vehicle excise duty (VED).

Chris Hunt, Acting Director General of UKPIA (UK Petroleum Industry Association), in welcoming the reduction, commented: 'Our member companies have responded positively in the past to the Government's desire for the early introduction of ultra-low sulphur diesel and petrol (50 ppm maximum sulphur) ahead of the EU mandated timetable, with consequent benefits to UK air quality. Sulphur-free petrol and diesel costs more to produce so the Chancellor's acknowledgement of this fact is welcomed. UK refiners have had to make substantial investment to produce these new fuels and our member companies will be working hard to ensure that they are introduced within the required timescale outlined in legislation.'

'The introduction of cleaner fuels over the last decade has enabled the use of new engine and exhaust clean-up technologies, bringing about a substantial reduction in exhaust emissions.'

'Sulphur-free fuels will optimise the potential benefits of new engine technologies such as petrol direct injection and exhaust de-nox catalyst clean-up technologies, with consequent benefits to fuel efficiency and carbon dioxide reduction.

Looking upstream, the Budget also saw further amendments to petroleum revenue tax (PRT), designed to remove anomolies and prevent tax leakage. The changes, which came into force on 17 March 2004, are designed to stop oil and gas companies from artificially creating or increasing certain losses by transferring fields. In addition, measures are to be introduced to prevent companies from creating an uplift in the cost of a North Sea asset for PRT purposes via a connected party transaction.

On the positive side, exploration and appraisal expenditure incurred on or after 1 January 2004 by a company that does not have sufficient taxable profits to make use of the 100% allowances on such expenditure (eg because they are not yet trading) will be entitled to the exploration expenditure supplement, which is an annual uplift of 6% in the value of unused capital allowances.

Commenting on the upstream announcements, Ian Palethorp, Director, PricewaterhouseCoopers said: 'Overall this is a mixed bag of measures for the oil and gas industry. The measures to prevent tax leakage are perhaps not unexpected, but the exploration expenditure supplement is a welcome additional relief for companies who are committed to further exploration in the UK North Sea sector.'

Business plans in the pipeline

Gazprom CEO Alexei Miller recently announced that the business plans for the North European gas pipeline and the Yuzhno-Russkoye gas field will be synchronised, reports analyst UFG. The 600bn cm field will become the key gas source for the new pipeline once it reaches its maximum output level of 25bn cm/y. Field development will require major investment in infrastructure: 400 km of pipeline and 1,000 km of roads. Gazprom has estimated the total development cost at about $800mn. The 30bn cm capacity North European pipeline is also a major project, with $5.7bn to be spent on a 1,200-km pipeline from Russia to Germany, then under the Baltic Sea and from there to the UK.

UFG comments that it is not yet clear when, and if, Gazprom will undertake these major projects. However, in its view they are not likely in the short- to medium-term. The analyst does not anticipate the field reaching peak output and the pipeline operating at full capacity before 2010.

ChevronTexaco to operate new LNG vessel

ChevronTexaco Shipping Company has announced that one of its affiliates will serve as the operator of the North West Shelf Venture gas project's newest vessel, the *Northwest Swan*. The vessel is currently planned to deliver LNG from the project's Western Australian operations to customers in Japan, Korea and China, as well as provide opportunities to deliver into the LNG spot market.

The *Northwest Swan* was constructed at the Daewoo Shipbuilding and Marine Engineering shipyard in Okpo, Korea. Unlike the fleet's other eight ships that are equipped with spherical tanks, the *Northwest Swan* will utilise a membrane containment system, which provides the ship with a more conventional profile.

Historical low in power sector M&A activity

Last year marked a historical low for mergers and acquisitions (M&A) in the global electricity and gas market, according to PricewaterhouseCoopers' annual report *Power Deals*. Whilst deal numbers fell marginally from 424 in 2002 to 398, values fell dramatically from $84.9bn to $43bn. However, a substantial 69% of the value of deals made in 2003 was achieved in the second half of the year, signalling renewed hopes that the market is finally over the worst.

Large gas deals were notably absent in 2003 as electricity dominated activity. The top ten deals were all in electricity, providing a total deal value of $18.4bn. Against a backdrop of the relatively mature electricity market, a number of mooted gas deals failed to materialise and aggregate deal values dropped dramatically from $36.3bn in 2002 to just $3.3bn in 2003.

European deal activity slumped in 2003. With much of the European utilities market already consolidated, there proved little opportunity for the mega deals that characterised much of 2001 and 2002. The total value of European transactions fell from $65.8bn in 2002 to $17bn, leaving Europe with a 40% share of the total deals value, compared to 78% in the previous year. Deal numbers fell 21% from 200 to 158.

Helped by the collapse in deal values in Europe, North America has increased its share of global deals from 13% to 42% of total value. Acquisitions in North America, mainly by US investors, totalled $18.2bn in 2003, up from $11bn. Financial investors drove much of this recovery, although there was evidence of renewed European interest.

The prime rationale for M&A activity in 2003 was consolidation through horizontal and vertical integration, which accounted for over 65% of the total number of transactions. A strong domestic theme continued, particularly in the North American market, and within Europe further steps were made to consolidate the domestic footprint. Domestic deals dominated the market in 2003, with 65% of number and 60% of value.

Visit the PricewaterhouseCoopers website at www.pwc.com/powerdeals for more details.

Expanding coal gasification power

Global Change Associates (GCA) has released a report – co-funded by the US Department of Energy (DOE) and the National Association of Regulatory Utility Commissioners (NARUC) – outlining a number of institutional initiatives to expand the use of coal gasification power plants. The study acknowledges that integrated gasification combined cycle (IGCC) technology is already being utilised successfully and that accelerated IGCC deployment could provide critical economic, environmental, national security, and technological benefits for the nation.

The report – entitled *An Analysis of the Institutional Challenges to Commercialization and Deployment of IGCC in the US Electric Industry: Recommended Policy, Regulatory, Executive and Legislative Initiatives* – is available from the NARUC website at **www.naruc.org**

New pipeline to aid Sinopec expansion plans

China's largest listed oil refining company Sinopec reports that the State Council has granted approval for its proposal to build a $471mn pipeline along the Yangtze River, bringing imported oil from China's eastern coast to refineries in the hinterland. Although Sinopec has released no further details, according to the official website of the China Petroleum & Chemical Industry Association (CPCIA), the 996-km pipeline, originating from Jiangsu Province on the east coast to Hunan Province in central China, is expected to link six Sinopec plants, including five refineries where there is currently a combined 24.5mn tonnes of processing capacity.

The pipeline is expected to carry some 15.8mn tonnes of oil in 2005, rising to 20.6mn tonnes in 2010 and 22.5mn tonnes in 2015.

At present, crude oil deliveries to waterfront refineries in central China, mostly run by Sinopec, still solely depend on the Yangtze River. This has restricted Sinopec's expansion plans in the past.

In Brief

UK

Trading Technologies International *(TT) and IntercontinentalExchange (ICE) have announced that they are collaborating to provide access to ICE's global energy markets via TT's 'X_TRADER' electronic trading platform. Through this arrangement, market participants will be able to use X_TRADER to execute trades in over-the-counter (OTC) cash energy products listed on the International Petroleum Exchange (IPE). TT is the first independent software vendor (ISV) to connect to ICE's electronic OTC markets.*

Pembrokeshire County Council has *given ExxonMobil the go-ahead for construction of an LNG terminal on the disused Esso oil refinery site at Milford Haven despite protests by environmentalists. The Council has already granted permission to another company, Petroplus, to build a separate LNG site in Waterstone.*

Oiltanking (OT) and Petrostar have *signed an agreement regarding the purchase of 100% of the OT France shares by Petrostar.*

Analyst Datamonitor has unveiled *its 'European Forecourt Retailing Model'– an interactive aide for service station operators across the Continent. The Excel database provides the user with quick access to key data on 29 forecourt retailing markets across western, central and eastern Europe.*

Eastern Europe

Celebrating the five-year anniversary *of its market presence in Romania, OMV reports that it plans to increase its forecourt network from the current 60 sites to 110 by 2008, investing some 80mn.*

North America

Syntroleum and Marathon reported *on 13 March 2004 the first shipment of diesel fuel from the newly constructed gas-to-liquids (GTL) demonstration plant at the Port of Catoosa, near Tulsa, Oklahoma. Once peak capacity is reached, the Catoosa GTL facility is expected to produce approximately 70 b/d of ultra-clean transportation fuels.*

In Brief

***Nuvera Fuel Cells of the US reports** that it has supplied its Avanti™ fuel cell power module to the Japan Gas Association under the Japanese Government's Millennium Programme – a five-year effort to examine proton exchange membrance (PEM) fuel cells for the purpose of establishing technical codes and standards for the Japanese market.*

Middle East

***Saudi Arabia has announced that it** may privatise some refineries, but only after conducting market surveys to see if this is in the country's best interests, Oil Minister Ali Naimi recently stated. Saudi Arabia has seven refineries, with a total capacity of 2mn b/d, writes* Stella Zenkovich.

Russia & Central Asia

***Following his recent re-election Russian** President Vladimir Putin is reported to have said he is opposed to independent natural gas suppliers having free access to external markets, emphasising the importance of Gazprom to the country's economic development. He said that gas is sold in Russia to both household and industrial consumers at below cost price, largely at Gazprom's expense. If Russia were to switch to free market conditions, it would have to sell gas to all its consumers at the same price as to Western Europe – $110/1,000 cm – a situation he regarded as 'impossible'.*

Asia-Pacific

***Reliance Industries of India is to** expand its network of fuel retail outlets, setting up 350 petrol pumps and seven terminals across the country by the end of March 2004, writes* Swineetha Dias Wickramanayake. *The company plans to add a further 150 pumps per month to reach a target of 1,500 retail outlets by 2006.*

***The Australian Government wants to** increase biofuels production to 350mn litres per year by the end of the decade in order to encourage cane-growers to switch from sugar to ethanol production, despite a recent report saying the policy could cut between A$70.9mn ($52.2mn) and A$74.3mn from GDP in 2010 because of costly subsidies. Transport fuel made from ethanol and biodiesel would be produced, reports* Matthew Brace.

UK site closures continue unabated

The Energy Institute's *UK Retail Marketing Survey* that was published last month, reveals that site closures in the UK are showing no sign of slowing down. In the last decade, the number of sites has declined by about 40% from around 18,000 to less than 11,000 today. In the last 12 months alone, closures have run at an average of three sites a day, totalling 987 sites.

The closures are a reflection of the poor viability of smaller sites that lack the location strengths to compete with either better located forecourts or those supported by high demand for ancillary services, especially from the increasingly sophisticated forecourt shop.

Fuel demand in the UK is relatively level, but with the number of site closures the average fuel volumes per site over the last four years have increased by about 15%, from 2.86mn litres in 2000 to 3.3mn litres today.

Regional variations are noticeable, as shown in the attached table. Most significant is the lower percentage of closures in Scotland, which has been badly hit by rural closures in the previous decade, and Northern Ireland, where the price differential with the South has already caused many sites to close in previous years.

UK region	Closures in 2003	% of total sites in region
East Anglia	59	10.9
East Midlands	106	11.7
North	59	9.8
North West	109	10.3
Northern Ireland	11	1.7
Scotland	69	5.9
South East	225	8.1
South West	98	7.8
Wales	60	7.9
West Midlands	106	10.4
Yorkshire & Humberside	85	9.0

Larger-engined vehicles still popular with fleets

Recent research from UK fleet and fuel management company Arval PHH suggests that company fleets, the biggest purchasers of new cars in the UK, are still favouring larger-engined models. This demonstrates that the more powerful vehicles now have cleaner engines and have become increasingly tax-efficient, reports the company. In 2003, some 56% of the cars Arval bought for its business customers had an engine size of 1,900–2,2090cc, which was up 2% from the figure for 2001.

'The Benefit-in-Kind (BIK) tax change introduced [in the UK] in 2002 means that company drivers have to pay more if their cars produce higher carbon dioxide (CO_2) emissions,' comments Clive Forsythe, Managing Director of Arval PHH's Business Customer Division. 'Although the trend towards lower-emission mid-size vehicles has been quite pronounced since the late 1990s, it seems to be levelling off.'

'There are several reasons behind the continuing appeal of more powerful cars – manufacturers have focused their attention on making cars with cleaner engines and lower emissions, hence even two-litre models generally do not present too many BIK problems for company drivers. The tax difference between a 1,600cc car and its two-litre version is often minimal. In addition, fleet drivers favour larger vehicles because they often have to cover great distances behind the wheel and need a more comfortable ride. It also helps that performance vehicles positively reflect the image of their employers and tend to retain their secondhand value more effectively.'

'Low-emission diesels have become very popular among fleets and they tend to have larger engines than their petrol-driven counterparts; for example, an 1,800cc petrol car will probably have a 1,900cc diesel version.'

The study also shows that corporate take-up of vehicles with engine sizes in excess of 2,200cc has continued to decline. Forsythe adds: 'The larger luxury models still have prices (and often, emission levels) that put them out of the reach of most company drivers. Although many employees now have a wider choice of cars, not all want the additional tax burden of a three-litre luxury sedan. However, the drop-off in sales of high-end marques is not as significant as it might have been. The increasing availability of tax-efficient executive diesels from the likes of Jaguar and Audi is helping to mitigate the fall in demand.'

Shift in fuel of choice for power generation

A major shift in the choice of fuels for the power generators of the world will result in investment of over $1tn in coal-fired generation plants between 2004 and 2020, according to new reports from McIlvaine Company. This figure includes both investment in new plants and the upgrading of existing plants.

In *World Power Generation Projects* McIlvaine has identified 300 projects for new coal-fired plants. The largest of these plants is 3,600 MW and will require an investment of $4.3bn. Even the smallest projects will require investments of more than $300mn each. The average plant size is 700 MW and the required investment is $lbn. The largest number of planned plants is in China, followed by India and the US.

The report indicates that in the US there has been a complete 'about face' over the last four years. In 2000 it was assumed that nearly all the needed capacity increases (14,000 MW/y) would be through gas turbines. It is now clear that natural gas will not play an important role as a fuel for base-loaded power generation. The cost of gas has risen to or above the price of the electricity which would be sold by the plant and a number of recently built gas-fired plants are not operating for this reason. There is no expectation of reduction in gas prices. As a result, there have been dozens of announcements of new coal-fired projects just within the last few months, states McIlvaine.

Meanwhile, the *Information Technology for Electricity Generation* report predicts that upgrading of existing coal-fired plants in the US will require an investment of $1.3bn/y just for information technology (automation systems, instrumentation, smart sensors, field devices, and software). In two other reports (*World FGD Systems* and *World NO_x Control Market*), McIlvaine predicts that annual expenditures to desulphurise and denitrify flue gases from coal-fired plants will require $9bn/y or $144bn over the 16-year period. Other McIlvaine reports quantify the substantial anticipated expenditures for particulate control equipment and emission monitoring.

Skepticism about the future of coal has been based on the assumption that coal plants will be dirty, says the company. However, the fact is that coal emissions can be reduced to very low levels. The level of reduction is a function of cost. McIlvaine predicts that the ultimate cleanliness of coal-fired power plants will be decided by rate payers. The average monthly electricity bill is $73 per household in the US. This level can be maintained even with the Bush administration programme to reduce sulphur dioxide, mercury and nitrous oxides (NO_x) by 70%. If consumers are willing to pay $85–$90 per month, then these emissions can be reduced by 85–90%, without any major technical breakthroughs.

The choice of coal, gas, or renewables is also going to be decided by the rate payer, states McIlvaine. Any alternative to coal is going to more than double monthly household bills. Modest reductions can be achieved in greenhouse gas reduction as plants are upgraded and efficiency is improved. However, the co-combustion of biomass and coal, along with increased efficiency, could result in significant greenhouse reduction.

For more information, visit the website **www.mcilvainecompany.com**

UK Deliveries into Consumption (tonnes)

Products	†Jan 2003	*Jan 2004	% Change
Naphtha/LDF	199,991	230,239	15
ATF – Kerosene	845,090	851,575	1
Petrol	–	–	–
of which unleaded	1,493,462	1,574,019	5
of which Super unleaded	72,640	62,053	–15
ULSP (ultra low sulfur petrol)	1,420,822	1,511,966	6
Lead Replacement Petrol (LRP)	19,728	8,175	–59
Burning Oil	500,386	519,460	4
Automotive Diesel	1,396,032	1,423,201	2
Gas/Diesel Oil	536,936	520,058	–3
Fuel Oil	247,398	286,478	16
Lubricating Oil	69,454	40,931	–41
Other Products	751,072	703,657	–6
Total above	6,059,549	6,157,793	2
Refinery Consumption	501,872	466,367	–7
Total all products	6,561,421	6,624,160	1

*† Revised with adjustments; *Preliminary.*

All figures provided by the UK Department of Trade and Industry, final figures as supplied by reporting companies

In Brief

***Tasmania's electricity retailer Aurora** Energy has been granted a licence to retail gas in the state. The gas network is being rolled out by New Zealand company Powerco.*

***P and Lembaga Tabung Angkatan** Tentera (LTAT) is to acquire for an undisclosed sum BP's 70% shareholding in the BP Malaysia fuels business, which comprises 240 service stations, a modern fuel terminal and two joint-venture automated LPG bottling plants.*

***Singapore Petroleum Company (SPC)** is to purchase BP's refining interests and one-third stake in Singapore Refining Company (SRC) for $140mn. The refining interests include BP's one-sixth equity interest in the Tanker Mooring Services Company. SPC already owns a one-third share of the 285,000 b/d refinery, with the remaining one-third being owned by Caltex.*

***The North West Shelf Venture** participants have signed a gas sale and purchase agreement with Western Power for a total of 700 PJ of gas. The agreement extends to the end of 2022 or until the 700 PJ of gas is consumed, whichever comes first.*

Latin America

***Shell Venezuela President, Joaquin** Moreno Uribe, is reported to have stated that the company will sell about 150 service stations that it began operating in the country in 1997.*

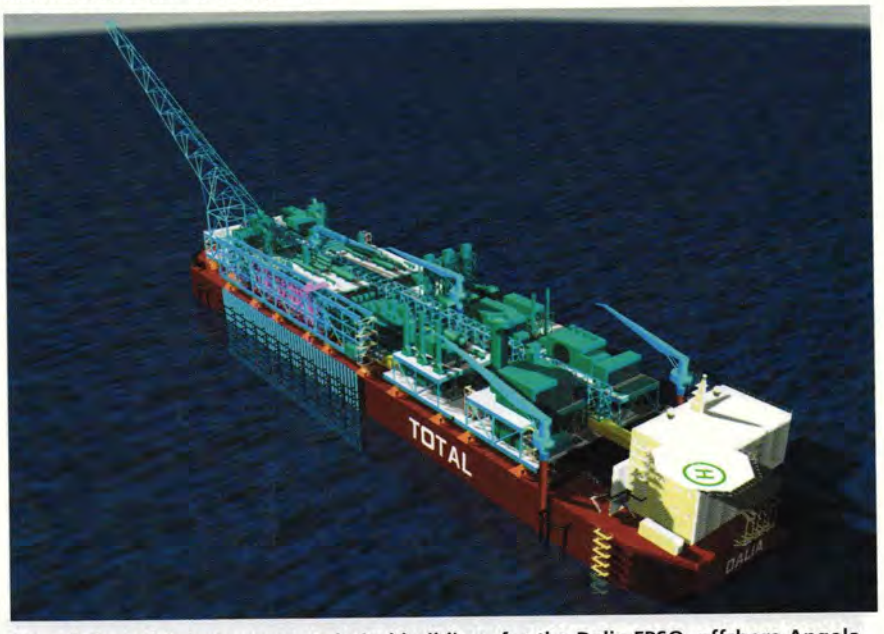
Africa

***BG Group has signed a Memorandum** of Understanding with the Tunisian Government for the development of the $250mn Barca power project in the city of Sfax. Construction is scheduled to begin in 2Q2004, with full commercial operation expected in late 2006. The 500-MW combined-cycle gas turbine (CCGT) power plant will use up to 12mn cf/d of unprocessed gas reserves from BG's offshore interests in the Miskar concession and, potentially, the Hasdrubal gas condensate discovery.*

***Fluor Corporation has been selected by** Shell and BP to provide engineering, design, procurement and construction management services for a clean fuels project at their jointly owned SAPREF oil refinery in Durban, South Africa.*

Tough times ahead

BP Valhall Flank development – North platform. EPCI contract for Heerema Tonsberg, delivered and installed July 2003



Consafe is to fabricate seven technical buildings for the Dalia FPSO, offshore Angola

Although UK and Norwegian fabricators have recently bolstered their order books with contracts from a few large-scale E&P development projects in the North Sea, they are still struggling to cope with excess capacity and competition from the Far East market that can offer lower cost bases for projects. *Kim Jackson* reports on how Europe's fabricators are faring and how they propose improving future prospects.

The European fabrication sector continues to struggle with excess capacity and a lack of large platform construction contracts as offshore operators are increasingly bringing new projects onstream via subsea completions. Many yards are having to diversify their operations, target new markets and embrace new contracting strategies in order to stay in business.

Bright spots on horizon

The UK fabrication sector has been hit hard in recent years, with a number of yards closing, including Ardersier, Methil and UiE Clydebank. Meanwhile, KBR Caledonia's facility at Nigg has remained on inspection, repair and maintenance (IRM). Its most recent contract is for operations and maintenance services to EnCana's Scott platform over a three-year period.

However, the Buzzard field – the biggest discovery on the UK Continental Shelf for over 10 years – has provided a much needed boost to order books, both in the UK and elsewhere in Europe. Burntisland Fabrications secured the contract for the management, fabrication and provision of assistance with commissioning of Buzzard's 3,650-tonne wellhead deck, to be constructed at the company's facilities at Burntisland and Methil. Meanwhile, Heerema Group was awarded the contract for the management, fabrication and commissioning of the 9,500-tonne utilities deck, to be constructed at its Hartlepool yard. Dragados of Spain will manage, fabricate and provide assistance with the commissioning of the 10,500-tonne production deck, to be constructed at the company's facility at Cadiz. In addition, Saipem UK has been awarded the contracts for pipelay and the transport and installation of the jackets

and topsides. Other contracts, including the accommodation module, flares and bridges will be tendered later in 2004.

The Norwegian sector, too, is to be bolstered in the short-term by large projects such as Statoil's Snøhvit and Kristin fields and Norsk Hydro's Ormen Lange development. Harald Svendsen of Heerema Tonsberg – which has secured a contract for the fabrication of two 800-tonne, eight-slot subsea templates for Ormen Lange – comments that some NKr50bn/y will be invested in the Norwegian Continental Shelf over the next six years, although the majority of the monies will be on modification work and the upgrading of existing platforms, the drilling of wells and new pipelines, rather than on large-scale fabrication. He also points out that subsea developments in deeper waters will call for templates – providing little work for the fabricators. Svendsen also notes that while floaters may prove to be the preferred development solution for other fields, such as BP's Skarv field and Marathon's Alvheim, European fabricators may well be battling against competition from the Far East market, which can offer reduced cost bases for such projects.

Moving markets

The renewable energy market is also emerging as a potentially lucrative new sector for UK fabricators to target. For example, the development of wind turbines in particular is creating great interest as Scotland possesses 40% of Europe's wind capacity. However, UK fabricators will face stiff challenges in securing the work from established European companies that have already secured high profile contracts in the wind-rich Scandinavian countries.

UK fabricators are also looking to diversify from their traditional central and northern North Sea market, targeting smaller southern sector contracts and developments in the Gulf of Mexico and West Africa. This trend is being followed elsewhere in Europe, with a number of fabricators reporting that they are also looking to secure onshore oil and gas construction work as well as civil engineering contracts for the fabrication of bridges, quays etc.

Rented accommodation

Those fabricators specialising in the construction of accommodation modules may not be overjoyed to hear that Duffy and McGovern claims to have become the first offshore accommodation company to provide rental engineering cabins in the Gulf of Mexico.

The company picked up three separate hire contracts in the last four

Operator/Contractor	Field*	Work	Delivery
UNITED KINGDOM:			
Amec Offshore Services			
BP	Clair Phase 1	£50mn contract for main deck fabrication and integration work	2004
Burntisland Fabrications			
BP	Rhum	Caisson riser/clamps	April 2004
EnCana	Buzzard	3,650-tonne wellhead deck	April 2005
Consafe			
BP	Magnus	Refurbishment of temporary refuge	April 2004
TSS Dalia**	Dalia, Angola	Seven technical buildings (electrical and instrumentation rooms, a workshop and lab) for Dalia FPSO (*TSS Dalia: jv of Technip, Saipem, Stolt Offshore, in consortium with Samsung and Daewoo)	Oct 2004
Tengizchevroil**	Kazakhstan	Safety shelter buildings for onshore Tengiz field	Nov 2004
Technip France**	East Area, Nigeria	Complete topsides facilities (>70 moduluar units) for a 90-man living quarters platform. To be executed in partnership with McNulty Offshore in Tyneside, who will fabricate the 1,400-tonne cellar deck	March 2005
Heerema Hartlepool			
BP	Clair, Atlantic Frontier	4,500-tonne drilling module	mid-2004
EnCana	Buzzard	9,500-tonne utilities deck	–
KBR Caledonia			
Nigg (formerly Barmac)		Inspection, repair and maintenance (IRM)	
McNulty Offshore			
ExxonMobil**	East Area, Nigeria	1,400-tonne cellar deck	–
NORWAY:			
ABB			
PPCon	Ekofisk	Process capacity upgrade, approx 800 tonnes	3Q2004
Statoil	Karstø/Draupner	$35mn, five-year contract for maintenance and modification of the Karstø gas treatment plant and Draupner platforms	–
Norsk Hydro	Visund	$80mn contract for 670-tonne and 300-tonne modules – one contains equipment to boost gas injection rate and increase oil production; the other will allow gas export from platform	2005
Aker Stord			
Phillips Petroleum	Maureen	Ongoing decommissioning contract pushed forward from cleaning to dismantling	Nov 2001+
Statoil	Kristin	NKr5bn contract; floating production platform	2004/5
Aker Verdal			
BP	Clair Phase 1	Steel jacket	2004
Heerema Tønsberg			
Norsk Hydro	Ormen Lange	Two 800-tonne, eight-slot subsea templates	2Q2005
ITALY:			
Intermare Sarda* **			
Agip Gas**	Sabratha, Libya	23,000-tonne jacket	Jul 2004
ExxonMobil**	East Area project, Nigeria	Three platform topsides	Oct 2004
Agip Gas**	Bar Essalam, Libya	Two SSIVs	Aug 2004
		***Also involved in management, procurement and sub-assemblies pre-fabrication in support as a technical partner at Saipem's Port Harcourt, Nigeria, yard on several Nigerian projects	
THE NETHERLANDS:			
Heerema Havenbedrijf			
ExxonMobil**	South Venture, Canada	1,464-tonne jacket	2Q2004
BP	Clair	4,500-tonne drilling facilities module	3Q2004
NAM	F3	300-tonne tie-in module	mid-2004
SPAIN:			
Dragados Offshore			
Statoil	Kristin	NKr300mn contract for 4,300-tonne riser balcony and 270-tonne flare boom	Mar 2004
EnCana	Buzzard	10,500-tonne production deck	–
SWEDEN:			
Emtunga			
Statoil	Kristin	1,700-tonne living quarters for 112 men	2004
BP	Mad Dog, Gulf of Mexico	1,000-tonne living quarters for 130 men	2004
AIOC**	Chirag FFD Ph2, Caspian	Two 1,200-tonne living quarters for 130 men	2004/2005

Current workload at some European fabrication yards *North Sea unless otherwise indicated

months of 2003. In two separate deals, it has supplied Technip and Expro with 20 x 8 Zone 1 engineering cabins on a six-month rental contract. At the same time, Schlumberger contracted Duffy and McGovern to provide two 20 x 8 and one 15 x 8 Zone 2 cabins for use on their current projects in Mexico for six months. The combined contract values are in the region of $100,000.

According to Craig Russell, the Commercial Director for Duffy and McGovern: 'The benefits of rental are quite compelling – a cabin which might cost $130,000 to buy outright, can typically be leased for as little as $80/d subject to the minimum rental period. Whilst this is already a significant saving, when you consider on top of that the costs of maintenance, storage and shipping, it's easy to see why many operators are now taking the rental option.'

The arrival of Duffy and McGovern in the Gulf of Mexico is expected to signal the start of an overall improvement in the standard of offshore accommodation in the market. Recent changes in the US Coastguard (USCG) regulations governing offshore accommodation mean that for an increasing number of operators their existing accommodation fleets are no longer up to standard. However, in the climate of reduced capital expenditure, these ageing and outdated fleets are not a priority for investment.

'Companies, not just in the Gulf of Mexico, but in all the global offshore markets are now recognising that with budgets tightening, switching from capex to opex-driven rental agreements is a far more commercially attractive project solution,' continues Russell. 'And, of course, for companies burdened by a fleet which is rapidly falling below the minimum standards, the rental option is a ready-made solution.' He also states that Duffy and McGovern cabins are guaranteed to meet and exceed safety standards anywhere in the world and can potentially be operational on the client's vessel within days.

Recent contracts

Staying with the Gulf of Mexico market, Petrobras has awarded the Technip/Fels Setal consortium a $775mn contract for the engineering and construction of the 180,000 b/d P-52 semisubmersible production platform to be located on the Roncador field in the deepwater Campos Basin offshore Brazil.

More recently, UK-based well performance and production optimisation company Expro International secured a contract to provide the process topsides for the Bourbon Opale FPSO facility that is currently being built in Norway. The facilities will be capable of processing up to 10,000 b/d of oil, 5,000 b/d of water and 26mn cf/d of gas at the Gulf of Mexico field, which is due onstream in early May 2004.

Meanwhile, a partnership between Eni subsidiary Saipem and Daewoo Shipbuilding and Marine Engineering has recently been awarded by ExxonMobil Canada the contract for the engineering, procurement, construction and installation for the Sable compression platform and facilities offshore Nova Scotia. Topsides weight is approximately 7,000 tonnes. The compression platform will be bridge-linked to the existing Thebaud platform, on which additional works will be carried out. The offshore installation phase will be carried out by the vessel *Saipem 7000* during summer 2006.

Other contract details are listed in the table on the previous page.

BP's Clair skid at Burntisland Fabrications yard

Cutting construction costs

Cutting the cost of offshore oil and gas platform design, construction and operation, while the reduction of risk and improving performance will be key to fabricators securing future contracts. And, thanks to a new information management solution – ORBISS – that utilises a unique data quality software system developed by Cambridge-based Datanomic, international engineering services company Amec is reported to now be able to do just that.

Typically, an oil or gas platform takes Amec three years to design, commission and construct. When complete, the company hands a structured information set related to platform build and operation to its customers. With up to 3mn data records, plus 80,000 documents and 150,000 data/documents reference links, detailing everything from individual valves and pipes to sophisticated software application codes, preparation of each handover is a massive undertaking.

The complexity and volume of data originating from many different source software systems has historically made collation, sorting and validation a long, labour-intensive process. A large team worked for up to six months to prepare data at a cost of up to £1mn per platform, with up to three platforms in construction at any one time. Not only were traditional and manual methods inefficient, they lacked repeatability and auditability in a mission-critical environment, reports Datanomic.

However, Amec is now able to gather, clean, store and manage the required information incrementally through the various phases of the particular project, offering improved information integrity and value and reducing this onerous handover to a simple information rollover. Datanomic's software has the flexibility through configuration to acquire disparate data in a variety of formats, then audit, clean and combine it so it can be delivered to any requirement specified by the project. Once purified, it is quick and easy to export data to the Amec STEP data model. With Datanomic embedded into daily data management, high quality data is on tap at all times and final hand-over takes days rather than months.

Peter Mayhew, Information Manager of Amec Oil and Gas comments: 'Datanomic has transformed our traditional business processes. We have radically improved performance, reduced risk, cut time to deliver information and made major savings. We know that dirty data is a problem but we took the strategic view to engineer this out of our processes rather than try a one-off exercise at the end. For our customers having high quality data when they acquire the platform has massive value in terms of operational cost savings. This is a major selling point for our project capability. As an integral part of Amec's operations, Datanomic provides excellent support throughout the design and build lifecycle.'

A tale of two planets

Julian Darley, Director of the Post Carbon Institute*, reports on the contrasting viewpoints recently presented by Saudi Aramco and Matt Simmons, President of Simmons & Co at the CSIS (Center for Strategic and International Studies) in Washington DC as regards the role that Saudi Arabia may play in meeting future global demand for oil. If the Saudis are right, the industrial world has decades more of abundant and cheap oil. If Matt Simmons is right, the world is almost certainly facing a decline in oil production before the end of the decade.**

The new millennium has not exactly been one of 'irrational exuberance' for many industries, and particularly not for the oil industry, despite high oil prices. Major oil discoveries have declined every year so that 2003 saw no new discoveries of over 500mn barrels, while in 2001 and 2002 the top ten non-state oil companies spent more on exploration than the NPV (net present value) of their discoveries – a new and alarming record. It is well over 20 years since more oil was found than consumed in a year. From the outset of 2004 large reserve write-downs, starting with Shell, and including El Paso and BP, have shaken the confidence of the financial community, setting in motion an official SEC enquiry, which may yet be just the tip of the iceberg.

Comforting then to know that the Middle East – producer of last resort and future saviour of the world oil system – still has nearly 700bn barrels of reserves and is publicly confident that it can deliver the required doubling of output to 40mn b/d by 2025. Even more reassuring, Saudi Arabia says it can happily deliver 10mn b/d for at least the next 50 years, possibly even rising to 15mn b/d – and still for 50 years. This output can be guaranteed because Saudi oil in place will rise to 900bn barrels by 2025, while new technology will help existing recovery and lead to many new discoveries. This was the message from Saudi Aramco, delivered on 24 February 2004 at the CSIS (Center for Strategic and International Studies) in Washington DC to an audience consisting of diplomats, CIA (Central Intelligence Agency), EIA (Energy Information Administration), the media, and many energy companies and analysts.

Another planet

The trouble is that the Saudi Aramco presentations of Mahmoud Abdul-Baqi, Vice-President of Exploration, and Nansen Saleri, Manager of Reservoir Management, seemed to be describing not just another country, but another planet when compared with what Matt Simmons, President of Simmons and Co (the world's largest private energy banker) had to say.

Industry observers noted that Aramco had never before said so much about its reserves and how it holds production of its ageing oil fields steady. But much of the company presentation concentrated on the benefits of new technology, especially in its medium-sized fields, and the possibilities of future discoveries, without noting that well productivity had fallen by more than half since the early 1970s. More than half of Saudi Arabia's oil comes from one giant field, Ghawar, the largest ever discovered in the world. However, the health of this field is now in serious doubt after decades of water injection to maintain pressure.

A dire warning

Simmons' case rests on the painstaking analysis of 200 reports written over four decades by petroleum reservoir engineers, as well as a fact-finding mission in 2003 and ten years of other detailed studies of oil and gas depletion. He has been publicly hinting for more than a year that assumptions about Saudi Arabia's seemingly limitless capacity may be misplaced, but now, ahead of the publication of his forthcoming book on Saudi oil, copious data and a dire warning have replaced the hints.

Simmons noted that 'in an era of poor energy data, Opec is a total vacuum'. But his latest work on Saudi Arabia does come at a time when, despite more than two decades of official secrecy, questions are being asked about Middle East capacity and reserves – especially since the surprise Opec cut in production in February 2004.

ASPO (the Association for the Study of Peak Oil) has recently analysed the extraordinary Opec reserve revisions of the 1980s, which saw volumes leap from 353.6bn barrels in 1982 to 643.5bn in 1990 despite no new large discoveries. Two different ASPO studies conclude that reserves are somewhere between 100bn and 300bn barrels smaller than officially claimed. Evidence from widespread and dramatic falls in well productivity suggests that reserves may now be about what they were stated to be in 1982. This would fit with the original numbers being understated by about 30%, and a comparable volume (to the 30%) being produced in the intervening 20 years.

Simmons' new work on Saudi Arabia, the greatest of all oil provinces, appears to have lit the fire under a fast-growing mass of evidence that the Middle East is no longer capable of increasing production at will, either to stabilise price or make up for sudden declines in production from other producers.

However, a major point of Simmons' work is that knowing when Saudi Arabia is in permanent decline will be very difficult to discern for some time. Despite the country's central role in world oil, there is no official agreement on how much it is actually producing (and this also applies to Opec producers in general). Aramco's own report of 6.79mn b/d in 2002 was notably lower than either the IEA (International Energy Agency) or press reports. This has led some to try to estimate production from tanker traffic. The OECD reported that Saudi exports were flat from 2000 to 2002, but Simmons questions how we can be sure of this.

During the question period that followed all the presentations, Simmons was noticeably reticent about when Saudi Arabia would peak – but did note that Saudi Aramco had briefly produced over 10mn b/d in 1981. Afterwards, however he was more forthcoming. 'We could be on the verge of seeing a collapse of 30% or 40% of their production in the imminent future, and imminent means sometime in the next three to five years – but

it could even be tomorrow.'

Simmons asks why the Saudis are expending so much effort on the old reservoirs if they have so many new ones in the wings, many of which have not even been tested. He asked could the reason be that many of the other 300 recognised reservoirs 'seem to lack permeability, porosity, or aquifer – or all three'?

The 'Big Five' giant oil fields – Ghawar, Safaniya, Abqaiq, Manifa, Shaybah – all found by the mid-1960s, produced 90% of all Saudi oil in the last half century. But now, Simmons said, they were only being kept going by massive water injection, so that the 'sweep of easy conventional oil flow is ending'.

This may be most alarmingly true for Ghawar. According to Saudi Aramco, Ghawar is only 48% depleted, although the company does admit that the northern and most productive region is 60% down. Simmons says that if Aramco's 1975 reservoir estimate of 60bn barrels is correct, and he intimates that it is, then Ghawar is in fact 90% drained.

Litany of problems

Many of the other large productive fields have a litany of problems, including sand control and water cut struggles in Safaniya's northern end, and hydrogen sulphide and pressure drops in Marjan. The next generation of production from Qatif, Abu Sa'fah, and Khurais all have 'complex production histories and each has its own set of challenges', commented Simmons.

For all the Saudi insistence on the importance of technology, according to Simmons: 'Aramco's reservoir models failed to predict accurate fluid behaviour' 15 years ago, and he wonders whether the company's new models will do any better. The knowledge now gained might have caused Aramco to manage its reservoirs differently in the 1960s and 1970s, when it first started peripheral water injection, which could have led to less oil being 'by-passed' and left behind. However, hindsight will not help Ghawar now.

Another key cause for Simmons' concern is the increasing use of MRC (maximum reservoir contact) wells, or 'bottle brush' wells, which, he says, 'now anchor future oil production'. These wells send out many offshoots into the reservoir – 'in simple terms, they hide from top-side gas and bottom-end water'. Such wells can certainly produce oil more quickly, especially from 'the last thinning columns of easy oil', but they rarely increase the total yield, and invariably hasten decline and increase its rate.

This is the same technology that led to the infamous production collapse of Oman's Yibal field, which 'after 30 years of water injection and pressure maintenance, embraced horizontal drills in 1990, then peaked in 1997 (at 25,000 b/d) and saw production fall by 65% by 2001. The collapse was a total surprise.' In 2004, production has fallen by another 50%. Yibal constituted almost one quarter of Oman's production in 1997.

Waving a wad of SPE (Society of Petroleum Engineers) reports, Simmons went on: 'What worries me is these 200 papers, because they've basically been written by all their [Aramco] colleagues. They really describe a blizzarding trail of problem after problem after problem – and what we heard today [from Saudi Aramco] is "we have no problems".'

Indeed Aramco stressed throughout its presentation that whatever the market wants the company can deliver, and talked frequently of how the 'tank' of Saudi oil would expand thanks to exploration, 'delineation', and more technology. Yet Simmons pointed out that much of Saudi Arabia lies outside the 'endowment horseshoe', which contains all the great Middle East oil fields, and pointed out that: 'For years we knew we had the giant fields on the California coast, we knew we had West Texas. A lot of people thought there must be stuff in between if we'd just drill for it. There wasn't.'

As for technology, Simmons says that: 'Instead of creating easy supply growth, the technology revolution created monstrous decline rates.' Monstrous means up to 20% a year, as in the case of Yibal, yet Aramco shows that Saudi depletion rates are generally lower than those of many other large producers. However, as an example of differences of interpretation perhaps, Aramco shows Yibal as 4.3% annual depletion – in company with Prudhoe Bay and East Texas, but less than half of a fast decliner like Brent. For the whole of Saudi Arabia, over its entire production history Aramco claims 28% depletion. This is plainly incompatible with Simmons' findings.

No room for middle ground

The two different reports presented by Simmons and Aramco are so utterly divergent that there seems no room for a middle ground. Either the Saudis are in the right direction or Matt Simmons is.

Simmons was one of the first in the world to begin to comment loudly on global oil peak, after he discovered that the North Sea giant fields of Forties, Brent and Ekofisk had peaked and already declined to 'pygmies' without anyone really noticing. Together with his staff, he has carried out some of the most meticulously detailed studies of US oil depletion and he has been proved right concerning his prediction of North American natural gas peak. 'Non-renewable things do some day peak, and there is some chance that that might be in the past tense. Scoffing at the notion today is, in my opinion, frankly naïve,' he said.

Call for energy transparency

Simmons, along with many others, is calling for a 'new era of true energy transparency', in which trust and 'flying blind' is replaced by 'timely field-by-field production and well-by-well data, budget details and third-party engineering reports' from Opec. But other parties are also implicated – there must be 'far better demand and cost data, and far better decline data for non-Opec oil' from the IEA, and financial reforms are needed to tame 'wild price volatility' – there must be 'a realistic economic model for how oil and gas needs to be priced'.

However, there are many reasons why none of the above will happen. Not least, that if the Saudi situation is as bad as Simmons portrays, then the country is facing economic and social catastrophe in the near future, and will be unwilling to advertise the fact. Other Middle Eastern countries may not be much better off.

'I think we should worry about the future', said Simmons after his presentation. 'I think we should basically look at this like we looked at nuclear warfare and say that would be so awful if it happened – let's do something, put in a warning system.' Referring to Saudi claims of decades of future supply, Simmons said 'we're just stupid as a society to say "Now I know we don't have any problems". Fifty years is great, if that's right. But if it's wrong, that's awful.'

If the Saudis are right, the industrial world has decades more of abundant and cheap oil. If Matt Simmons is right the world is almost certainly going to see a decline in oil production before the end of the decade. Taken together with the baseless 1980s Middle East reserves increases and no new mega-finds elsewhere, this will most likely signal the end of the first half of the Oil Age when steady production growth gives way to decline.

*Julian Darley is Director of the Post Carbon Institute, which is based in Vancouver, Canada. He can be contacted at e: **julian@postcarbon.org***

For a full transcript of the two main presentations given at CSIS on 24 February 2004, visit **www.csis.org

*The author's short, but revealing, video interview with Matt Simmons just after his presentation is available at **www.globalpublicmedia.com***

UAE moves ahead with oil and gas sector expansion

Abu Dhabi National Oil Corporation (ADNOC) is moving ahead with a major oil and gas production expansion programme designed to increase the UAE's sustainable crude oil production capacity by almost 1mn b/d, from a claimed 2.63mn b/d at present to 3.58mn b/d by 2006. Apart from enabling local oil producing companies to respond more readily to changing demands in the global crude oil market, the programme also involves modernising the UAE's oil and gas industry infrastructure as well as expanding the undeveloped downstream chemicals and petrochemicals sector. *David Hayes* reports.

Above: Abu Dhabi street and mosque, United Arab Emirates

Reservoir conditions in Abu Dhabi's main producing oil fields have reached a level of maturity that now requires injected pressure support to ensure maximum ultimate oil recovery. As much of the existing oil field infrastructure is ageing, the ambitious development programme will include upgrading and renewing the oil and gas industry's infrastructure. The cost will be enormous and will require a huge investment estimated at more than $30bn during the next ten years. A number of production capacity expansion projects already have been launched in both offshore and onshore oil fields where investment is due to climb to unprecedented levels during the next five years.

The government's intention in expanding oil production capacity is for the UAE to become a swing producer and to increase the nation's international standing. ADNOC is expected to award the largest projects to single source engineering, procurement and commissioning (EPC) contractors, most likely the major international contractors. These will then divide up and subcontract smaller project components to other companies. 'That's where interested companies should be looking – seeing who wins the EPC contracts and then contacting them,' said a Western Diplomat. 'ADNOC is doing it this way as it is easier and it gets the job done.'

Abu Dhabi is a member of Opec and OAPEC. The UAE's current Opec quota stands at 2.16mn b/d, of which Abu Dhabi is allocated 2.02mn b/d and Dubai 135,000 b/d. Opec's recent agreement to cut production by 10% from April will result in the UAE's quota falling to 2.05mn b/d. The reduction in output is likely to be borne by Abu Dhabi.

With huge reserves of oil and gas, Abu Dhabi is the richest of the UAE's seven emirates and funds the majority of the national budget. According to the *BP Statistical Review of World Energy 2003*, Abu Dhabi has 9.3% of proven world oil reserves and 3.9% of gas reserves. Until now only 10% of the total oil reserves is estimated to have been recovered. At present output levels the UAE claims to have enough oil for over 100 years' production. The UAE's gas reserves of 212tn cf are the world's fourth largest after Russia, Iran and Qatar. Abu Dhabi alone has reserves of 196tn cf, including the non-associated Khuff gas reservoirs beneath the Umn Shaif and Abu al-Bukoosh oil fields. The remaining 16tn cf is shared among the other emirates. Current gas reserves are forecast to last for another 150 years or more.

ADNOC overseer

The government's oil and gas industry expansion programme is being overseen by ADNOC, the domestic oil and gas production agency, which consists of five upstream operating companies and five downstream companies, some of which also are active overseas. In fact, no timetable has been announced for the investment programme, which started in 2001. Project timings consequently are likely to change, depending on the government's prevailing priorities.

ADNOC is involved in all aspects of the oil and gas industry, including exploration, production, refining, gas processing, chemicals and fertilisers, and marine transport, as well as the marketing and distribution of crude oil, LNG and refined petroleum products. Its Abu Dhabi Company for Onshore Oil Operations (ADCO) subsidiary is responsible for oil exploration, production and export operations from Abu Dhabi's onshore oil fields. Crude oil production for export is piped to Jebel Dhanna oil terminal, while the remaining production is used as feedstock at Ruwais and Umm Al Nar oil refineries, which have a combined refining capacity of 500,000 b/d and are operated by Abu Dhabi Oil Refining Co (Takreer), another wholly-owned ADNOC subsidiary.

ADCO also supplies associated gas to ADNOC subsidiary GASCO's three natural gas liquid extraction plants in Bab, Bu Hasa and Asab. In addition, ADCO operates non-associated gas wells and gas gathering pipelines in the Bab field for ADNOC's Thamarna C and F gas processing plants. Ruwais refinery is designed to refine 420,000 b/d, while the smaller Umm Al Nar refinery is able to refine 80,000 b/d following the earlier completion of debottlenecking and a recent expansion. Ruwais refinery produces light products that are exported mainly to Japan and India. Fuel oil from Ruwais is sold locally and used for domestic power generation. All refined products supplied by Umm Al Nar are used locally.

Expanding production

Various oil production expansion schemes have been proposed to help Abu Dhabi increase its crude oil production capacity by 1mn b/d. The Bab onshore oil field upgrade, estimated to cost $250mn to $300mn, is one major project now underway. ADCO is planning to expand production at the field by 100,000 b/d. Bab currently can produce about 250,000 b/d and will increase to 350,000 b/d when the project completes about the end of 2004. JGC Corporation was awarded the $91mn EPC contract in March 2003 to supply and install two processing trains, two- and three- phase gas separators, a degassing station and related pipe works.

Abu Dhabi National Oil Corporation (ADNOC) service station

Elsewhere, ADNOC is expected to invest about $1.6bn increasing oil production in the Northeast Area Development (NEAD) from 20,000 b/d to 180,000 b/d. A smaller scheme involves developing the 10,000 b/d Huwaila project next to the Bu Hasa oil field. Parsons International has been appointed contractor for the $350mn Bu Hasa upgrade contract, which includes construction of a new 730,000 b/d degasification plant and the replacement of the four existing 50,000 b/d two-phase gas separators with four new 120,000 b/d three-phase separators. The project also includes the supply and installation of gas and water injection facilities and a variable speed motor drive for the injection compressor, which has a designed capacity of 150mn cf/d and 120,000 b/d of water.

Crude oil export facilities also are being expanded and upgraded. Tebodin Middle East is due to complete a conceptual study shortly, to expand the capacity of the oil processing facilities on Zirku Island, off Abu Dhabi. The planned project involves increasing the combined capacity of the processing facilities from 600,000 b/d to 700,000 b/d by 2005 by debottlenecking the three existing trains and a standby unit.

Elsewhere, Abu Dhabi Gas Liquefaction's (ADGAS) LNG/LPG plant on Das Island receives associated gas from the Umm Shaif, Lower Zakum and Bunduq oil fields. ADGAS's Das Island LNG plant started production in 1977 and is claimed to be the most complex LNG plant in the world and the only one to process associated gas. Installed with three trains and capable of producing 5.4mn t/y, the plant exports most of its LNG output to Tokyo Electric Power Co of Japan.

ADGAS also operates an LPG plant on Das Island, producing 1.7mn t/y, of which about 800,000 tonnes is shipped to Japan, along with facilities that produce 535,000 tonnes of propane and 338,000 tonnes of sulphur annually. A planned new LPG train currently is at the engineering design stage. Expected to cost from $350mn to $400mn to construct, the fourth train will require 220mn cf/d of gas to produce about 1mn tonnes of LPG annually, raising ADGAS's total LPG output capacity to 2.7mn t/y when the new train is commissioned in 2006.

Gas expansion

Meanwhile, ADNOC's plans include boosting gas production and utilisation. In particular, gas use for reinjection to enhance oil recovery will increase in future.

The UAE has not taken full advantage of its gas reserves so far due to the sulphur content that has to be removed. In the absence of an easy method to clean the gas, the optimum use for associated gas is to reinject it for enhanced oil recovery. 'The UAE is lacking in clean gas. Most of the gas is sour associated gas,' the Diplomat said. 'As there is a no flare policy, they remove the sulphur and then reinject the gas either for disposal or for enhanced oil recovery.'

ADNOC's plans to increase gas reinjection for enhanced oil recovery are forecast to cost $2.3bn and will be the largest ever investment in the UAE's gas industry. The agency recently approved the release of the first tender packages for Habshan onshore gas development phase three (OGD-3) and phase two of the Asab gas development (AGD-2) project, ten years after OGD-1 was launched.

Unlike OGD-1, launched in 1993, and later OGD-2 – which were designed to

produce dry gas for power generation – the OGD-3/AGD-2 project is planned to produce substantial quantities of gas liquids and 1,300mn cf/d of gas to reinject in oil fields. About 135,000 b/d of condensate and up to 24,000 t/d of natural gas liquids (NGL) will be delivered to Ruwais for processing. The products will either be exported or used as feedstock to expand the UAE's own petrochemical capacity.

Various offshore gas reinjection projects for enhanced oil recovery also are due to move ahead. Abu Dhabi Marine Operating Co (ADMA-OPCO), for example, is planning to reinject some 600mn cf/d into the Umm Shaif reservoir, supplied from the Khuff gas field, along with associated gas into the offshore Arab C and D reservoirs. A new gas compressor will be built to maintain oil production levels after 2005 at a cost of about $1bn. Pipelines ranging from 12- to 24-inches in diameter will be built to existing wellhead platforms.

In addition ADMA-OPCO plans to inject a further 200mn cf/d into the crestal area of the Zakum field to increase oil production. The project, which is expected to cost $200mn to implement, will be tendered as a separate package in early 2004.

Qatari gas supplies

Qatar could become another source of gas for reinjection into depleted oilfield reservoirs to assist in enhanced oil recovery, by supplying the UAE through the proposed Dolphin gas pipeline. Due to enter commercial operation in 2007, the Dolphin project involves building a 440-km, 48-inch diameter subsea pipeline to transport gas from Qatar's North Dome field to Abu Dhabi and Dubai, although some gas will be supplied to the other emirates. The pipeline is planned to continue from the UAE to Oman and Pakistan, if Pakistan is able to afford the proposed gas imports.

Expected to require an additional $10bn investment over the next five years, the Dolphin gas pipeline project will supply about 2,600mn cf/d of gas to the UAE, most of which ADNOC will reinject for enhanced oil recovery purposes. Most of the remaining Qatar gas imports will be supplied to desalination plants that will generate electricity as a bi-product.

The project is already well advanced. Wells have been drilled in Qatar's North Dome gas field and the project design and pipeline construction contracts have been signed. The main outstanding issue is for the Qatari and UAE Governments to agree a gas price. 'The gas agreement is pending on price,' commented the Diplomat. 'The volume has been agreed, not the price. It will be a commercial rate, but the retail gas price probably will be subsidised by the UAE Government.'

Staffing problems

Meanwhile, plans to expand the UAE's oil and gas sector have major staffing implications. ADNOC already has launched an emiratisation programme among its workforce that is due for completion in 2009, at which point some 70% of ADNOC's employees are expected to be emirates nationals. 'ADNOC has a big staffing requirement for its programme,' explained the Sales Manager in one ADNOC subsidiary company. 'Individuals will be trained to come up to the required level of competence. People will be reviewed and their training needs specified.'

One difficulty that ADNOC faces is the reluctance of many young emirates nationals to accept junior positions while undergoing training. Other sectors in the UAE economy also face similar problems in recruiting local staff. 'It's hard to get people at the bottom. It's hard to get apprentices to do five to seven years' study before they can be appointed to a management post,' the Manager said. 'There is no preferred occupation in the UAE. Everyone wants to start as a general manager. Emiratisation is happening as the government realises they need more day-to-day control of the country. Emiratisation is a way to control their own heritage.'

While recruiting young emirates nationals poses a challenge, senior management development is also causing concern. Early retirement concessions for emirates-born staff have resulted in a growing reliance on expatriate managers. 'ADNOC's emirates staff retire on full pay at 40 and then go into private business or run representative companies serving the oil and gas industry,' the Manager explained. 'Expat managers stay on, but many are now nearing European retirement age and there is no one to take their place. ADNOC is putting in training programmes to catch emirates staff at secondary school. They start at 15 and get a petroleum degree. ADNOC also had a previous emiratisation programme. The current senior ADNOC managers started with foreign oil companies before joining ADNOC, but now they are nearing retirement.'

Developments in the pipeline

Meanwhile, ADNOC's oil and gas development programme includes the development of piped gas transmission facilities as well as construction of piped gas distribution systems to serve major urban areas and industrial zones. Plans to import gas from Qatar will ensure the availability of clean gas if local clean gas supplies are not sufficient.

Gas consumption in Abu Dhabi has doubled during the past decade due to the growth of gas-fired power generation and the increased use of gas for petrochemicals and fertiliser production. With growing volumes of gas being used for reinjection to maintain crude oil production, gas consumption in Abu Dhabi is forecast to increase to 4,000mn cf/d by 2005. Nearby in Dubai, gas consumption is expected to grow by almost 7% annually until 2005, when consumption is forecast to reach 810mn cf/d. Increased industrial use of gas and an expansion of gas-fired power generation will be responsible for much of the rise in demand.

Until recently Sharjah has supplied Dubai's entire gas requirements, which in 2003 was estimated at about 660mn cf/d. However, an ADNOC subsidiary has recently completed construction of a gas pipeline from the main Abu Dhabi gas receiving station to Dubai to provide a second gas supply source. In the future Dubai's gas supply will be further expanded when the planned Dolphin gas project to import gas by subsea pipeline from Qatar is completed.

In addition, ADNOC Distribution, which is in charge of piped gas distribution, plans to build piped gas distribution systems serving Abu Dhabi and a smaller emirate, Al Ain. Plans call for two distribution systems totalling 3,500-km in length, to be built over an eight-year period to supply industrial and residential customers as well as ADNOC service stations supplying CNG to taxis.

Consultants are due to be appointed shortly to complete the engineering design of the piped gas systems and prepare tariff and marketing plans. Expected to cost about $200mn to complete, the first stage of the multiphase project will include equipping up to 30 service stations to supply CNG and converting 16,000 taxis in Abu Dhabi to use the fuel.

GASCO, another ADNOC subsidiary, operates the existing 1,400-km gas pipeline grid in Abu Dhabi. The company is due to appoint consultants to carry out a pipeline risk management study to map any hazardous sections where the pipeline is too close to housing, industrial plants and road crossings. The consultant team selected will prepare bid documents for each necessary modification contract and will act as project management consultant while the modification contracts are carried out.

All photos: David Hayes

Lukoil looks overseas

As part of our series of articles analysing oil and gas companies from around the world – based on information supplied by *Online-Data – we take a closer look at the international activities of *Lukoil*.**

Lukoil has established a considerable portfolio of international assets, beginning in 1994 with its acquisition of a 10% interest in the Azeri-Chirag-Guneshli (ACG) field, the largest oil field in Azerbaijan. It later entered other joint international oil projects in Azerbaijan, as well as Kazakhstan and Iraq.

In July 2001, Lukoil Overseas Holdings (LOHR) acquired a 100% share in Bitech Petroleum of Canada, which, at the time, possessed E&P licences for prospective blocks and deposits in Egypt, Colombia, Morocco and Tunisia. LOHL also participated in a joint venture to develop the Dzhimdan block on Sakhalin Island.

The following year, in June 2002, LOHL acquired a participatory share in Canadian company Naftex Energy Corporation, in the WEEM concession in Egypt – becoming the sole contractor under the concession agreement for exploration and production of oil.

Having studied more than 35 projects in different parts of the world, LOHL has selected 16 projects in which to continue additional operations that includes those in Azerbaijan, Kazakhstan, Uzbekistan, Egypt, Colombia, Iran and Saudi Arabia.

Middle East focus

Most recently, in March 2004, Lukoil signed an upstream agreement for exploration, development and production of non-associated gas and condensate in Contract Area A in Saudi Arabia. The agreement has a maximum term of 40 years. Contract Area A is located in central Saudi Arabia, near Ghawar, reportedly the world's largest oil field. The project will be implemented by LOHL, on behalf of parent Lukoil.

A corporate joint venture with state-owned Saudi Aramco has been established to implement the project, with Lukoil holding an 80% stake. The joint venture has been named Lukoil Saudi Arabia Energy (LUKSAR). During the first five-year exploration period, Lukoil will drill a minimum of nine exploration wells and acquire 8,750 line-km of 2D seismic at an estimated cost of $215mn. In the event of a commercial non-associated gas discovery, Saudi Aramco guarantees to buy the produced gas to be supplied to the domestic market in Saudi Arabia. There is also the possibility of gas condensate export.

Meanwhile, in Iraq, Lukoil is nearing completion of the contract conditions required for phase two development of the Western Qurna (Western Qurna–2) oil field following the removal of the sanctions by the UN Security Council. The original contract for phase two was signed in March 1997. Signatories were the Iraqi Government, Lukoil, the Russian international economic union Zarubezhneft and the state enterprise international economic association Mashinimport.

The 23-year contract can be extended for a further five years. Lukoil holds a 52.5% stake in the project, with the Iraq side holding 25%, and Zarubezhneft and Mashinimport holding 11.25% each.

Proven recoverable field reserves are put at 6bn barrels of oil. Accumulated production for the period of the contract could reach 4.8bn barrels of oil and 56.4bn cm of gas. Project development is expected to cost in the region of $4bn.

Looking to neighbouring Iran, in September 2003 the National Iran Oil Company (NIOC) approved the participation of LOHL in a geological and exploration project on the Anaran prospective onshore block to the west of the country. The following February, Lukoil and Norsk Hydro signed a contract to jointly develop the block.

Three prospective structures – Azar, Shangule and Musia – have been discovered at Anaran. Potential reserves are forecast to be as much as 350mn tonnes of oil. The total estimated project budget is $137.3mn and exploration will be carried out until 2005.

Lukoil holds a 25% interest in the project, with Norsk Hydro Exploration and Production International holding the remaining 75%.

Caspian development

In January 2004 Lukoil signed a joint operating agreement with KazMunaiTeniz covering the Tyub-Karagan and Atashsky projects in the Kazakh sector of the Caspian Sea. Operating companies are to be established for imple-

continued on p25...

Figure 1: Overseas core projects

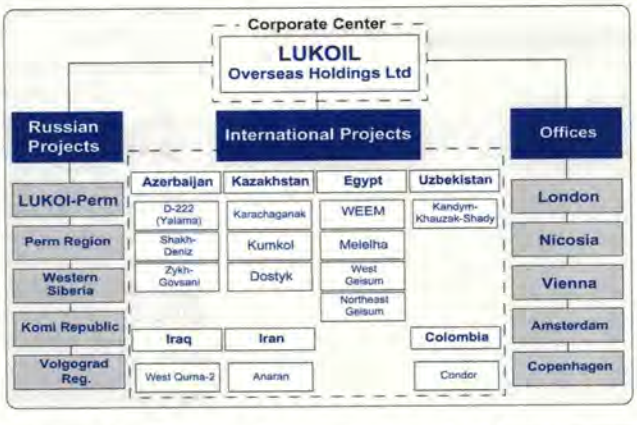


Figure 2: Corporate structure

Alleviating partner drag

The traditional model of managing joint ventures in the oil and gas industry is through an operator and a governance model of operating/management committees to represent the non-operating partners. Strategic Decisions Group's *Jan Paul van Driel* and *Nick Lowes* explore the workings of this model and its common failure modes. He suggests that, particularly in large, complex projects, the traditional model of 'operator advocates and partners challenge' can lead to unproductive partnerships and significant value loss.

Relative to other industries the upstream oil and gas sector has tremendous exposure to working in joint ventures, with about 95% of all significant projects currently in progress having some form of joint ownership. The reasons for this vary – some projects are simply too big and risky for a single company to pursue, while others are legacy partnerships either through joint exploration, re-determined licences, or farm-ins.

The operator's perspective

The role of the operator is to create maximum value from an opportunity and thus represent the best interests of all equity holders. Why is it, then, that oil companies prefer operatorship to equity partnership?

Looking specifically at the E&P sector, there appear to be a number of reasons for the 'operating premium':

- People have an inherent preference to be in control.
- Operatorship provides the opportunity to do what's best – fundamentally this illustrates a belief that we, the operator, will do better than anybody else.
- Steering the opportunity to our advantage – for instance create infrastructure that benefits our other positions in the region.
- Charge costs to the partnership – for instance project personnel, R&D, offices and other general costs.
- Learn from the operatorship – the active role in opportunity development gives bigger exposure to learn from the experience; we also can point to the project as evidence of capability.
- Privileged future access – as operator we develop a superior relationship in the basin that could provide preferential access.

From an operator's perspective, an opportunity will be developed more effectively without the interference of partners, or the national/governmental agencies for that matter. The operator will plan to progress the development in line with its stage-gate process (see **Figure 1**), which in all likelihood follows the industry standard model (with possible variations in nomenclature).

The process is designed to ensure that the project follows best practice throughout the development cycle, thereby maximising the value for all owners. But what typically happens?

In practice, a project execution mindset shapes actions and outcomes in the early stages. The 'assess' gate is a feasibility hurdle, where an opportunity is considered robust if the hurdle is met using proven concepts. Once this gate is passed, the pressure is on to deliver as quickly as possible, within time and budget. Any dramatically alternative opportunity development concepts are raised in the early stages, if at all; but if a conventional concept will do (meet the hurdle), pressures are such that this will be the base case that is developed. Ironically, operators put their best brains and effort into looking for creative solutions for projects that do not meet hurdle criteria in an effort to get the project across the hurdle. Projects that are so attractive that they pass the hurdle without any creative thought, simply proceed fast. As a result, development performance converges towards the (minimum) hurdle requirements, regardless of whether they start off as great or marginal opportunities.

We can characterise such behaviour as 'advocacy'. Once an adequate way forward has been found, the operator advocates this approach as the best and all effort is focused to reduce the uncertainty around this plan, and proceed through the gates as swiftly as possible.

The non-operating partner's perspective

Not surprisingly, partners can be uncomfortable with this advocacy model and can resort to belligerent behaviour. It's certainly not difficult for operators to understand what it is like to be on the 'other side of the table'. All operators have minority stakes elsewhere, and their behaviour as non-operating partner is probably similar to that which frustrates them in their own operated ventures!

There are two basic reasons for a non-operating partner to have misgivings:

- Perceived misalignment of objectives.
- Perceived lack of operator competency.

These two can be present in isolation, or in combination, providing a rich mixture of potential conflicts as shown in **Figure 2**.

Of course, a lot depends on what the

non-operating partner is seeking from its involvement in the venture. We have identified different roles and perspectives for non-operating partners and applied this model effectively in various situations (see **Figure 3**). In our experience, most organisations tend to feel comfortable with one type of role across their portfolio of non-operated ventures, with only the occasional exception. Different companies have different dominant models, but few assess opportunities individually to establish what role is the most appropriate given the broader context.

Partner drag

In order to further probe the issue of 'partner drag', Strategic Decisions Group (SDG) has reviewed the 200 most significant current global oil and gas projects and assessed two dimensions of complexity:

- Stakeholder alignment complexity (conflicting objectives, organisational complexity, governance, cultural differences).
- Non-technical project complexity (commercial dynamics, degree of functional integration, infrastructure complexity, political challenges).

Figure 4 illustrates our findings. Around 80% of the projects are 'technical' oil and gas developments without too much further complexity. In our judgement about 70% of the projects do not have serious misalignment issues. However, what is interesting to note is that highly complex projects have a high probability (three in four chance) to develop partnership alignment issues. In projects with a low degree of (non-technical) complexity there is a much lower probability of such problems to develop (one in five).

In other words, complex projects (other than technical complexity) attract a disproportionate degree of partner conflict. Noted this way, this may make intuitive sense – but from our experience, technical issues dominate partner conversations.

Let's examine the decision-making processes a little more closely. The traditional behaviour of the operator is to propose a way forward to the partnership, who essentially can choose to accept, ask for clarification or reject. Often the proposal is framed from a 'now' or 'regret' mindset that raises the pressure for the advocated solution. When things go well, partners may accept their passive role and the operator has the free rein it needs to progress the opportunity as soon as possible. When things go wrong, however, partners may seek an active involve-

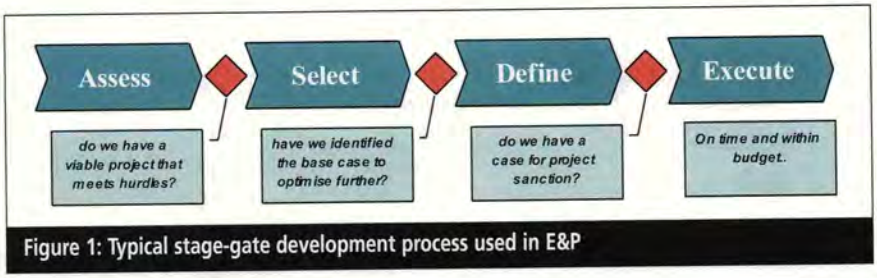


Figure 1: Typical stage-gate development process used in E&P

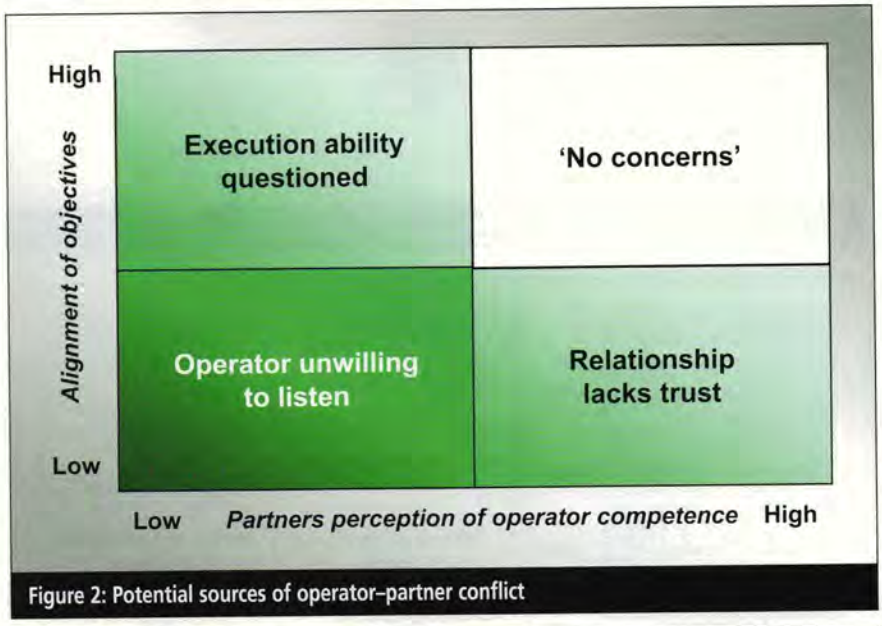


Figure 2: Potential sources of operator–partner conflict

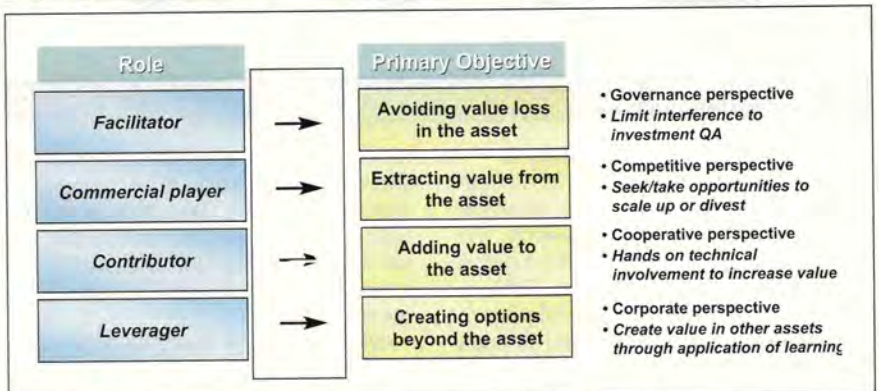


Figure 3: Roles of non-operating partners

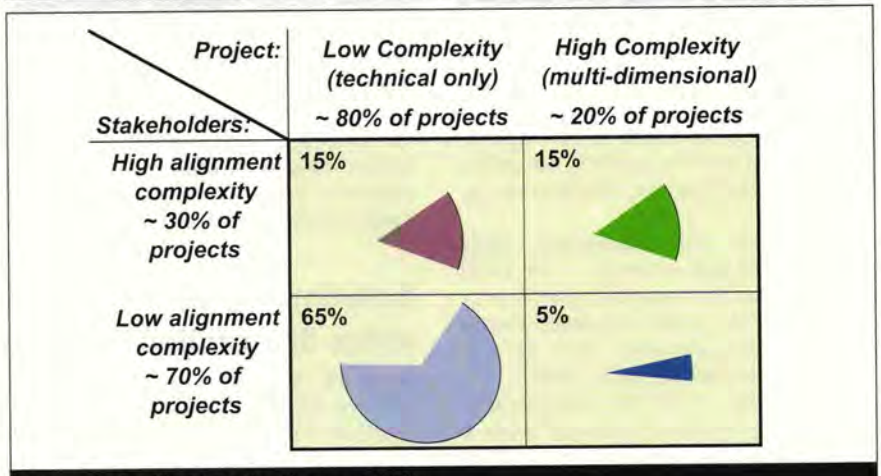


Figure 4: Classification of project complexity

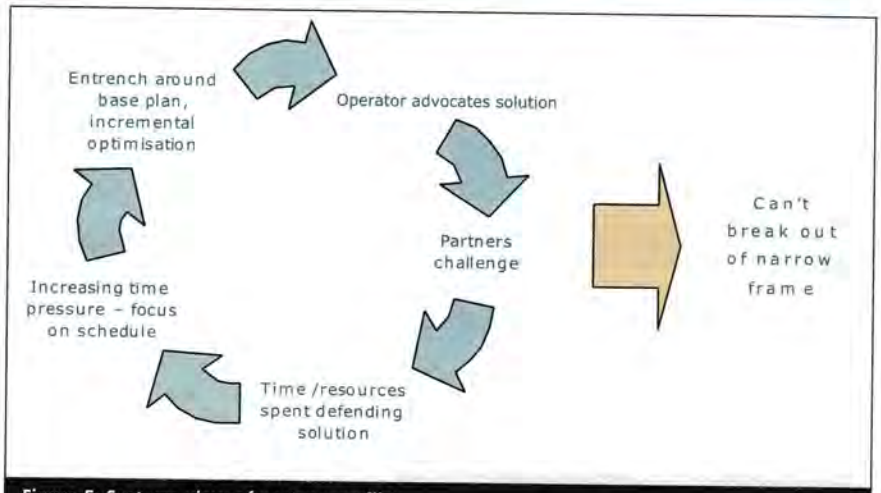


Figure 5: Systems view of partner conflict

Partner Role		Primary Objective	Partner value
Facilitator	→	Avoiding value loss in the asset	Value assurance
Commercial player	→	Extracting value from the asset	Negative (fight for the pie)
Contributor	→	Adding value to the asset	Embrace in decision process
Leverager	→	Creating options beyond the asset	Nil

Figure 6: Partner value add for different roles

ment beyond the problem at hand.

It is relatively easy to see what happens once an advocated solution appears to be biased, favouring the operator in some way. Quickly trust is lost and a vicious circle begins. This systems view is illustrated in **Figure 5**. Sometimes the operator does not even have the time to get into difficulties before partners force a stalemate and downward spiral.

What value is at stake because of this problem? There is little evidence other than anecdotal about the impact of partner drag as primary cause to project delays, overruns, or break-ups. In fact, where we as a firm do have knowledge about partner conflict, the public domain often does not explicitly recognise this.

Based on our experience, once partner conflict emerges, the most notable and immediate impact is project delay. We have witnessed delays of anywhere between one to five years. It is not all bad news – for example, the conflict can serve to prevent a big mistake (certainly from a partner's perspective). Skilled project managers may be able to manage the conflict well – although this simply hides the issues and raises the stakes. If there is fundamental disagreement, it will surface – the later it does so, the worse the conflict and the greater the set-back. Burying conflicts until the sanction decision can be extremely damaging.

We hypothesise that the more tangible and visible elements of a sub-optimum partnership are only the tip of the iceberg. These include excessive project reviews, sanction delays, start-up delays, etc. What is much harder to see are the opportunities lost, the time wasted on advocating the way forward, the valuable alternatives not considered (eg they would contradict earlier advocated positions) and more pervasively a reluctance to change leading to a reluctance to learn.

Solutions to avoid value destruction

So, if we cannot measure partner drag and the impact to opportunity value, how can we alleviate it? SDG has contemplated embarking on a benchmarking exercise – but although interesting, we felt that if you have partner drag, you know it!

In **Table 1** we have identified six different categories of fundamental sources of conflict in order of difficulty to resolve. Broadly speaking, these sources are either a perception of a missed benefit to all investors (increase of the pie) or a desire for preferential advantage (bigger slice of the pie). We have also tabled suggested approaches for resolution before they lead to irresolvable disagreement and major value destruction.

Whether, and how, a partner (operator or non-operator) will take action on the source of conflict depends on factors such as materiality, patience, perceived impact, politics etc. A logical trade-off from a non-operating partner's perspective is whether the prospect of intervention is better than the prospect of letting the operator operate. In the extreme case where the partnership reaches a fundamental stalemate (ie level 6 conflict), it will be very difficult to resolve the basic disagreements and re-structuring the partnership may be the only answer.

Solutions to grow more value

So far, we have addressed why conflict arises and suggested some approaches to deal with this, the negative aspect of partnerships. We have been involved in assignments where the operator is, in our view, out of its depth. In each of these instances, the operator was willing to accept help in specific areas but resisted partners becoming involved in thinking strategically about how to create and capture the most value from the opportunity. We believe that integration across multiple dimensions is the key source of complexity, so, ironically, the targeted help which was offered did not address the real issues the operator was struggling with. Would it not be more effective if, instead of reactively resolving partner conflict, we could apply these ideas pro-actively to grow more value?

As discussed earlier, partners have a choice on role they play in a venture. Where partners are prepared to play a value-added role (be it passively as 'facilitator', or actively as 'contributor'), the operator could choose to interact with this partner at a more strategic level (**Figure 6**). We believe that the potential for added value from the involvement of a partner is tremendous – but we rarely see a partnership take advantage of this. The key source of added value lies in the different knowledge and perspective that a partner can bring.

Potential benefits of this more inclu-

Source of conflict	Partner's perspective	Resolution	Suggestion
Pressure to progress	Feeling railroaded, lack of choice	Fairly easy	Shift the conversation from schedule to value
Base plan	A different (better?) approach is dismissed		Include partner ideas as broad alternatives to be considered
View of the future	Different belief of what will happen; different view of key uncertainties		Explore uncertainty explicitly, using wide ranges and independent assessments
Preferences	Different criteria for making trade-offs		Structured facilitation to figure out whether differences are real and if they open up win/wins
Analytical rigour and logic	The (base) case makes no consistent sense		Requires a rigorous independent analysis
No trust, or no faith	No confiden ce in ability to deliver and/or fairness	Very difficult	Time for restructuring?

Table 1: Sources of conflict and suggested solutions

sive strategic approach include:

- The strategic conversation steers the interactions where they are relevant.
- Broader and different perspectives could surface higher value paths.
- Proactive identification of problem areas and utilisation of partnership capability.
- Alignment on how to deal with the unforeseen.
- Consistent messages to other stakeholders.

To make a strategic partnership work, a learning perspective is required as opposed to the advocacy perspective that currently dominates. The magic lies in making sure that interventions are timely, helpful and structured so that the operator is set up to use the ideas, and partners see their use. Naturally, not all ideas prove valuable, so learning is essential for all parties.

Three critical questions

This article provides distinctions that are helpful to understand the sources of conflict better and to frame up the resolution of these problems. However, there is no 'silver bullet solution' to all your partner and joint venture related problems. The context of the opportunity, the perspective that the partners take, and involvement of other stakeholders all play a major role in how conflict should be addressed.

To conclude, there are three critical questions that both operator and partners should ask before venturing further into any project partnership:

- Am I interested in a solution that I perceive to be the best for all, or do I want to push through my own agenda?
- Is the cost of conflict worth the prize?
- What tactics should I adopt to achieve my objectives?

... continued from p21

mentation of both projects on a parity basis in Western Kazakhstan.

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

Colombian operation

In April 2002 LOHL and Colombia's state-owned Ecopetrol signed a contract under which Lukoil Overseas Colombia will undertake exploration and production on the Condor contract block in the Llanos Basin. Recoverable reserves of seven prospective structures of the block are put at 2bn boe. The maximum exploration period is up to six years. LOHL holds a 70% interest in the project, with Ecopetrol holding the remaining 30%.

Competitive player

Lukoil's international operations produced some 2.53mn tonnes of oil in 2003, accounting for more than 3% of the company's total oil output. From 2001 to 2003 the annual production growth rate for its international projects was 18%, accounting for one-quarter of Lukoil's total production growth.

The key indicators of operational efficiency show that Lukoil's international projects have reached competitive levels – opex in 2003 stood at $1.5/boe, with average net revenue for production projects at $4.7/boe and a ROACE (return on average capital employed) of 14%.

The merger of Lukoil-Permneft with Lukoil-Perm is now complete, with the transfer of assets in the Republic of Komi, Khanty-Mansiysky Autonomous Area and Volgograd region to the relevant Lukoil divisions.

During 2003 the company sold its share in the Azeri-Chirag-Guneshli project to the Japanese company Inpex Southwest Caspian Sea for more than $1.3bn. Meanwhile, in Egypt, two new exploration blocks were acquired in the Gulf of Suez – North-East and Western Geisum. Covering a total area of 170 sq km the blocks are thought to contain recoverable reserves of nearly 200mn boe.

China tackles energy shortages

China's booming economy has placed the energy sector under extreme pressure this winter as the electricity and petroleum industries struggle to keep pace with the rise in industrial and residential energy demand, writes *David Hayes*.

In January 2004 electricity blackouts affected some 16 provinces due to power shortages caused by rapid economic growth and insufficient coal supplies being delivered to power stations. Energy conservation measures have been introduced in many cities to reduce such power cuts. In Shanghai, for example, shopping malls and department stores have been asked to shut down their central heating systems from 10 am to noon daily in order to reduce peak time energy use.

The government has also asked two leading state-run oil producers to increase production and reduce exports in order to increase petroleum supplies, including diesel fuel, to those provinces where energy shortages are most severe – Chongqing, Guangdong, Jiangsu, Yunnan, Zhejiang along with Shanghai.

Coal dependence

Dependent on coal for about 75% of its primary energy requirements, China has been forced to re-open many of its small coal mines – which were closed down in the late 1990s – in a bid to meet the unexpected surge in coal demand that has caused energy shortages countrywide. In Shanxi, the country's main coal mining province, almost all the coal mines that had been closed have now been re-opened.

In the mid-1990s China had about 70,000 coal mines, many of which were supported by municipal authorities but were operating illegally without central government approval. In a bid to modernise China's coal industry and increase efficiency while clamping down on ill-equipped, unsafe mines producing low quality coal, the government ordered all illegal mines to close in the late 1990s. This resulted in the number of operational mines reducing to 28,000. However, many of these are still small and ill-equipped, producing an average of 50,000mn t/y of coal.

China relies on coal-fired power stations to generate 70% of its electricity supplies. Power shortages have occurred despite domestic production of 1.6bn tonnes of coal in 2003, a 14% increase compared with 1.4mn tonnes in 2002. Most coal produced is 'thermal coal'. In fact, China has to import coking coal for its booming steel industry due to a shortage of local coking coal supplies.

Power plants consume about half of the nation's coal production. According to the official Xinhua news agency, power stations were expected to consume 826mn tonnes of coal in 2003, a rise of more than 13% compared with 2002.

The coal supply shortage is so serious that seven major power producers, including China Huaneng Enterprise Group, recently sent a petition asking the government to intervene. Coal shortages have forced power companies to shut down some of their generators, disrupting electricity production and supplies.

Delivery problems

Some local coal supply shortages have been caused by China's inadequate railway freight system. Major coal fields are located far from urban centres where coal is needed and coal has to compete with other commodities such as oil, grain and fertiliser to be transported. In spite of their small size, many of the closed mines had the advantage of being located close to their customers and did not face coal freight delivery problems.

Since November 2003, the Chinese railway authorities have increased the number of railway wagons used to transport coal from 38,000 to 50,000, cutting freight services for other commodities. According to the state media, China's railways carried 62mn tonnes of coal from January to November 2002 – 11mn tonnes more than scheduled.

Increasing power tariffs

As part of measures to curb electricity use and help finance new power plant projects the government has allowed power companies to increase their tariffs since 1 January 2004. Large generating companies have complained that they cannot afford to produce electricity at the old rates, as coal producers have been asking prices up to 25% higher than before due to the coal shortage.

In trying to cope with the current power cuts, the government has found that the lack of large coal firms has made it hard to relieve serious coal shortages. Although China has recently overtaken the US to become the world's largest coal producer and consumer, only four coal mining companies in China are capable of producing 30mn tonnes or more of coal annually, and supply only 14% of the domestic market demand. The largest is the Shenhua Group, which is believed to have produced a record 100mn tonnes of coal in 2003.

Coal sector reform

According to plans revealed at a recent conference on coal sector reform by the Chinese Society of the Coal Industry, formerly the Ministry of the Coal Industry, China is planning to reorganise its coal industry and overcome the country's serious energy shortage by encouraging the formation of eight to 10 large coal mining companies with large individual production capabilities. Xinhua News Agency reported that the companies will be created through mergers and are expected to control 60% of the domestic coal market.

Under the Coal Industry Society plan, the large mining companies each will be capable of producing more than 50mn t/y of coal. Four or five of the mining firms are expected to produce about 100mn t/y, eventually. The Society is also planning to build large coal mining centres and establish big and medium-sized mines equipped with advanced equipment.

Reorganising China's coal sector is intended to prepare the industry to cope with future coal production and consumption growth. The government had previously forecast that the actual coal production volume of 1.6bn tonnes in 2003 would be achieved in 2010.

According to current unrevised official long-term forecasts China will produce 2bn tonnes of coal in 2020. However, given the current rate of economic and energy demand growth, China's long-term coal and energy production targets will soon need to be reviewed.

EI aviation contract awarded to Air BP

Location for installation of EI aviation filter conditioning facility

The Energy Institute (EI) has awarded a £100,000 contract to Air BP for aviation fuel filtration research in 2004. The contract covers the design and construction of a filter conditioning facility, and its installation and operation at O'Hare International Airport, Chicago.

When operational, the conditioning facility will enable a series of 'conditioning experiments' to be performed on filter monitors, which can then be removed for analysis. O'Hare has been identified as the ideal location for the facility as it will be installed in the fuel farm and connected to a loop of the hydrant system returning fuel to storage. Filtration equipment will therefore be exposed to fuel which is ultimately provided into-plane, representing in-service conditions.

Based on a 2004 cost estimate for the facility of $350,000, and the desirability to engage wider stakeholder groups such as filter monitor manufacturers, together with fuel suppliers, into-plane fuelling companies and airlines, the EI established the jointly-funded project towards the end of 2003. Some £90,000 of research funds have been provided from oil companies via the EI's 2004 Technical Programme, and to date five other companies have joined by providing funding. The total research contributions currently stand at $252,000.

Brian Hahle, Operations Engineer for Air BP, will be the Project Manager for the duration of the contract. It is anticipated that the first filter monitor elements conditioned with high fuel throughputs at Chicago will be available for analysis later this summer, by which time a second contract will be in place for analytical work.

The EI continues to seek further project participants. If your company has an involvement with aviation fuel and you would like further information on the project please contact Martin Hunnybun, Technical Manager – Distribution and Aviation at the EI on t: +44 (0)20 7467 7133, e: **mh@energyinst.org.uk**

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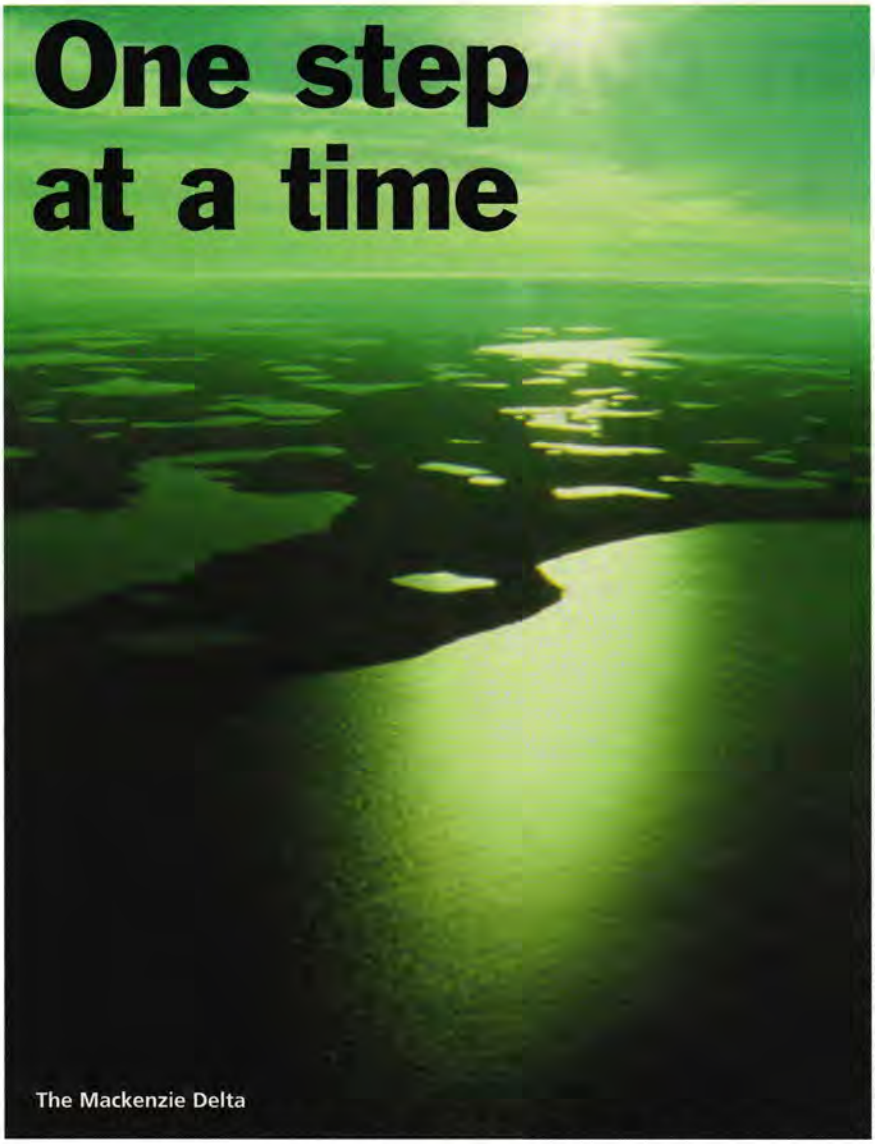
One step at a time



The Mackenzie Delta

Photo: Imperial Oil

In a regulatory waltz that would do Schubert proud, the major Arctic pipeline projects are moving two steps forward and one step back. Will they finish the dance in time to meet North America's growing needs? *Gordon Cope* reports.

Guinness World Records take note: the Mackenzie Valley pipeline may no longer be in the running for the longest-delayed project. Recent developments could mean that the oft-postponed scheme may actually be built! To whit:

- In June, 2003, the Aboriginal Pipeline Group, or APG (representing Native groups along the right-of-way), obtained funding for its share of the project's initial costs when TransCanada Pipelines agreed to lend it C$80mn.
- Over C$100mn of the $250mn in preliminary engineering and environmental work has already been spent.
- By mid-2004, the Canadian producers expect to file applications for the development of the field and pipeline facilities.

'I'm optimistic,' says Hart Searle, spokesman for the Mackenzie Gas Project, the consortium formed by gas producers in the Canadian Arctic. 'We've spent over one million man-hours and held thousands of meetings. If we look at where we were a few years ago and where we are now, we've made a lot of progress.'

The long-term outlook for Arctic pipelines is strong. The EIA (Energy Information Adminstration) estimates that US gas demand – currently in the range of 22tn cf/y – may rise to 35tn cf/y by 2025.

Conventional supplies are also on the wane. In 2003, Statistics Canada reported that natural gas production fell 3.8% to 16.04bn cf/d, while domestic consumption rose 2.2% (as a result, exports to the US fell by almost 6% to 9.83bn cf/d). Prices reflect the squeeze – the Nymex futures contract for May 2003 delivery at the Henry Hub during the normally-quiet refill season hovered in the range of $5.50/mn Btu, indicating another strong year.

But even the most lustrous of silver linings have their storm clouds, and this one is no exception. Regulatory processes, environmental reviews, economic vagaries and political shenanigans all lurk. Will the dream once again be postponed?

Pas de deux

For several decades, there have been two competing plans to pipe the vast amounts of natural gas locked in North America's frozen tundra to market – the Mackenzie Valley pipeline and the Alaska Highway project.

The Mackenzie Valley pipeline seeks to connect 5.8tn cf of proven reserves in the Mackenzie Delta to the existing North American natural gas network through a 1,300-km pipeline running south to Alberta. The project is jointly owned by Imperial Oil, Inuvik's Aboriginal Pipeline Group, ConocoPhillips, Shell Canada and ExxonMobil, while TransCanada Pipelines has the option to eventually buy at least 5% interest from the producers. The 1.2bn cf/d pipeline, which can be expanded to 1.9bn cf/d, is expected to cost in the order of $3bn.

The Alaska Highway pipeline is designed to tap 34tn cf of stranded gas reserves in Prudhoe Bay and deliver them to markets in the lower 48 States. Producers BP, ConocoPhillips and ExxonMobil propose to follow a 2,800-km path south through Alaska, the Yukon Territory and British Columbia to the Alberta border. The project, which would transport 4–4.5bn cf/d, could be expanded to 5.66–6bn cf/d. Although a construction figure of $20bn has been bandied about, that estimate is based upon upgrading infrastructure all the way to Chicago. If the expected natural gas production decline in the mature Western Canada Sedimentary Basin

occurs, there should be sufficient spare capacity within a decade to handle the load, and the *Pipeline & Gas Journal* recently estimated that $15bn may be closer to the mark.

The Alaska scheme is strongly backed by the State legislature and the Bush administration. Congress has attempted (so far, alas, unsuccessfully), to enact various forms of an energy bill that would have provided, among other things, guarantees of up to 80% of costs and accelerated deprecation to support the project.

Anyone for limbo?

However, several barriers still stand in the way of both projects.

The Alaska producers envision a lengthy negotiating process to resolve royalty and tax guarantees, permitting legislation and binding dispute arbitration before any pipe hits the permafrost. But the most significant hurdle is the extravagant cost. Even if Congress were to pass a funding scheme, it would face potential roadblocks in Canada. The federal government, worried about the competitive viability of the Mackenzie pipeline, has stated its objections to US Government subsidies for the Alaska Highway project, and could use its regulatory powers to prevent connection to the Canadian system.

Proponents of the Mackenzie Valley project can take little comfort from Alaska's woes. The Canadian pipeline route, which is expected to cross 500 rivers, five major bird areas of international importance and countless fragile habitats, has environmental groups salivating. In January, the Canadian Environmental Assessment Agency announced that the project would be subject to a full federal review panel. The Mackenzie Valley Environmental Impact Review Board also proposes to hold an additional round of panel hearings. Producers object to the latter, citing time-wasting redundancy. 'Even a couple of month's delay when dealing with the North can manifest itself in longer delays down the road,' warns Searle. 'It could serve to tack on six to eight months to the timeline.'

Another concern is funding for the Aboriginal Pipeline Group's 33.3% interest of the $3bn project. Filing of the preliminary information proposal languished until TransCanada loaned the APG C$80mn to meet its share of the initial engineering and environmental costs. The federal government has not officially ruled out public loan guarantees for the larger portion, but has made it abundantly clear that it favours a marketplace solution. Could financial troubles further delay the project?

Oil and gas experts think not. 'Financing for this will come aboard when you have shipping agreements,' says Tom Ebbern, Managing Director of Research at Tristone Capital. 'Pension funds are always interested in something that generates a nice dividend off guaranteed fees.'

Potential showstopper

A significant wrinkle has recently emerged over the last few years, however, one that has the ability to stop both pipelines – LNG.

At a liquefaction facility, or train, natural gas is run through a succession of refrigeration levels until it reaches approximately –160°C, where it turns into liquid. It is then loaded onto special, insulated carriers and shipped to market. A regassification facility returns it to gaseous form, and it is then injected into the conventional distribution system. Because LNG has historically been far more expensive than piped gas, only those countries with no indigenous supplies, such as Japan, have relied on it as a major source of energy.

However, all that has changed. Production costs have fallen from $400 t/y in the 1980s to as little as $175 t/y today. This has been accomplished through the growth in train size from 1mn t/y to 4mn t/y (a 4mn t/y facility equals approximately 0.56bn cf/d production), and advances in technology. Ship costs have also come down due to increased size, increased competition and better technology. The price of a 140,000 cm tanker has dropped from $250mn to $160mn over the last decade. Delivery price for LNG is in now the $2.50–$3/mn Btu range, which puts it in competition with supplies delivered to the lower 48 by pipelines from the Arctic.

The oil companies are doing their sums. In the US, Lehman Brothers estimates that expansion of existing import facilities is expected to increase capacity to 3.5bn cf/d by 2005. Energy companies have come up with dozens of proposals for new regassification facilities in the lower 48 States (and are hoping that innovative, offshore terminal designs will mitigate concerns over safety and the environment). Significantly, BP intends to build in New Jersey and ExxonMobil envisions at least one facility along the Texas Gulf Coast, while ConocoPhillips and Shell have announced plans for a multi-billion dollar plant in Qatar.

'We're acutely aware that our project needs to be competitive with all major supply sources, including the US Gulf Coast, the Western Canada Sedimentary Basin and offshore East Coast,' says Searle. 'We have to look out 10, 15, 20 years and ask where do we see the demand picture? There's no question; as we gaze into the crystal ball, we look at the potential impact of LNG.'

Ebbern doesn't think the advent of LNG will have negative ramifications for the Arctic pipelines, however. 'In fact, when you look at natural decline (in conventional, domestic North American production), you'll probably need both. The US consumes around 63bn cf/d; LNG will supply 10bn cf/d at most, while the Alaska pipeline will move 4.5bn cf/d and the Mackenzie pipeline around 1.2bn cf/d.'

One step at a time

In the meantime, field-preparation work is progressing in the Mackenzie Delta. As many as 40 production wells are being drilled at Taglu (3.8tn cf, owned by Imperial), Parson's Lake (1.8tn cf, owned by ConocoPhillips and ExxonMobil) and Niglintgak (1tn cf, Shell), in order to firm up production.

Petroleum companies not involved in the Mackenzie Valley project are also meeting their exploration commitments in the region. Since 1999, 20 new exploration licences covering 3mn acres have been issued in the Mackenzie Valley areas. Seven members of the Mackenzie Delta Explorer's Group – Petro-Canada, EnCana, Devon, Chevron, Burlington and BP Canada – have a combined commitment of around $900mn over the next five years.

Devon plans to drill two natural gas wells this year, one in the Mackenzie Delta in partnership with Shell Canada and the second on a separate licence with Petro-Canada. One of the wells drilled last year, Tuk m-18, produced up to 30mn cf/d and has an estimated reserve potential of 200–300bn cf. Chevron, BP and Burlington announced the successful drilling of a well that tested 18mn cf/d restricted flow rate.

Such successes have spurred the Mackenzie project to bump the planned expandable capacity of their pipeline up to 1.9bn cf/d, and to add a second pipeline to their proposal. 'From Inuvik to northern Alberta is the main transmission pipeline, 1,300-km in length,' says Searle. 'And from Inuvik to Norman Wells (a distance of 500 km), we're looking actually at a separate natural gas liquids line, which would go into the existing Norman Wells pipeline to Zama, Alberta.'

These changes have increased the initial engineering and environmental impact costs above the estimated C$250mn price tag and added to the regulatory burden. 'There's a whole

Proposed Mackenzie Valley pipeline route

Map provided by Northern Gas Pipelines: www.arcticgaspipeline.com

host of applications; the certificate of public convenience and necessity, applications for supporting construction, operating licences, water use, quarry use, wildlife – there's around 400–500 applications for licences and permits to be filed,' explains Searle.

But, if all goes well, Searle estimates that the regulatory review should take no more than 36 months. 'We envision a positive regulatory decision by 2006. Assuming that the project is a go, we will have three winter construction seasons: 2006–2007 for staging, 2007–2008 and 2008–2009 for construction, with a startup in late 2009.'

Save the last dance...

Don't count Alaska out just yet. In a wildcard move, legendary investor Warren Buffet announced in January that a subsidiary, MidAmerican Energy Holdings, wants to build the 1,200-km pipeline section from Alaska's North Slope to the Alaska–Yukon border. The plan is for the 4.5bn cf/d pipeline to extend from Prudhoe Bay to the Yukon border, where it will be connecting up to a line to be built by TransCanada. 'The importance of getting the stranded gas to the lower 48 States cannot be overemphasised,' stated Buffett. They aim to start construction as early as 2006, and complete it by 2010.

An Alaska pipeline being built at the same time would be a serious blow to the Mackenzie project. 'We are cognizant of the need to continue to move forward so we remain in advance of Alaska projects,' comments Searle. 'Otherwise, we potentially face delays if we're competing for the same contractors, labour pool and supplies. There is also spare transportation capacity in the existing system. If Alaska utilises that spare capacity, we're likely in the ditch. A big slug of Alaska gas might have an impact on gas prices.'

But, tellingly, a strong endorsement from BP, ExxonMobil as well as ConocoPhillips was absent from Buffet's initial announcement. 'The three producers are proposing their own pipeline,' says Ebbern. 'Nobody will be able to build a line unless the producers step up.'

At this point, it seems likely that the Mackenzie gas project will cross the finish line first. 'It's been a lot of hard work and effort to get to a commercial project state,' says Searle. 'We also recognise it's going to take the cooperation and goodwill of a lot of different partners – landowners, government and industry. We don't take any gains for granted. We have a sense of accomplishment, but recognise there's much more to do.'

Snøhvit and Ormen Lange – waking the gas giants

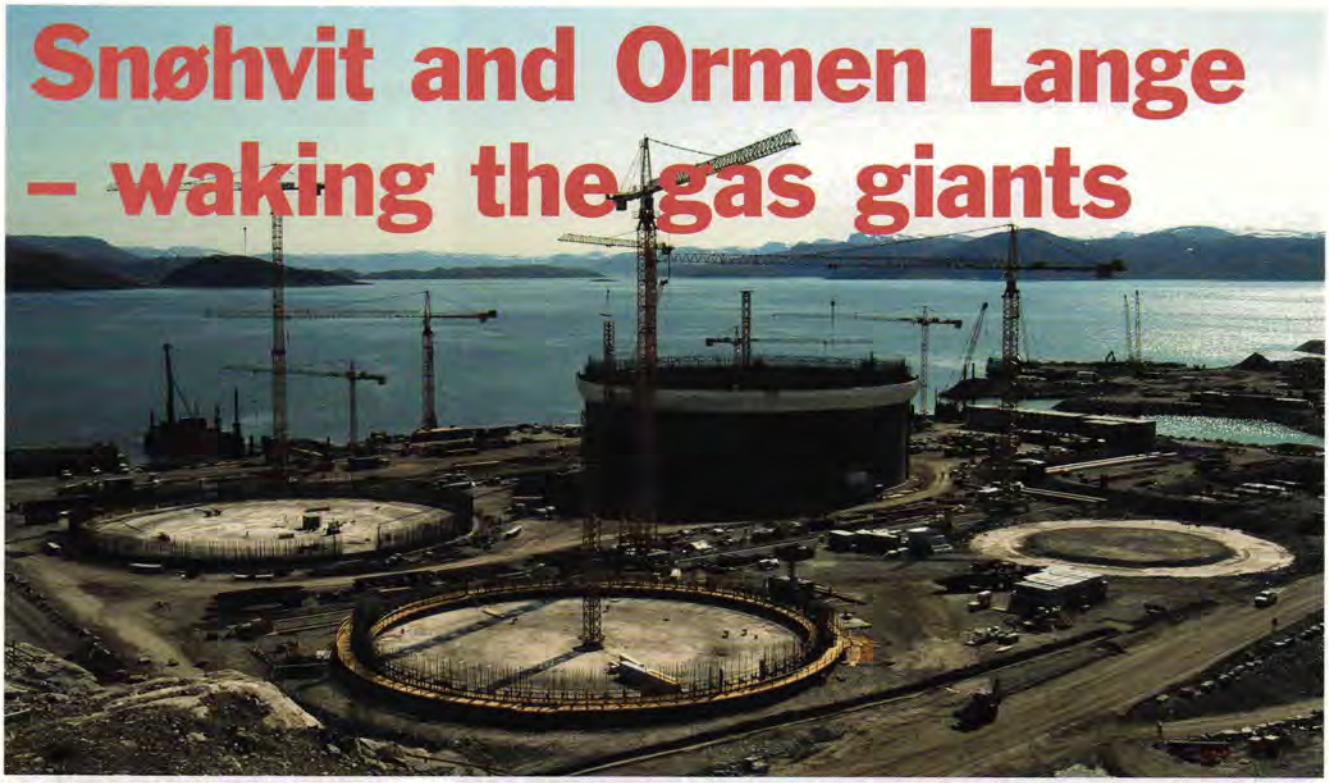


Photo: Statoil

Norway's largest gas developments – Snøhvit and Ormen Lange – follow a new trend in which subsea gas wells are connected directly to processing facilities on the coast. 'Flow assurance' will have great significance for both these projects since, with combined investment of more than NKr100bn. Any disruption to production would have serious economic consequences, reports *Jeff Crook*.

Snøhvit LNG storage tanks under construction

Snøhvit will be the first full-scale LNG export terminal in Europe. The project was controversial from the beginning, as the first offshore development in the Barents Sea – a region famous for its fishing grounds. However, after a major national debate, the plan for development and operation (PDO) – with budget of NKr39.5bn – was approved by the Norwegian Storting (Parliament) on 7 March 2002.

The project covers the development of the Snøhvit, Albatross and Askeladd gas/condensate fields and is notable, from a technical viewpoint, as the longest subsea tie-back in the world. The 4.3mn t/y gas liquefaction plant on Melkøya island near Hammerfest, in northern Norway, is also notable as the most northerly plant of its type.

Flow assurance

One significant 'flow assurance' measure will be to continuously inject mono ethylene glycol (MEG) at the subsea wellheads to absorb moisture from the reservoirs, and thus prevent the formation of hydrate, a slushy compound that can block pipes and valves. The MEG will be regenerated in the onshore plant before it is pumped back to the subsea production system via a pair of 4-inch diameter pipelines.

Natural gas from the fields also contains 0.625% of carbon dioxide (CO_2), which will be separated out at the land plant and returned via a separate line to be injected into a layer below the seabed. Statoil claims that the process for separating the CO_2 entails mixing the produced natural gas with the chemical amine in a vessel at high pressure and moderate temperature. The amine binds itself to the CO_2 and separates out at the bottom of the vessel.

The CO_2 is separated from this sediment in a second vessel where the pressure is lower and the temperature higher. After separation, the CO_2 is compressed and flows through an 8-inch pipeline to an injection well. Around 700,000 tonnes of the greenhouse gas will be stored annually and will thus be unable to reach the atmosphere. It will be injected 2,600 metres below the seabed, at the edge of the Snøhvit reservoir, into a 45- to 75-metre thick sandstone formation that is capped by a sealing formation.

Subsea templates will be provided with slots for 21 production wells, together with one CO_2 injector, in water depths of 250–345 metres. A 28-inch production pipeline, together with ancillary pipelines and umbilical, will link the subsea production facilities over a 143-km subsea route to the terminal. The first offshore development phase involves 10 wells and is expected to produce 5.7bn cm/y of gas after start-up in 2006. Further wells will be drilled in later phases.

Onshore control

The subsea production system is controlled from the onshore terminal at Melkøya, via an umbilical cable whose

Photo: Statoil

Snøhvit subsea production system

Photo: Statoil

LNG tanker loading at Melkøya

length of 160 km will be a world record. This length will increase to 210 km as more remote wells are brought onstream. To deliver electric power over this enormous distance it will be necessary to transmit at 3,000 volts – three times the conventional level for a subsea facility. In addition to the high-voltage power, the umbilical will also transmit chemicals and hydraulic power, as well as fibre-optics to convey monitoring and control signals – all bundled together within a 150-mm diameter protective sheath.

Control room operators at Melkøya will be provided not only with real-time data, but also with predictions of future process conditions within the subsea pipeline, allowing them to take the necessary action to ensure optimum production. Fantoft was awarded the contract for a dynamic production model (DPM) based on its D-SPICE Pipeline Management System. The DPM will supervise the flow of gas, condensate and water from the subsea field installations to the process plant at Melkøya. 'Keeping tabs on liquid volumes in the pipeline and receiving this flow into the gas liquefaction plant is the DPM's primary job,' explains Statoil Staff Engineer, Jan Kjeldstad.

Fantoft claims that as part of the D-SPICE installation there will be a seamless integration with a multiphase flow model of the production pipeline, covered in OLGA 2000 or PeTra. 'The online DPM will support the daily operation of the complex Snøhvit multiphase pipeline, such as monitoring the risk of pipeline leakage, hydrate formation and liquid accumulation,' says Knut Erik Spilling of Fantoft HQ. Fantoft was also awarded a contract to supply a simulator for the LNG plant.

Work programme

Statoil is field operator, with a 33.53% interest subject to regulatory approval of recent stake purchases from Norsk Hydro and Svenska. Other partners are Petoro (30%), Total (18.4%), Gaz de France (12%), Amerada Hess (3.26%) and RWE-DEA (2.81%). An upward revision of the budget from NKr39.5bn to NKr45.3bn in December 2002, prompted a tightening of project management controls.

Installation of the subsea templates is due to take place in the summer of 2004, under a NKr80mn contract placed with Aker Marine Contractors. During this operation, six subsea structures will be submerged to a depth of 70–100 metres in calm water close to land, before being towed to the field for placement on the seabed. The subsea production system is being supplied under a NKr1.2bn contract by ABB Offshore System on the basis of a frame agreement.

Technip was awarded a 65mn contract for installation of the in-field pipelines, the CO_2 line, service lines and umbilical, including the spool installation and tie-ins. The in-field pipelines will be installed during summer of 2004, with remaining pipes run during 2005. Development drilling is due to start in August 2004. Transocean received a Letter of Intent worth NKr700mn for the ten wells in phase one of the project; work will be carried out by the rig *Polar Pioneer*.

A major contract was awarded to the Swiss-based Allseas Marine Contractors for laying the main production pipeline from the subsea hub to the shore. This work, which is valued at NKr400mn is scheduled to start in the spring of 2005. The pipe route was surveyed by the specialist ship *Normand Tonjer*, using remote-controlled subsea tools such as multi-beam echo sounders, side scan sonar and video cameras. The deepest point of the sinuous pipe route is 445 metres below sea level.

The dynamically positioned monohull laybarge *Solitaire* is due to lay the main production pipeline. This vessel can stay on station with engine power alone and does not need to deploy anchors. 'Using a laybarge of this kind avoids causing anchor damage to the seabed,' explains Olav Hagland, Pipelaying Manager in the Snøhvit project team. The steel pipes were ordered from Mitsui/Sumitomo under a contract valued at NKr340mn.

Melkøya LNG terminal

Construction of the terminal on Melkøya Island presents an enormous challenge because of its remote location and harsh environment. First, a tunnel needed to be built under Melkøya Sound to provide land-access to the site. The 2-km route was officially opened by the Mayor of Hammerfest on 17 November 2003. The sun does not appear for several weeks during the winter at this northern latitude and weather protection is needed against snow and ice as well as the harsh Arctic

Photos: Norsk Hydro

Ormen Lange gas will be exported 1,200 km via Sleipner (on right) to Easington on the UK coast

Photo: Norsk Hydro

Artists impression of Ormen Lange terminal at Nyhanna

winds. As a result, site work has been reduced by building much of the process plant on a barge at Spanish contractor Dragados' yard in Cadiz.

The barge will be towed to site during 2005, where it will be linked up to heavy components such as the 60-metre high 'cold box', which contains innovative heat exchangers supplied by Linde. These units are based on licenced technology developed by the German group in cooperation with Statoil. Linde's contract also covers preliminary engineering for the single-train gas liquefaction plant, together with the supply of mechanical equipment. Site hook-up for the onshore plant is being carried out by Aker Stord.

Tractebel, the energy division of SUEZ, was awarded a contract for the tank storage, jetty and loading facilities. The project consists of two 120,000 cm LNG tanks, a third 45,000 cm LPG tank and a fourth 75,000 cm condensate tank, together with the loading jetty. The outer containment of the three largest storage tanks for liquefied gas were cast in summer 2003, with the actual tanks installed in the autumn. Outfitting was able to continue during the cold winter months due to internal heating.

Ormen Lange project

UK and Norwegian Energy Ministers signed a cooperation agreement during October 2003 which opened the way for import of 20bn cm/y of gas from the Ormen Lange field to the UK – meeting some 20% of domestic gas demand. The plan for development and operation (PDO), with an overall value of NKr66bn was submitted to the government on 4 December 2003. It received approval from the Norwegian Petroleum Directorate (NPD) during January 2004 and Norsk Hydro is hopeful of receiving final approval from the Storting by mid-April this year.

Ormen Lange is the second largest Norwegian gas field, after Troll, with recoverable reserves of 375bn cm of dry gas and 22mn cm of condensate. It lies 100 km off mid-Norway, in water depths of 800 to 1,100 metres. As anticipated (see *Petroleum Review*, July 2003) the PDO covers a subsea development connected back to a processing plant at Nyhamna, with a 1,200-km long, 42-inch diameter pipeline running via Sleipner to Easington in Humberside.

Third-party gas will initially be delivered through the southern leg from the Sleipner riser platform to Easington, commencing in October 2006, with Ormen Lange gas starting to flow through the northern leg from Nyhamna to Sleipner from October 2007. Norsk Hydro is development operator (18.0728%) of the entire scheme, including export pipelines, while Shell is operator (17.0375%) for Ormen Lange production. The other partners are Petoro (36.475 %), BP (10.3420 %), Statoil (10.8441 %) and ExxonMobil (7.2286 %). Gassco is operator of the export pipeline system during both its operation and decommissioning phases.

The subsea production system for the first development phase involves two subsea templates with manifolds, with eight Christmas trees, control systems, intervention system, tie-in tools and accessories – all being supplied by FMC Kongsberg Subsea under a NKr1bn contract. This contract also includes an option for a second similar subsea system for a second phase of development. After a gradual production build-up during the first two to three years, the field will supply up to 70mn cm/d of gas.

The wellstreams will be conveyed over 120 km to the onshore process plant at Nyhamna, via a pair of 30-inch pipelines. The sub-zero seafloor temperature in water depths greater than 600 metres presents a major challenge. To prevent hydrate formation, large quantities of MEG will be supplied to the subsea production system by two 6-inch pipelines, for continuous injection into each of the subsea wells. The dual pipelines system also greatly reduces the risk of flow disruption.

The rough and uneven nature of the seabed along the pipe route presents one of the most significant challenges for the project. Huge rocky outcrops, measuring some 20–60 metre-high, jut up along the pipe route to shore, with a steep slope up the back wall of the 8,000-year-old seabed feature called the Storegga mudslide. Prior to pipelaying it will be necessary to prepare the seabed by cutting off peaks and filling in hollows. As part of this operation, around 2.8mn tonnes of rock will be dumped on the seabed. A NKr700mn contract was awarded to Van Oord ACZ for rock dumping during December 2003. Norsk Hydro is confident that the pipelaying challenge can be overcome and the operation will be watched with great interest by outside observers.

Kashagan dispute finally resolved

Christopher Pala takes a closer look at the Kashagan project in Kazakhstan – the development of which has been delayed for two years while the Kazakh Government and consortium partners struggled to resolve their differences.

Kashagan. Winter temperatires routinely go below –30°C in the North Caspian

For the second time in a year, Kazakhstani demands for financial compensation from major oil companies have met stiff resistance and resulted in delays that tarnished the country's prospects for further investment. While the first dispute, involving the financing of an expansion of the giant Tengiz field, did not exceed three months, the second, over the development of the much bigger Kashagan field, lasted more than a year and resulted in a project delay of two years.

It was finally resolved on 25 February 2004, when the government and a consortium of oil majors signed the field's $29bn development plan.

'The Kashagan delay has created a lot of negative perceptions about the investment climate in Kazakhstan,' says Laurent Ruseckas, Senior Caspian Analyst for the Eurasia Group. 'That's particularly true for the members of the Kashagan consortium, most of whom are generally looking for new offshore projects.' The consortium includes Agip, ExxonMobil, Shell and Total, with 20.37% each, while ConocoPhilips and Inpex split a similar share. No other consortium has so many majors with identical shares – which has made it all the more difficult to manage.

Challenging project

Kashagan – named after an obscure local Kazakh poet – is arguably the most challenging large hydrocarbon deposit in the world, which is why it was passed over by the Soviets in favour of easier pickings in Azerbaijan, Siberia and the Urals. It is currently the planet's largest untapped deposit. If new, high-pressure gas-reinjection technology is successful, the field is expected to yield between 9bn and 13bn barrels of light crude – making it the sixth-largest oil field in the world, and the largest outside the Gulf.

When Kazakhstan became independent in December 1991, President Nursultan Nazarbayev – a reformist who had been appointed Party Secretary by his ally Mikhail Gorbachev in 1988 – invited a select group of major oil companies to explore the country's sector of the North Caspian, where Soviet-era seismic surveys had indicated there may be significant deposits of crude. Exxon stayed away but, by 1993, Mobil, Agip, Total, British Gas, Shell and a BP/Statoil alliance had signed up for the initial 26,000-km seismic work as the Caspian Sea Consortium. It was operated by Kazakhstan Caspi Shelf, the offshore subsidiary of state oil company Kazakhoil.

The agreement provided for the consortium members and the government

to negotiate a production sharing agreement (PSA) and for the consortium to select a number of blocks as a reward for financing the survey. The survey revealed a super-giant structure, Kashagan, and three other smaller deposits, which the consortium members chose. About 150 other blocks were left out of the PSA, to be auctioned off at a later date.

In November 1996, a North Caspian project team was assembled, informally led by Shell, the largest company in the consortium. Within a year a 40-year PSA had been signed, which named Shell as the manager of the company that would perform a six-well exploration drilling phase. The company was named the Offshore Kazakhstan International Operating Company (OKIOC) and it was based in Shell's offices in The Hague.

The team grappled with such issues as how to deal with a deposit that began more than 4 km beneath the seabed and was under pressures reaching 1,500 psi, with a high gas and hydrogen sulphide content. It was located in an ecologically sensitive sea where seals and much of the world's last population of caviar-yielding sturgeon live, so the operation had to yield zero emissions. Furthermore, the water was less than 4 metres deep for most of Kashagan and 1.7 metres for Aktote and Kairan, while Kalamkas, the fourth structure in the PSA, was about 9 metres deep. The PSA covered 6,000 sq km and included 12 blocks.

Decision time

The team, according to former participants, faced a critical choice – whether to bring a barge that would sit on a berm (submerged island) for the drilling period and then move on to another berm, or to construct artificial islands.

It chose the barge solution. A swamp barge was rented from Parker Drilling. Just being shipped from Nigeria to Louisiana, where it faced an uncertain future, the barge was instead reconfigured for Arctic conditions – winter temperatures routinely go below –30°C in the North Caspian, reaching as high as 40°C in summer – and higher ecological standards.

The barge left the Red Fox yard in Michoud in 1998, before work was completed so it could be shipped across the Atlantic through the Bosphorus and the Volga-Don canal to Astrakhan, at the top of the Volga delta on the Caspian Sea. Once there, work was completed during the spring of 1999. After the thaw, the barge moved into the Caspian Sea with the goal of drilling its first well before the end of the year.

The problems begin

However, the barge – named *Sunkar* ('falcon' in Kazakh) – turned out to be less efficient and more costly ($130mn instead of $40mn) than previously envisioned. It did not reach the oil reservoir until May 2000 for safety reasons – notably fears of a blowout – and because of inexperience with the rig and with icy conditions.

The decision to hold off further drilling during the winter was endorsed by Radius Latfulin, head of Kazakhstan's agency for the safety of oil operations at sea, former OKIOC officials have pointed out.

Under the terms of the PSA, the consortium agreed that if it succeeded in drilling its first well before the end of 1999, the appraisal and development would be on a fast-track basis to produce first commercial oil in 2004. If that happened in 2005, the consortium would pay an extra $50mn production bonus. The PSA is silent on what happens if first commercial oil begins in 2006.

Since *Sunkar* did not complete the first hole until 2000, OKIOC members assumed that the pressure to produce by 2005 was off. But the Kazakh authorities saw this as a case of negligence and in 2000 attempted to renegotiate the terms of the PSA. They failed – but the Kazakhs were biding their time.

In the spring of 2001, when it came time for the consortium members to select an operator for the appraisal and development phases, Shell, much criticized for its management of the exploration, lost out. Some critics charged that at $600mn, the first well was the most expensive in history, and blamed the Anglo-Dutch giant – and Parker Drilling – for the six-month delay. Others said that given the difficult conditions, Shell had performed reasonably. Still, in the end, the *Sunkar* barge was given a back-seat role in favour of building a series of artificial islands.

Agip – already co-operator of Karachaganak, Kazakhstan's third-largest hydrocarbons field – was elected as Kashagan operator on 12 February 2001. In greeting the new operator that same day, Nazarbayev announced that it would have to fulfil five conditions – the most controversial and specific of which was that commercial oil would have to start flowing in 2005. Agip officials said they would try their best.

Consortium executives noted that the phrase 'all reasonable efforts' occurs more than 70 times in the PSA and few expected that the missed deadline would be an insurmountable problem.

New development plan

On 30 December 2002, toward the end of the appraisal phase, Agip KCO, the new operating company, submitted its development plan to the Kazakh Government. At some $29bn, it was the biggest in history and it provided for first commercial oil to flow in late 2006, with a $100mn production bonus.

'The government participated in the elaboration of the plan,' said one senior executive at the time. 'They knew what was in it before they received it.'

Again, the government said the delay was unacceptable, accused the consortium of gross negligence and incompetence, and according to several sources, sought a production bonus in the hundreds of millions as a condition for approving the development plan. However, the consortium refused to budge, with ExxonMobil (Exxon and Mobil had merged in late 1999) as the leading hardliner. 'We're ready to go to arbitration,' said a source involved in the talks. 'I don't think you're going to find a judge that's going to say that Agip, Shell, ExxonMobil and Total don't know how to drill a well.'

Without a signed development plan in hand, the consortium was loath to proceed with the massive spending the project required. Instead of speeding up, work on Kashagan slowed down and the summer 2002 construction season was lost.

Energy Minister Vladimir Shkolnik announced last summer that an agreement was at hand – but the deal fell through after the Kazakh side abruptly jacked up their demands, consortium sources said. The 2003 season went the way of the 2002 season.

Final agreement

With the 2004 season looming, an agreement was reached in early February when senior executives of the consortium met in Astana with officials of KazMunaiGaz, the successor agency to Kazakhoil and KazTransOil, which is at once Kazakhstan's hydrocarbons regulatory agency and a commercial company owning and operating oil fields and pipelines. The sources said that in the end, the fine for the initial one-year delay that the consortium agreed to pay was under $200mn – a far cry from what the government had asked for and close to the consortium's $100mn interpretation of the PSA, which was not modified. The agreement reportedly also includes a clause that protects the consortium against similar situations in the future.

Under the plan, the field will produce

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Volume correction factors by velocity of sound

A recent study carried out by members of the HM-L-4B Oil Transportation Measurement Committee – supported by the Energy Institute (EI) and the API – has confirmed the general accuracy of the existing IP/API/ASTM Petroleum Measurement Tables (1980). The tables are used to convert densities and volumes measured at ambient conditions to standard conditions. In addition, new, simple equations have been developed based on velocity of sound, which can provide improved precision over the existing tables. *Paul Harrison, Melverley Consultants, and *Denis Fitzgerald***, H&D Fitzgerald, report.**

The volume correction factors (VCF) that are used to convert liquid hydrocarbon volume measured at ambient temperature to volume at standard temperature (60°F or 15°C) are derived from IP/API/ASTM Petroleum Measurement Tables (PM Tables) – Table 54 or Table 6. The standard comprises the calculation routines that lie behind these tables and their sister Tables 53 and 5, which convert observed density to density at 15°C (60°F).

The calculation routines and PM Tables (referred to as the 1980 Tables) are based on laboratory work carried out by the US National Bureau of Standards (NBS; now the NIST) in the mid-1970s using samples of crude oil and petroleum products. The new CD-ROM based Tables currently in preparation are derived from the same data and relationship between density and the thermal expansion coefficient, α. The results obtained by the NBS are shown in **Figure 1**.

Due to the diverse molecular nature of hydrocarbon liquids there is no physical reason why α should be related to density alone, and this is reflected in **Figure 1**. The scattering of results was overcome in part by separating crude oils, petroleum products and lubricating oils and then using best-fit curves for each population. However, results are fairly scattered around the curves as can be seen from **Figure 1**. The PM Tables were named 'generalised' tables, noting the fact that specific hydrocarbons can vary from the curves.

Concerns have been expressed over the years since the work was carried out, as many new crude oils are now being traded that were not included in the original laboratory work. It has also been suggested that modern techniques would enable more precise results to be obtained and there has been some suspicion regarding results that were discarded by the API.

Method	Mean error kg/m³	Residual standard deviation
PM Tables	0.01	0.58
Generalised equation 1	0.00	0.45
Generalised equation 2	0.03	0.39

Table 1: Equation predictions compared with PM Table results

However, given that the underlying physical relationship is questionable, these concerns have, probably rightly, not been pursued. The tables have fulfilled their purpose in providing the industry with a standard from which VCFs can be derived from density, which, in turn, can be readily determined from samples – initially by hydrometer, but increasingly by laboratory density meter or in-line instrument.

Why velocity of sound?

High-precision density measurements at the H&D Fitzgerald laboratory indicated that the PM Tables are less accurate for liquids that had either a high paraffinic or aromatic content. It was felt that a second parameter, which reflected the molecular nature of the liquid, could perhaps be used as a 'correction factor' for the density-based standard calculations.

Following some experience of measuring the velocity of sound in liquids, it seemed that this might be a worthwhile technique, especially since it was known that paraffins and aromatics with the same carbon number had appreciably different propagation speeds for ultrasound. It was also known that velocity of sound (VoS) is closely related to compressibility, which is heavily dependent on molecular composition.

The use of VoS as an additional factor in determining expansivity was also attractive, as VoS cells are readily available as an accessory to laboratory density meters. In-line VoS cells for field use are also available and, with regard to field measurements, there is an increasing use of ultrasonic flow meters for custody transfer measurement. These devices offer a VoS output that could easily be used to assist in expansivity determinations.

The VoS project

Following initial test work funded by the Institute of Petroleum (IP) – which suggested a close relationship between VoS and expansivity for a limited number of samples – sponsorship for a wider study was obtained from the IP (now EI), the API and a number of oil companies and manufacturers, through

the Institute's HM-L-4B Oil Transportation Measurement Panel.

The project set out to collect and test a minimum of 200 samples of crude oils, petroleum products and lubricating oils to make precise determinations of density, temperature and VoS over a range of temperatures, with the aim of developing a simple universal equation to allow volume corrections with equal or better precision than the PM Tables. At the same time, the precision of the PM Tables could be tested with a completely new sample set, representative of today's trade.

Test procedure and data

The work was carried out using an Anton Paar DSA 5000 density meter, which has a VoS cell in series with the usual vibrating tube density cell. The DSA 5000 was programmed to provide multiple determinations of density and VoS, while the temperature was varied randomly to cover the test range (5°C to 60°C) in 5°C steps from 5°C to 40°C and then at 50°C and 60°C. (This is a wider range than was covered by the NBS work).

Density, VoS and temperature were measured at these 10 set temperatures, with 20 sets of observations being made at each step.

Density, temperature and VoS measurements are all traceable to National Standards, with uncertainties of ±0,04 kg/m³, 15 mK and 3.5 m/s respectively. A graph of a typical data set is shown in **Figure 2**.

Samples collected

A total of 222 samples were collected with the aim of covering as wide a range of crude oils as possible, with an emphasis on those crude oils that represent the largest traded volumes as indicated by the EI Marine Oil Transportation Database. Additionally, samples from a wide range of petroleum products and lubricating oils were collected, including products to European and US specifications.

Samples were tested 'as received'. Any free water was removed but samples were not dried, so as to better reflect 'typical' conditions. The water content of each sample was determined using the Karl Fisher titration technique. In a separate exercise, water was progressively added to samples of toluene, diesel fuel and two crude oils. However, the liquids would not hold sufficient water in solution to affect density or VoS measurements within experimental limits, and it was concluded that determinations were not affected by 'normal' quantities of dissolved water.

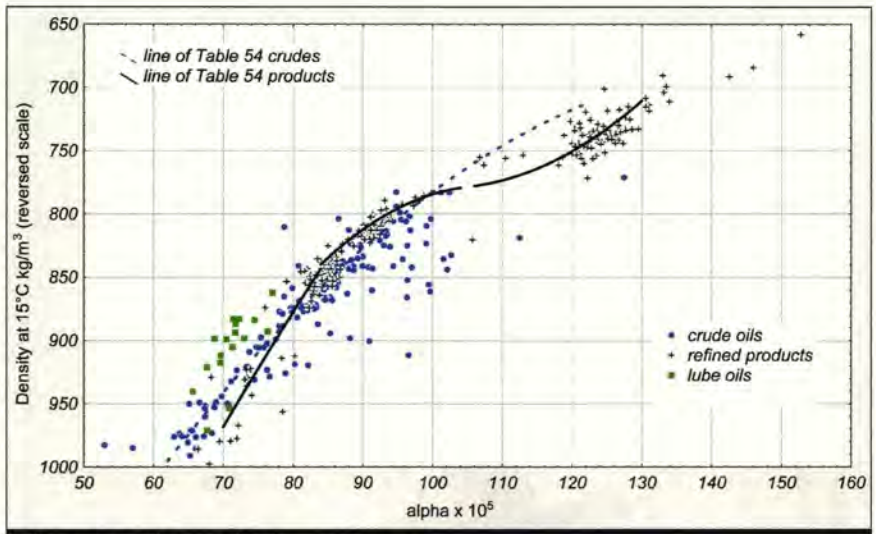

Figure 1: NBS data set density$_{15°C}$ versus α

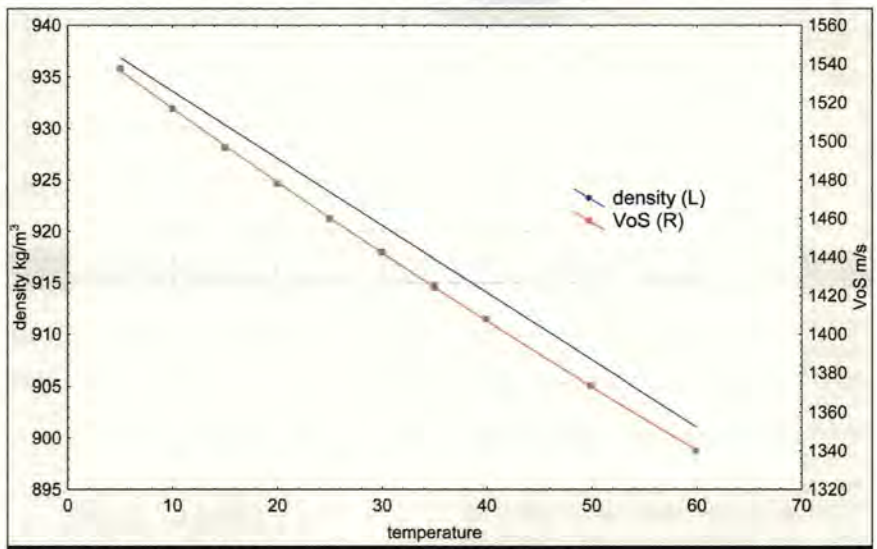

Figure 2: Density and VoS versus temperature for Harding #12

Reference density

Since the main aim of the work involved the comparison of reference densities (density$_{15}$) from PM Tables, experimental measurements and new relationships, it was essential to establish the basis for obtaining density$_{15}$ from the experimental data. Placing total reliance on the single experimental value measured at the set temperature of 15°C was felt to be inadvisable, so density versus temperature curve fits were used for each sample and density$_{15}$ was predicted from the individual equations.

In deciding what form the density versus temperature relationship should take, three equations were assessed – linear, quadratic and the API exponential equation. A quadratic relationship was found to provide the best fit with the experimental data and this was used to provide experimental density$_{15}$ for all samples.

Generalised equation for density$_{15}$

The work set out to derive a generalised equation in density, VoS and temperature to enable density$_{15}$ to be predicted from ambient measurements. Analysis of the results gave the following relationship:
n=1921 R=0.999973

$$density_{15} = -23.605 + (1.01448\ density_t) + \left[1093.9461\ \frac{t}{VoS_t}\right] - \left[2.200616\ \frac{t^2}{density_t}\right]$$

This holds for all crude oils, petroleum products and lubricating oils in the study, and provides density$_{15}$ with a residual standard deviation of 0.45 kg/m³ and a mean error of 0. For comparison, comparing the experi-

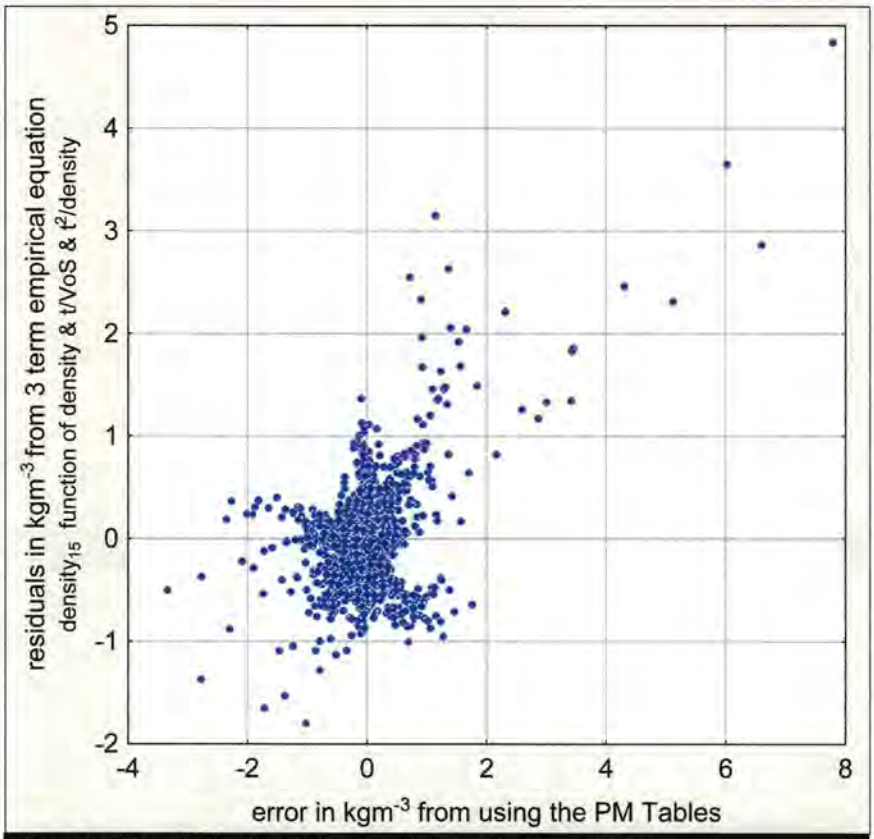

Figure 3: All samples liquid at 15°C – empirical equation versus Tables

mental data with the PM Tables gives a residual standard deviation of 0.58 kg/m³ and a mean error of 0.01 kg/m³.

The reduced errors that result from using **Equation 1** is clear from **Figure 3**.

It should be noted that PM Table errors are generally well controlled with very little bias. It is also clear that 'problem liquids' are common to both methods, although the errors for these can be significantly reduced by using **Equation 1**.

Individual three-term equations using the same parameters as **Equation 1** have been derived for individual hydrocarbon groups. These also show improvement over the PM Tables and are presented in the EI report, which is available from the EI Library.***

Generalised density conversion equation

In addition to the main aim of the work, it was hoped that it might be possible to derive a relationship that would enable density at any temperature to be calculated from a single determination of density, VoS and temperature.

Although, as mentioned above, the best fit for the experimental density versus temperature relationship, $\partial\rho/\partial t$, is a quadratic, the sensitivity of the quadratic coefficients is such that it was decided to use a more robust linear equation for this part of the work:

$$density_{t2} = density_{t1} + \partial\rho/\partial t \cdot (t_1 - t_2)$$

The following equation was then derived for $\partial\rho/\partial t$:

$$\partial\rho/\partial t = 8.627785 - 0.0120172 \cdot density_t + 0.000005344 \cdot density_t^2 - 2602.6770 \cdot \frac{t}{density_t^2} - 782.2974 \cdot \frac{VoS_t}{density_t^2}$$

To test this equation it was used to predict density$_{15}$ from the experimental data, and the results compared with the generalised **Equation 1** and the PM Tables. A summary is given in **Table 1**.

It is felt that the standard deviation of 0.39 kg/m³ with a mean error of 0.03 kg/m³ in the predicted density$_{15}$ for all 1921 data points, compares favourably with the results for the generalised **Equation 1** and for the PM Tables.

This method also has the advantage that it is easy to convert an observed density or volume to another temperature, without needing the concept of a reference density.

Wax formation (crystallisation)

A number of the crude oil and fuel oil samples began to form crystals above the minimum test temperature of 5°C. During the experimental work it appeared that the damping value parameter, which is output from the density meter, could be used as an indication of the wax appearance temperature. This was used to identify those samples where crystals had formed at above 15°C.

These samples were excluded from those used to produce **Equation 1**. However, including these samples produces a very similar equation:

n=2102 R=0.999968

$$density_{15} = -24.147 + (1.01512 \cdot density_t) + \left[1094.6146 \cdot \frac{t}{VoS_t}\right] - \left[2.185587 \cdot \frac{t^2}{density_t}\right]$$

Residual standard deviation is 0.50 kg/m³ compared with 0.59 kg/m³ for the PM Tables.

The generalised equations for both the sample sets – those that do not exhibit wax formation at 15°C, and those that do – show very similar residual standard deviations. It therefore seems probable that, in generalised terms, it is unimportant whether a sample has crystals present or not. When examining the behaviour of individual samples however, the presence of wax crystals does play a more important role in the $\partial\rho/\partial t$ relationship.

Conclusions

From analysis of over 200 samples of hydrocarbon liquids, which provide a reasonable representation of crude oils, petroleum products and lubricating oils traded today, a single general equation involving VoS has been derived which can predict density$_{15}$ more precisely than PM Tables. A second equation that enables density conversion between temperatures without the need for a reference temperature has also been developed.

Both equations can be applied using VoS and density data gathered in the laboratory, or by combining online densities with VoS values measured by ultrasonic flow meters or in-line VoS instruments.

This should allow volume corrections or density transitions with temperature for hydrocarbon liquids to be calculated simply ,and with greater precision than the existing PM Tables, without the need to refer to separate calculation routines based on the class of the product.

These new equations offer greatest

improvement for 'problem' liquids, ie those with high paraffinic or aromatic content.

In carrying out this work the PM Tables have been confirmed as being reasonably precise and to have negligible bias.

For these relationships to become adopted for general use and possibly to become standardised it will be necessary to obtain VoS standards for instrument calibration. During the course of this work the UK National Physical Laboratory has been developing its equipment and techniques and should be able to supply standards with uncertainties around ±0.2 ms^{-1} from mid-2004.

This work is now being considered by the EI and API with a view to development of improved and simplified measurement standards.

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*** Denis Fitzgerald is a Director of H&D Fitzgerald, density specialists and UKAS-accredited density laboratory.*

**** To obtain a copy of the project report please contact the EI Library e:* **lis@energyinst.org.uk**

Please address any technical comments or questions to the EI Technical Department e: **technical@energyinst.org.uk**

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International Federation of Inspection Agencies (IFIA)

Kelton Engineering *in Aberdeen provided software for calculations using the PM Tables*

Adding a little spice to the mix

The negotiations over the Kashagan development plan were given added spice by the presence of David Giffen, representing the Mercator Corporation, a New York pocket merchant bank, at the negotiating table. Since the early 1990s, its President, James H Giffen, who is David's father, has been Nazarbayev's lead adviser on oil negotiations, including those involving Kashagan.

Restricted to the New York area since his arrest last year, James Giffen goes on trial on 4 October in a US federal court in New York. He is charged with funneling $60mn in bribes and kickbacks to Nazarbayev, and another $18mn to Nurlan Balgimbayev, an Oil Minister and then Prime Minister. The case involves six transactions, one of which focuses on the $175mn that the OKIOC consortium partners paid Kazakhstan as a signature bonus.

According to the indictment, Balgimbayev allegedly directed that the bonus should be 'divided into three Swiss bank accounts'. One of them, at Credit Agricole Indosuez in Geneva, allegedly received $23mn in April 1998, which it had agreed to redistribute to various consultants on the transaction. Mercator is alleged to have received $5.25mn and CAI itself '$11.85mn for providing financial and analytical services'.

But, under what the indictment calls a 'sham agreement', Giffen and an unnamed CAI banker agreed that CAI, for a fee, would pass on the money to other accounts. According to the indictment, $10.35mn went into an account called Denlay, controlled by Giffen, who allegedly sent $5mn into an account called Orel, or 'eagle', which is Kazakhstan's national symbol, controlled by Nazarbayev. Another $2.5mn went to an account controlled by Balgimbayev. The indictment does not say what happened to the $2.35mn left in Giffen's Denlay account from the transaction. Both Kazakh officials have denied receiving any kickbacks or having any private accounts in Switzerland.

When a Swiss prosecuting judge closed a number of Swiss accounts totalling some $120mn held by Nazarbayev and other Kazakh officials in August 1999, lawyers representing the republic of Kazakhstan went to court, arguing that the accounts belonged to the government and benefited from sovereign immunity. But the Swiss Federal tribunal denied the appeal, ruling in December 2000 that the accounts were clearly private and that 'it was doubtful they served ordinary commercial transactions'. The accounts are still frozen, according to Swiss officials.

What role the Giffen trial's revelations will play in future relations between the Kashagan consortium and the Kazakh Government is anybody's guess. But oil men in Almaty say one thing is for sure – 'Everyone is going to be extra careful that any payments go into government bank accounts.'

...continued from p35

1.2mn b/d – about as much as Libya or Indonesia today – by the end of the next decade.

'It's a disgrace to have lost so much time over so little money,' commented one oil man.

Meanwhile, the 150 offshore blocks that the government is considering auctioning off, under conditions widely perceived as less than advantageous, are not likely to find takers any time soon. 'There's zero interest right now,' said an oil man familiar with the process.

Sources close to the Kashagan consortium noted the similarities with a dispute between the government and the consortium operating the onshore Tengiz field. In that case, KazMunaiGaz, which holds 20% of the partnership, refused to put up its share of a three-year, $3.5bn expansion plan devised by TengizChevroil (TCO), the operating company, which would have increased the field's output from 280,000 b/d to 460,000 b/d. The other partners are ChevronTexaco (50%), ExxonMobil (originally Mobil, 25%) and Lukoil (5%).

Instead, KazMunaigaz – whose Vice-President, Timur Kulibayev, a son-in-law of Nazarbayev, is considered the country's second most powerful man – demanded that the consortium borrow its share and pay the interest as well. The consortium refused and on 14 November 2002, TCO surprised the government by suspending the project and sending the contractors home. It was not until 25 January 2003 that a financing package was agreed to. Its contents were not disclosed, in keeping with the country's tradition of secrecy over oil deals.

Informed sources said the American partners had agreed to borrow KazMunaigaz's share – at lower interest than KMG could obtain – but that KMG would pay the interest. The cost of the interruption was estimated at several hundred million dollars.

Many challenges for Opec

Over recent months Opec producers have been operating surprisingly close to capacity with prices remaining high and stocks, particularly in the US, remaining low. Over recent years the oil cartel has gained a reputation for much improved output discipline among its members, which has been a key element in stabilising prices at high levels. However, it is worth asking the question as to whether Opec's recent cohesion actually has more to do with most of its members already operating close to capacity. *Chris Skrebowski* reports.

Over the last four months there has been the considerable incentive for the Opec producers to maximise production. Prices have not only been high but, for much of the period, have been above the $28/b top of the Opec preferred price band. Although Opec country finances are in better shape than for many years, as a direct result of three years of high oil prices, they remain acutely concerned about the impact of the effective devaluation of the dollar against the yen, and particularly against the euro. In euro terms, oil prices have been fairly stable over the last three years.

Review of Opec members

Reviewing the individual Opec members in turn we find that, although there is notional spare capacity in a number of countries, only Saudi Arabia has actually demonstrated the ability in the last year to produce more than that produced in the last three months (see **Table**).

Algeria has been proceeding apace, bringing on new capacity, although the growth has peaked over the last few months and the country seems unlikely to expand production much without further projects.

Indonesian production continues to decline with little or nothing likely to slow this shrinking of capacity until the 600–1,000mn barrels of reserves of the ExxonMobil-operated Cepu block comes onstream. Profit sharing arrangements have just been agreed but production is still some time away. Indonesia retains its 1.27mn b/d production quota (1.22mn b/d from April) but has no ability to meet it. Opec, however, has no precedents as to what to do when a member has no ability to meet its allocated quota and countries are naturally reluctant to cede quotas they possess but cannot fill.

Iran appears to be operating flat out, with day-to-day operational constraints leading production to vary a little from month to month. The start-up of the Shell-operated Nowrouz/Soroush fields at the end of the first quarter should add 130,000 b/d to capacity. After that the next significant capacity increase would be the Azadegan development in 2007, although the country is keen to licence exploration areas (see *Petroleum Review*, March 2004).

Operating flat out

Kuwait, Libya, the UAE and Qatar all appear to operating flat out and the only incremental production will be the start up of Eni's Elephant field in Libya in the third quarter (+50,000–100,000 b/d) and Abu Dhabi's Bab North East field (+100,000 b/d)at the end of the year.

Nigeria had been bringing back shut-in production in the Delta as fast as possible, but recent unrest has started to erode production capacity again. Meanwhile, although exploration and development investments had been reinstated in Venezuela and production capacity was stabilising, recent political unrest may be starting to impact production. Towards the end of the year the completion of the upgrader for Hamaca heavy oil from the Orinoco will allow production of the full 500,000 b/d capacity of the four heavy oil projects built so far.

The wild card

Iraq remains the wild card in the Opec pack, but, having rebuilt production to around a claimed 2.5mn b/d, further expansion will proceed in a fairly predictable manner towards the 2.8mn b/d target for April/May and over 3mn b/d by year end.

There are reports that the Northern pipelines to Ceyhan may now be operational, which gives potential export capacity of up to 800,000 b/d from the Northern fields – which is probably more than they are capable of producing until further refurbishment is undertaken.

In the south, export capacity has recently been expanded with the reopening of two of the jetties at Khor al-Amaya, closed since the Iran-Iraq war of the 1980s. This, and possible plans to export oil to Abadan refinery in exchange for loadings at Kharg Island in Iran and to route oil via Kuwaiti export facilities, means the export loading constraints of recent months may soon disappear.

Opec concerns

Significant additional exports from Iraq remain a major concern to Opec. This, combined with fears about the likely demand reduction in the second quarter (now estimated by the International Energy Agency (IEA) as a

continued on p47...

Opec member	Nov-03	Dec-03	Jan-04	Feb-04	Sust. cap	April quota
Algeria	1.15	1.15	1.13	1.13	1.20	0.75
Indonesia1.00	0.98	0.98	0.99	1.10	1.22	
Iran	4.05	3.95	3.90	3.95	4.00	3.45
Iraq	1.92	1.97	2.04	1.94	2.80	–
Kuwait	1.98	2.00	1.95	1.95	1.95	1.89
Libya	1.45	1.46	1.47	1.48	1.50	1.26
Nigeria	2.27	2.13	2.35	2.32	2.50	1.94
Qatar	0.74	0.75	0.75	0.75	0.85	0.61
Saudi Arabia	8.19	8.25	8.25	8.25	9.20	7.64
UEA	2.20	2.35	2.28	2.28	2.45	2.05
Venezuela2.20	2.22	2.19	2.16	2.35	2.70	
Subtotal	***27.15***	***27.39***	***27.29***	***27.20***	***29.90***	***23.51***
Orinoco Heavy	0.378	0.378	0.378	0.378	0.378	
Neutral Zone	0.63	0.61	0.61	0.60	0.65	
NGLs	3.97	3.97	4.00	4.01	4.00	
Total	**32.128**	**32.348**	**32.278**	**32.188**	**34.928**	

Opec production and capacity, mn b/d

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New publications

IP Research Report
Electrostatic discharges in two-inch aviation fuel filter monitors Phase 2: Properties needed to control discharges

This report documents an investigation commissioned by the Energy Institute's Aviation Committee to develop recommendations for the resistance characteristics of 50 mm (two-inch) nominal diameter aviation fuel filter monitor elements. The resistance characteristics have been deemed to be required to dissipate electrostatic charge safely without generating incendive or damaging discharges.

This investigation forms Phase 2 of the study of electrostatic discharge in filter monitors, the first Phase having been published in October 2002 as IP Research Report Electrostatic discharges in two inch aviation fuel filter monitors.

The findings of this investigation will be of interest to all those involved in aviation fuel handling operations and filter monitor manufacture and supply worldwide.

ISBN 0 85293 408 4 | Full Price £48.00 | 25% discount for EI Members | February 2004

IP Model Code of Safe Practice Part 7: Design, construction, operation and maintenance of aviation fuelling facilities. API/IP Recommended Practice 1540.

This publication supersedes the third edition of the Institute of Petroleum's Model Code of Safe Practice Part 7 Airports Safety Code, published in 1998, and the second edition of the American Petroleum Institute's Publication 1500 Storage and Handling of Aviation Fuels at Airports, which was withdrawn in 1998. The new publication has been prepared jointly by the API Aviation Technical Services Subcommittee and EI Aviation Committee, with technical feedback from other industry stakeholders, and is intended to provide guidance on the siting, layout, design, construction, operation and maintenance of aircraft fuelling facilities, including the design and construction of fuellers, hydrant servicers and ancillary equipment used in fuelling aircraft. Essential reading for engineering contractors, aviation fuel handling equipment suppliers, aviation fuel suppliers, hydrant operators, into-plane fuelling companies, airlines and airports worldwide.

ISBN 0 85293 414 9 | Full Price £88.00 | 25% discount for EI Members | 4th Ed. March 2004

Operational guidelines on the use of oil spill dispersants at sea

In 2001 the Institute of Petroleum published a guidance document entitled Planning for the use of oil spill dispersants. This formed the third edition of the IP's guidance on oil spill dispersant use and was updated to include recent advances in research and development on dispersant application and also considered the concept of Net Environmental Benefit Analysis. In producing the 2001 guidance, which is primarily aimed at managers involved with planning for the use of dispersants as part of response to an oil spill incident at sea, it became clear that there was a lack of available guidance on dispersant application aimed at those operating on the ground during an incident. These new guidelines aim to fill that gap, and provide guidance for those making decisions at the operational level. Essential reading for environmental managers, local authorities, consultants and everyone involved in oil spill clean-ups at sea, worldwide.

ISBN 0 85293 384 3 | Full Price £44.00 | 25% discount for EI Members | March 2004

Looking forward: Health as a business management issue in the 21st Century

The Energy Institute's Occupational, Environmental Medical Subcommittee commissioned a workshop to explore Health as a Business Management Issue in the 21st Century. The aim of the workshop was to bring together a range of different views on occupational health provision within industry, and how it should develop in years to come. Speakers were from the UK, USA and mainland Europe, and represented academia, industry and regulatory bodies. Subjects covered included Management and Workforce views of health interventions in the workplace, Environment and health, Government and European perspectives of occupational health provision, and the Economics of occupational health provision. This new publication is a record of the presentations given, and the discussion which followed. An interesting and informative read for medical directors, HR specialists, doctors, health and safety managers and all those responsible for the health and well-being of their workforce.

ISBN 0 85293 403 3 | Full Price £44.00 | 25% discount for EI Members | March 2004

Available for sale from Portland Customer Services, inc. postage in Europe (outside Europe, add £6.00 per order). Contact Portland Customer Services, Commerce Way, Whitehall Industrial Estate, Colchester CO2 8HP, UK.
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training courses 2004

energy INSTITUTE

GEOPOLITICS AND RISK IN THE OIL AND GAS INDUSTRY

COURSE DATES:
14 - 16 April, 2004
COURSE VENUE:
London, UK
EI MEMBER:
£1400.00
(£1645.00 inc VAT)
NON-MEMBER:
£1600.00
(£1880.00 inc VAT)

This course outlines systematic, holistic and quantifiable approaches to risk management and integrates this with an overview of the regional and global geopolitical issues that now confront the oil and gas industry. It addresses risks from upstream, downstream, strategic, portfolio and corporate perspectives, and how they influence the valuation of assets. It addresses community, contractual, environmental, financial, fiscal, political, public relations, safety, security and technical risks, and the techniques used to assess, quantify and mitigate them in various risked valuation procedures.

WHO SHOULD ATTEND?

The course is structured for a multi-disciplined audience with diverse technical and professional backgrounds and experience levels from within oil and gas companies. Professionals from the industry support and service sectors, including government ministries and departments, will also benefit from participation in this course.

OVERVIEW OF THE NATURAL GAS INDUSTRY

COURSE DATES:
20 - 23 April, 2004
COURSE VENUE:
London, UK
EI MEMBER:
£1900.00
(£2232.50 inc VAT)
NON-MEMBER:
£2100.00
(£2467.50 inc VAT)

This **four-day course** provides an overview of the economic and contractual aspects of the natural gas industry. The peculiar features of natural gas will be highlighted in order to explain the economic differences between a crude oil chain and a natural gas chain. Gas chains can become very complex, rigid networks which penetrate deep into energy markets and the associated, broad range of crucial economic, marketing, and legal issues of the gas industry will be examined.

WHO SHOULD ATTEND?

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

ECONOMICS OF REFINING AND OIL QUALITY

COURSE DATES:
21 - 23 April, 2004
COURSE VENUE:
The Møller Centre,
Cambridge, UK
£1550.00
(£1821.25 inc VAT)

This **three-day course** opens the Refinery "Black Box" and explains the capabilities and constraints of each main process, enabling delegates to be more effective in their jobs. Crude oil selection and the effects of crude quality on key properties of both intermediates and finished products are explored. The value and opportunities presented by quality slacks are identified.

Delegates will discover the key trading profit opportunities through a Processing Deal that has recently been agreed at one of Invincible's fictional refineries. The Deal not only has the advantage of enabling this highly flexible, complex refinery to run at near capacity, but also highlights how the capabilities of its hardware and the qualities of its product pools generate opportunities for making additional profits. It is the delegate's ability to identify, evaluate and fully exploit these opportunities that enables additional gains to be realised. Emphasis is placed on the interface between refinery activity and international oil trading. As with all Invincible training, the course will consist of a mixture of formal lectures, exercises and plays. The course expects a high degree of participation from delegates and there is a high staff-to-pupil ratio.

CUSTODY TRANSFER OF CRUDE OIL - TRADING AND LOSS CONTROL ISSUES

COURSE DATES:
26 - 27 April, 2004
COURSE VENUE:
London, UK
EI MEMBER:
£1000.00
(£1175.00 inc VAT)
NON-MEMBER:
£1200.00
(£1410.00 inc VAT)

This **two-day course** covers the principles of custody transfer, the units of measurement and the terminology used. Participants will look at the need to minimise the uncertainties during the various measurements that are crucial in performing a custody transfer. They will also learn the acceptable limits within which measurements may differ and what can cause excessive differences and their effect on the final outcome.

WHO SHOULD ATTEND?

Personnel responsible for product loss; vessel operators, ship brokers, bankers, lawyers, oil brokers, independent inspectors, insurance brokers, cargo underwriters, vessel P&I clubs and storage companies; operational and trading personnel; managers and administrators and other professionals within oil trading companies; accounting, financial and legal personnel; professionals from energy related consulting groups.

2004 COURSES' CALENDAR AVAILABLE

For more information, see enclosed inserts or contact Nick Wilkinson

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or visit: www.energyinst.org.uk e: nwilkinson@energyinst.org.uk

More highlights

In the second-part of a series of articles, *Petroleum Review* Editor *Chris Skrebowski* briefly reviews further highlights during IP Week 2004.

The final session of the first day of IP Week 2004 became very international in its outlook. Lyzzat Kilnor, Vice Minister of Kazakhstan's Energy and Mineral Resources, gave a detailed rundown of the prospects for further development in Kazakhstan and the attractive financial terms on offer, particularly in the light of resources available. He also detailed the positive approach of the Ministry in dealing with international oil and gas companies whose involvement Kazakhstan valued very highly.

At the time his speech was delivered, the final go-ahead on the Kashagan field – the largest discovery in the last 30 years – had not been given (see p5 and p34), but it was clear from the tenor of his speech that this major project had been close to sanction.

He was followed by Dr Manoucher Takin, Senior Petroleum Analyst for the Centre for Global Energy Studies (CGES). Dr Takin indicated the sheer size of the resource in Saudi Arabia and Iraq, claiming that the publicly quoted reserves figures of 260bn barrels and 115bn barrels, respectively, were reasonable. He then went on to identify some of the upcoming projects in Saudi Arabia and Iraq that had the potential to expand the production of these two countries very significantly by the end of the decade.

The final session of the afternoon was from John Williams, Manager, Exploration, ConocoPhillips, who tackled head on concerns about oil peaking and depletion. He started by conceding that those who were concerned about peaking were directionally right. But, then he demonstrated that the size of the likely resource once enhanced recovery and heavy oils/tar sands were included meant that the peak would be much higher and later than many feared. This extra time would allow either more resources to be discovered or alternatives to be developed. He felt it most likely that requirements would be covered by a combination of the two.

Following the Chairman's closing remarks, most of the delegates moved over to the reception in the House of Commons – which was hosted by Philip Hammond, MP.

Day Two – parallel events

The second day of the week saw parallel events taking place. At Great George Street an all-day conference tackled 'Exporting Oil and Gas from Russia and the CIS'. Over at the Dorchester a morning and two afernoon seminars were held, as well as the IP Week Luncheon addressed by Inge K Hansen, Acting President and CEO of Statoil.

The Russian exports conference saw the morning session being chaired by Gerald Rohan, Director, Global Energy and Mining for PricewaterhouseCoopers. His first task was to introduce Ria Kemper, Secretary General of the Energy Charter Secretariat, who spoke on Russia's role in global gas markets – liberalisation of project and policy. Kemper focused on three key issues:

- Russia's role as a major gas supplier and how this may develop in the future.
- The challenges if Russia is to develop an open, fully competitive gas market.
- The creation of a pan-European gas market.

Kemper concluded that security of supply will depend on extending market principles beyond the European Union. That policy makers must seek to reduce risks to investors by developing clear rules on investment and transit. Noting that producers still saw liberalisation as a threat to their interests, Kemper noted that dialogue between the parties was the key to productive working arrangements.

Russian export routes

Semyon Vainshtok, President of Transneft, then gave his company's views on the development of export routes. He stressed the way that the port of Primorsk and the Baltic Pipeline System (BPS) had been developed and expanded to create Russia's premier export facility, with further expansion both possible and likely. Turning to the export facility at Novorossiysk, he noted the potential to expand the flows of Azeri crude and to link in Kazakh crude exports. He then talked about the linking of the Druzba and Adria pipelines to allow exports of Russian crude directly to the Adriatic.

After briefly mentioning a possible oil pipeline to Poland, Vainshtok turned his attention to the much-discussed Far East pipelines. He then proceeded to discuss the rival merits of the Angarsk-Nakhodka pipeline, which would open up exports to a number of Far East countries versus the shorter, and cheaper, option of Angarsk-Daquing, which would provide only one customer. He indicated fairly clearly that the ideal solution was Angarsk-Nakhodka, with a branch to Daquing. However, the problem was that, so far, not enough crude had been proved up to fill both lines.

He explained that Transneft had been assigned the task of preparing a feasibility study with the five Russian oil companies and the Ministry on the proposed Western Siberia to Murmansk pipeline project. A project he described as very interesting but one where a lot of questions needed to

be satisfactorily answered. Finally, Vainshtok noted that the development and expansion of the BPS and Primorsk port meant that it was now economically unattractive to use the port of Ventspils for Russian exports.

Pipeline developments and risk mitigation

Tom Dimitroff of BP and Legal Manager of the Baku-Tbilisi-Ceyhan Pipeline Company, gave a rundown of the latest status of the pipeline. He looked forward to the start-up of the line in 2005 and the ramping up of production from the Azeri-Chirag-Guneshli fields directly to the Mediterranean for export.

Constantine Demetriou, Principal Banker, Natural Resources Team at the EBRD, examined some of the challenges and opportunities in financing major pipeline developments. He first assessed Europe's need for additional gas imports and the potential suppliers. He then turned to oil supply and the new links that might be needed, moving on to the potential involvement of the EBRD, risk mitigation and political support. He concluded with a case study.

Following up the idea of risk migation, the next speaker, Ronnie King, Partner at Ashurst London, examined the legal pitfalls in developing export routes and the way these risks could be avoided or mitigated.

Company news

German Khan, Executive Director of TNK-BP, explained the logic of the merger and the potential it had to expand production. He detailed what he called the 'brownfield renaissance' and noted that the application of electric submersible pumps, waterflood optimisation, hydro-fraccing, corrosion management and the reactivation of idle wells had transformed the production outlook in mature regions and produced rapid output growth. He then talked of the company's support for new export routes and plans for the Vistino terminal.

Hans Van Lamoen, Vice President, Gas and Power, Shell Exploration and Production Services, gave a detailed explanation of the potential supply and associated costs of future Russia gas exports, noting that Shell's involvement in the Sakhalin LNG project was a key part of Shell's future. Outlining the potential shortfalls in European gas supply after 2007, he showed the potential to expand gas supplies from Russia as both pipeline gas and LNG to meet the shortfall.

Victor Baranov, President of the Union of Independent Gas Producers of the Russian Federation, described the potential for the independent producers to expand supply and the challenges they faced in developing their businesses.

Frank Kuijlaars, Managing Director, Integrated Energy, Central and Eastern Europe, Central Asia, Middle East and Africa, ABN Amro, then took a closer look at investment potential in Russia. Sergey Rogov, Deputy Head of the Strategic Planning Department, Lukoil, closed the afternoon session, by outlining the ten-year strategic plan for development of Lukoil's oil exports.

Also at Great George Street in the morning was the 'Transporting Gas' seminar, organised in conjunction with IGEM. The seminar tackled a number of detailed concerns about the safe transportation of gas. Richard Jemmet, Vice President of IGEM, reviewed the current gas scene and was followed by Tony Henshaw, Director, CPL. Brian Mumme, Manager, Global LNG for BP, explained that a new merchant business in LNG was developing and Susan Farmer, a Partner with Denton Wilde Sapte, evaluated the competitive strategies of the international gas companies.

Energy hot topics

In parallel to this, at the Dorchester the morning session was the 'Energy Hot Topics 2004: A Strategic Seminar', in partnership with Ashurst Morris Crisp. The first speaker was Michelle Turner, Solicitor, Environmental and Health & Safety Group, who talked about the likely impact of emissions trading on business. She noted that, whatever one's view on climate change, there were now legislative drivers in place that will drive the process of reducing carbon dioxide emissions and increasing the usage of renewable energy. She then discussed the impacts and effects of the EU's Emissions Trading Scheme (ETS) and the way it would operate. Turner then examined the legal, financial and reputational impacts that could result.

Melville Haggard, Executive Director of Impax Capital examined the finance and strategy for environmental infrastructure. He then gave details of the likely costing and development of renewables for power generation and the potential sources of capital and the routes for financing the rapidly evolving renewable s sector.

Dr Jozsef Balogh of Enron/Semyra took a trader's view of how deregulation of Eastern European energy markets post 1 May would actually develop. His view was that trading would evolve in response to the economic dynamics and that if regulation inhibited profitable trading activity it would be circumvented in a variety of way. He was optimistic that large-scale energy trade with Eastern Europe would develop, but not necessarily as the regulators planned.

In my position Editor, *Petroleum Review*, I then spoke to the title of 'Golden Handshake or Golden Goodbye' in an examination of the current state of the UK North Sea. Having demonstrated that way production of both gas and oil was set to decline, I then looked at the way new, smaller, innovative companies were seeing business opportunities while some of the established players were actively selling off their interests. I drew the analogy of the second-hand car market, where both buyers and sellers have good reasons for the decisions and suggested something similar was now happening in the North Sea.

John Dashwood, ExxonMobil, Gas & Power Marketing, looked at the way energy demand was expected to grow and the way that he expected inter-regional trade to develop, with particular reference to the supply of gas into the UK as indigenous supplies declined after 2004. He described in some detail the potential for LNG imports and ExxonMobil's plans to bring LNG from Qatar to Milford Haven.

Strategies for success

The afternoon at the Dorchester brought the 'Strategies for Success in European Retail' seminar, organised in conjunction with Wood Mackenzie. Following an introduction by Mike Wilcox, head of Downstream Consulting at Wood Mackenzie, the Principal Consultant–Downstream Oil, Sat Roopra, outlined strategies for success in European retail based on a recent multi-client study that examined the rel-

training courses 2004

energy INSTITUTE

TRADING OIL ON INTERNATIONAL MARKETS

COURSE DATES:
26 - 30 April, 2004

COURSE VENUE:
The Møller Centre, Cambridge, UK

£2800.00
(£3290.00 inc VAT)

During this **five-day course**, delegates will become part of Invincible's fictional trading team, taking decisions about the company's activities to maximise profits through an understanding of the economics of trading and the management of inherent price risks.

Delegates will trade the live, crude oil and refined product markets worldwide, under the guidance of an expert team of lecturers, reacting to events as they happen and using real-time information from Reuters and Telerate screens and daily price information from Platts and Petroleum Argus.

Exercises are performed in syndicates, with comprehensive debriefs studying the consequences of the decisions made. The course expects a high degree of participation from delegates.

FUNDAMENTALS OF PETROLEUM REFINING PROCESSES

COURSE DATES:
11 - 14 May, 2004

COURSE VENUE:
London, UK

EI MEMBER:
£1900.00
(£2232.50 inc VAT)

NON-MEMBER:
£2100.00
(£2467.50 inc VAT)

This **four-day course** examines the composition, main characteristics and new trends of petroleum products, examining the roles of the different refining units and their process characteristics. Participants will gain an understanding of the main manufacturing schemes encountered in the oil refining field and look at the overall economic context of this industry.

Subjects covered include: petroleum products; refining processes (crude oil fractionation, catalytic reforming and isomerisation, hydrorefining processes, conversion units); manufacturing schemes; and main economic features of refinery operations

WHO SHOULD ATTEND?

Anyone working in the oil and gas and related sectors whose activity, whether technical, commercial, legal, financial, or human resources, is in some way connected with oil refining.

PRICE RISK MANAGEMENT IN THE OIL INDUSTRY

COURSE DATES:
17 - 21 May, 2004

COURSE VENUE:
The Møller Centre, Cambridge, UK

£2800.00
(£3290.00 inc VAT)

During this **five-day course**, delegates become part of Invincible's fictional trading team, identifying and then managing the exposure to price risk. They trade the full range of derivative markets, including the live futures markets which are received on-line through Telerate and Reuters. Options are traded using a simulation programme. Delegates compare the performance of different instruments over time and in changing market conditions and learn how to choose the appropriate instrument to match their objectives.

The course explains the workings of futures, forwards, swaps and options markets and how they can be used for hedging and price management purposes. The costs and relative benefits of the instruments and the implementation of risk management strategies are explored as well as technical analysis and the principles of management control. Exercises are performed in syndicates, with comprehensive debriefs to study the consequences of the decisions made.

The course expects a high degree of participation from delegates.

FINANCIAL PERFORMANCE MANAGEMENT IN THE OIL BUSINESS

COURSE DATES:
26 - 28 May, 2004

COURSE VENUE:
London, UK

EI MEMBER:
£1400.00
(£1645.00 inc VAT)

NON-MEMBER:
£1600.00
(£1880.00 inc VAT)

A highly participative, **three-day course** which provides a good understanding of the essentials of the successful management of financial performance in the oil industry combining a theoretical framework focused on rigorous benchmarking of competitive position, with real-life practical examples and syndicate exercises.

Subjects covered include: the financial framework and key measures; benchmarking of performance; and managing capital and conclusions.

WHO SHOULD ATTEND?

The course is suitable for experienced management and staff who wish to gain a broader perspective and to learn about current best practices; new recruits to the industry who need to learn how performance management processes are adapted to this highly competitive business; people from outside the industry who require a thorough introduction to the performance management processes.

2004 COURSES' CALENDAR AVAILABLE

For more information, see enclosed inserts or contact Nick Wilkinson

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or visit: www.energyinst.org.uk e: nwilkinson@energyinst.org.uk

ative strengths and competitiveness of European fuel retailers. Detailed analysis of the various markets showed the differences in marketing margins, operating costs, site volumes and shop sales across Europe. In addition, he showed the relative performance of the key players and the way that their net cash margin was key to profitability.

Michelle Muller, Managing Director of Tango, explained the Tango concept of company-owned and operated sites being unmanned, with large shops done in partnership with retailers, while retailer sites were run in groups with the dealer responsible for investment. She explained how the Netherlands, Spain and Belgium had been identified as the most attractive markets for the Tango concept. She noted that the company was founded in 1999, opened its first station in Nijmegen in 2000 and, by end-2003, had 62 operational stations in the Netherlands, three in Belgium and one under construction in Spain.

Alexis Vovk of Total gave a rundown of the company's retail position across Europe, describing the current market environment and recent developments. He then described Total's rebranding programme, the way Total, Fina and Elf operations had been integrated and the competitive response to the dominance of super- and hypermarkets in France.

The final presentation of the seminar was from Stephen Brooks, Principal Consultant with Wood Mackenzie, analysing end-user price and gross margin trends. He started by describing the methodology used by Opal (relatively recently acquired by Wood Mackenzie) in determining price and margin trends. He then illustrated trends and relationships between spot and pump prices in various European countries. He then drew some conclusions about the relationship between end-user pump prices, fuel gross margins and the profitability of fuels retailing.

Evening meeting

An evening meeting at the Energy Institute was organised in conjunction with the UK Department of Trade and Industry (DTI), entitled 'The UK Energy White Paper – One Year On' and 'Economic Instruments for the Reduction of Carbon Dioxide'. Joan MacNaughton, Director General, DTI, explained the government's position on the application of the White Paper.

She was followed by Sir Eric Ash, Chairman of HydroVenturi who examined the likely impact of the White Paper on commercial companies.

Energy price

The Wednesday featured the 17th Energy Price seminar – 'A Financial Health-Check'. Sally Clubley, Director of Training, Invincible Energy, opened the proceedings by providing a market overview. Anthony White, Head of Research, Climate Change Capital, looked at the impact of dealing with climate change legislation on top of liberalisation requirements, asking 'Can we cope?'. He was followed by Jon Edwards, Senior Manager, Europe, Middle East and Africa, London Stock Exchange, who outlined the impact of recent poor stock market performance on the shares in the energy sector.

Mergers and acquisitions were covered by Angus McPhail, Equity Research Analyst, Oil and Gas, ING Financial Markets, who looked at likely demand scenarios for different fuels and the likely impact on prices in the 2004/2005 period.

After coffee, Axel Busch, Chief Correspondent – Oil Markets, Energy Intelligence Group looked at pricing structures and asked whether benchmarks were set in stone. Julie Allen, Energy Manager, Bhs, talked on consumer and industrial demand scenarios for different fuels and assessed how these could drive prices in 2004/2005.

Vying for attention

Over at Great George Street, two seminars competed for delegates' attention. The 'Intermodal Petroleum Transportation Security Conference' was a detailed examination of the preparedness of shipping, ports and terminals to meet the July 2004 implementation of the ISPC (International Ship and Port Security Facilities) Code and was organised in conjunction with Cargo Security International. It also assessed the impact of terrorism, piracy and theft on shipping, trucking, pipeline and terminals, and potential counter measures.

James Wilkes, Managing Director, Gray Page; Gunnar Knudsen, Manager, Port and Terminals Department, Intertanko; Sander Doves, Policy Advisor, Port of Rotterdam; and Andy Easdown, Manager of Marine Training Services, Lloyd's Register, spoke of the implications for tanker and barge owners and operators. Dominick Donald, Senior Analyst, Aegis Defence Services; Roy Winfield, Lloyd's MUI – Risk Management; and Tom Cantero, Marketing Director, HERNIS Scan Systems talked of the risks and prevention steps to shield petroleum transportation from the war on terrorism.

Captain Pottengal Mukundan, Director, International Maritime Bureau, talked about the challenge of cargo crime – load theft and hijack – to shipping. Mark Schwarz of Tri-Mex International described the problems and solutions in relation to trucking, while Rafael Kahn, Director, Secure-Marine looked at the problems and solutions associated with pipelines and terminals. He was followed by Alan Costain, Consultant, TraceTag International, who spoke on DNA tagging.

The final session, entitled 'The Technology Vortex' was tackled by Ian Taylor, Publishing Manager, Cargo Security International, who analysed the costs and benefits of a wide variety of cargo security technologies.

Maximising upstream assets

Also held at Great George Street was an all-day conference organised in association with the AAPG (Amercian Association of Petroleum Geologists) and sponsored by Landmark. Entitled 'Maximising Assets in the Upstream Business: The Oil and Gas Field of the Future', the conference had the highest technical content of all the sessions during the week.

Nick Muir, Exploration Commercial Head, Shell UK, chaired the morning session. He started by introducing Murray Roth, Executive Vice President, Marketing & Systems for Landmark Graphics. Roth described the latest innovations, which, when combined together, offered the prospect of continuous analysis of field and well production as well as previously undreamt of seismic resolution, even in technically difficult areas such as subsalt.

Jeff Dickins, Field of the Future Consultant, BP, developed the technical theme, in describing how the various digital technologies can be linked together to give greater monitoring and control of field operations – reducing costs and enhancing recovery. He described how real-time control of field variables dramatically improved performance in bringing wells onstream.

Kevin Flanagan, Manager of Geoscience Technology for Kerr-McGee North Sea described how 4D interpretation of reservoir performance was no longre the preserve of the larger companies, but was now finding profitable application by the independents. Outlining the results from his company's Gryphon field, he noted that a large associated benefit was the way it helped to blur the boundaries between individual disciplines and helped to get everyone working together to enhance reservoir performance.

Tim Dodson, Senior Vice President, Technology Development Arena for Statoil, described his company's approach as a national oil company to technology and its application to Statoil's

business. Phil Hemmens, Vice President Exploration and Production Services, Eni – London, gave a very detailed presentation on Eni's use of 4D seismic and its recent application to the Cervia and Amelia fields in the Adriatic and to Grand Isle 102 in the Gulf of Mexico.

Saleh M Al-Dawas, Manager, Exploration Technical Services Department, Saudi Aramco, analysed the challenges and opportunities facing the company. Noting that the primary drivers were to lower unit costs and increase recovery, he explained the massive expansion of data as they increasingly focused on the drilling of MRC (maximum reservoir contact) wells. These wells provided as much as 23,000 ft of reservoir contact, offering productivities up to four times those of conventional wells. He explained in some detail the way that effective data capture, interpretation and handling was allowing recoveries to advance from the 60% deliverable conventional technologies, towards the 70% that they expected to achieve by emerging and future technology. In order to achieve this Saudi Aramco was currently drilling around 200 development wells per year, all long horizontal MRC wells.

Kevin Boyne, Developments and Planning Manager, Total, examined the role of risk management in maximising

...*continued from p40*

1.6mn b/d reduction in the second quarter versus the first quarter) are the reason for the agreement to a sharp reduction in the quotas from 1 April 2004. Continuing high prices, market tightness and a public commitment to supply required volumes while prices remain high seem set to undermine strict adherence with the new quotas. To date there is little evidence of output reductions by any Opec members.

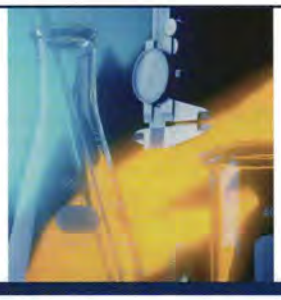
As all the other Opec members apart from Saudi Arabia appear to be operating at the maximum available capacity available to them, the conclusion is that the only immediate spare capacity is in Saudi Arabia. The IEA in its monthly market report quotes 9.5mn b/d as the capacity that can be achieved within 30 days and sustained for 90 days, but indicates that this could be expanded to 10.5mn b/d within 90 days. In March 2003 Saudi production was just under 9.4mn b/d.

If Opec's ability to act as a cartel and set prices depends on having spare capacity then Saudi Arabia and its oil production policies are Opec until more spare capacity emerges.

assets. He described in detail the way that Total was seeking to maximise utilisation and reserves recovery in its North Sea facilities, noting that up to 75% of expenditures were now to defend and enhance the capabilities of existing facilities.

Hroar Hermansen, Director, Ekofisk Subsurface Team for ConocoPhillips, described the development of the Ekofisk field, past and future. He noted that, at sanction, they expected to recover 17% of the oil in place reserves. The company had now produced 22–23% of the oil in place reserves and was targeting 44% recovery, but working to increase this to 50%. The Ekofisk area waterflood was now injecting 900,000 b/d of water, of which 600,000 b/d was injected into the Ekofisk field – this had boosted recoverable reserves from 460mn boe to 850 boe and increased the recovery fraction by 10%. He concluded the challenge of 50% recovery was tough, but achievable.

The final presentation by Martijn Kleverlann, Well Engineer – Technology, Shell Exploration and Production, gave a case study on the use of through tubing rotary drilling on Shell's heavily depleted North Cormorant field in the North Sea. His presentation showed the way that the technology provided economic access to a whole series of small targets, the development of which would extend the field life and provide a good example of brownfields excellence.



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