Petroleum review

DECEMBER 1998

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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: The number of Scottish service stations continues to fall.

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ROUNDUP From the Editor

Time to rebuild downstream profits

At a time when the outlook for the oil and gas industry appears so poor it takes an effort of will to recognise the positive aspects. However, the industry has historically always bounced back from its setbacks and there is no reason to think that it won't do so again.

Currently demand may be pretty flat and little ahead of year earlier levels but we are still talking of 72.6mn b/d of oil production and of oil and gas representing 63% of total global energy supplies. The rapid substitution of alternative fuels when oil prices were high means that oil use is now effectively confined to areas where there are few, if any, substitutes. The oil industry is increasingly a supplier of transport fuels and speciality products, both areas where there are no real alternatives.

Paradoxically, the gas industry is also relatively immune to ready substitution. Once a conversion to gas has occurred it is rare for back substitution to take place. The one notable exception is dual-fired power stations in the US where fuels are interchanged simply on price. This, however, reflects the fact that the gas is simply used as an under-boiler fuel. Once investment in the markedly more fuel efficient CCGT (combined-cycle gas turbine) technology is made the usage is robust in the face of price changes.

To a very large extent the use of oil and gas is not under immediate competitive pressure. The pressure comes from the external influences of global supply and global economic activity.

The oil companies' third quarter results were, however, so disappointing that fundamental changes can no longer be postponed. Privately-owned non-Opec production capacity is overwhelmingly high cost which makes the companies reluctant to shut it in when the market is oversupplied. In fact the only shut-ins to have occurred are in the high variable cost, low productivity production onshore the US and Canada and particularly the heavy oil facilities. The industry suffers from a lack of low cost production capacity that could be shut in at times of weak demand. For most of the last decade annual reports have announced plans to expand production by 5%/y despite demand growth of 2%/y or less. Who was going to cede market share was never made clear.

The other overwhelming problem for the industry is lack of refinery profitability even though private industry owns and operates the bulk of the world's capacity. The reluctance to close capacity, largely because the owner takes the closure cost while the rivals are perceived to take most of the benefit, has meant that there are few refining profits to offset against the declines in upstream earnings. This reluctance to close capacity has arguably led to the industry's largest 'own goal'. The industry constantly supplies marginal cost gasoline to supermarkets and hypermarkets who then beat it in the marketplace. Supermarkets never supply their rivals with marginal cost supplies so why do the oil companies?

When it comes to the oil industry reaction to tightening environmental standards the situation is even more bizarre. In California the refiners have embraced and met the highest standards in the world. Reformulated fuels and exhaust catalysts mean that the emissions from the tailpipe are cleaner than the intake air. This environmental triumph means that alternative fuels and alternative vehicles are no longer rivals to existing fuels and systems. By meeting the environmental challenge California's refiners have successfully defended their own markets. Is this a strategy that can be applied more widely?

If refinery capacity is cut until it closely matches demand and the tightest of environmental standards are embraced, the oil companies would differentiate their products and start to re-establish their status in the eyes of the consumer. The oil companies could then start to move away from selling a branded generic product. High taxation on oil products is actually an advantage as the proportionate cost increase for the top quality product is small.

Once again brand values could be rebuilt and provision of the generic product left to the low cost producers.

The third quarter results were so bad that really original thinking is called for. The industry has a unique opportunity to abandon the profitless pursuit of volume and market share and to rebuild profits and reputation in the downstream.

Chris Skrebowski

Web World

As the festive season is almost upon us, Webworld this month brings you some fun sites. The National Motor Museum at Beaulieu **(www.beaulieu.co.uk/museum/index.html)** offers you the chance to view its collection of vehicles and memorabilia, including world record breakers and 'film star' cars, all from the comfort of your own desk.

For faster cars, try the Shell Ferrari site **(www.shell-ferrari.com)**. Here you can find out the latest Grand Prix results and play a Java-based Formula 1 game complete with sound and video action.

For a glimpse of what future technology may bring, try the website of the Tech Museum of Innovation **(www.thetech.org)** – California at its best.

To join in the countdown to Christmas, you can have your very own online advent calendar **(www.aloud.com/advent)** with the chance to win prizes each day. Blue Mountain **(www.bluemountain.com)** will let you send those last-minute electronic cards.

The IP website is now attracting over 13,000 page hits per week, and it is used by many as their primary resource for online oil and gas information. We are continually adding new data to improve the service to our visitors. If you are a subscriber to *International Petroleum Abstracts (IPA)*, you can now search the records electronically. There is also a sample database available for those interested in subscribing. *IPA* is a quarterly journal which covers a wide range of sources on technical aspects of the petroleum industry. Material is abstracted from a world-wide coverage of scientific and technical journals, conference papers, research reports, trade literature, standards and patents.

Don't forget that if you are a Member of the IP, we can include a link to your site. Corporate Members can be featured in our Corporate Directory, complete with a 100-word company description and your logo. You can also advertise job vacancies in our Careers section.

All the regular features are still there, such as full listings of events in London and around the branches, and also the *News in Brief* service which is updated daily. If there is anything else you would like to see, just let us know!

Finally, Webworld would like to wish you a very Happy Christmas and a prosperous 1999.

If you have any questions regarding the IP website of the Internet in general, please contact Catherine Pope at **cpope@petroleum.co.uk**

New Omani E&P joint venture

Amoco, Occidental Petroleum and Neste Oy are to establish a joint venture to explore for, develop and produce natural gas reserves in blocks 9, 15, 27, 31 and 44 in northern Oman. Production is targeted for markets in northern Oman, around the city of Sohar, and the northern United Arab Emirates via the large natural gas supply hub located in Sharjah.

Amoco Oman Gas will hold a 60% interest in the project, Occidental of Oman and Neste (E&P) holding 26% and 14% respectively. Occidental will lead initial gas reserve definition and exploration efforts for the joint venture – operations are expected to commence this year. Amoco will lead infrastructure development and gas marketing activities.

Development plans include development well drilling and the construction of a gas collection system and processing plant in northern Oman in addition to gas transmission lines to Sohar in northern Oman and the Amoco-operated Sharjah gas hub in the northern UAE.

The joint venture partners anticipate that the large Sharjah gas hub will eventually be linked with other large gas hubs in the region to form part of the proposed Gulf Cooperation Council gas grid.

Deepwater drilling

According to Smith Rea Energy Analysts and EIS Energy Information Services, a total of 70 wells were spudded in water depths greater than 500 metres in 1996, a figure forecast to rise to 200 in 1998. The Gulf of Mexico is the prime focus of activity: 44 out of the 70 wells drilled in this region in 1996, 120 in 1997 and 120 predicted in 1998.

It is also reported that, having already established large-scale deepwater reserves, Angola is now leading West African exploration into previously unexplored ultra-deep waters of greater that 3,000 metres.

Waveney onstream

The Arco-operated Waveney gas field in southern North Sea block 48/17c has come onstream following a 14-month fast-track development programme. The field is expected to produce 84bn cf of gas over the next eight years, with peak production rates of 80mn cf/d.

The field is being developed via a two-well not normally manned platform, remotely controlled from Arco's Great Yarmouth shore base and tied into the Lancelot pipeline system by an 8-km, 10-inch diameter pipeline. Gas is exported to shore at Bacton where it is sold on the short-term UK gas market.

Value of UK oil turns around as output rises

Daily oil revenues climbed above the £20mn mark in September 1998 for the first time since May, reflecting higher output and a modest rise in prices, according to the latest Royal Bank of Scotland's *Oil and Gas Index*. However, on an annual basis oil revenues remained sharply lower – down by 30.3%.

Oil production increased on the month to 2,573,613 b/d – its highest level since April, although much of this increase can be attributed to a rebound from the earlier period's maintenance downtime. Gas production also rose on the month, reaching 6,126mn cf/d in September (up from 5,629mn cf/d in August).

Year Month	Oil production (av. b/d)	Gas production (av. mn cf/d)	Av. oil price ($/b)
Sep 1997	2,526,529	6,343	18.49
Oct 1997	2,619,632	8,193	19.89
Nov 1997	2,568,987	10,015	19.07
Dec 1997	2,709,258	10,880	17.38
Jan 1998	2,598,757	11,012	15.20
Feb 1998	2,582,700	10,305	14.07
Mar 1998	2,595,594	9,803	13.17
Apr 1998	2,571,241	8,844	13.53
May 1998	2,433,059	6,381	14.40
Jun 1998	2,406,521	6,226	12.12
Jul 1998	2,432,040	5,721	12.06
Aug 1998	2,378,912	5,629	12.05
Sep 1998	2,573,613	6,126	13.28

Source: The Royal Bank of Scotland Oil and Gas Index

North Sea oil and gas production

In Brief

United Kingdom

***Ramco Oil Services has secured a five-**year contract to manage Shell Expro's tubular goods for its North Sea platforms and rigs. The contract, which involves the storage, service and maintenance of 40,000 tonnes of pipe per annum, is valued at more than £17mn.*

***UK oil and gas independent Lasmo is** reported to be planning to sell interests in 25 of its southern North Sea blocks. The gas interests are valued between $75mn to $100mn.*

***Mobil North Sea has started up its** £34mn Lancelot compressor at the Phillips-operated Bacton gas terminal in Norfolk. The compressor will enable Mobil to maximise production levels from its southern North Sea gas fields.*

***Wood Group Pressure Control has** secured a three-year contract for the supply of wellheads and christmas trees for Phillips Petroleum's central North Sea projects. Wood Group has also won a contract from Rockwater to supply subsea gas valves for Mobil's North Sea Buckland project.*

***Dana Petroleum has reported what is** claims is its most successful half-year results to date. Turnover in the six months to 30 June 1998 increased to £10.2mn (from £1.7mn in 1997) while average production increased by over 350% to 5,735 boe/d. It discovered a new oil field in block 21/12 in the UK central North Sea during this period, and made a gas find in block 44/24 in the southern sector of the North Sea. Also important was the acquisition of National Power's assets, trebling Dana's UK gas production and doubling its Atlantic Margin acreage.*

***Geoscience consultancy Scott Pickford** has been awarded the processing of what it believes is the world's largest continuously acquired land 3D survey. The survey will cover more than 2,000 sq km of Algeria's Berkine (Ghadames) Basin, including the MLN, MLSE, EKT and EMN fields in blocks 405 and 208.*

***The Flora field in central North Sea** blocks 31/26a and 31/26c has come onstream with initial production expected to reach 20,000 b/d. The field is being produced through the existing Fife FPSO facilities. Field partners are Amerada Hess (operator, 85%) and Premier Oil (15%).*

NEWS Upstream

Arco agrees North Sea asset swaps

Arco British has agreed licence interest exchanges in the North Sea Waveney field through separate deals with PanCanadian North Sea and Oranje-Nassau Petroleum Search. Under the first agreement, Arco has acquired PanCanadian's entire 14.2857% stake in Production Licence P780, blocks 48/16c and 48/17c – which encompass the Waveney field – transferring in return a 10% interest in Production Licence P200, block 20/10a to PanCanadian together with a cash consideration.

In a separate deal, Oranje-Nassau is to acquire from Arco a 14% interest in Production Licence P780, transferring in return its entire 8.888% stake in Production Licence P747, block 22/22c and paying a cash consideration.

Following the deals, Arco will hold an 86% stake in the Waveney field – which came onstream in October (see p3), Oranje-Nassau holding the remaining 14%.

Deben flows first gas

The Arco-operated Deben gas field in the North Sea has flowed first gas 14 months after project sanction. The western extension of the Bure reservoir is also reported to be ready to produce gas. Both fields are being developed via one subsea well each, tied into a new minimal facilities platform which has been added to the existing Arco-operated Thames complex in block 49/28 of the southern North Sea. From here, gas is exported to shore at Bacton, Norfolk.

The Deben field holds estimated recoverable reserves of 33bn cf of gas to be produced over a five year period. Production is expected to peak at 37mn cf/d. Bure West's recoverable reserves are put at 31bn cf, also to be produced over five years, with output peaking at 40mn cf/d.

North Sea sale for BHP

BHP has sold all its exploration and producing assets in the UK southern North Sea to Eastern Group for £100mn. The deal includes the Ravenspurn and Johnston gas producing fields, in which BHP holds 18% and 30.11% interests respectively, plus a number of non-producing gas discoveries and prospects in seven exploration licences. Subject to approval of the UK Department of Trade and Industry and the consent of BHP licence partners, the sale is expected to complete during the 1Q1999.

BHP will continue to hold a number of UK assets in its E&P portfolio, including a 16% interest in the Bruce gas and condensate field in the central North Sea, 31.8% in the neighbouring undeveloped Keith field and a 46.1% operating interest in the Liverpool Bay oil and gas development.

Venture expands Trinidadian portfolio

Aberdeen-based Venture Production has further expanded its operating interests in Trinidad with the acquisition of a 55% working interest in the offshore Brighton Marine field.

The field, which contains reserves in excess of 500mn barrels of oil, will be jointly developed with national oil company Petrotrin. Brighton Marine has nine platforms and over 200 wells, most of which are currently idle. Field production has declined to 350 b/d.

Venture plans to rehabilitate the field using modern technology and practices. Phased redevelopment is expected to increase production to 15,000 b/d. Start-up is scheduled in early 1999.

The company also recently acquired interests in the Trinidadian Forest Reserve and Tabaquite fields.

Sibir holds on to onshore UK assets

Sibir Energy has decided to retain and develop the UK onshore production and exploration assets of its wholly owned subsidiary, the Pentex group, which it had planned to sell.

The company states that, although it has received six formal offers, none of them is considered to reflect the value of the assets which include the Stockbridge, East Midlands and Rempstone areas. Sibir is to have discussions with the highest bidder to explore alternatives to an outright sale.

Interest has also been expressed in using certain of the fields for gas storage. This would be compatible with continued development plans and would provide further commercial benefit as well as the possibility of enhanced hydrocarbon recovery, states Sibir.

In Brief

Europe

Statoil is understood to have raised *projected costings for its Norwegian North Sea Huldra project by 15% to NKr5.5bn. Higher than expected equipment tender prices and the recent decision to pipe Huldra gas to Norsk Hydro's Heimdal installation rather than Kollsnes has pushed the price up, states the company. Huldra gas is due onstream in October 2001.*

Smit Maritime Contractors has won *the marine installation contract for Esso Norge's Balder FPU which is currently being outfitted at UiE's Glasgow Inchgreen drydock. The FPU is due to commence production in the Balder field offshore Norway in 1999.*

It is understood that Statoil plans the *start-up of the Yme Beta West satellite in the Norwegian sector of the North Sea in March 1999. Recoverable oil reserves are put at 16mn barrels, to be developed via two subsea wells tied back to the template on the Yme Beta East satellite.*

Amerada Hess is reported to have *shelved development of the North Sea Freja oil field due to low oil prices and high rig rates. The high temperature/high pressure field, which straddles the Norwegian and Danish continental shelves, was due onstream in 2000. Field reserves are put at 20mn barrels.*

North America

Brown & Root Energy services and *Agra Monenco are understood to have formed a new 50:50 joint venture which will provide engineering, project management, construction management, procurement and other services for Canadian oil and gas proejcts as well as some international projects.*

British-Borneo Petroleum Syndicates' *Morpeth field in the Gulf of Mexico is understood to have come onstream, producing at 15,000 b/d of oil. Output is expected to reach 35,000 b/d and 36mn cf/d of gas.*

Anadarko Petroleum Corporation and *partners are understood to have made a commercial sub-salt discovery – Hickory – in 320 feet of water at Grand Isle 116 in the Gulf of Mexico. First production is expected in 2000.*

NEWS Upstream

New vessels to break the Caspian ice

Kvaerner Masa-Yards has delivered two ice-breaking supply vessels – the *Arcticaborg* (pictured above) and *Antarcticaborg* – to Wagenborg Kazakhstan (see *Petroleum Review*, May and June 1998).

The vessels are designed to meet the heavy ice conditions in the northern Caspian Sea and will initially serve drilling platforms operated by OKIOC (Offshore Kazakstan International Operating Company. Use of an Azipod propulsion and steering system (pictured below) with a very short propeller shaft mounted in a rotateable pod provides a very manoeuvrable vessel without the need for a rudder.

Russian rehabilitation

Tyumen Oil Company has announced that US oilfield services company Halliburton is to carry out a feasibility study to work over the giant Samotlor oil field, reports United Financial Group's *Russia Morning Comment*. The field is jointly operated by Chernogorneft and Nizhnevartovskneftegaz (part of Tyumen). It is said that the Nizhnevartovskneftegaz side of the Samotlor field had been badly mismanaged under the previous company management.

Tyumen's new management plans to focus on ways of improving performance and to seek a \$500mn loan from the US Exim Bank to fund field rehabilitation.

In Brief

***Shell Canada and Nova Scotia Power** are understood to have signed what is said to be the first contract for the use of natural gas from the Nova Scotia Sable field development. Under the terms of the deal, Shell will supply Nova Scotia Power with 60mn cf/d of gas over 10 years for use at its Tufts Cove power plant. The Sable project is due to produce first gas by the end of 1999.*

Russia & Central Asia

***The Khanty Mansiysk Autonomous** Okrug (KMAO) and the Ministry of Natural Resources of the Russian Federation have handed over the production licences for the West Salym, Vadelyp and Upper Salym fields to Salym Petroleum Development. The company, a joint venture between Shell and Evikhon, plans to initiate a pilot development (15,000 b/d) in the Upper Salym field with facilities due onstream in 2001.*

***Azerbaijan, Georgia, Kazakhstan,** Uzbekistan and Turkey are understood to have signed an agreement to cooperate in the development of a cross-border oil pipeline linking the landlocked Caspian Sea to the Mediterranean port of Ceyhan.*

***Canadian company Ocelot Energy is** reported to be taking over a 50% stake in the Stepnoi Leopard KTT joint venture project in northwest Kazakhstan. The prospect is estimated to contain over 100mn boe of proven reserves. Development drilling and initial production are scheduled during 1999.*

***OMV and Petreco, the oil and gas subsidiary** of UK company Melrose Resources, are reported to be planning to develop Bulgaria's first offshore gas field – Galata – near the Black Sea port of Varna. Proven gas reserves are put at 40bn cf. First gas is expected in 2000.*

Latin America

***Harken Energy Corporation has** reported total proved reserves of 44.5mn boe at 30 September 1998 compared with 16.6bm boe at 31 December 1997. Much of the increase is the result of discoveries on the Bolivar block and interpretation of a 3D seismic survey in the Alcaravan Palo Blanco field, both in Colombia, and the Louisiana Gulf Coast property acquisition in May 1998.*

NEWS Upstream

Green light for ECA development

The UK Department of Trade and Industry (DTI) has given the green light for the development of the Easington Catchment Area (ECA) in the North Sea. The £150mn first phase of ECA will involve the development of two gas fields – Neptune and Mercury – located 25 to 30 miles off the Yorkshire coast, with total reserves of 370bn cf.

ECA gas will be produced using subsea wells for Mercury and an unmanned platform at Neptune. The combined production will be piped to a new riser tower adjacent to BP's existing Cleeton facilities. After initial processing the gas will be exported through BP's existing southern North Sea pipeline system to its Dimlington terminal.

ECA is said to be one of the first field developments to fall within the terms of new European Union environmental regulations for offshore developments. A full environmental impact assessment was conducted, and comments sought from over 20 consultees on environmental issues. Copies of the environmental statement were made available locally, and organisations and members of the public were also invited to comment to the DTI.

A £24mn contract for the engineering, procurement, fabrication, installation and commissioning of the Neptune platform and ECA riser tower has been awarded to Brown & Root. The units will be constructed at the company's Ardersier yard in Scotland. A £23mn contract for pipelines and subsea facilities has been awarded to ETPM UK. Modifications to the Cleeton facilities to allow for the introduction of ECA gas will be undertaken by BP and Amec.

The wells are to be drilled using the Global Marine jack-up *Glomar Adriatic XI*. Global Marine Integrated Services and Expro Group Integrated Services will provide well design, planning and operational services.

Installation work is scheduled to begin in March 1999, with first gas production expected in 4Q1999.

Partners in the Neptune field are: BG Exploration & Production 61%, BP 18% and Amerada Hess 21%. Mercury field partners are: BG Exploration & Production 73% and Amerada Hess 27%.

Geoservices has secured an integrated drilling services contract for up to five rigs in Bolivia from Andina, a consortium of Argentinian companies YPF, Perez Companc and Pluspetrol. *The contract includes the drilling of a number of gas wells whose production will be exported to Brazil via the Santa Cruz–Sao Paulo gas pipeline which is presently under construction.*

Harken Energy Corporation is to participate *in an exploration and production contract covering 1.4mn acres in the North and South Limon Back Arc Basin onshore and offshore Costa Rica. The project doubles the company's E&P activities in the region.*

Petrolex Energy Corporation has *announced that its Rubiales oil field in Colombia has estimated proven recoverable reserves of 211mn barrels of oil, an increase of 58% from the figure reported in October 1996.*

Amerada Hess reports that it has *plugged and abandoned exploration well 14/9-2 offshore the Falkland Islands. The abandonment completes the initial drilling campaign on Tranche A in which two wells have established good source rocks and potential reservoir rocks.*

It is understood that an Elf *Aquitaine–Conoco consortium plans to invest $60mn by the end of 1998 to explore the Guanare oil tract in Venezuela. It is thought that the area could hold up to 835mn barrels of oil reserves.*

A YPF-led consortium is reported to *have signed a joint venture contract with Petronas to operate block BES-3 in the Espiritu Santo basin offshore eastern Brazil. It is thought to be the first joint venture agreement to have been made in the upstream sector since Brazil recently altered its hydrocarbon laws.*

Asia-Pacific

Pogo Producing Company reports *that a number of wildcat wells have extended the area of the currently producing Benchamas field in the Gulf of Thailand.*

Apache is reported to have acquired *certain oil and gas interests in the Carnarvon Basin offshore Western Australia from Novus Petroleum for $49mn plus adjustments. The interests are said to have proved and probable reserves of 10.7mn boe.*

In Brief

Saga Petroleum is understood to have *sold its 50% interest in the Jambi-Merang block in Indonesia to YPF and Amerada Hess for $17.7mn. The deal marks the end of Saga's activities in Indonesia.*

Santos is reported to have discovered *a new gas field in the South Australian sector of the onshore Cooper/Eromanga basins. The Verona One well – located near the existing facilities of the Cuttapirrie gas field – flowed at 5.25mn cf/d.*

Smit International Singapore has *secured a marine services contract for the mooring and installation of a floating, storage and offloading system in the Pogo Producing Company-operated Benchamas field in Gulf of Thailand block B8/32 in March 1999.*

Apache Corporation's John Brookes 1 *discovery well offshore northwest Australia is reported to have tested at 53.4mn cf/d of natural gas and 460 barrels of condensate.*

The Chengdao field in the Bohai Sea *offshore east China is understood to have been brought onstream. Claimed to be the largest oil deposit in the region, the field has an annual output capacity of 1.05mn tonnes.*

Petronas is reported to have brought *the Ruby field, located in blocks 01 and 02 offshore Vietnam, onstream 10 days ahead of schedule. Initial production is averaging 8,000 b/d and is expected to reach 20,000 b/d in 1999.*

Africa

Canadian oil and gas company Canop *Worldwide Corporation has signed an agreement under which Paladin Resources of London, UK, will earn a 20% interest in a 4.3mn acre oil and gas exploration concession in coastal Tanzania.*

TOTAL has acquired a 28% stake in the *Astrid and Anton deepwater exploration blocks in the northern part of the lower Congo oil basin offshore Gabon. TOTAL is block operator; partners are: Unocal (25%), Kerr McGee (14%), Vanco Energy (22%) and RB Falcon (11%).*

Exxon reports that its fourth deep- *water oil discovery – Dikanza – in block 15, offshore Angola, has tested at 4,400 b/d.*

NEWS Industry

Arco and Mobil finalise asset swap

Arco and Mobil have completed a deal under which Arco's heavy oil properties in California's San Joaquin Valley were exchanged for certain Mobil oil and gas properties in the Gulf of Mexico. Arco, in turn, transferred the Gulf of Mexico properties to Houston-based Vastar Resources, through the sale of a wholly-owned subsidiary for $470mn. Arco owns an 82.2% interest in Vastar, a major oil and gas producer in the Gulf of Mexico and onshore Gulf region.

The Gulf of Mexico properties include working interests in 23 producing fields and 93 platforms, as well as interests in over 80 lease blocks in the western and central Gulf of Mexico. Most of the production is natural gas and is expected to average 180mn cf of gas equivalent per day in 1999. As of 1 July 1998, net proved reserves were 360bn cf of gas equivalent. In addition, Vastar acquired interests in pipelines, gathering lines and a shorebase in Cameron, La.

California properties transferred to Mobil include five fields in Kern and Los Angeles counties and an interest in a cogeneration facility in the Midway-Sunset field in Kern County. Net production from the fields is 37,000 b/d of oil and 6mn cf/d of gas. Proved reserves total 160mn boe.

Arco is closing its Bakersfield, California, office as a result of the deal which has resulted in an after-tax charge to the company of $109mn.

DTI releases provisional energy statistics for UK

The UK produced 63.5mn toe of indigenous primary fuels in the 3Q1998, up 1.9% compared with the same period a year earlier, according to the UK Department of Trade and Industry (DTI). Coal production fell by 14.1%, while production of oil, gas and primary electricity rose by 3%, 6.8% and 2.8% respectively.

Total inland consumption of primary fuels, including deliveries into consumption, during the period, reached 47.5mn toe, 1.8% higher than a year earlier. Consumption of primary electricity fell by 2.3% while coal, petroleum and gas consumption increased by 0.3%, 1.4% and 5.1% respectively. Primary electricity consists of nuclear electricity, natural flow hydro electricity and, for consumption, net imports of electricity from France. DTI's annual data also includes electricity generated from other renewable sources, such as wind and photovoltaics. In 1997 primary electricity is estimated to have accounted for about 32% of all electricity available in the UK.

The DTI statistics also indicate that total use of petroleum, including non-energy use, reached 20.3mn tonnes in the 3Q1998, up 0.4% from 3Q1997. Energy use increased by 2.3% while non-energy use decreased by 7.3%.

Total motor spirit deliveries were 0.9% lower, but deliveries of unleaded gasoline rose by 8.4%. In the period, unleaded gasoline deliveries represented 79.3% of total motor spirit deliveries, compared with 72.5% a year earlier. Diesel fuel deliveries rose by 1.9% and deliveries of other gas diesel oils, primarily used for heating purposes, increased by 5%. Fuel oil deliveries fell by 7%, a much smaller decrease than seen in earlier periods, comments the DTI, due to the significant switch away from fuel oil by electricity generators and industry during 1997.

Prices of motor spirit and diesel fell steadily from September 1997 to March 1998. Following the duty increases announced in the March 1998 budget, prices increased by about 4 p/l in April and have remained broadly static since then. In the year to mid-October, prices for 4-star, unleaded and diesel rose by around 2 p/l. In the year to mid-September, prices for super unleaded gasoline rose by just over 5 p/l, an increase of 7%.

BP posts 35% fall in 3Q1998 profits

BP has reported that the one-third fall in oil price over the past year has led to a 35% fall in 3Q1998 replacement cost profit, before exceptional items and after adjusting for special items, to $736mn.

On a more positive note, BP Group Chief Executive Sir John Brown pointed to a 12% rise in third quarter oil production following the start up of ETAP and Schiehallion and increased output from Foinaven, the Viking Phoenix project (BP 50%) and the second phase of the Bruce development. The refining and marketing business recorded a 3% improvement in replacement cost operating profit of $449mn while the chemicals business achieved a 10% increase in production during the period. Brown also stated that volume growth and cost improvements so far during 1998 have delivered $250mn towards the group's target of $2bn of net income improvement by 2002.

Commenting on the BP–Amoco merger, he said that he expected the deal to complete by the end of the year.

In Brief

United Kingdom

Ranger Oil has posted total 3Q1998 *revenues of $234.2mn, slightly lower than the $240.1mn reported for the same period in 1997. The company also reported that a 69% increase in daily oil production to 53,430 barrels was offset by the decline in oil prices.*

Amerada Hess is reported to be cutting *up to 30 jobs from its Aberdeen office and possibly a further 40 posts from London. The job losses form part of the company's drive to cut annual costs by 12% in the face of low oil prices.*

Fortune Oil, the UK listed company *which is involved in oil-related projects in China, reports that the Asian financial crisis led to a 16% drop in turnover to £183.9mn for the six months ending 30 June 1998 compared with the same period a year earlier.*

TOTAL Oil GB Ltd is moving its head- *quarters from Cavendish Square, London, to Watford.*

Europe

Hungarian oil and gas company Mol *has posted a 3Q1998 net income of HUF38.8bn ($182mn), up 111% from the same period a year earlier. Upstream operating profit is reported to have grown by 64% to HUF28.7bn ($134.3mn) as a result of improving gas returns, while downstream operating profits rose by 62% to HUF25.8bn ($120.8mn).*

Statoil has reported a NKr7.2bn *operating profit for the first nine months of 1998, against NKr13.2bn for the same period a year earlier. The company stated that low oil prices accounted for NKr4.2bn of the decline.*

North America

Chevron has reported a 3Q1998 net *income of $461mn, a decrease of 37% from net income of $727mn in the same period a year earlier.*

Oryx Energy has reported a 3Q1998 *net loss of $43mn compared with net income of $42mn.*

Apache Corporation has reported a *3Q1998 net income of $2.6mn, down from $30.8mn a year earlier.*

NEWS Industry

A not-so-sure future for Shell as profits plummet

Shell has revealed a 56% fall in profits in the 3Q1998 to $841mn. The company attributed the 'disappointing' results to the 33% decline in oil price and narrowing refining margins. Earnings in the exploration and production sector fell by 69% to $288mn while chemicals earnings plummeted by 90% to $27mn as a result of the Asia-Pacific economic crisis. The company's oil products business suffered least, posting a 6% fall in net profits to $489mn.

Shell Chairman Mark Moody-Stuart said that the company has a number of significantly underperforming areas, such as the Tejas Gas pipeline operation in the US, and Montell, its loss-making polypropylene division, that 'need to be fixed or eliminated'. A number of its chemical businesses are to be sold and refinery closures have been announced in the UK, US and Japan. Moody-Stuart predicted that the company could face further problems in forthcoming months, with oil prices likely to fall below the $12 to $16 per barrel he forecast a few months ago.

Shell's return on capital employed (ROCE) fell to 9.2% from 12% a year ago.

BP unveils blueprint for UK chemicals

BP has revealed plans to invest £500mn in chemicals manufacturing in the UK as part of a programme to boost the competitiveness of its European chemicals business. New plants will be built at BP sites in Grangemouth, Scotland, and Hull in northeast England. An existing ethylene pipeline from Grangemouth to Teesside will be extended to Hull and ethylene manufacturing at Grangemouth will be stepped up to more than 1mn tonnes.

According to BP, the investment, due to complete by 2002, will enable both the Hull and Grangemouth sites 'to benefit from close integration with North Sea feedstocks, highly productive new technologies and low-cost, on-site power generation, taking them firmly into the top rank of chemicals manufacturing locations in Europe'. The Grangemouth site has the advantage of being located adjacent to BP's refinery and the terminal of the company's Forties pipeline system which provide access to a variety of liquid and gas feedstocks, while the Hull site is pipeline-linked to North Sea methane for acetic acid production and utilities supply.

The UK government recently approved the construction of a combined heat and power (CHP) plant for the Grangemouth site. The plant, to be built by IVO of Finland and Mitsubishi of Japan, will generate 230 t/h of steam and 130 MW of power principally for on-site consumption. BP has already invested £1bn since 1990 in highly efficient integrated oil, gas and petrochemicals manufacturing at Grangemouth and the increasing quantities of liquid gas feedstocks which will become available from the North Sea from around 2000.

Construction work will create up to 2,200 jobs at Grangemouth and 900 jobs at Hull by 2002. An additional 225 new chemicals industry jobs will also be created.

The company has been developing a blueprint to increase the competitiveness of its chemicals business in Europe since 1990. Between 1990 and 1997, it closed or sold chemicals assets with a combined capacity of 1.75mn t/y because they were either uncompetitive or inconsistent with long-term development strategy.

Job losses announced – more on the cards

Shell has now announced that it is to shed some 3,000 jobs, about 20% of its European downstream workforce, following the reorganisation of its European products businesses. The cuts include the 15% staff reduction previously announced by the company. Consultation with employees is currently under way and the new organisation will be implemented during 1999. Shell UK is expected to account for up to 600 of the cutbacks, with 290 disappearing from the closure of the Shellhaven refinery. Around 200 jobs are expected to go in the Netherlands and more than 350 in Germany.

There are fears of more job losses in the UK resulting from the merger between Shell and Texaco, the latter having recently announced plans to reduce its global expenditure by 20% to $3.7bn. It is understood that Shell is looking for cost savings of $200mn from the link-up, although analysts believe the total could reach $400mn.

Texaco's cost reduction programme aims to cut its global E&P workforce by 12% and is expected to include the loss of 750 employees in the US and 250 overseas, the majority of which will be in the UK. The lay-offs are said to be equivalent to 5% of the company's total payroll and are expected to be completed by March 1999. Chevron, Arco, Mobil, Unocal and Occidental have stated that they, too, are to scale-back capital outlay – many analysts predict job losses will follow.

In Brief

Arco reports that its 3Q1998 operating *earnings, excluding special items and discontinued operations, fell from $313mn in 3Q1997 to $61mn in 3Q1998. The decline reflects the continued weak oil and gas prices, states the company.*

DuPont Company's sale of a 25% *stake in its Conoco subsidiary in what is claimed to be the biggest US initial public offering to date is reported to have raised $4.4bn.*

Phillips Petroleum Company has *reported a 3Q1998 net income of $46mn, a fall of 79% from the same period a year earlier.*

Russia & Central Asia

Lukoil is reported to have confirmed *that any further debt default by the Russian Government will not prevent the oil company making future repayments, according to United Financial Group's* Russia Morning Comment. *Lukoil President Vagit Alekperov is reported to have stated that the company still regards foreign borrowings as key to its development plans and will borrow $340mn this year. He expects the company to raise a maximum $250mn in 1999.*

The Russian Government is reported to *have formally accepted that the sale of Rosneft has failed and has cancelled the tender. Rosneft is also reported to be withdrawing from the Sakhalin-1 development consortium. The Russian company holds a 49% interest in the project.*

Oil production from Russia in the first *nine months of 1998 was down by 0.9%, while gas output rose by 4.6% against the same period a year earlier, according to a recent report from United Financial Group's Russia Morning Comment. The refining sector is understood to have suffered following a drop in demand for refined products in both the export and domestic market, output falling by 8.1% in the same nine-month period.*

Asia-Pacific

It is reported that Nippon Oil and *Mitsubishi Oil are to merge in April 1999 in a bid to cut costs and increase competitivity. The new company will be Japan's biggest oil distributor.*

NEWS Downstream

UK tax said to escalate diesel prices unfairly

David Green, Director General of the UK Freight Transport Association (FTA) recently stated that the fuel tax escalator, which increases the tax applied to diesel each year by 6% above the rate of inflation, is 'an unfair, ineffective and aggressive form of taxation which is seriously damaging UK industry and failing to achieve its purpose' of reducing carbon dioxide exhaust emissions.

Commenting that the UK Government 'had not thought this approach through,' Green said: 'The scale and frequency of the increases are so great that no operator can possibly make sufficient improvements in fuel efficiency to keep pace with the rising cost of fuel. The means of improving efficiency inevitably involves investment in equipment, new vehicles or driver training. But the fuel escalator is removing much of the cash available which would otherwise be invested in such measures.'

According to the FTA, a typical small business, with a turnover of £750,000/y, operating ten 38-tonne vehicles, would have had an increase in fuel costs from £207,000/y to £226,000/y as a result of the fuel escalator in the 1998 Budget.

Chrysler and Syntroleum to develop designer fuels

Chrysler Corporation and Syntroleum Corporation have announced plans to jointly develop 'designer fuels' derived from natural gas that they claim 'will be sulfur-free, affordable and potentially cleaner than any viable transportation fuels currently available'. Syntroleum estimates that the new designer fuels could sell for less than $1.50 per gallon.

The new fuels will be designed from Syntroleum's patented natural gas-to-liquids process. The company states that the technology has the potential to enlarge the world's readily available fuel supply by 25% by enabling oil and gas companies to economically convert huge untapped reserves of so-called 'stranded' natural gas, which are currently flared, into more widely available and marketable liquid fuels. Industry estimates suggest there is enough stranded gas to make 250bn barrels of synthetic oil, a figure which Syntroleum believes to be a conservative estimate. These designer fuels could be distributed throughout the existing infrastructure, so drivers could continue to fill up at service stations just as they do today, explains the company.

According to Syntroleum President Mark Agee, enough natural gas is currently being flared to make an estimated 1mn b/d of synthetic fuels or approximately 7% of the daily volume of transportation fuel consumed in the US.

The new agreement calls for Chrysler to test several fuel formulations made by Syntroleum on various engines to determine the optimum physical and chemical characteristics for each fuel. It also allows for joint testing of lubricants and automatic transmission fluids made with the Syntroleum process.

European auto LPG demand set to increase

Demand for automotive LPG in Europe is forecast to increase by 13.4% each year until 2008, according to a recent report from UK analyst MarketLine International. The automotive sector currently accounts for just 12.4% of overall LPG sales in the region. However, high levels of governmental support for its benefits over diesel – reduced emissions of carbon monoxide, carbon dioxide and particulates, lighter tanks and less vehicle noise – are expected to drive sales significantly. The UK is expected to experience an average annual growth of 61.7% in autogas consumption to 2008.

The report states that total sales of LPG in Europe reached 26.2mn tonnes in 1997, with Italy the largest market consuming 3.4mn tonnes that year. France (which consumed just over 3mn tonnes in 1997) is predicted to overtake Italy to become Europe's largest LPG market by 2008. Total LPG demand is expected to reach 6.8mn tonnes, mainly as a result of the French government's support for the environmentally friendly autofuel.

Southern European countries, in particular Turkey (where volumes have climbed by an average of 8.6% per year), Greece and Portugal, have seen demand for LPG rise significantly in recent years due to the lack of other competing forms of energy such as natural gas. However, the introduction of piped natural gas into these countries in the remainder of the 1990s and into the next decade is expected to slow down demand growth.

However, other LPG market sectors are not expected to perform as well as the autofuel sector predicts the report. The domestic LPG sector is forecast to be the worst performing market. This sector currently accounts for 53.5% of total LPG demand in Europe, a figure expected to fall to 37% by 2008 as natural gas encroaches into its market. The industrial market for LPG is expected to fall from 25.8% to 24.3% during the same period.

In Brief

United Kingdom

The Smithy service station at Arnprior, *Stirlingshire, is the first in Scotland to carry the new 'Highland' branding of Highland Fuels, Esso's branded distributor of fuels and lubricants in the country.*

Europe

Spanish oil company Repsol has *launched the 'Visa Repsol' payment card as part of an agreement with the BBV and 'la Caixa' groups. The card provides the holder with a 2% discount on fuel, services and other products made at Repsol, Campsa and Petronor service stations belonging to the 3,200-strong Solred network.*

OMV is to purchase BP's 28-strong *Hungarian service station network for an undisclosed sum.*

BG plc has sold a 5% equity interest in *the Interconnector gas pipeline to Snam of Italy. The sale leaves BG plc with a 35% stake. The UK gas company has also sold 1bn cm/y of the Interconnector's 20bn cm/y capacity to Snam and Norsk Hydro, each company taking 0.5 bn cm/y.*

North America

Texaco and Chevron have formed a *new 69:31 joint venture combining the global residual fuel and marine lubricants marketing businesses of both companies. Fuel and Marine Marketing LLC (FAMM) will have annual sales of 170mn barrels of fuel and 80mn gallons of marine lubricants.*

Exxon and Toyota are understood to *have signed an agreement to jointly develop 'next generation automotive systems', including advanced internal combustion engines and hybrids, fuels and lubricants.*

Middle East

Oman LNG is reported to have now *signed up contracts to sell 75% of its export capacity following an agreement with Osaka Gas Co in Japan. Under this latest agreement, Oman LNG will supply Osaka Gas with 0.7mn t/y of LNG for a 25-year period beginning in 2000.*

NEWS Downstream

Hypermarkets gain fuel sales market share

In 1997, the leading oil company in the western European service station market was Shell, with a volume share of 11.4%, followed by Esso and BP/Mobil, with 10.1% and 7.9% respectively, according to a recent report from UK analyst MarketLine International.

The report also concludes that the hypermarkets' share of the fuel retail market is still growing the fastest. However, it was pushed into second place in the growth league by the recent merger between Agip and Italiani Petroli, the new company now holding 10% of the market.

Despite having just 4.7% of the service station sites in western Europe, hypermarkets now hold a 16.6% share of fuel sales, having increased by 1.42 percentage points over the last year.

According to MarketLine, this share has been attained largely at the expense of the smaller oil companies and independents, whose share has dipped by over 3% over the past year.

Commercial gas buyers vet gas shippers

All UK gas shippers, except Eastern Gas Trading, have improved their performance in 1998 against last year, according to commercial gas buyers in the Utility Buyers' Forum (UBF).

UBF members – who are responsible for spending over £200mn/y on gas supplies in the UK – were asked to grade performance on a scale of 1 to 10, where 1 is best and 10 the worst. Areas assessed included customer service, supplier invoicing and supply point administration.

Southern Gas, Vector, TOTAL and Mobil all tied in first place with scores of 1.6, closely followed by Amerada, Yorkshire Gas, BP Gas and Shell with scores of 2.

Agas and British Gas/Centrica scored 2.2, followed by Alliance with 2.3. Kinetica and Scottish Power/Manweb scored 3.25 and 3.5 respectively, while Midlands Gas and Eastern scored 4 and 4.8. Only Eastern Gas Trading registered a score below 5.

CPC pipeline set to get green light

Chevron reports that the Caspian Pipeline Consortium (CPC), in which it holds a 15% interest, has received final approval of its modernisation feasibility study from the Kazakh Government and has received official assurances of an imminent green light from the Russian Government for its final approval. The approvals will enable CPC to begin the construction schedule and award contracts for pipe and major equipment.

Construction is due to complete in early 2001, with first oil expected to flow in mid 2001. Initial capacity of the oil pipeline will be 600,000 b/d, rising to 1.5mn b/d once more pumping stations have been added to the line and additional marine loading facilities installed.

The $2.2bn pipeline is said to be the key to unlocking the tremendous potential of the Tengiz oil field in western Kazakhstan. The field, which currently produces more than 200,000 b/d, is expected to produce 700,000 b/d in 2010.

CPC was founded in 1992. Equity interest is: Russia 24%, Kazakhstan 19%, Oman 7%, Chevron 15%, Lukarco 12.5%, Rosneft-Shell 7.5%, Mobil 7.5%, Agip 2%, British Gas 2%, Kazakhstan Pipeline Ventures 1.75%, and Oryx 1.75%.

In Brief

Russia & Central Asia

United Financial Groups' Russia Morning Comment *reports that gasoline prices rose by 10% in Moscow in mid-October, to reach $1.12 per gallon.*

Latin America

Shell and Petrobras *are to invest $200mn in the joint development (50:50) of a LNG regasification terminal at Suape in the state of Pernambuco, northeast Brazil. The terminal will have a daily capacity of between 5mn to 6mn cm of natural gas, equivalent to around 1.5mn t/y of LNG, and is due to receive its first delivery at the beginning of 2003. The plant is claimed to be the first of its kind in Latin America.*

Belgian gas company Tractebel *is understood to have secured a contract to distribute natural gas in the state of Queretaro in central Mexico.*

Brazil was reported to have approved *the first shipment of crude oil imports by a foreign company in October, ending 45 years of state monopoly. It is understood that Argentinian oil and gas company YPF and a US consortium are to import 190,000 barrels of Argentinian crude for testing at the Manguinhos refinery near Rio de Janeiro in which YPF has a 50% stake.*

Asia-Pacific

South Korea is reported to have sold a *50% stake in Hyundai Oil Refinery Company to a state-invested firm in the United Arab Emirates for $500mn.*

UK Deliveries into Consumption (tonnes)

Products	†Sep1997	*Sep 1998	†Jan–Sep 1997	*Jan–Sep 1998	% Change
Naphtha/LDF	237,385	150,313	1,494,508	2,111,895	41
ATF – Kerosene	780,121	826,838	6,332,986	6,786,737	7
Petrol	1,795,913	1,792,333	16,652,676	16,194,813	–3
of which unleaded	1,308,220	1,430,243	11,851,698	12,588,663	6
of which Super unleaded	39,032	33,732	393,360	310,268	–21
Premium unleaded	1,269,188	1,396,511	11,458,338	12,278,395	7
Burning Oil	242,683	266,377	2,335,260	2,542,454	9
Automotive Diesel	1,299,854	1,236,828	11,120,893	11,195,192	1
Gas/Diesel Oil	585,777	624,708	5,411,272	5,340,269	–1
Fuel Oil	245,436	192,210	2,997,148	2,084,251	–30
Lubricating Oil	72,229	64,515	657,989	619,059	–6
Other Products	756,446	752,092	6,503,326	6,116,777	–6
Total above	6,015,844	5,906,214	53,506,058	52,991,447	–1
Refinery Consumption	549,840	505,583	4,857,510	4,852,748	0
Total all products	6,565,684	6,411,797	58,363,568	57,844,195	–1

† Revised with adjustments   *preliminary

Driving well costs down

The reduction of well costs is one of the vital target areas as the oil and gas industry strives to shape itself to live in a world of continuing low oil prices and the threat of global recession. Some studies have indicated that well costs have risen 20% in the space of just one year. There is, however, the potential for major savings, with some benchmarking studies indicating that the best performers can drill wells at two-thirds of the price that it is costing the rest of the pack. *Neil Potter* looks at some of the methods used to achieve such results.

Frances Gugen, Managing Director of Amerada Hess, is reported to have recently said that the cost of wells are 'killing us', and has called for a 50% reduction in the per well cost or doubling the 'value' of each well. The cost of drilling wells in the UKCS varies between £5mn and £30mn, depending on whether it is an exploration, appraisal or production well and on location, environment, formation, structures and many other factors.

Individual operators have their own concepts for cutting well costs. Chevron, for example, in the pre-drilling of the 17 Britannia development wells, cut £25mn off the original £109mn drilling budget. This was mainly due to the use of slimhole drilling, with the elimination of some of the casing saving £1.5mn per well in materials and rig time.

High rig rates have been held much to blame for soaring well costs. The Centre for Marine and Petroleum Technology (CMPT) says that it is estimated that an extra $4bn is being spent by the industry because of increased rig costs. But there is now a belief in some quarters, including the Crine Network, that there are other factors apart from rig rates which have led to high well costs. One of the main factors is the time the rig is on location.

Technology plays an increasingly important part in the drive to reduce rig time. For example, the use of Baker Hughes INTEQ's new AutoTrak Rotary Closed Loop Drilling System in the drilling of the 3/9a-N37 well in TOTAL's Alwyn North well is claimed to have saved 64 hours of rig time compared with conventional guiding systems.

Delving deeper

Generally, well costs are quoted as a total sum. It is of interest, therefore, to delve deeper into one aspect of the cost factor and look at the 'bits and pieces' utilised.

Analysts at Smith Rea Energy have produced a comprehensive report* on the downhole equipment and services market which details and discusses everything from drilling tools, mud logging and directional drilling to coring, fishing, sidetracking and abandonment.

Sector	UKCS	Norway	Rest of NWECS	Total NWECS
Drill bits	30	–	–	45
Mud logging	27	12	5	44
Directional drilling and survey	116	53	18	187
Downhole motor drilling	20	15	1.5	37
MWD	49	22	7	78
Electric wireline logging	75	50	15	140
Coring	24	14.5	4	42.5
Casing crews	6.5	5	1	12.5
Fishing	70	32	11	113
Abandonment	–	–	–	1
Total drilling	–	–	–	708
Mechanical wireline	25	14	–	50
Perforation	15	12.5	7	34.5
Well testing	9	6	3	18
Sand control	19	28	–	47
Sand control screens	–	–	–	25
Stimulation	50	215	9	74
Coiled tubing workovers	30	1	–	50
Downhole safety valves	5	4	–	9
Gas lift	1	1	–	2
Downhole pumps	–	–	–	3
Packers	1.6	1.2	–	3
Total completion	–	–	–	315.5

Table 1: Estimated market values for the separate market sectors in the NWECS region in 1997 (£mn/y)

'Dipstick drilling' project

The Centre for Marine and Petroleum Technology (CMPT) believes that there is great scope in an era of low oil prices for a more basic, highly mobile drilling system, designed simply to prove or disprove the existence of hydrocarbons by actually finding them – or not, as the case may be. It is launching a project – Drilling Independent of Depth (DIODe) – which is known in the industry as 'dipstick drilling'.

Dick Winchester, Director of Technology Programmes at CMPT, believes that what is really needed to reduce well costs is 'a step change in drilling technology'. Part of CMPT's role is to help the development of new technology to discover new reserves and for novel ways to reduce the cost dramatically and thus the economic risk associated with drilling exploration holes.

He points out that any new concepts must be kept within the bounds of the possible, because time is of the essence. Any solution has to be available to the market within two to three years. 'There is', he comments, 'little room for manoeuvre here and although the temptation is to create and investigate entirely new ideas for punching holes in the ground – of which there are many – these may have to be reserved for economically healthier times'.

Winchester believes that it is possible to try to attack 'certain preconceptions and old habits'. Invariably an exploration hole is not just a hole designed to determine whether the target holds hydrocarbons. 'Modern exploration holes are also major data gathering exercises deemed by the geologists and petrophysicists as essential to update and add some "groundtruth" to an otherwise theoretical model. However, gathering data whilst drilling is an expensive exercise and there may well be a case for at least reducing or even eliminating the data gathering exercises and aiming only to prove or disprove the existence of hydrocarbons by actually finding them, or not as the case may be'.

The basis of DIODe is the adaptation of micro-coiled tubing technology for seabed drilling. Aimed initially at deeper water operations, the system will be supported and deployed from a relatively simple support vessel that will promote rapid mobilisation and demobilisation. This should reduce costs substantially when compared with conventional drillships and semi-submersibles.

'Without doubt', says Winchester, 'savings could be achieved by improving the existing technology. More automation, reducing manpower and increasing the drilling rate are all possible options. However, it is unlikely that any of these could produce the level of cost reduction needed given the base cost of the rigs themselves. Standardising equipment for both shallow and deepwater operations is one possible means of achieving that'.

He explains that the DIODe system is perceived as a mobile unit capable of being easily moved from one seabed location to another with minimal surface facilities. Using remote control technology that is already well understood by the manufacturers of ROVs (remotely operated vehicles), the system will be controlled via an umbilical to a surface support vessel, such as a DSV (diving support vessel). The umbilical will supply DIODe with power, drilling fluids and other consumables, possibly utilising the closed loop drilling fluid systems developed for underbalanced drilling.

Many of the enabling technologies needed to develop such a system are either already in place or close enough to being in place to have sufficient confidence that they will be available soon.

It is estimated that the programme, to which companies will be invited to join, will cost between £10mn and £15mn and will aim to develop and build a basic system capable of proving the concept.

It subdivides the market into 12 discrete specialist services and hardware categories for which, traditionally, operators used to place separate contracts (see **Table 1**). But according to the study, 'with the introduction of operator cost-saving schemes and initiatives such as the Crine Network, many of the larger equipment suppliers and service providers are now involved in integrated service contracts where a complete package of downhole equipment and services is provided by the one contractor, and other services are sub-contracted through the main service provider'.

Chevron, for example, currently has a project underway to streamline the current 12 separate contracts with six subsidiaries of Baker Hughes into one incentivised alliance contract for the Alba field. These are: Hughes Christensen – drill bits; INTEX – drilling technology; Baker Oil Tools – completion and workover technology; Baker Petrolite – oilfield chemicals; Centrilift – electric submersible pumps; Baker Process – production services. This is part of the ongoing Alba operating cost reduction project, aimed at savings of £3mn/y on operating costs.

The study shows that by the end of last year, the offshore drilling and completion services market in the northwest European continental shelf (NWECS) region was £1bn to £1.1bn per year, of which offshore drilling services (excluding drilling contractors) was £700mn, the completions market accounting for £300mn to £400mn of expenditure. It concludes: 'The NWECS market for downhole equipment and services is expected to continue approximately at this level for the next two years or so. Longer term, the market will inevitably be influenced by macroeconomic forces, such as oil price and reserves depletion. Nonetheless, the downhole equipment and services sector, with its close association with existing as well as new wells, and its continued scope for technical advance, is likely to fare better than many other sectors of NWECS activity'.

During the first three quarters of 1998, Arthur Andersen Petroleum Services reports that 58 exploration and appraisal (E/A) wells were spudded in the UKCS (one less than last year) and 41 in Norway, Denmark, the Netherlands and Ireland. Smith Rea points out that the number of E/A wells in the NWECS region will decrease in 1998 and 1999 due to low oil prices and the long period of uncertainty over the UK tax regime.

'However,' it continues, 'development drilling in the region is less immediately affected in the short-term by these factors. Its level will continue to rise on 1998 and probably in 1999 as field development commitments and long-term drilling contracts are fixed to at least mid-1999. Nonetheless, with continuing low oil prices, development drilling activity in the region may decrease after late 1999/2000.'

Leading the field

The Crine Network is a leader in attacking the problem of costs. The average cost of extracting a barrel of oil from the North Sea is $12 (excluding royalties and tax). This includes the cost of exploration, development, operations and support. Crine Network aims to reduce the cost of a North Sea barrel of oil to $10 by 2000 and to $8 by 2002.

One of the central elements of its plan is focusing on major areas of expenditure, such as well engineering.

There are, in fact, two routes to cutting well costs – human and technological. It is becoming increasingly clear to many in the industry that the planning of wells, in particular exploration wells, has not been well organised in the past. Too many dry holes have been drilled because of the lack of integration between geologists, geophysicists, drillers, well engineers and others.

There has almost been a situation in which the reasons why a well was being drilled have become obscured. At the same time, costs were incurred because the geologists wanted wells drilled to gather data and to be drilled as a potential producer. These facets are being tackled by the Crine Network and will, without doubt, lead to cheaper wells and less dry holes.

The other route is technology. Great strides have been taken, for example, through the use of coiled tubing (see *Petroleum Review*, June 1998). The Smith Rea study points out that: 'Besides circumventing the time-consuming procedure of making and breaking the string while tripping, coiled tubing implies a slimmer hole, which is already recognised as a way of saving costs by reducing the material removed from the hole and the weight of the tubulars needed. Coiled tubing also lends itself to underbalanced drilling, in which the pressure in the well is controlled by a seal at the blowout preventer (BOP) rather than by mud weight. This offers both cost savings and advantages within the hole and reservoir'.

Underbalanced drilling has been used onshore worldwide for many years, but is only now starting to emerge offshore (see *Petroleum Review*, September 1998). This year Smedvig and Santa Fe completed a second well incorporating underbalanced drilling technology in the southern North Sea for Shell.

Shell's NeuRobot Project is an example of new downhole equipment which is designed to assist coiled tubing operations. As part of this project Shell is designing a coiled tube drilling system with an advanced geosteering capability and a drilling tractor capable of exerting 11 tonnes backwards or forwards in a horizontal hole, and combining this with spooled casing.

'By 2001', says Smith Rea, 'it is envisaged that expendable casing can be deployed, replacing the conventional telescopic casing design with a single casing expanded up to 25% in the hole'.

There continues to be, the study says, a spearhead of companies with active research and development programmes which are developing new designs based on existing equipment types. Many of these are tested and then deployed in the NWECS region, which has become a primary region for testing new designs and services for the oil and gas industry.

In October, the CMPT awarded ten research and development Pathfinder Fund grants worth £400,000 to seven universities and three UK companies to work on oil and gas related projects, aimed specifically towards cost reduction or efficiency. The areas include drilling, downhole sensors and downhole measurement. The Pathfinder Programme is supported by 18 oil companies as well as a number of service companies and the DTI.

* Downhole Equipment & Services. Offshore Business Special. *Report No 6. Smith Rea Energy Analysts, Hunstead House, Nickle, Chartham, Canterbury, Kent CT4 7PL. Price: £600.*

Climate change debate at the IP

Anyone reading a newspaper, or listening to the radio, or watching the television, could be forgiven for believing that climate change in the form of global warming was an established and incontrovertible scientific fact and that rising levels of carbon dioxide (CO_2) were the cause. However, this is very far from the truth as neither climate change nor the link with carbon dioxide is proven in any testable or verifiable way. The very stridency with which the proponents and opponents pursue their arguments is testimony to how ambiguous the data and the science actually are.

For the world's oil and gas industry the issue is urgent and topical. At Kyoto specific targets for the reduction of CO_2 emissions were set and the implementation of these targets will have a direct impact on the industry and its clients. On 14 December 1998 the Institute of Petroleum is organising a debate entitled 'Global Warming: Hot Air or Cool Appraisal?'. The motion is that: 'This house believes that cost effective precautionary measures should be taken, starting now, to address the climate change risk, with the Kyoto Protocol providing a sensible next step in the process'. The motion will be proposed by Michael Jefferson, Director of Studies and Policy Development, The World Energy Council, and opposed by William O'Keefe, Senior Vice-President of the American Petroleum Institute. (see P54)

The debate is particularly timely in the light of the fact that last year's El Nino – a well established climate phenomenon, albeit a very severe one – produced a series of headline grabbing catastrophe reports. These appear to have confirmed the general public's view that climate change is an established phenomenon largely caused by the burning of fossil fuels. There seems to be only limited appreciation of the fact that last year's forest fires in Indonesia, Central America and the Russian Far East produced more CO_2 than all the fossil fuels burnt in the last year or more. It should also be noted that there is an almost wilful confusion between three separate phenomena. The first is low level urban pollution in the metropolitan centres where transport fuels are undoubtedly the main cause. The second is the 'ozone hole' said to be primarily caused by the fluorocarbons used in refrigerators and aerosols. Chlorine, bromine and solid fuel rockets have also been associated with the phenomenon but any link with high-flying aircraft and jet fuel has not been established. The third is climate change, which refers to the possibility that temperature, and other climate parameters may be moving outside historic ranges, begging the question as to what is 'normal'.

There are two primary theories to explain the apparent increase in average temperatures normally referred to as climate change. The best known associates the changes with carbon dioxide levels ,the other correlates the changes with sun spots and other phenomena varying the incident energy reaching the earth. It should be noted however, that the actual temperature record, which is normally related to the average of the 1961 to 1990 period, is ambiguous. In the period 1860-1910 temperatures were between 0.3 and 0.4°C below the average. Temperatures then rose steadily from 1910 to 1940, to a point nearly 0.1 degrees C above the average. They then fell back to 0.1°C below the average from 1945 to 1980 and then climbed steadily to their present position 0.3°C above the average. In contrast CO_2 levels, which were at 280 ppm before the industrial revolution, rose steadily and progressively to reach their current levels of around 360 ppm. The mechanism by which CO_2 is said to elevate temperature is that it absorbs and re-emits some of the incoming infrared radiation from the sun. Complex negative feedbacks are required to get the predicted to fit the observed. It promises to be a lively and informative debate.

Gas rich but oil poor as regional development focus changes

The second part of our Asia-Pacific survey features Indonesia and Australia. In both countries enormous discovered gas reserves await development while only minimal quantities of oil have been identified for exploitation. As a result, Australian oil imports are set to increase while Indonesian oil exports will decline. Both countries have high hopes for expanded LNG exports to Japan/Korea. Hopes somewhat undermined by the current low oil and gas prices coupled with depressed demand.

Australia

Over two-thirds of Australia's primary energy consumption is met by coal and oil. Of the 102mn toe consumed in 1997, approximately 45.6% of demand was met by coal, 35.9% by oil, 17.2% by gas and 1.3% by hydroelectricity. The country is totally self-sufficient in coal, producing more than twice its annual requirements. Reserves are put at 90,940mn tonnes. Australian oil production, however, covers just 82% of the country's needs. With an oil R/P ratio of only eight years, crude oil imports look set to continue to rise.

Australia is a major gas exporter, exporting some 35% of its production in the form of LNG. In 1997 it produced 30bn cm of gas and consumed 19.6bn cm. Gas reserves are estimated at 990bn cm, half of which lie in the Canarvon Basin on the NW Shelf. These reserves will underpin a planned doubling of Australian LNG exports, mainly to Asian markets, which are forecast to rise to 15mn t/y by 2005.

According to analysts at Wood Mackenzie, the Canarvon Basin continues to dominate drilling activity and is the country's premier producer of both oil and gas (having usurped the Bass Strait Basin in 1996). The region produced around 280,000 b/d in 1997 (up 5,000 b/d from the previous year), almost 50% of Australia's total oil/condensate production for the year. The Browse/Bonaparte Basins in Northern Australia are also reported to be attracting considerable exploration interest.

The Australian Petroleum Production & Exploration Association (APPEA) reports that the Canarvon Basin will account for approximately 50% of Australia's total offshore exploration expenditure in 1998, and between 36% and 60% of offshore development investment. Total exploration expenditure in 1998 is forecast to increase by 51% to between $1.2bn and $1.6bn. Expenditure on development activity is predicted to reach between $1.4bn and $1.7bn.

Key offshore discoveries in 1997 included the Reindeer gas field, the Woollybutt and Cornea oil finds, the Tenacious oil and gas discovery and the Keast gas/condensate find.

Full field production from the 72mn barrel, $480mn-Wandoo field commenced in March 1997, followed by the Bass Strait fields Moonfish and West Tuna in July and August 1997 respectively. The marginal Agincourt oil discovery in the Harriet area was also placed onstream that year with the Stag field entering production in early 1998.

Onshore Australia also saw a number of significant finds, including success for Santos in the Barrolka Complex in Queensland and Pennzoil's discovery in the Whicher Range in the Perth Basin, Western Australia. Santos puts proven and probable reserves for the entire Barrolka area at 650 PJ, while the Whicher Range field is thought to have the potential to contain over 1tn cf of gas.

A total of 25 offshore exploration, retention and production licences were awarded in Federal waters in 1997, more than double the number awarded the previous year. The Carnarvon and Browse Basins dominated the awards, with Mobil, Woodside and Shell among the winning bids, while six awards were made in the Timor Sea, highlighting renewed interest in the prospectivity of the area. A number of new players entered the Timor Sea arena, including US independent Coastal Oil & Gas which was awarded operatorship of two permits.

As already indicated, oil/condensate production from the Carnarvon Basin reached 280,000 b/d in 1997, a 2% increase year on year. Part of the rise in output was driven by significant increases from the NW Shelf and the onset of full production from the

Country/Field	Operator	Oil or Gas output	Start-up date	Oil reserves (mn barrels)	Gas reserves (bn cf)	Capex ($mn)	Production system	Peak oil/*gas* Prodn
INDONESIA								
BD (Madura)	Mobil	gas	2002+	20	437	310	platform	
Bentu	Santos	gas	end 1999				near Asamera-Duri pipeline	
Block A, N Sumatra	Gulf Canada (Asamera)	gas	2001		585		supplies to Arun LNG	*200mn cf/d*
Corridor blk gas dev*	Gulf Canada (Asamera)	gas	1998		1,600	522	onshore for Duri steamflood	*300mn cf/d*
Natuna	Exxon	gas	2010+				16 platforms	*15mn t/y LNG*
NSO 'A' field	Mobil, in Malacca Strait	gas	1999		1,400	500	Nnm platform	*450mn cf/d*
Nelayan (Kakap blk)	Gulf (ex Clyde)		end 1998					
Nubi	Total	gas	2001	50	800	200	platform	
Pase A*	Mobil	gas	1998		120	53	onshore	
Peciko	Total	gas	end 2001	100	5,600	1,250	two platforms	
Singa, in S Sumatra	Energy Equity Corp	gas	2000+		500-1,000			
Sirasun/Terang	Arco, in Java Sea	gas	2000+		1,100	500	subsea via Pagerungun	*250mn cf/d*
Sisi	Total	oil/gas	2001+	50	800	200	subsea, platform	
S'th Lho Sukon A&D	Mobil	gas	1998/99		790		gas supply to Arun LNG	
Tangguh	Arco	gas	2005+	50	18,400	1,750	onshore, platform	
Natuna West	Conoco/Premier/Gulf Canada	gas	mid-2000		2,500	1,100	platform, pipe to Singapore	
Wunut* Lapindo		gas	1998		105	30	onshore	
Sub total				**270**	**34,737**	**6,415**		
Papua New Guinea								
Gobe and SE Gobe	Chevron	oil	mid-98	95			link to Kutubu pipeline	**50 kb/d**
Sub total				**95**				
ZONE OF COOPERATION								
Bayu-Undan	BHP/Phillips	cond	2002	404		1,620	platform	**110 kb/d**
Bayu-Undan (LNG)	BHP/Phillips	gas	evaluation		3,400			*2-3mn t/y LNG*
Elang/Kakatua*	BHP	oil	Jul-98	29		105	floater	**32 kb/d**
Sub total				**433**	**3,400**	**1,725**		
AUSTRALIA								
Agincourt*	Apache	oil	Sep-97					**6.5 kb/d**
Angel	Woodside	gas/cond	2000+					
Bambra	Apache	gas					wellhead plat to Harriet	
Blackback, Bass St	Esso Australia	oil	end-99	7.5		30	subsea to Mackerel platform	**18kb/d** *24mncf/d*
Brecknock	Woodside	oil/cond	2003?				possible LNG development	
Chrysaor*	Wapet	gas	2002*	40	2,600	150	*part of A$10 bn project	
Dionysus*	Chevron/Texaco	gas	2010		2,400			
East Spar*	Apache	gas/oil	Nov-96	28	441		subsea to Varanus Is	**40mn cf/d** *3 kb/d*
Echo/Yodel/Dockrell	Woodside	cond	2002+					
Evans Shoal	Shell Australia	gas	Jun-09		5,000			
Gorgon*	Wapet	gas	2002*	14 oil,50 cond	6,600		poss 6mn t/y LNG plant	
Lambert-Hermes	Woodside Petroleum	oil	97,2000?				Tieback to Cossack FPSO	
Legendre	Woodside Petroleum	oil	2001		25			
Loxton Shoal/Sr/Trb	Woodside Petroleum	gas	2005?		5,000		Darwin LNG, 7.5mn t/y?	
Macedon/Pyrenees	BHP	gas/oil	2001	11	580	A$300mn	platform	
Manta/Baskar (Bass St.)	Shell Australia	oil?	2000/01				FPSO and subsea	
Minerva (off Victoria)	BHP	gas	under eval				subsea or monotower	
Nappermeri trough	low perm gas Queensland		end 2003					
Perseus*	Woodside	gas/cond	1999		11,500		North Rankin + subsea	
Ramillies		oil	2000					
Reindeer	Apache	gas	2001		600			
Scarborough	Esso Australia/BHP	gas			7,978	420mn	proposed LNG ?	
Scott Reef/Brederoc	Woodside	gas/cond		306	20,000			
Spar	Chevr/texaco/ampol/shell*	gas	2002*					
Stag*	Apache	oil	early 1998	35-55			fixed plat 50,000b/d cap	**22 Kb/d**
Tern/Petrel Bonap'te Glf	Santos	gas	2005		3000	160	platform or FPS	
West Tyral Rocks*	Wapet	gas	2010	19 oil,21 cond	1,600			
Wonnich	Apache	gas/oil	mid-99				Nnm platf to Varanus Island	
Woollybutt	Hardy	oil		25		platform		
Yolla	Boral Energy	oil/gas/cond	2000+	300	600		platform	
**Greater Gorgon field development, subsea drill centres to be installed as required to service onshore LNG plant with two 2.3mn t trains*								
Sub total				**856.5**	**67,924**	**1,060**		
TIMOR GAP								
Buffalo	BHP		Q1999	11 kb/d test	25mn b oil?			
Laminaria/Carollina	Woodside	oil	3Q1999	253		A$1.35bn	170 kb/d FPSO,6 subsea	**135 kb/d**
Laminaria East	BHP	oil		11 kb/d test			close to Buffalo field	
Sub total				**253**		**1,200 mn**		
NEW ZEALAND								
Kupe South	Fletcher Challenge	gas/oil	2004		286	250	platform	*80mn cf/d*
Mangahewa	Fletcher Challenge	gas	1997 (EPS)		1000	213		*200mn cf/d*
Sub total					**1,286**	**463**		
Grand Total				**1,907.5**	**107,347**	**10,863**		

Source: Wood Mackenzie, South East Asia and Australasia Upstream Reports, Australian Petroleum Production & Exploration Association (APPEA)

Table 1: Current and planned field developments in Australasia and Indonesia

Wandoo oil field. However, this was partly offset by a marked dip in output from the Griffin field which had experienced problems with its FPSO. Production from the Bass Strait returned to a level in excess of 200,000 b/d due to the Bream B and West Tuna developments coming onstream.

Output from the Timor Sea was down 33% to 15,000 b/d of oil in 1997, reflecting the continued decline of the existing Jabiru, Challis and Skua fields. At present this region contributes just 3% of total Australian liquids production. However, this is set to turn around with the start-up of the Laminaria/Corallina and Buffalo fields in 1999. The Laminaria/Corallina development, currently the deepest water project in Australia, will be developed via subsea tie-backs to a purpose-built FPSO (claimed to be the largest of its kind in the world). Five wells are planned for Laminaria and two on Corallina. An additional gas disposal well is also required. Output is not expected to exceed 150,000 b/d, although the FPSO has a design capacity of 170,000 b/d.

The huge number of fields in the Cooper/Eromanga Basins continue to underpin onshore oil/condensate production. The area produced 33,000 b/d in 1997, marginally down from 34,000 b/d in 1996. According to APPEA, this region is expected to account for 59% of onshore exploration expenditure in 1998 and around 80% of onshore development expenditure.

Output from the country's major onshore gas producing region – the Cooper Area in South Australia – increased by 8% in 1997 to 540mn cf/d.

According to Wood Mackenzie, the instability of the financial markets in the Asia-Pacific region, coupled with increasing levels of gas-to-gas competition had led to much uncertainty for Australia's bigger gas projects which are vying to supply LNG. It is possible, for example, that the NW Shelf expansion and Gorgon development programmes may suffer some degree of setback.

The NW Shelf LNG expansion project orginally envisaged the addition of two trains at the Dampier facility, doubling capacity to 14 mn t/y. However, more recently, the NW Shelf joint venture has resigned itself to the addition of just one train. The 6tn cf Perseus gas reserves are the cornerstone of the NW Shelf project.

Speaking at the Gasex '98 conference in Seoul in September 1998, Gorgon Australian LNG General Manager Dr Jim Briggs stated that the Gorgon project will be one of the lowest cost greenfield plants in the world. He reported that the company had managed to shave A$1bn from its original upstream cost estimates by adopting innovative technology and the use of a modular approach to install subsea drill centres one at a time as required. This, he claimed, improved the project's economics by distributing the level of investment over the life of the project. The use of two liquefaction trains, said to be of the largest and most modern design in the world and each having a capacity of 4.3mn/y, were reported to have allowed the downstream team to take about 20% off the unit cost per tonne of Gorgon LNG.

New Zealand

Exploration activity in New Zealand fell to an all-time low in 1997, due primarily to difficulties in securing both onshore and offshore drilling rigs and the paucity of appraisal work states Wood Mackenzie. Despite the reduction in activity, the analysts recorded an anomalously high wildcat commercial success rate of 75%, including a large gas find at Mangahewa which was immediately put on long-term test delivering gas to the Methanex plant in the Taranaki Basin. It is anticipated that the Mangahewa field could hold as much as 1tn cf of gas reserves, making it the second largest gas find in the country.

Liquids production increased significantly in 1997 following the commissioning of the Maui B field in September 1996 which pushed production up by 26% to 60,000 b/d by the end of 1997.

According to Wood Mackenzie, some of the exploration focus is beginning to shift from the more mature Taranaki Basin to the relatively underexplored East Coast Basin, following recent gas discoveries.

The New Zealand Government effectively opened up the whole of the country for exploration on a first come-first served basis in 1996 in a bid to address the problem of its ageing oil and gas fields.

Liquids output reached 60,000 b/d in 1997, up 35% year on year, primarily due to the first full year of production from the Maui B field. Production from the Waihapa/Ngaere oil field stabilised in 1997 at 2,500 b/d, while output from McKee fell by 2% to 5,400 b/d. More promising, however, was a 30% increase in production from Ngatoro following the success of the previous year's appraisal drilling programme.

Gas production from the Maui field increased from 412mn cf/d in 1996 to 436mn cf/d in 1997. Fletcher Challenge's Ahuroa and Tariki fields also contributed to total 1997 gas sales of 578mn cf/d after their first full year of production.

Zone of Cooperation

Drilling activity continues at the plateau level recorded in recent years, with only six wells sunk in 1997. Only one discovery was made that year – the gas/condensate Sunset-1 find made by Shell.

The ZOCA Joint Authority approved the A$42mn development plan for the Kakatua North oil field, part of the Elang/Kakatua project in the Timor Gap, in November 1997. First production of around 30,000 b/d is expected in December 1998.

The other major project in this region is the Bayu-Undan field, incorporating a liquids stripping/gas recycling project. First liquids are expected at the end of 2001 with production peaking at 85,000 b/d in 2002. It is anticipated that the bulk of gas production/injection and gas processing would be performed on a fixed steel process platform located towards the centre of the field with a wellhead platform providing limited gas production/injection in a more remote part of the field.

Wood Mackenzie explains that the liquids stripping initiative would provide an early cash flow for the entire Bayu/Undan project while lengthy issues such as LNG marketing and plant design are resolved.

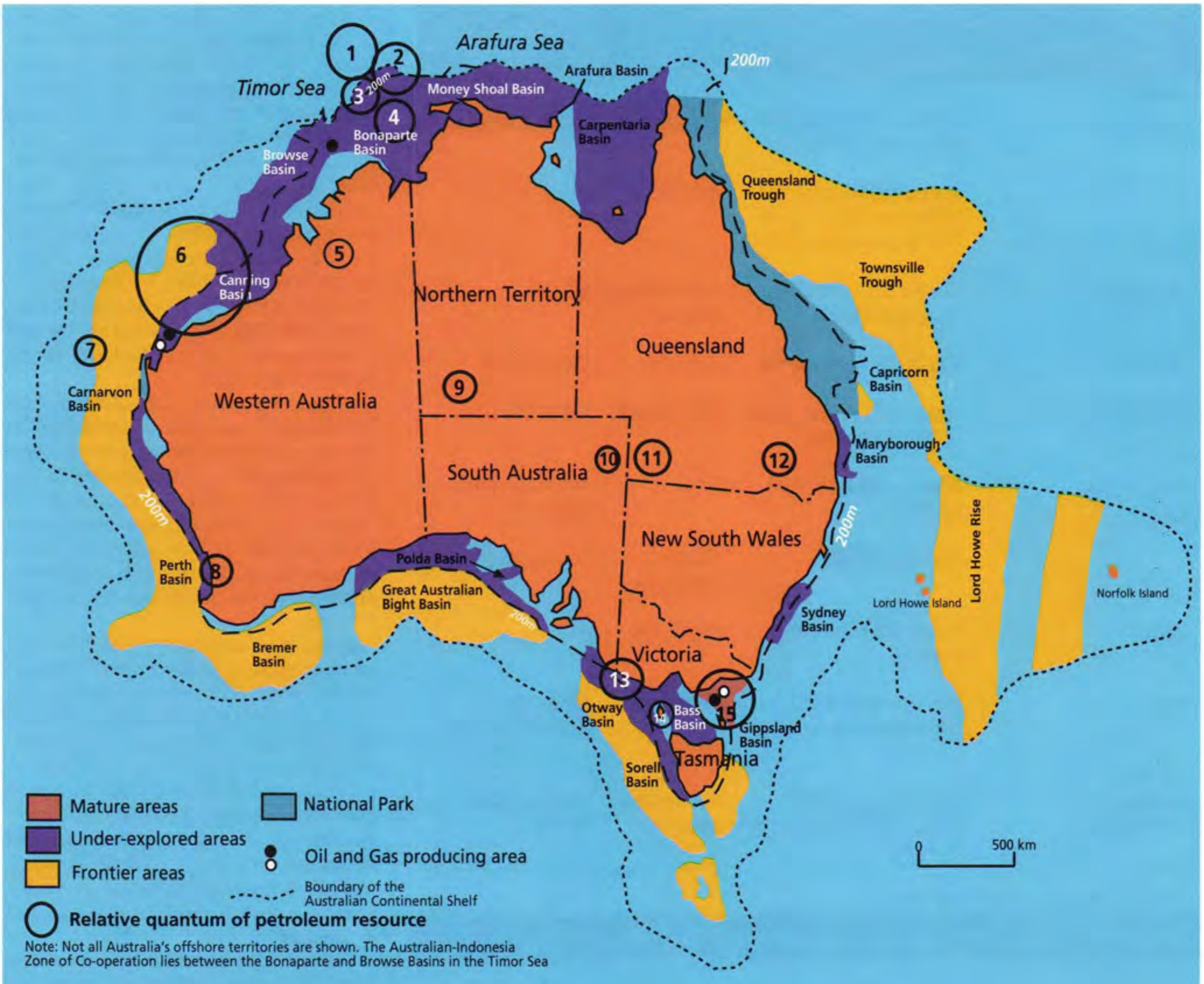
In May 1997, Woodside and Shell proposed a combined Bonaparte Gulf and Zone of Cooperation LNG scheme, comprising a 7.5mn t/y LNG facility in Darwin with an anticipated 2005 start-up date. The scheme would be underpinned by the 5tn cf of gas reserves in Shell's Sunrise and Troubadour fields. Additional reserves from the region would be called upon to fulfil long-term LNG contracts.

Papua New Guinea

According to Wood Mackenzie, drilling activity in PNG improved marginally on 1996 levels with all indications pointing to continued improvement over the next few years.

Oil/condensate production fell by 28% from 105,000 b/d in 1996 to 76,000 b/d in 1997. Development drilling on the country's sole producing oil field – Kutubu – is reported to have temporarily arrested the previous year's decline in output. Kutubu field production peaked at over 67,000 b/d of oil in July 1997.

The Moran exploration trend was successfully appraised in 1997 and an extended well test performed in 1998.



Area 1 – Laminaria/Corallina; **Area 2** – Sunset, Sunrise/Troubador, Elang/Kakatua, Bayu-Undan; **Area 3** – Tenacious, Buffalo; Area 4 – Petrel/Tern; **Area 5** – Sundown, Blina; **Area 6** – Angel, Bambra, Barrow Island, Cossack, Crest, Docknell, Echo/Yodel, Gorgon/Chrysaor, Griffin/Chinook/Scindian, Keast, Lambert, Legendre, Macedon, Maitland, Perseus, Pyrenees, Reindeer, Searipple, Saladin, Stag, Wilcox, Wonnich; **Area 7** – Scarborough; **Area 8** – Momdarra; **Area 9** – Mereenie, Palm Valley; **Area 10** – Moomba Area; **Area 11** – Jackson Area, SWQ Gas Plant, Tintaburra Area; **Area 12** – Roma/Surat; **Area 13** – La Bella, Minerva, Port Campbell Gas Project; **Area 14** – Yolla; **Area 15** – Blackback/Terakihi, Turrum.

The onshore Gobe oil field came onstream in 1998. Combined recoverable reserves of the Gobe Main and SE Gobe fields are put at 116mn barrels. The development plan comprises three producing wells and one gas reinjection well on Gobe Main and five producers, one gas reinjection well and one water reinjection well on SE Gobe. Processing will be handled by a central, shared facility with the oil transported via a 15-km spurline to the main Kutubu/Kumul terminal export pipeline.

Chevron is leading a project aiming to export PNG gas to Queensland, Australia. Plans involve a pipeline system to carry approximately 3tn cf of Chevron gas reserves from the PNG Highlands to the Gulf of Papua.The gas would be exported via a 300-km subsea pipeline to Cape York and a 990-km overland pipeline to Townsville in north Queensland.

Indonesia

As **Table 1** shows, Indonesian E&P activity is dominated by gas development. The country is the world's largest marketer of LNG with a 50% market share in the Asia-Pacific region. Indonesia has 2.05tn cm of gas reserves. It produced 69bn cm of gas in 1997, of which it only consumed 32.8bn cm. With an R/P ratio of 29.7 years, the country is well-placed to expand production even further.

Despite the collapse of the Indonesian Rupiah and the continuing economic crisis, Indonesia saw a record year in terms of licensing activity in 1997 – a total of 28 new contracts signed that year according to Wood Mackenzie.

E&P attention continues to focus on the mature western basins of Sumatra, Java, Kalimantan and the Natuna Sea (85% of acreage under licence in 1997), with Eastern Indonesia (comprising Sulawesi, Irian Jaya and Timor) accounting for a minority of contracts due to the commercial and technical risks associated with the region.

Country/region	Japanese company (% interest)	Area	Licensees (% interest)
1997			
Australia	Nippon Oil Exploration (Dampier) (25%)	WA-191-P	Santos, Ampolex
	Nippon Oil Exploration (Vulcan) (75%); Timor Sea Exploration (25%)	AC/P-23	–
Azerbaijan	Itochu Oil Exploration (Caspian) (20%)	Ashrafi/Dan Ulduzu	NAOC
Egypt	EPEDECO Suez (40%)	Ashrafi	IEOC (60%)
Indonesia	Japex Sabo/Inpex Sabo (70% combined)	Sabo block	Elf, TOTAL
North Sea	Nippon Oil E&P (MF) (4.19%)	Ross	Talisman, Lasmo Clyde, BG
	Summit UK Oil	Galley, Sedgwick	Texaco, Enterprise
Qatar	Qatar Oil Exploration (100%)	Block 1SE	–
Syria	Summit Syria Petroleum Development Co (30%)	Tishreen	Elf (40%), Petronas (30%)
1998			
Indonesia	Inpex Bunyu (50%)	Sebawang 1	TOTAL (50%)
Kazakhstan	Inpex North Caspian Sea (7.14%)	offshore	OKIOC

Source: Information supplied by JNOC

Table 2: E&P projects in which Japanese companies became involved in 1997/98

A total of 23 new fields came onstream in 1997, including four recent discoveries (KRN, KG-5, KR and Nelayan-1) on the Kakap PSC. PT Exspan's Kaji and Semoga fields came onstream in March 1997, reaching 10,000 b/d by year-end. The Energy Equity/Tenneco joint venture brought the 348bn cf Kampung Baru field in Sulawesi onstream in September 1997. The field produces 26mn cf/d which is sold under a 20-year gas sales agreement to a dedicated 135 MW combined cycle power plant operated by a sister joint venture.

Santa Fe's North Geragai field in the Jabung PSC, central Sumatra, also came onstream in 1997. The field is estimated to hold between 25mn and 30mn barrels of oil, with 200 cf of gas. A second discovery, Makmur, containing a further 13mn barrels, is likely to be tied into the North Geragai facilities.

Pertamina-Santa Fe commissioned the Mudi field late 1997. Field reserves are put at up to 65mn barrels and production is expected to average 20,000 b/d by the end of 1998. The first phase of development of Gulf Indonesia's 2tn cf of gas reserves in the Corridor PSC was due onstream mid-1998 with a mid-plateau of 300mn cf/d.

Key future projects include the giant Natuna gas field. Unlikely to be due onstream before 2015 the field has estimated in place reserves of 222tn cf, of which some 46tn cf is believed to be recoverable.

Other significant offshore projects include Arco's 183tn cf Tangguh find located on the Weriagar and Berau blocks – ranked as one of the world's largest natural gas discoveries. Development plans call for LNG production to begin in time for anticipated increases in market demand in 2005+ with the Berau Bay region emerging as a major new gas basin.

Japan

Japan has virtually no indigenous oil and gas resources and is reliant on imports to supply almost all of its energy needs. In 1997 its primary energy consumption stood at 506.3mn toe, accounting for some 21.3% of the Asia-Pacific region's total primary energy demand and 5.95% of world demand. Despite major efforts to reduce the country's dependence on crude oil following the first oil crisis in 1973, some 52.6% of Japan's energy requirement was met by crude oil in 1997. Coal accounted for a further 17.73%, nuclear power 16.47%, natural gas 11.57% and hydroelectricity 1.63%. Japan has continued to diversify its energy balance in recent years, however, with LNG imports increasing and nuclear power generation set to be further expanded.

Japan National Oil Corporation (JNOC) assists Japanese oil companies in various oil and gas exploration and production projects around the world in a bid to help increase the level of Japanese-produced crude imports. In 1997, 690,000 b/d of imported crude was produced by Japanese companies, accounting for 15.2% of total crude imports.

JNOC had assisted a total of 294 companies by end-December 1997, at which time 132 of the companies were still actively involved in the oil and gas sector. Of these 132 companies, 50 were producing, or about to produce, crude oil and natural gas in over 30 countries while 82 were conducting oil and gas exploration and development work. **Table 2** summarises those E&P projects in which Japanese companies became involved in 1997/98.

Not surprisingly, E&P attention has focused on the Asia-Pacific region to date with 33.3% of JNOC-assisted companies (44) working on projects located in this region in December 1997. A further 16.7% (22) of companies were working on projects in Oceania and 12.1% (16) in the Middle East. JNOC was also involved in 14 projects in North and South America, 13 in Europe, nine in China, nine in Africa and five in the FSU.

JNOC also recently announced plans to build what will be the Japanese government's first LPG stockpiling facility at Nanao City, in the Sea of Japan coastal prefecture of Ishikawa. The new site will help the country meet plans to stockpile 1.5mn tonnes of LPG by 2010 to ensure stable supply. LPG imports currently account for nearly 80% of Japan's consumption, the bulk of supplies sourced from the Middle East. Concern has grown in recent years, however, regarding the stability of supplies in the face of political and social disputes. JNOC is to establish a joint company with the private sector to manage the Nanao City stockpiling project which is due to be commissioned in 2003.

Featuring three major international conferences and seminars

Monday 15 February

International Conference on **Financing the International Oil Industry – The Challenge of Major Projects**

The reduction in the crude oil price and financial uncertainties in Asian and other emerging markets have added new dimensions to the challenge faced by the oil industry and its bankers. This major international Conference will concentrate on the important issue of financing major projects, particularly those in areas of economic transition.

Speakers include: **Stephen Hodge** (Group Treasurer, Royal Dutch/Shell Group), **Philip Lambert** (Director, Global Head of Oil and Gas, Dresdner Kleinwort Benson), **Kenichi Nakazato** (General Manager, The Bank of Tokyo-Mitsubishi, Ltd), **James Polin** (Manager, OPIC), **Gunther Vowinckel** (Deputy Director, EBRD) and **Peter Rigby** (Head, Energy Group, Standard and Poor's).

Who should attend?

- Senior Management in the Oil and Services Industries
- Finance Directors, Bankers and Professional Advisers
- Policy Makers, Planners and Commentators.

Wednesday 17 February

The 12th Oil Price Seminar and Exhibition on **Crude Oil Pricing in Deregulated Markets in Asia**

Supported by New York Mercantile Exchange

Notwithstanding the Asian and Russian economic difficulties, crude oil continues to flow to the Asia-Pacific region from the Middle East, the Atlantic Basin and from the former Soviet Union westward to Europe and North America. The Asian and the FSU oil markets are gradually being deregulated with the result that prices are being set not by governments, but by the market.

This Seminar will review the latest fundamental supply/demand balances, the effects of deregulation, particularly in Asia, and will then focus on the changing way crude is priced east of Suez and in the FSU.

Who should attend?

- Risk Managers
- Analysts
- Information Providers and Forecasters.

Exhibition

An Exhibition by suppliers of prices and other information for the oil industry will be held in association with the Seminar. Further information on stand availability and sponsorship opportunities is available from the IP conference department.

Thursday 18 February

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Scottish survey reveals all

The *1998 UK Retail Marketing Survey (RMS)* published in March attracted considerable interest and comment as it reported a notable increase in the number of operating service stations. The additional numbers over and above those reported in previous years resulted from exchange of information with the service station monitoring company Catalist. This identified a number of operating sites which had not replied to the *RMS* questionnaire. Catalist has just completed a detailed survey of Scottish service stations. Managing Director *Nigel Lang* reports on the survey's findings.

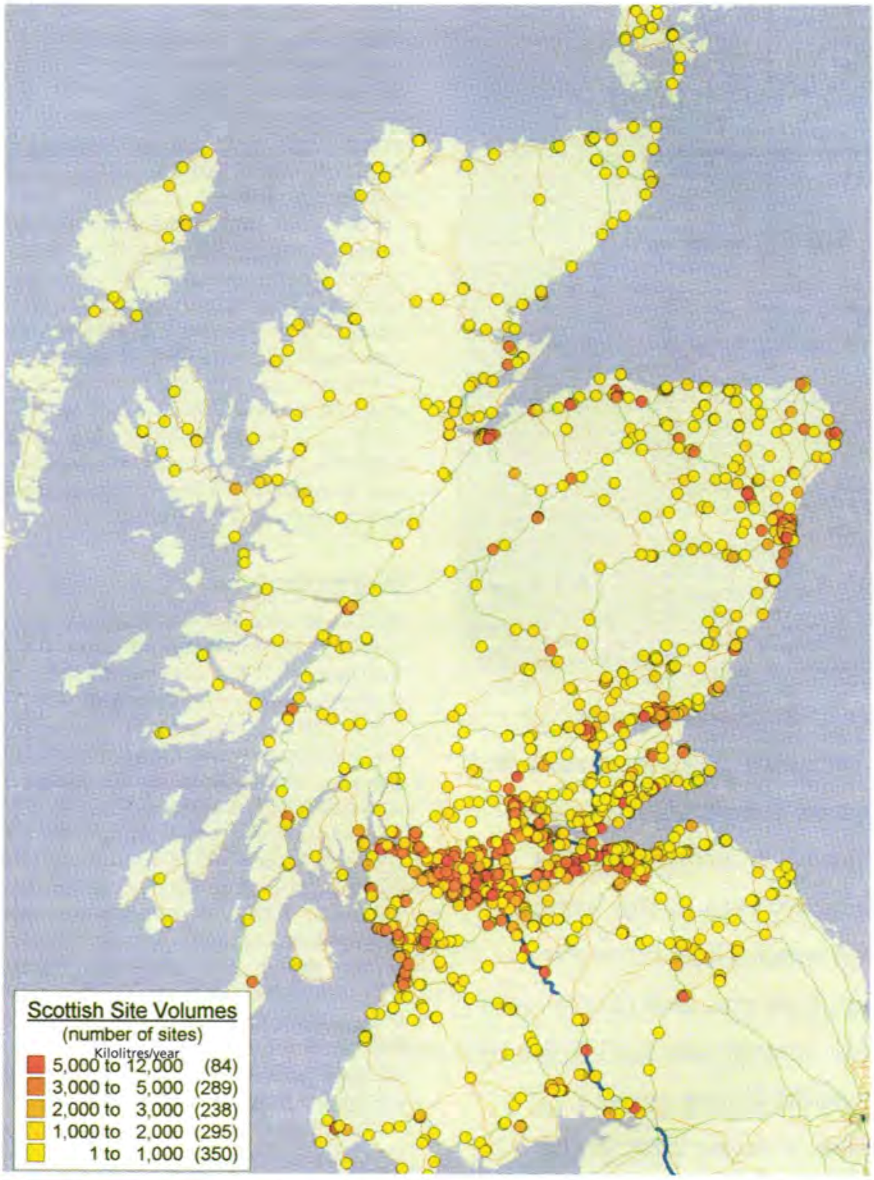
No statistics are perfect in such a dynamic market but the figures quoted here refer to sites in Scotland known to be retailing motor fuel during the period May to July 1998. As expected, the number of sites is on the decline.

Our survey shows that there are now 1,288 open sites in Scotland compared to 1,358 outlets for a similar period last year. This reduction of 77 service stations comes from 93 outlets that closed and 16 that re-opened or were new industry sites in the period. The 93 closed sites had fuel sales totalling about 110mn litres. The re-opened and new sites sell about 27mn litres of fuel between them. Overall, we estimate that average site volumes have grown between 6% and 7% from 1.84mn l/y to 2.065mn l/y. This is due partly to the lower number of sites and partly due to an increase in the total volume of our retail sales estimates from 2.5bn litres to 2.66bn litres.

Brands

The brand shown on the pole sign changed at over 12% (155 sites) in the last two years, although there was relative stability among the major brands. Many of the brand changes are accounted for by Gulf to Shell, Shell to Gleaner, BP to National, Burmah to Save and previously branded sites becoming unbranded (see **Tables 1 and 2**). We conclude that most of the activity is at the 'authorised distributor' end of the market with less movement of major brand supplied dealer sites.

The survey identified that 6% of sites were new developments or major rebuilds in the last three years and these represent nearly 12% of the volume for the whole of Scotland. These modern sites are dominated by the major brands



Brand	Sites	Average volume	Volume share (%)	Outlet share (%)	Market effectiveness*
Shell	262	2,516	24.7	20.5	1.2
Esso	244	2,242	20.5	19.1	1.1
BP	263	1,953	19.3	20.5	0.9
Safeway	29	5,166	5.6	2.3	2.4
Texaco	69	2,113	5.5	5.4	1.0
Jet	64	2,206	5.3	5.0	1.1
Asda	18	5,556	3.8	1.4	2.7
Tesco	14	5,179	2.7	1.1	2.5
J Sainsbury	10	6,395	2.4	0.8	3.0

Table 1: 1998 Scotland site numbers and volume estimates

Brand	Sites	Average volume	Volume share (%)	Outlet share (%)	Market effectiveness*
Shell	298	1,985	24.00	23.10	1.04
Esso	239	1,967	19.10	18.50	1.03
BP	279	1,646	18.60	21.60	0.86
Safeway	25	6,400	6.50	1.90	3.42
Texaco	68	2,123	5.90	5.30	1.11
Jet	70	1,894	5.40	5.40	1.00
Asda	18	6,028	4.40	1.40	3.14
J Sainsbury	10	7,645	3.10	0.80	3.88
Tesco	14	4,750	2.70	1.10	2.45

** Market effectiveness – marketshare divided by outlet share*

Table 2: 1997 Scotland site numbers and volume estimates

and hypermarkets, with 48 being undertaken by Shell, Esso or BP, a further 23 by the hypermarket chains, leaving only seven developments by other brands.

Highlands and Islands

The differences between the urban and rural site are nowhere more marked than in Scotland. For the whole region dealer sites have an average volume of 1.35mn litres, company sites 3.1mn litres and hypermarket sites 5.42mn litres. In the whole of the Highlands & Islands there are only 17 company sites with an average volume of 2.05mn litres compared with the 147 dealer sites selling an average volume of under 900,000 litres.

The two hypermarkets in the area have an average volume of 6mn litres giving them a volume share of 7% from only 1% outlet share. When visiting a number of sites we were told that the dealers bought fuel for their own cars from the hypermarket as far as 20 miles away because it was cheaper than buying it from their own tanks! It is therefore surprising that only one site closed in the Highlands & Islands in the two-year period between our two surveys. In fact, one previously closed site re-opened in the period and as a result the number of operating sites remains unchanged.

We can only speculate as to whether any of these sites make any money from selling fuel – but there is no doubt that they provide a valuable service to the community. On more than one occasion our own surveyors nearly ran out of fuel having underestimated the great distances between sites. If we can run into trouble knowing where the sites are, then how much worse will it be in the tourist season if more sites start to close?

Main photo: Esso's best location? Scenically at least; Far left: No major competition but poor demographic support; Left: 'Spot the pump competition!' – hotel pumps are a lifeline for tourists; Above: A genuinely abandoned forecourt.

Innovative technology for East Spar

The Carnarvon Basin off Western Australia is believed to have great potential with some industry experts considering the region to be at a similar stage of development to the Gulf of Mexico 40 years ago. Innovative technology has played a major role in recent developments in this area, including the use of an unmanned production buoy for development of the marginal East Spar gas and condensate field – claimed to be a 'world first'. It was also said to be the first gas/condensate field in the world to use subsea multiphase meters. *Jeff Crook* takes a closer look at the development of East Spar.

The East Spar field presented an interesting marginal field development challenge: it was not really large enough to justify a production platform and was also rather too far offshore for economic development by conventional subsea systems. The project illustrates how operators are now using innovative approaches to finding production system solutions – achievements recognised by the Sir William Hudson Award for 1997, a top honour for excellence in the field of Australian engineering.

East Spar was discovered in March 1993 and lies in 95 metres of water 63 km off Varanus Island. The island's existing gas processing plant for the Harriet field meant that gas from East Spar could be exported to the mainland through an existing pipeline. East Spar has estimated recoverable reserves of 12.5mn cm of gas and 28mn barrels of gas liquids. First gas was achieved in November 1996 and the field now produces around 60mn cf/d of gas and 3,500 b/d of condensate from two subsea wells.

Fast-track development

A fast-track development was called for as this allowed the field partners to take advantage of a window of opportunity created by deregulation of the gas market in Western Australia. The development project was undertaken by an alliance formed between Western Mining Corporation, as field operator, Kvaerner R J Brown and Clough Engineering. Western Mining sold its interests in the field after the project was completed and Apache, which holds a 45% interest in the field, took over as field operator.

The alliance concept, with its sharing of risk and reward between operator and contractors, is said to have been a factor which promoted the innovative approach. The cooperative environment created by the alliance enabled the conceptual design to be changed three times during the detailed design phase, with each change leading to reduced whole-of-life costs and reduced project risk.

The initial concept of an unmanned tripod platform changed to a slender guyed tower and then an all-subsea solution. This subsea solution, which would have involved a 63-km long umbilical to convey control signals and chemicals to the shore, was then changed in July 1995 to a scheme in which the control signals are transmitted to a Navigation Communication and Control (NCC) buoy moored adjacent to the export manifold.

World first

Apache and its partners claimed a world first with the installation of the production buoy. This feature resulted in a cost saving of $15mn compared with a more conventional development plan. The buoy supports a radio link to allow the subsea production wells to be monitored and controlled, it also supplies chemicals to the subsea production system. The cost saving was achieved through the elimination of a 63-km electro-hydraulic umbilical from the development plan (the umbilical would normally carry the control signals and chemicals). Further cost savings were achieved by the use of subsea multiphase meters. These meters have only recently been developed and allowed a 63-km well test pipeline to be eliminated from the overall plan.

The offshore facilities consist of two production wells, two heat exchangers, subsea manifold, NCC buoy, interconnecting pipework and export pipeline. The output of the wells are cooled by heat exchangers before the product is mixed at the manifold and conveyed by a 14-inch diameter subsea pipeline to the processing facilities on Varanus Island. The heat exchanger reduces the temperature of the well fluid to minimise corrosion rates of the carbon steel subsea pipeline. Each heat exchanger comprises 530 metres of 6-inch duplex stainless steel pipe coated with non-toxic anti-marine growth paint and mounted in a steel frame. The choke valves and control pod for each well are mounted on the heat exchanger.

The complete NCC buoy, with its radio mast, stands around 55 metres high. When floating the main body is submerged to a depth of 25 metres below sea level. The buoy is held in place by a tension leg mooring system with wire ropes connected to four arms extending out from the body of the buoy, rather like a mini TLP. The buoy is connected to the subsea manifold by an electro-hydraulic umbilical.

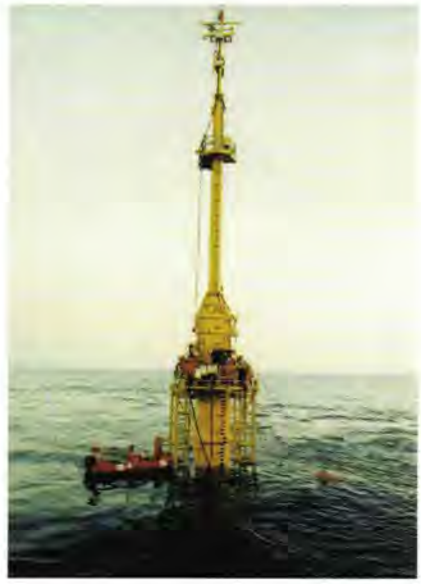
The tension leg mooring system reduces motions of the buoy enabling a directional UHF radio communication link to be continuously established with the shore base. There is a boat landing giving personnel access to five internal levels. The stable working environment provided by the tension leg mooring system also reduces the risk of accidents to personnel and equipment. The buoy's motions are transmitted to the onshore control room enabling safe landing periods to be identified.

The buoy is unmanned except for emergency repairs, routine visits to replenish the chemical and fuel tanks, and maintenance work. The subsea components are designed for diverless intervention.

The UHF radio on the buoy operates over a line of sight to a station on Barrow Island from where another line of sight link transmits signals to the control centre at Varanus Island. There is a back-up satellite communication link. The buoy has electrical generation with a high degree of redundancy and sufficient battery back-up for five days operation. The buoy is also equipped with a hydraulic power unit, fuel and chemical storage tanks and chemical injection equipment.

A paper presented to OTC '98 in Houston in May indicated that East Spar's first year of operation had been judged 'successful overall', although a number of repairs were required during the first half-year of operation, many of which were attributed to component failure during the 'burn-in' period.

The authors commented that, with hindsight, many of the difficulties of the first year's operations could have been avoided by a complete system integration test in the shipyard before deployment of the buoy offshore. This complete test was planned, however timescale constraints meant that some of the tests needed to be performed offshore, rather than in the shipyard.



Subsea multiphase meters

Subsea multiphase meters are mounted on the subsea manifold and allow well testing to take place close to the wellheads, rather than at the shore terminal. The meters thus saved the cost of an extra well test pipeline to the shore, or complicated well test procedures in which wells are shutdown for extended periods.

Well testing involves measuring the oil, gas and water produced by each well for reservoir management purposes. The tests may, for instance, warn of excess water production from part of the reservoir which would lead to a change in production strategy. Well tests are traditionally carried out on the surface by a test separator with individual meters to measure the flow of oil, gas and water.

This traditional arrangement for well testing is costly for multi-well subsea satellite developments because the need to carry the output of individual wells in isolation from the commingled wellstream means that a test pipeline is needed in addition to the main production pipeline. The only alternative is to shut down wells in turn and then deduce the output of each well by a method of deduction. However, this method of well testing leads to long periods of well shutdown as production stabilises, and is a complex procedure to organise.

The use of subsea multiphase meters allows the measurement of oil, gas and water flow to be measured immediately downstream of each Christmas tree and thus eliminates the need for test pipeline or well shutdown. The potential economic benefit has been widely recognised by operators for a decade but the technology has only recently become available. In fact, this was claimed to be one of the first commercial applications of the technology anywhere in the world – a slightly earlier application in Amerada Hess's South Scott field in the North Sea ran into teething problems which took a few months to resolve.

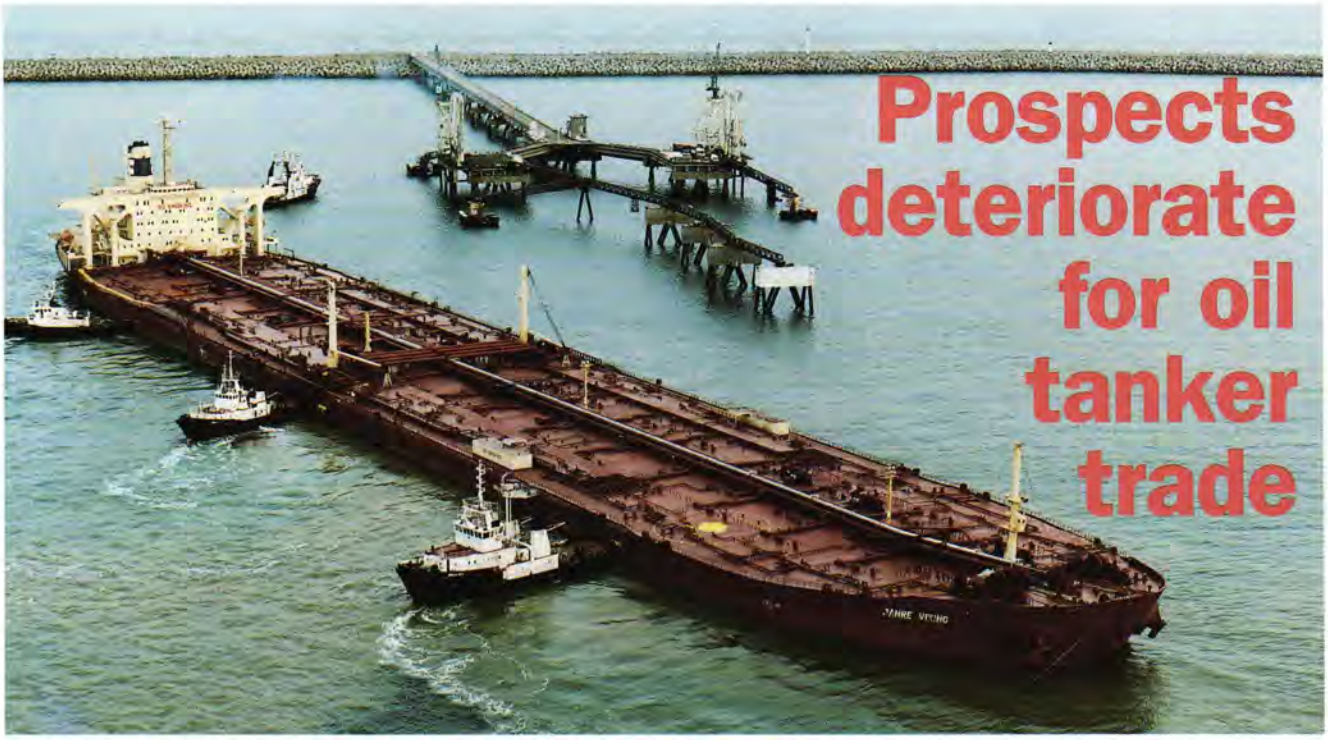
The subsea multiphase meters used for the East Spar project were manufactured by Framo Engineering of Sandsli, Norway. This is one of three companies to have developed this type of meter. The meter is built around a patented flow mixer which provides a stable and homogeneous flow for the measuring section. The measuring section incorporates a venturi meter to measure fluid velocity, and a dual energy gamma fraction meter to measure the oil, water and gas fractions.

The Framo subsea multiphase meter consists of a retrievable insert cartridge carrying all the active elements. The cartridge is locked into a receiver barrel which is permanently installed on the subsea manifold structure. The retrievable insert allows the internal parts of the meter to be pulled to the surface without the need of divers, independent of other components in the production system.

A dedicated flow computer for the two meters is installed in the NCC buoy. The flow computer, which is connected to the host system, can also be directly accessed by the telecom modem. This enables Framo service engineers to access the system from Norway, if assistance is required.

Apache says that to date the usefulness of the multiphase flow meters has been limited due to initially only one well being in production and the subsequent failure of one of the gamma ray detection units on the subsea multi phase meters.

Prospects deteriorate for oil tanker trade



When the oil business sneezes, the tanker market catches a cold. Its fortunes are fundamentally linked not only to the volume of crude oil and products traded around the world, but also to the pattern of trade. The following article highlights recent trends in the crude oil and products shipping sector.

The disruption to the level of world oil demand that has been a feature of this year's oil market has resulted in both a global decline in the demand for tanker capacity and a change in the pattern of tanker movements as sellers have sought out new buyers for their product. Weak oil prices are, similarly, usually bad news for tankers. As the price of oil or products falls, demand for tanker capacity rises initially while buyers seek to capture as much of the cheap oil as they can. Unless oil demand rises, however – and the current low price of oil is as much a result of poor demand as it is of surplus output – then storage capacity soon fills up, reducing the potential for additional cargoes to be shipped. Low oil prices also make it harder for traders to find arbitrage opportunities and squeeze the margins available for the freight element.

Such has been the background to the tanker market in 1998, in contrast to the bonanza year of 1997. Following the Asian currency and economic crisis that developed during the 3Q1997, tanker owners will not have been surprised at the dramatic fall off in demand and freight rates in November 1997. The significant recovery that occurred – albeit briefly – in the middle of 1998 may have been more of a surprise, however.

VLCC ups and downs

The VLCC (very large crude carrier of 200,000–300,000 dwt; anything over 300,000 dwt is referred to as an ultra-large crude carrier (ULCC)) sector might have been expected to have been worst affected by the slippage in demand. Certainly the slump in crude oil imports to Korea and Thailand – countries which had been expected to provide much of the motor for incremental demand in coming years – has reduced employment on eastbound trades from the Middle East. Similarly, although 80% of Japan's oil requirements are carried in VLCCs under contract arrangements, the remaining 20% makes a very significant contribution to the spot market for VLCCs.

During the 4Q1997 demand for VLCC tonnage dropped alarmingly, almost exclusively for eastbound cargoes. Westbound business was also affected over the following few months as the high stock position combined with a relatively mild winter to reduce demand for new imports. Nevertheless, by May 1998 US buyers were beginning to return to the market with additional demand for Middle East crude and this helped boost VLCC earnings back to the high levels realised during much of 1997. Further assistance to VLCC demand came from West Africa, where the larger ships had begun to oust Suezmax vessels from one of their traditional markets.

According to Norwegian shipbroker Fearnleys, timecharter equivalent earnings for a 280,000 dwt VLCC trading Arabian Gulf-West averaged $29,400/d for 1997 as a whole, an improvement of 56% against the 1996 figure and more than three times the level realised during the recent market low of 1994. The high point was reached in October 1997 when earnings exceeded $41,000/d. Over the first three quarters of 1998, earnings have averaged some $31,100. However, by September earnings had slipped to under $20,000/d and the last quarter continued weak as demand faltered once more.

The selling of older tonnage for scrap is also having a positive impact on the VLCC sector. When vessels come up for their fifth special survey, owners have to assess whether the costs of the survey and any upgrading work, which can run into several million dollars, can be recouped from additional earnings from another five years' trading. Although based on current freight rates this looks an attractive proposition, such ships are shunned by Japanese and Korean refiners and are finding it increasingly hard to attract business from US importers, which until recently have been willing to charter older ships.

Additions to the VLCC fleet continue to outstrip deletions, however. In the first nine months of the year eleven new ships were delivered and seven were scrapped. The new ships are also larger and more efficient, so the effective rise in carrying capacity is more marked than the bare numbers might suggest. The market had anticipated this fleet renewal process, however, and appears to have already taken it into account.

More significant for future years is the sharp increase in newbuilding orders that occurred in the 2H1998. This has been encouraged by the low prices being offered by Korean and Japanese shipyards – some reports quote Korean builders offering a standard VLCC design for as little as $63mn, at least $10mn less than a year earlier. The depreciation of the yen and, in particular, the won against the dollar has allowed these builders to pass on locally denominated cost savings to buyers. As a consequence the VLCC orderbook rose from 50 ships in October 1997 to 75 a year later, accompanied by warnings from analysts that demand from oil majors and large owners could raise this figure to 100 very soon. Such a level of newbuilding could destabilise what is currently a comparatively healthy market during the early years of the next century.

Suezmax sector squeezed

If VLCC owners are pleasantly surprised by the performance of their ships this year, the same cannot be said of the Suezmax (120,000 – 150,000 dwt) sector which has been squeezed by competition from VLCCs, especially for loadings in West Africa, and the new breed of larger Aframax tankers. This has to be laid on top of the long-term loss of much of their traditional business; originally designed to be able to pass through the Suez Canal while fully loaded, their position has largely been usurped by the practice of discharging from VLCCs into the Sumed pipeline at Ain Sukhna and reloading at the Mediterranean end of the line again into VLCC tonnage. The loss of Iraqi exports from the Ceyhan pipeline terminal has also never been fully recovered elsewhere and, although the prospect of rising oil exports from the Caspian via the Black Sea holds out some promise of additional demand, Turkish authorities are still concerned at the safety aspects of the large volume of incremental tonnage passing through the Bosporus and other export routes are being explored.

Although Fearnleys calculates an average timecharter equivalent earning of $23,640/d for 1997 as a whole, this is only 22% ahead of the 1996 figure, nothing like the improvement enjoyed by VLCCs. Furthermore, for the first nine months of 1998 the average has slipped back to $23,180/d, based on a 140,000 dwt vessel trading West Africa-US Gulf.

A substantial proportion of the Suezmax fleet will be affected over the next two years by the US Oil Pollution Act 1990 (OPA90) which, inter alia, will bar single-hull ships from US ports according to a rolling, age-related schedule. Intertanko calculates that some 30% of the existing Suezmax fleet will be hit by this restriction in 1999 and 2000, pointing out that the fact that LOOP (Louisiana ofshore oil port, the only VLCC discharge port in the US) and the lightering areas are exempt from the regulation means that VLCCs will be unaffected in the same way. Over the past five years, while spot employment of Suezmax tankers on the West Africa–US Gulf route has increased gradually, there has been quite rapid expansion in the employment of these ships on cross-Mediterranean routes, suggesting that owners have already looked for alternatives.

Aframax flexibility

A larger fleet and more trading flexibility mean that the Aframax (80,000–110,000 dwt) sector is less responsive to the swings of the market. Average timecharter earnings for an 85,000 dwt vessel trading North Africa–UK/Continent were $16,025/d in 1996, according to Fearnleys, rising to $19,500/d for 1997 as a whole. This year has, however, seen a general decline in earnings, becoming more precipitous as the year has progressed. For the first three quarters average earnings were down to $15,100/d and by 4Q1998 had slipped below $10,000/d.

It is clear from fixture records that Aframax tankers are increasingly being used on 'dirty' trades. The volume of dirty spot fixtures has continued to rise through the second half of the 1990s whereas clean spot fixtures have stalled. Analysts put this down to the regionalisation in crude oil trades, particularly in the Caribbean, North Sea and Mediterranean regions. In fact, this concentration has been at the root of the fall in rates since the middle of the year, reflecting the reduction in crude oil output in Venezuela and some other Atlantic Basin producers.

Shipbroker Lorentsen & Stemoco also points out that the tight supply position in the Aframax sector during much of 1997 has resulted in a 'ridiculous' level of newbuilding orders, equivalent to nearly one quarter of the existing fleet. The orderbook stood at 5.2mn dwt at end 1996 but had risen to 8.5mn dwt just a year later and by the end of September 1998 had shot up to 10.6mn dwt, compared to an existing fleet of some 46mn dwt. It is feared this overhang will pull the rug from under the promise of continued firm earnings, a promise based on Aframax tankers' ability to meet the needs of changing trade patterns.

Smaller product tanker slump

High inventories and slack demand have also hit the markets for smaller product tankers during 1998. Indeed, as the rise in earnings in 1997 was less marked than in other sectors, the subsequent decline in rates has brought earnings down well below those obtained over the past few years.

Rates in the benchmark Caribbean trades have varied wildly from month to month, responding primarily to short-term demand factors in the US. On the whole, however, the lack of longhaul demand into the Far East and the general undermining of demand have combined with a substantial volume of new deliveries into the sector over the past two years to reduce the potential for any significant improvement, a situation which is unlikely to ease in the short term. According to Drewry Shipping Consultants only 12 ships in this size sector were demolished between the beginning of 1997 and the end of September 1998; over the same period 51 ships were delivered to the fleet, a further 27 were due by the end of this year and another 83 are scheduled for 1999 delivery.

Cost benefits

Where operators have all benefited in 1998 is in terms of costs. The price of bunker fuel has followed that of crude oil and plummeted to levels which, in real terms, are lower than ever before. Insurance costs are also reported to have fallen as a result of overcapacity in the marine insurance markets worldwide.

The outcome of these cost reductions is that, even in cases where earnings have not been as high as they were last year, net income has often been at very acceptable levels. This is especially the case for older ships whose capital cost has been written down and which, by virtue of their lower efficiency, gain more from low bunker prices.

What is less certain is that this situation will persist; analysts are now concerned that the growing orderbook will block any significant improvement in freight rates for some years to come to the point that, even if costs remain low, net income will inevitably suffer.

Due to space constraints, the LNG shipping sector will be reviewed next month.

Heating values of petroleum products

Comparing the sales of different energies is difficult, since some are sold by weight, some by volume and some in heat units. All need to be converted into a common format before making comparisons. The most sensible way to do this is to convert all statistics into units of energy or standardised units such as 'tonnes of oil equivalent' (toe). Since a toe is defined as a certain quantity of energy, the heating value of each product needs to be known in order to calculate the conversion factor from commercial units to toe. *Dennis Jenkin* explains further.

Calculating the energy balances of the petroleum industry is particularly difficult, since products such as lubricants and bitumen are not normally used as fuels. Others, such as light distillate feedstock (LDF) may be used to manufacture petrochemicals or conventional fuels according to market demands. Nominal heating values need to be nominated to products that are not used as fuels, so that an energy balance for the whole industry can be built up.

Calculating heating values

Various organisations have produced formulae for deriving the heating values of petroleum products from their densities or specific gravities, and some include corrections based on the contents of contaminants and other minor components. For example, British Standard methods of calculating the heating values of petroleum products include the effects of the sulfur, water and ash contents. Typical sulfur contents of major products are published annually by the UK Petroleum Industry Association (UKPIA) while typical ash and water contents are given in various reference books – but general users may not know where to find all the data.

Ideal formulae could also include corrections based on the contents of other components, but they would involve analysing the composition of each product. That may be practical in a laboratory, but it is too complex for most people in the industry. A simple formula is required for general use.

The UKPIA web site at **www.ukpia.com** gives typical densities of virtually all products sold in the UK, so that the most practical formula should be based solely on that property.

A simple and practical formula

Figure 1 shows heating values derived from a wide selection of sources. Each mean line is based on the regression analysis of over 50 samples. However, the samples for the two lines are not identical – some sources gave only one of the heating values. The constants in the formulae were rounded off to the nearest 0.1, since dozens more samples would need to be included before quoting them to a greater accuracy could be justified. Moreover, many sources quote heating values to the nearest 0.1 MJ/kg so that a greater precision would be misleading.

Since the curvature of the mean line does not always match the trends shown by the spot points, mean lines were tested based on various combinations of d, d2 and d4. The desirability of using one mean line for distillates and another for residuals was also tested. None of these complications produced results that were sensibly better than the mean lines shown on the graph. It was decided that a simple formula was better than a complex one which reduced the mean error by less than 0.01% of the actual heating value.

The lower heating values for some gasolines on the graph seem to be unusually small and it is possible that the samples contain ethers or other compounds that improve the octane ratings but reduce the heating values. A different mean line would need to be calculated for gasolines containing those components but it would be of limited value, since members of the general public do not know whether such products are incorporated in a particular fuel.

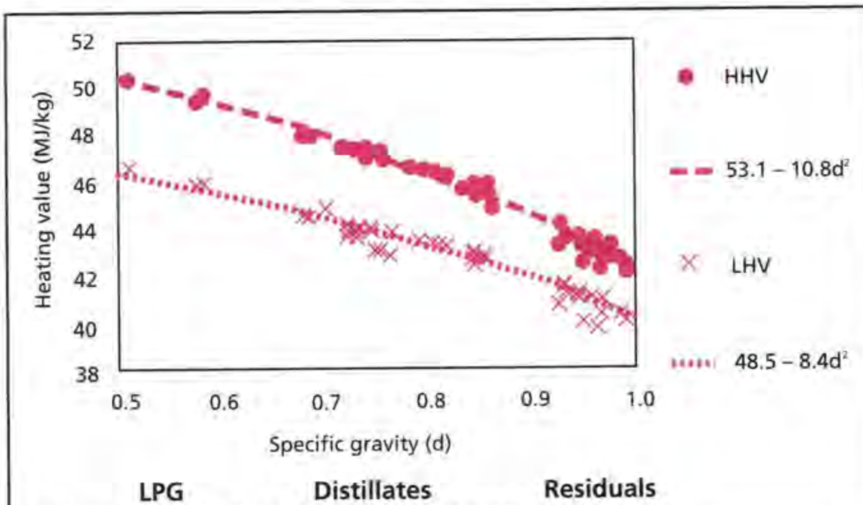
The graph includes the heating values of three fuel oils (light, medium and heavy grades) whose heating values are significantly lower than those of other products of the same densities. These three samples had very high sulfur contents and were typical of products sold in the 1960s. Similar products are still sold in some countries, but they are uncommon in the UK. They were ignored when preparing the mean lines in the graph.

Lows and highs required

Most engineers, marketers and economists in English-speaking countries use higher heating values (HHV) for general work while lower heating values (LHV) are standard in Continental Europe and many other countries. Everybody needs LHV when converting energy consumptions into the 'tonnes of oil equivalent' (toe) used by the IEA and EU, since 1 toe is defined as 10 Gcal, based on the lower heating value (equal to about 41.87 GJ, 396.8 therms or 11.63 MWh). [It should be noted, however, that the UK Government Statistical Service's toe are shown later in this article to be different from that used by others.]

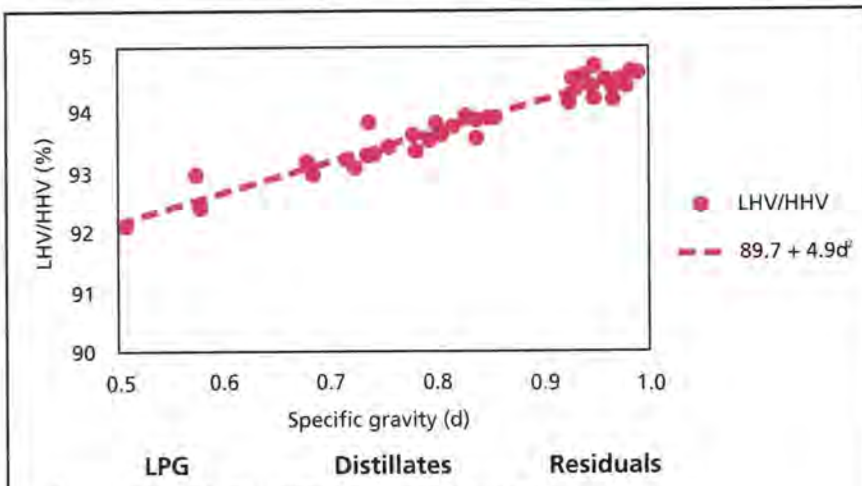
The consumptions and efficiencies of gas turbines are also declared in LHV, even in the UK and US.

A quick conversion from HHV to LHV (or vice versa) is sometimes required when comparing data from different sources. **Figure 2** shows the LHV as a percentage of the HHV for 50 of the products illustrated in **Figure 1**. Once again, a variety of more complex formulae were examined but none was found to improve the accuracy sufficiently to justify its complexity. The simplest formula is the most practical.



Sources: BP, BSRIA, Esso, OFTEC, Shell, UKPIA and others

Figure 1: Heating values of UK petroleum fuels



Sources: BP, BSRIA, Esso, OFTEC, Shell, UKPIA and others

Figure 2: Relationship between the LHV and HHV of UK petroleum fuels

Reason for the study

The latest *Digest of United Kingdom Energy Statistics* (DUKES) says that its authors could not find any recent work on the relationship between densities and heating values. As a result they used a US Bureau of Standards formula for the higher heating value:

HHV (MJ/kg) = 51.83 – 8.78d2

This was surprising, since past studies have shown that the relationship is affected by the characteristics of the crude oil and the refining techniques. The US formula used for DUKES seems to be roughly correct for British gasoline and gas oil, but it underestimates the heating values of lighter products and overestimates those of residual fuel oils.

The DUKES higher heating values are nearly 1 MJ/kg below the line at the left-hand end of **Figure 1** and nearly 1 MJ/kg above figures for the heaviest fuel oils. A line showing the DUKES values passes above every fuel oil point on the graph. Assuming that the products in the graph are typical, the average error of the graph's line for the higher heating value (HHV) is about half that from the formula used in DUKES.

If the DUKES authors did not want to ask oil companies to supply suitable numbers, they could have got more accurate higher heating values from Shell International Gas's *Natural Gas Terms and Measurements* published in 1969. The values in that publication were not included in **Figure 1**, but they are surprisingly close to the mean line.

Not all toe are created equal

The toe used by the UK Government Statistical Service in DUKES and other publications are based on the higher heating values of fuels, not the lower heating values used by international bodies. Thus, the absolute values for fuels and the ratios of the demands of different energies are different from the numbers based on the IEA toe. The LHV/HHV ratios of **Figure 2** might be used to convert DUKES's toe for individual petroleum fuels into the toe used elsewhere, but it would still be necessary to develop LHV/HHV ratios for the solid fuels quoted in DUKES. The amount of work required could be large.

The final word

Although the empirical heating value formulae in this report are based on a relatively small sample, they include values supplied by major oil companies and other reputable organisations. There is no reason to believe that a larger sample would affect the mean lines greatly.

However, it may be necessary to develop separate formulae for certain products if the content of non-traditional components becomes significant. That could be important for motor gasolines incorporating alcohols, oxygenated compounds and other special additives. It may also be necessary for the residues from refineries that convert the maximum possible amount of heavy products into motor fuels and other distillates.

In the spirit of software integration

The launch of the new OpenSpirit E&P Component Framework facilitates the plug and play integration of E&P software applications and datastores for the oil and gas industry, reports *Gregg Shenton* of PrismTech Ltd.

Both end users and developers of E&P software applications currently face the problems of high costs, long cycle times and reduced efficiency. This is the result of:

- E&P applications which are not well integrated (for example, in order to use the results from one application such as seismic interpretation in a subsequent application such as seismic modelling, data must often be translated from one data store to another);
- E&P applications which are 'full featured' and expensive;
- heterogeneous data access which is difficult and expensive;
- the difficulty of adding functional enhancements; and
- the inertia of legacy applications and data stifling new innovation.

It was against this background that the OpenSpirit Alliance (Alliance) was formed in 1997, with the aim of providing a solution to these pressing problems. The Alliance is a partnership of oil companies and E&P software vendors including Shell, Elf Aquitaine, Statoil, Chevron, BG plc, CGG Petrosystems, Shared Earth Technologies, Jason Geosystems, de Groot-Bril Earth Sciences, Foster Findlay Associates and IFP.

The Alliance is sponsoring the development of the OpenSpirit E&P Component Framework (OpenSpirit) that enables developers to build interoperable applications with access to a number of key industry datastores including Open Works/Seiswork, Geoframe/IESX and Epicentre. PrismTech was appointed by the Alliance as the development and marketing partner for OpenSpirit. As well as providing sponsorship, the Alliance provides customer requirements and technical expertise to qualify the framework design, ensure standards-conformance and promote broad industry take-up.

By enabling 'plug and play' integration, OpenSpirit introduces new and powerful capabilities for both users and developers of E&P software applications, significantly lowering the cost of application and datastore integration and reducing application development and purchase costs.

The system's lightweight applications can add value to existing (bought or built) applications. Applications integrated through OpenSpirit can transparently access data from different datastores; new (customised) applications can be assembled from low-cost, lightweight components and browser-based or desktop applications can be integrated with proprietary applications.

PrismTech launched OpenSpirit V1.0 at the SEG Exhibition and Conference in New Orleans in September 1998 and the product will be commercially available from 1Q1999.

Underlying concepts

The OpenSpirit requirement is for an open component framework with standardised and published application-component interfaces. OpenSpirit is written entirely in Java and consists of a services-based architecture which is decomposed into two main architectural layers: a Distributed Object Facility (DOF) and an E&P Component Framework.

The DOF consists of implementations and extensions of OMG/CORBA Services. It ensures consistent usage patterns of these standard services, so that applications built by different organisations (teams, groups, companies, etc) can be guaranteed to interoperate.

The E&P Framework provides both generic E&P components (such as coordinate transformations) and components specific to subsurface interpretation. These components can be grouped into several sub systems:

Data Framework Components provide data servers for well, seismic, culture and interpretation (V2.0) data types. Interfaces to these data types are defined in OMG's Interface Definition Language (IDL) and provide application developers with access to data independently of the data store, location or the implementation language of the data access (Vendor Dev-Kit) technology. Initially the OpenWorks/Seisworks, GeoFrame/IESX and Epicentre data stores are supported, however the architecture also allows for custom servers and datastores to be developed as required.

GUI Application Components have been developed in Java to provide cross-platform portability and to support web-based applications. 2D Graphics Components provided by INT's JCarnacTM graphics toolkit with Java and C++ extensions provide integration with the Data Framework.

In action

To demonstrate the capabilities of OpenSpirit, a number of legacy and new applications based on OpenSpirit alpha code were shown interoperating together at the SEG Conference and Exhibition. These example applications were developed by six different teams working in Houston (US), The Hague (Netherlands), Paris and Pau (France) in under 10 weeks. They are described below.

Geographical Data Selector The Geographical Data Selector (GDS™) is a new application developed by Petrotechnical Data Systems as an interactive application component that runs on any standard web browser and allows a user to explore and select E&P data against a backdrop display of cultural data (for example roads, rivers, coast lines and political boundaries).

It is a GIS component that extends the OpenSpirit framework to provide a single point of access to project or corporate data stores and repositories regardless of their underlying technology or location. GDS™ works with any other application built for the OpenSpirit Framework, offering a unique level of application interoperability for E&P end users, and openness for E&P software developers who wish to incorporate GIS based browsing functionality into their applications. GDS™ user interface was built using only standard OpenSpirit and Java technologies and the main display was created by extending the OpenSpirit basemap view.

Data Analysis Tools Shell Services International has developed a number of OpenSpirit Data Analysis Tools which allow analysis of data from the OpenSpirit supported data sources. All of these tools were written in Java and use the OpenSpirit Data Framework.

The Data Query Tool utilises the OpenSpirit Query Engine to query data from any OpenSpirit data source and returns a collection of data meeting the prescribed constraints. The Chart Tool, based on a third-party JavaBean, charts the attributes of any OpenSpirit data object. Bar charts, pie charts, 2D and 3D charts are all available. GIS MAP Tool uses the OpenSpirit Data Framework in conjunction with the OpenSpirit Coordinate Service to ensure all data on the map are in a consistent coordinate system. The Seismic Preview Tool displays seismic and well data from

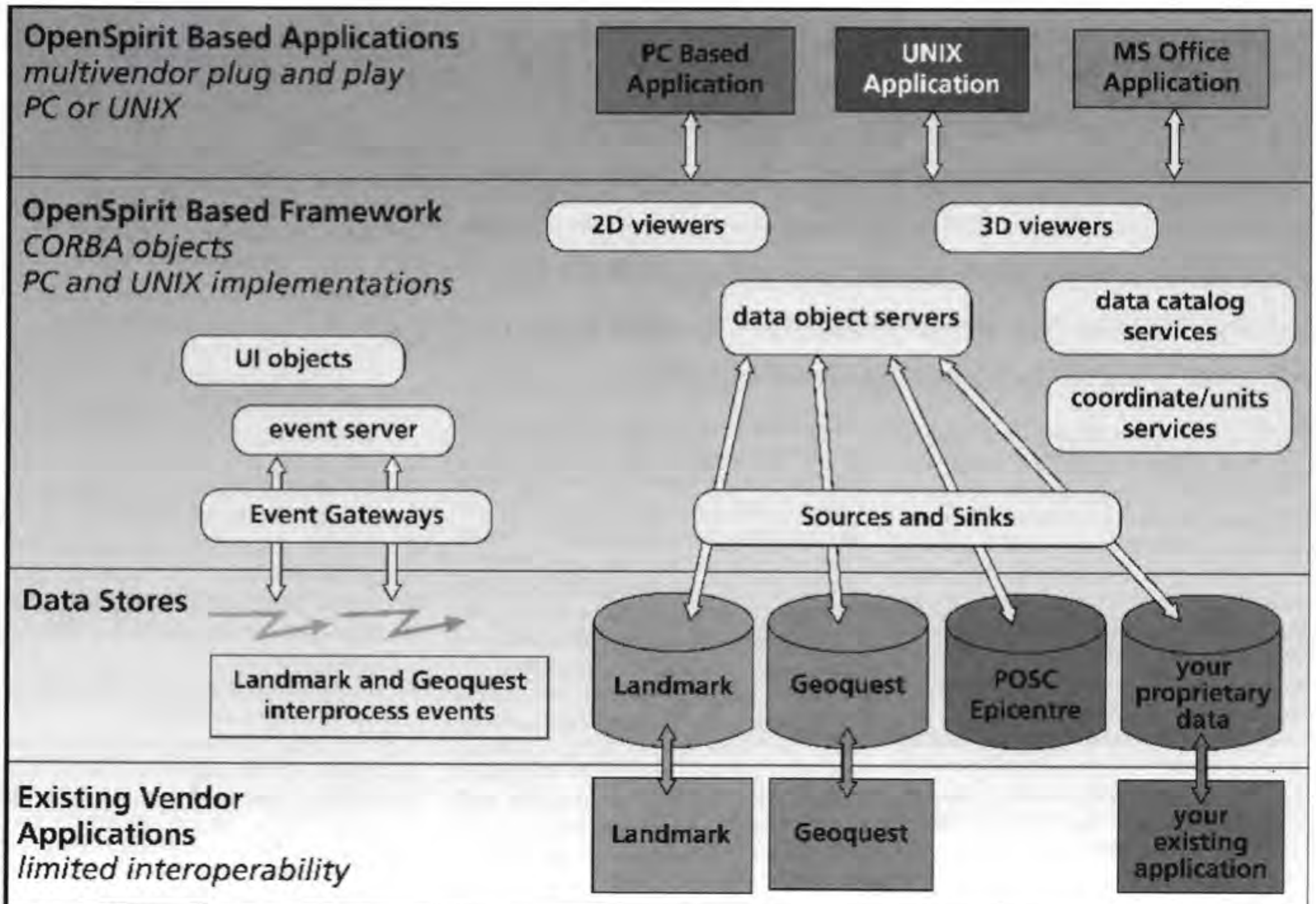


Figure 1: OpenSpirit architecture

OpenWorks and Geoframe which is built on the OpenSpirit Cross Section Viewer.

All these tools use the OpenSpirit event services to enable a high level of interoperability. Specifically, data can be easily viewed in any of these tools by simply using copy and paste functions.

Stratimagic Petrosystems, CGG's software division, has begun incorporating the OpenSpirit seismic and well data servers into its own GEM-3D application integration platform. GEM-3D is designed to support development of highly interactive applications like Stratimagic, its stratigraphic analysis package. OpenSpirit has also been incorporated in Petrosystem's new Structcad 3D structural package based on the integration of GOCAD into the GEM-3D framework.

GOCAD This earth modelling package provides an integrated definition of geometry, topology, and properties of the sub-surface through objects such as points, lines, surface (multi-valued tri-mesh), and volumes (regions bounded by surfaces filled with tetrahedras, regular grids or stratigraphic grids). Chevron, Elf, and T-Surf have made a preliminary version of a GOCAD plug-in that ties into the OpenSpirit Framework, allowing GOCAD to directly use OpenSpirit data object servers to access well path, well log, well pick, line of section and seismic 3D volumes from Landmark (OpenWorks/Seisworks) and Geoquest (Geoframe/IESX) systems.

This allows the use of Landmark and Geoquest data in place without having to replicate data in GOCAD format. This means, for example, that a GOCAD user can display slices of a Landmark/Geoquest 3D seismic volume inside the GOCAD camera without creating a voxet on disk; the vendor native formats are accessed through the standard OpenSpirit object interface.

Sismage With the pre-release of OpenSpirit, Elf Exploration and Production has initiated an evaluation program based on a phased incremental approach. As the first version focuses on the seismic interpretation domain, Elf selected Sismage, the in-house software in the same domain, as the natural candidate for the evaluation program. The basic goal of image analysis techniques applied to seismic data is to meet the needs of geologists and geophysicists in charge of large surveys and different types of 2D/3D data. In addition to conventional interpretation, interpreters are currently seeking new patterns for sedimentological interpretation, reservoir models, lithological prediction and hydrocarbon detection.

The goal of the OpenSpirit prototype is to gradually replace the common functionalities with the 'by default' services provided by the OpenSpirit Framework. The first step was to replace the exchange filters by the OpenSpirit object servers (ie seismic and well objects) and to use the event services to run Sismage concurrently with other OpenSpirit applications. The next step will be to investigate how to integrate other OpenSpirit services, notably the graphic frameworks.

The added benefits

OpenSpirit can significantly lower the costs of application and data store integration, and also lower application development and purchase costs. Furthermore, users benefit from applications which better support their work processes, and are freed from many frustrating inconveniences such as data reformatting, incompatible user interfaces, and long cycle-times for functional enhancements.

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IP to extend training provision

The IP's Lifetime Learning programme has become an established process since its inception two years ago. Although Lifetime Learning covers a range of initiatives far wider than formal training, the provision of high-quality courses forms a key part of the IP's function. The Institute is pleased and proud to announce that it is to add ten new courses to the training portfolio in 1999.

The IP's involvement in training received considerable attention, some two years ago, in the early deliberations about Lifetime Learning. However, it was difficult to secure general recognition that the concept was much wider than just 'formal training'. It was then decided to defer extending training provision until IP Lifetime Learning was an established process, so as not confuse the picture or divert resources.

Of the 12 original IP Lifetime Learning projects, ten are now fully up and running. Importantly, an additional major element, the development of our own IP Lifetime Learning Plan and Workbook, was launched early this year. The IP can now see further involvement in training as a natural development of its role in Lifetime Learning.

Even now, without promoting the concept, industry representatives assume that the IP has a major part to play in this sector and enquiries are often received for relevant training, in some cases for 'in house' bespoke events. At the same time a number of training providers have recognised the IP's pivotal position in the industry and wish to share in its credibility and reputation, working under an IP umbrella.

The IP is now becoming a 'commissioning partner' for economics, business and management industry related training, using alternative sources to deliver. This involves contracting with third parties to present courses under the IP banner, in non-exclusive arrangements. For 1999 this will comprise about eight to ten courses from various sources to add to the two that the Institute already runs:

- Introduction to Oil Operations
- Introduction to Petroleum Economics.

The detailed programme for 1999 will be published in December 1998 but will include arrangements with four partners to deliver courses covering:

- operations practice in supply trading;
- UK oil and gas accounting standards;
- US SEC (Securities and Exchange Commission) and FASB (Futures and Securities Board) requirements for oil industry accounting and reporting;
- production sharing arrangements and joint interest accounting;
- refinery economics, planning and optimisation;
- trading oil in the international markets;
- price risk management in the oil industry; and
- price risk management in the deregulated power industries.

The IP sees this new departure as an important further step in support of our membership and its needs for Lifetime Learning and a natural adjunct to the existing portfolio of information and educational services offered by the Institute.

John Evans,
Director, Membership Services

CPD in lubricant and hydraulics industries

Responding to the changing needs of the lubricant and hydraulics industries, De Montford University, Leicester, has launched an MSc in Lubricant and Hydraulics Technology. Beginning in January 1999, the course is offered as a distance learning programme, delivered primarily via the Internet and CD-Rom.

The three-year Masters programme – run by the University's Lubricant Research Centre – features a progressive 'staircase' structure enabling participants to gain a postgraduate certificate (PgC) after completing just one year, and postgraduate diploma (PgD) after two.

The course is aimed at those scientists and engineers holding a degree qualification that are interested in pursuing their personal continuous professional development (CPD).

During the first year of the course (PgC), participants from different disciplines are brought up to the same level of knowledge. Subjects covered include the chemistry and physics of fluids, tribology and the fluid dynamics of power systems. The second year (PgD) modules cover the physical and chemical analyses of fluids, advanced tribology and the testing of lubricant and hydraulic fluids. The third year (MSc) modules are fluid formulation and performance, and a choice between greases and solid lubricants, or high performance fluids, together with a research project (normally undertaken at the participant's place of employment or as a review/library project, with an individual supervisor).

Instruction is provided via the University's website supplemented by CD-Rom. There is also the opportunity to participate in Internet conferences and seminars. Students attend four weekend workshops in Leicester each year, sessions include tutorials and seminars.

Assessment is by regular post tests, an assignment for each module and two formal three-hour examinations in each of the first two years. A particular feature of the course are 'advanced professional skills' modules in the first and second years, which are aimed at further developing participants skills in IT, research methodology, report writing and providing an appreciation of industrial and commercial structures.

For more information contact Professor Malcolm Fox on +44 (0)116 257 7117 (e-mail: **mff@dmu.ac.uk***) or Dr Sarah Davies on +44 (0)116 257 7698 (e-mail:* **sjd@dmu.ac.uk***) in the Lubricant Research Centre, or visit the website at* **www.as.dmu.uk/chem-msc**

At the Rubicon?

Following the surprise results of the US elections, *Peter Adam* examines the potential impact of the election on the international oil and gas industry.

With gasoline at the pump about as inexpensive as it has ever been, energy in general, and oil and gas issues in particular, did not enter into the recent local and state elections in the US at all. But as analysts, journalists and policy-makers survey the surprisingly altered political landscape following an election in which the 'Comeback Kid' came back, yet again, energy may be the dog that isn't barking. For now, complacent Americans are free to forget politics for a while and resume loading up on gas guzzling sports utility vehicles and outsized vans which in many cases are modified versions of vehicles originally designed for rhino hunting and transporting building supplies, and bid up the share markets, while the Clinton administration breathes easy. But there may be surprises ahead.

Impact on energy policy

The results of the election are not likely to impact one major US energy policy with wide-ranging international consequences (and opposition): economic sanctions against Iran and Libya. The election saw the defeat of New York Senator Alfonse D'Amato who as Chairman of the powerful Senate Banking Committee, was a strong backer of sanctions. Senator D'Amato's departure will have negligible impact on the sanctions or US policy in the Middle East, however. His replacement as Committee Chairman, Texas Senator Phil Graham, is not likely to change anything here. And former Congressman from New York, Charles Schumer, who unseated Senator D'Amato, is Jewish and is expected to be just as pro-Israeli in his representation of New York City constituents.

Sanctions against Iran are likely to stay in place until the Clinton Administration, which has been moderating its stance towards Iran and has shown flexibility in their enforcement, lets them wither completely.

Apart from this, the US election's outcome may well have significant impacts on the energy sector, internationally, that are not apparent. The defeat of the 'radical Republicans' in Congress, led by former Speaker of the House, Newt Gingrich, who expected to win several seats and press ahead with the impeachment process, has left the Clinton Administration with a mandate of sorts to press its policies for the remaining two years of its tenure, domestically and internationally – meaning that the US federal government will step up the pressure on major oil companies to construct pipelines out of the Caspian region that conform to US national security and geopolitical considerations: dual-route East-West pipelines starting with one from Baku to Ceyhan, which at current oil prices are not economic, but may well become so, due to developments not unrelated, at least in part, to the recently-held election. However, this is the only area where the election's results may have energy impact.

Bolstered by the election victory and in the wake for now, of a revived Palestinian-Israeli peace process, the Administration is likely to be more decisive in dealing with Iraq, particularly now that Russia and France which have been more indulgent of Saddam Hussein's regime, are, in light of Iraq's repeated refusal to let the UN weapons inspectors carry out their mandate, tossing in the towel and now apparently supportive of US/UN plans for military action. The backing down of Iraq in the face of US determination to press ahead with air strikes has, for the moment, defused the crisis. Whether this is simply another postponement as in February or whether this will lead to the full lifting of sanctions remains to be seen.

But while most planners and analysts seem confident that air attacks on Iraq will have no unintended consequences, there is cause for apprehension. Nothing is less predictable than what happens when nations resort to arms, and this is particularly true in the Middle East. The aftershocks of the Anglo-French action in Suez in the 1950s prompted, a few years on, the fall of the monarchy in Baghdad and stoked the fires of Arab nationalism which helped turn the Middle East into a Cold War hot spot. And there is tacit support in the region for US/UN military action against the government of Saddam Hussein. Cornered more tightly than ever before, Saddam Hussein may well unleash weapons that the UN inspectors have been looking for but have proved impossible to find. This cannot be ruled out, nor can sabotage, nor something totally unpredictable.

Oil supplies appear plentiful worldwide, but analysts admit there are 300 million barrels they can't quite account for. However, this enormous amount of crude oil may be in 'shadowy storage' facilities wich are not normally factored into analysts' numbers or to volumes in transit on the seas. This is quite a margin of uncertainty. There is a chance that this crude does not in fact exist and supplies are much tighter than markets would have one believe, – something that a number of contrarian analysts have recently made cases for.

When the Iraqis started playing cat-and-mouse with the UN inspectors last February, one of the factors which prompted US policy makers to opt for the figleaf/olive branch approach that UN Secretary General Koufi Annan negotiated at the 11th hour with the Iraqis, was the fact that worldwide oil production capacity exceeded consumption by about 1–2 million barrels a day, down significantly from 6 million barrels a day during Operations Desert Shield and Desert Storm. Plans for military action earlier this year initiated a brief price spike. Current world excess capacity remains what it was earlier this year.

Financial impacts?

With prices at or near historical lows, planners may not be fully factoring in the price impact of military action. Perhaps they should. The run up in oil and product prices during the Desert Shield Operation increased the severity of the recession that is widely seen as having cost President George Bush re-election in 1992. And this summer as the Asian contagion and Russia's financial meltdown sent world financial markets into a tailspin, economists thought the US was teetering on the edge of a recession. Recent soundings on the economy and a return to buoyancy in the US have somewhat allayed such fears. But the slow-down could well develop into a recession, or worse, some say, and higher oil prices certainly would not help things.

Given world economic and oil supply uncertainties, military action against Iraq might involve greater risks than generally realised. The Clinton Administration along with Americans generally seem in the post-election glow to be up for striking Iraq. But problems in the Gulf as history has repeatedly shown do not often lend themselves to quick military fixes. Shakespeare, typically, had it right: 'Cry havoc, and let slip the dogs of war.' And havoc ensuing from military action against Iraq could alter, once again, the political landscape and not only in the US.

Holistic oil field value modelling

There is growing pressure on oil and gas field management teams to deliver increased asset value. Despite the wealth and variety of modelling tools available, there are few tools which help to reconcile value-based thinking with complex operational reality. However, a new approach to oil field value management is now available, write *David Corben*, Senior Consultant and *Richard Stevenson*, Managing Director, of Cognitus Ltd.

Much importance is given to the valuation of oil and gas fields at all stages of appraisal, development and exploitation. Company and industry analysts employ a wide variety of strategic and financial methods to appraise fields for value and the results are reflected in company balance sheets and share prices.

However, at the field operational level there are also many opportunities for creating or destroying value. Capital investment, technological innovation and creative field management strategies can all add significant additional value to producing assets and can often extend recovery and field life beyond original expectations. However, there may also be financial and operational risks associated with such strategies.

How do companies assess the viability and risks associated with value-enhancing strategies, given that the impact of many such interventions may be uncertain, may play out over lengthy periods of time, or may have 'knock on' effects on other elements of field management?

To understand how field value may be created or destroyed by field management strategies, it is necessary to adopt a holistic 'whole field' perspective over the remaining life of the field and to assess the revenue, capital, operating costs and tax implications.

But taking a holistic perspective is often difficult because the necessary knowledge and experience is contained within specialist operational disciplines: reservoir, wells, facilities, commercial, tax, etc.

Conventional operational management planning tools and models are also based within these same discipline boundaries. As a result it may take considerable time to work through even a single whole field scenario and it may be impractical to screen a wide range of options, because of complex interdependencies between the different elements of the field.

Modelling in the oil industry

Computer modelling has long been an accepted and valued tool in the oil and gas industry. At the field level, for example, the field management team will typically have access to a number of models, each of which provides detailed information about specific aspects of the business. Such tools include reservoir simulators, production and processing facility models, financial spreadsheets and tax planning models.

Precisely because these models are detailed and specific however, none of them can provide the management team with the 'big picture' of the field as a whole. The independent nature of such models also makes it difficult and time consuming to explore a wide range of assumptions and strategies.

At another level, system dynamics models (SD) and systems thinking (ST) have been widely used for strategic planning by many major oil companies over the years. Shell, in particular, has pioneered the use of SD to support strategic debate.[1]

Such highly aggregated strategic models, used centrally within the organisation, are in sharp contrast to detailed operational models used within oil fields.

Neither the detailed operational or aggregated strategic modelling can be used to deliver value insights at the field management level. To help a field management team understand the dynamic value drivers of their assets, a different type of model is needed. The challenge is to develop a systemic or holistic approach which is 'strategic' enough to capture the big picture and show how value may be created or destroyed, but 'operational' enough to generate confidence and to reflect the complex interdependencies between different elements of field management and performance. A new 'intermediate level' of modelling is required.

A new approach

'FieldValuer' is a new approach to oil field value management that has been developed by Cognitus as an outcome of a number of strategic and operational system dynamics modelling projects in the oil industry. It is not a model per se, rather it is an integrated method for creating 'intermediate level', 'value-based' models, comprising a system dynamics toolset, a process for knowledge capture, analysis and synthesis, templates to accelerate model development and a competence framework to enable management teams to become self sufficient with the method and tools.

The outcome of a FieldValuer project will usually be a field-specific system dynamics model which captures operational reality at a level which can reflect the value implications of a wide range of management options and decisions.

The underlying philosophy is that of using system dynamics modelling with management teams. Managers are challenged to develop shared perceptions of the business as a whole. The process of facilitating the building of models with the management team is the vehicle for achieving this goal. The philosophy is in direct contrast to the use of 'black box' models to produce 'answers', or forecasts. It is much more challenging and much more rewarding.

A structured approach to knowledge capture, analysis and synthesis is used (see **Figure 1**). The process is designed to ensure that all the operational and commercial interests and perspectives which impact field value, are represented. It develops learning and commitment across the management team, and provides a basis for improved communication across the entire field.

Modelling is carried out using the ithink® simulation software. This is an easy-to-use, yet powerful system dynamics simulation tool. In addition to its simulation capability, ithink® provides for the easy creation of 'management flight simulators' (see **Figure 2**), which allow the management team to quickly and easily test the impact of a wide range of strategic and operational scenarios.

As field knowledge is captured and

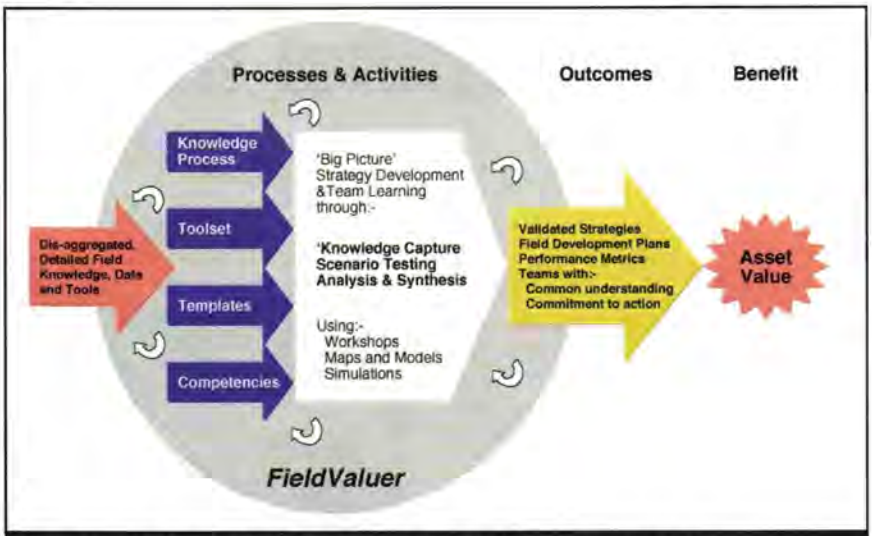


Figure 1: Using knowledge to create value with the FieldValuer methodology

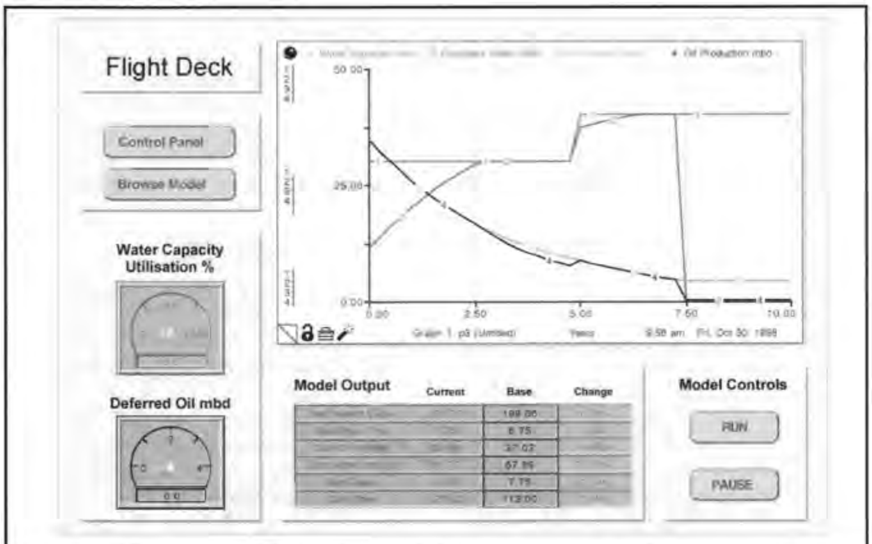


Figure 2: The 'Flight Deck', part of the control panel of an ithink® based management flight simulator

synthesised within the tool-set, generic structures (or templates) are delivered which can be used to assist with knowledge capture and model development in different field situations. As companies progressively apply FieldValuer for themselves, the development and application of such templates can considerably accelerate the model development process.

A background awareness programme in system dynamics and ithink® is provided for the full management group, supplemented by specific training for individuals. In this way, field management teams can progressively become self-sufficient to extend the application of the method.

FieldValuer simplifies, consolidates, models and links together detailed and disaggregated field based knowledge, enabling quick and rigorous testing of potential capital, technical and operating strategies, with the overall aim of maximising field value.

Forties case study

BP's Forties field was commissioned in 1975 as the largest oil field in the British North Sea. By the mid 1990s, as the field approached the end of its planned life cycle, BP had various options. For example, to extract the remaining reserves more quickly by investing in new well stock or to reduce operating costs by shutting down one or more of the producing platforms and extracting reserves more slowly.

The problem was to identify the options that would create value. Forties is a complex field with five platforms and there are many interactions, both on the topside and in the reservoir.

The aim of the project was to develop a model that could be used to explore quickly and easily interdependencies across the field. In particular there was a need to screen technical and commercial strategies, make best use of existing tools and models, unify different management perspectives and provide a communication tool that would convey the developing 'late life strategy' across the asset.

The production planning team on Forties summed up the benefits by saying: 'For the first time we have a "big picture" of the entire oil field over the remaining years of its life. We can explore many options without risk; and by eliminating unattractive options quickly, we can focus hard on the options we need to examine in more detail, using the detail tools where necessary. All in all, a breakthrough in oil field planning.'

Other applications

The methodology has also been applied to the modelling of produced water handling on a mature oil field. The problem here was that field production was being lost because of a constraint on the produced water handling capacity and to a lesser extent on water injection capacity. The model has been used to explore both short-term operational interventions and longer-term solutions to the problem.

Another major application of the methodology has been in a new field, part way through its pre-sanction phase. In this application the key issues were to help understanding of the content and timing of the drilling plan, to investigate alternative facilities sizing and to examine the interconnectedness of these issues under reservoir uncertainty. The intention is that the model will be developed in parallel with the field, creating a 'whole life strategy' model.

1. Morecroft, J D W and van de Heijden, K A J M. 1994. Modelling the oil producers: capturing oil industry knowledge in a behavioural simulation model. In *Modelling for Learning Organisations*, J D W Morecroft & J D Sterman (eds). Portland: Oregon.

A paper, which describes the FieldValuer methodology in more detail is available from Cognitus, a specialist system dynamics modelling and systems thinking consultancy. It can be downloaded in PDF format from the company's website at www.cognitus.co.uk. Alternatively, contact the authors at Cognitus on +44(0)1423 562622. Cognitus is the exclusive UK distributor for the ithink® simulation software.

The promise of methanol fuel cell vehicles

Each of the first eight months of 1998 set new record highs for global temperatures. When you consider that every litre of gasoline burned in an automobile produces 2.5 kg of carbon dioxide, it is easy to see why the road transport sector is responsible for a quarter of all carbon dioxide emissions across Europe. These emissions present a real challenge for the European Union to meet its goal under the Kyoto Protocol to reduce greenhouse gas emissions by 8% from 1990 levels. *William Bell,* Chairman, Market Development Committee, American Methanol Institute and Vice-President Ammonia and Methanol, ICI Synetix, explains the role that methanol fuel cell vehicles could play in meeting this target.

Motor vehicles are also responsible for much of the air pollution that chokes our cities. The introduction of lead-free gasoline and the requirement that all new gasoline-engined cars in the EU are fitted with catalytic converters will do much to reduce urban air pollution. However, these gains are jeopardised by the increasing number of vehicles on the road.

Our reliance on gasoline-fuelled motor vehicles also raises significant energy security concerns. While the EU has done a better job than most regions of the world in conserving energy, 1996 accounting for 30% of world economic activity while consuming only 16% of the world's total energy demand, Europe is dependent on oil imports. EU member countries consume 18% of world oil production, and produce only 5%.

Fuel cells meet challenge

Many thoughtful people have concluded that the 100-year reign of the gasoline-fuelled, internal combustion engine must begin to give way. In its place, we need a clean, advanced-technology vehicle that retains all the performance and consumer convenience of today's motor vehicle while offering an alternative to our dependence on oil. Fortunately, it is now clear that fuel cell vehicles will soon be available to meet this challenge.

Methanol – a liquid fuel made from natural gas or renewable biomass resources – is the leading candidate to provide the hydrogen necessary to power fuel cell vehicles. The commercialisation of methanol-powered fuel cells will offer practical, affordable, long-range electric vehicles with zero or near-zero emissions while retaining the convenience of a liquid fuel. By 2004 or sooner, fuel cells operating on methanol will power a variety of cars and buses in Europe and worldwide.

Manufacturers and component suppliers are spending billions of dollars to develop these advanced technology vehicles. The industry leaders include Daimler-Benz, Toyota, General Motors, Volkswagen, Nissan, Ford, Honda and Volvo. The broad-based industrial commitment to fuel cell vehicles derives from their inherent energy efficiency and low emissions.

Today's internal combustion engine converts only 19% of the useful energy in gasoline to turning a car's wheels. Methanol fuel cell vehicles are projected to achieve efficiencies of at least 38%, while bringing smog-precursor emissions close to zero and cutting greenhouse gas emissions in half.

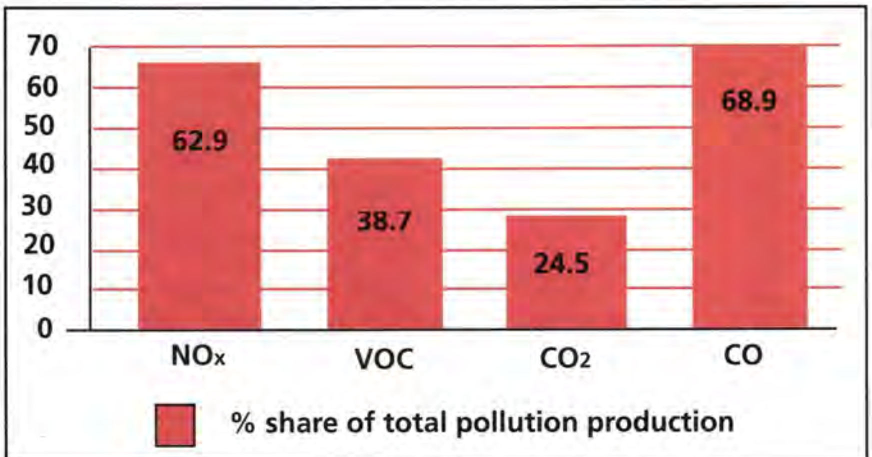
Daimler's NECAR

Leading the field

Leading the automotive industry in fuel cell vehicle development is Germany's Daimler-Benz. At the 1997 Frankfurt Auto Show, Daimler unveiled the NECAR 3, a compact car running on a 50-kW methanol-powered fuel cell. To ensure the commercialisation of fuel cell vehicles Daimler has formed a $700mn global alliance with Canadian fuel cell developer Ballard Power Systems and American manufacturer Ford Motor Company. DBB Fuel Cell Engines, the alliance's joint venture, plans to complete work on its prototype series car – the NECAR 5 – in late 1999, and intends to build 40,000 methanol-powered fuel cell drive trains in 2004. Daimler believes that with a production volume of 250,000 vehicles per year, the fuel cell vehicle will be cost-competitive with traditional internal combustion cars.

Japanese automaker Toyota also showcased a prototype methanol fuel cell vehicle at the Frankfurt Auto Show. Based on the popular RAV4 sport-utility vehicle and operating on methanol, this prototype car has a range of 500 km, while demonstrating a hybrid design concept quite different from the Daimler prototype. Toyota's fuel cell RAV4 employs a 25-kW fuel cell that works in conjunction with a downsized electric vehicle battery pack that is recharged from the fuel cell.

A parade of other manufacturers have committed to developing methanol fuel cell vehicles. General



Road transport air pollution in Europe *Source:* www.eea.eu.int

Motors announced plans to have a production-ready methanol fuel cell vehicle by at least 2004. Nissan is working with Ballard on a methanol fuel cell vehicle it hopes to begin selling by 2003 to 2005. Volkswagen plans to unveil a functioning prototype vehicle in 2000, in a development effort with Johnson Matthey and Volvo, supported by the European Union.

While Daimler's NEBUS is fuelled with compressed hydrogen, for more than 14 years researchers at Georgetown University have been developing methanol fuel cell buses. In 1994 and 1995, Georgetown rolled out three 30-foot buses that were the world's first fuel cell vehicles capable of operating on liquid fuels. This year, Georgetown is unveiling two methanol-fuelled prototype 40-foot transit buses using two different fuel cell technologies. International Fuel Cells has provided Georgetown with a 100-kW phosphoric acid fuel cell, and DBB Fuel Cell Engines is building a 100-kW proton exchange membrane (PEM) fuel cell.

It is projected that the number of vehicles worldwide will increase from 600mn today, to 1bn by the year 2015. The introduction of large numbers of low-emission, energy-efficient methanol fuel cell vehicles is not only needed but well within reach. Based on announcements from various manufacturers and the political and regulatory pressure to introduce advanced-technology vehicles, the American Methanol Institute (the trade association for the methanol industry in the US) recently estimated that by the year 2010 manufacturers will have introduced at least 2mn methanol fuel cell vehicles worldwide. By 2020, the total fleet of methanol fuel cell vehicles on the road may reach or surpass 35mn vehicles.

Looking at the alternatives

Earlier versions of the Daimler-Benz fuel cell vehicle – the NECAR I and NECAR II – were fuelled by gaseous hydrogen stored in bulky high-pressure cylinders, as is Daimler's fuel cell-powered transit bus called the NEBUS. On vehicles, hydrogen can be stored as a cryogenic liquid or as a pressurised gas. Recently, a panel of fuel cell experts reported to the California Air Resources Board that 'hydrogen is not considered a technically and economically feasible fuel for private automobiles now or in the foreseeable future'.

The panel found that fuelling infrastructure problems and the storage of an extremely cold liquified fuel or highly compressed gas on board a vehicle would not be 'practical'. It concluded that fuel cell vehicles must get their hydrogen through the onboard processing of a hydrogen-rich fuel.

Methanol emerges as the ideal hydrogen carrier for vehicles because it is liquid at room temperature and ambient pressure. Methanol is a simple molecule consisting of a single carbon atom linked to three hydrogen atoms and one oxygen-hydrogen bond. Releasing the hydrogen from its bonds in a methanol molecule is easier to accomplish than for other available liquid fuels. Moreover, methanol fuel contains no sulfur, which is a fuel-cell contaminant, has no carbon-to-carbon bonds, which are hard to break, and has a very high hydrogen-to-carbon ratio. Methanol fuel cell vehicles use a steam reformer operating at relatively low temperatures to split the methanol molecule and produce the hydrogen needed by the fuel cell stack.

Gasoline is also being considered as a hydrogen source for fuel cell vehicles, however this technology has yet to overcome some significant obstacles. Today's gasoline has several components that make it more difficult to reform into a hydrogen stream. It is likely that a light fraction of straight chain hydrocarbons with little or no sulfur will be desired for fuel cell vehicles. This specially formulated fuel would require separate distribution and storage at the retail station. On the vehicle, the gasoline reformer will operate at a higher temperature than methanol, yield a lower concentration of hydrogen, and produce more carbon monoxide which adversely impacts fuel cell performance.

Another fuel cell technology is on the horizon: the direct methanol fuel cell. This technology is expected to reach commercial maturity as early as 2008, just a few short years after the introduction of the steam reformer methanol fuel cell vehicles. Methanol is injected directly into the cell in a direct methanol fuel cell removing the need for a reformer and its associated controls, thereby reducing weight and cost, and eliminating the small amount of nitrogen oxide emissions produced in steam reforming.

Georgetown fuel cell powered bus

Fuelling infrastructure

Given the strong commitment to developing methanol fuel cell vehicles, we must begin to address the need for fuelling infrastructure to serve these vehicles. The largest network of

States/countries	Existing stations	10% of stations	25% of stations
California	11,700	59	146
New York	6,504	33	81
Massachusetts	2,600	13	33
Germany	17,632	88	220
Japan	59,990	300	750
Target regions subtotal	**98,426**	**492**	**1,230**
Canada	13,782	69	172
Rest of US	167,088	835	2,089
Rest of Europe	100,212	501	1,253
Target regions total	**477,934**	**1,897**	**4,744**

Source: American Methanol Institute

Infrastructure cost estimate for selected countries

methanol fuelling stations is in California, where 100 public and private stations serve 15,000 methanol-powered alternative fuel vehicles. Given California's experience in building methanol fuelling stations, we can estimate that the cost to add methanol fuelling capability to an existing gasoline station is about $50,000. While consumers have come to expect near universal availability of fuel for their motor vehicles, the most likely methanol fuel distribution development scenario does not depend on a decision to create a complete system overnight. Rather, it will build upon the existing gasoline distribution system as the methanol fuel cell vehicle fleet grows.

Fuel cell vehicle introduction will focus initially on the three states in the US requiring the sale of Zero-Emission Vehicles by 2003 (California, New York and Massachusetts), as well as Germany and Japan. These highly populated areas are strong candidates for early adoption because they tend to have higher levels of pollution and offer maximum scale efficiencies for the first wave of methanol fuel infrastructure. It would cost less than $500mn to convert 10% of the stations in these target areas to methanol operation. Assuming that retail stations are required to cover all of North America, Europe and Japan would still only cost $1.9bn for 10% of the stations and $4.7bn for 25% of the stations.

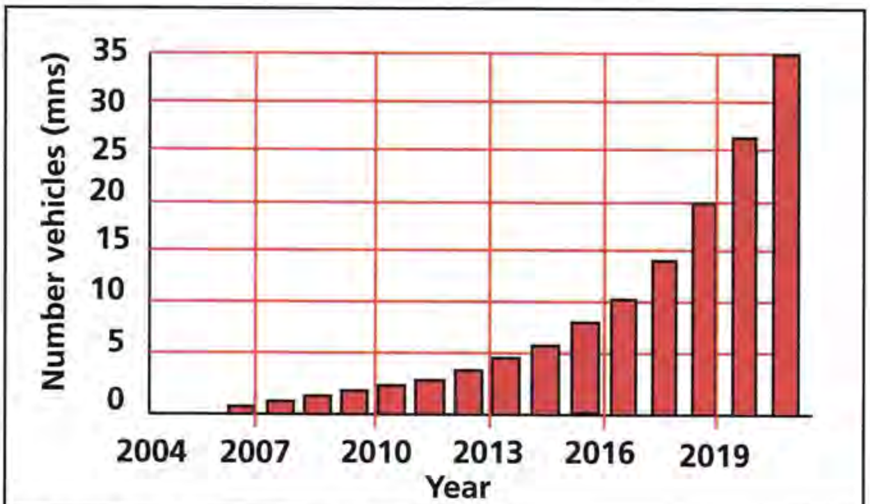
The introduction of a methanol fuelling infrastructure will also prove to be a major advance for the protection of water quality on land and in the ocean. Methanol is easily biodegradable in aerobic and anaerobic environments. In fact, methanol is used to facilitate the breakdown of municipal sewage as part of the treatment process before discharge into sensitive oceans or rivers. No-one would argue that the accidental release of methanol into the environment would be a good thing, but a leak of methanol from an underground storage tank would have a less adverse impact than a gasoline leak.

Market outlook

In 1998, worldwide methanol production capacity stands at about 11.4bn gallons (34mn tonnes). The methanol industry has a significant impact on the global economy, generating over $12bn in annual economic activity while creating over 100,000 jobs. Given the above estimates of vehicle market penetration, we can make several assumptions about the demand for methanol fuel. By 2010, manufacturers will have introduced 2mn fuel cell vehicles, each using 441 gallons of methanol per year, producing a demand of 882mn gallons of methanol per year, or less than 8% of current world capacity. By 2020, our estimated fleet of 35mn vehicles would consume 15.4 bn gallons of methanol – roughly 135% of current world capacity – and would require significant capital investments in new methanol production plants. Because large-scale methanol plants can be built in two to two-and-a-half years, there should be no problem adding the necessary capacity.

The vast quantities of natural gas in the world ensure the availability of feedstock to produce the methanol needed for this future fleet. In 1996, reserves stood at 49,912tn cf with annual consumption of 78tn cf. Producing 15.4bn gallons of methanol would create a demand for 1.4tn cf of natural gas (less than 2% of current annual consumption). With 3.8tn cf of natural gas flared and vented each year, offshore natural gas also offers a tremendous opportunity for methanol production that ICI Synetix is working to capture. In 1994, the first 54,000 t/y development plant using Synetix technology started in Australia, built by BHP on land to test the concept for a floating production, storage, and offloading system (FPSO). BHP expects to go offshore with world-scale plants using this technology early in the next decade. Finally, methanol can be produced from a variety of renewable feedstocks including woody biomass, municipal solid waste, sewage and even seaweed.

Buoyed by the commitment of the automotive industry to develop methanol fuel cell vehicles, the methanol industry is excited about the prospects for these clean vehicles to create significant new markets for methanol fuels. For less than $2 per person, a state of nation the size of California, with 30mn people, could put methanol fuelling pumps into one out of 10 retail stations. Clearly, methanol fuel cell vehicles are one of the great environmental – and energy security – bargains in history.



Projected growth in methanol fuel cell vehicle fleet

The American Methanol Institute's recent report Looking Beyond the Internal Combustion Engine: The Promise of Methanol Fuel Cell Vehicles *is available on its website at* **www.methanol.org**

Siting seeps from space

Use of satellite imagery in the onshore oil industry is now a routine part of almost all new venture programmes, as detailed by Dr Martin Insley from the National Remote Sensing Centre (NRSC) in the October issue of *Petroleum Review*. Offshore, however, geology is obscured by a water column impenetrable to satellite sensors, but satellites can still play a key role by their ability to detect minute quantities of oil leaking from untapped oil and gas pools as surface seeps. *Alan Williams,* Director NRSC Exploration Services and *Adrian Huntley,* Manager NRSC Offshore Exploration Services explain in Part II of our look at remote sensing's role in global oil and gas exploration.

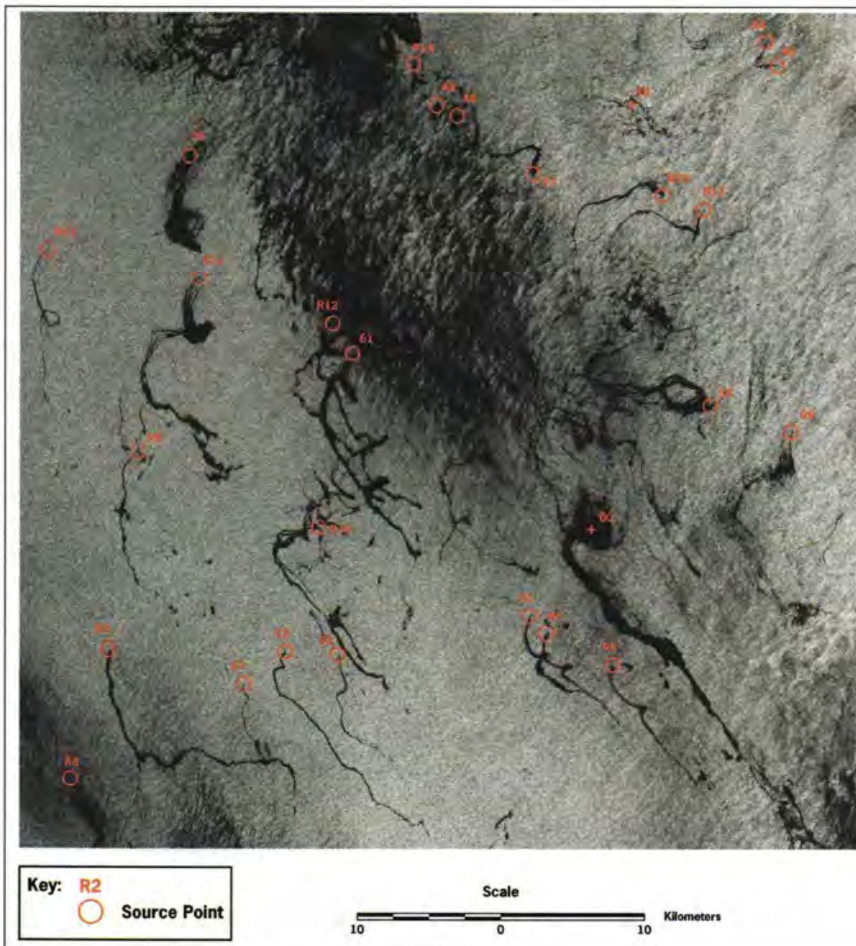


Figure 1: South Caspian Basin – example of multiple seeps (ERS data)

Seepage detection as an exploration tool is not a recent concept and the observation of onshore seeps by the early explorers was the stimulus for the discovery of many of the world's largest oil fields. The world's first oil well was drilled in the now prolific Baku region of Azerbaijan in 1848 and preceded Colonel Drake's first Pennsylvania oil well by 11 years. Both were drilled on seeps. In the period up to the 1930s, of course, BP and others discovered huge fields in Iraq (eg Kirkuk) and Iran (eg Majid-i-Sulamain) again chasing surface expressions of seepage.

However, the realisation that seeps can be detected in offshore basins is much more recent. The introduction of commercial satellites deploying high-resolution synthetic aperture radar (SAR) sensors since 1991 has now enables explorers to map the seepage distributions in any deepwater frontier basin around the globe.

SAR satellite method

The technique is based on a very simple premise known to generations of mariners, which is that of 'pouring oil on troubled waters'. Oil, of whatever origin, when in contact with water reduces the amplitude of the capillary waves, causing a wave-damped area (or slick) to form which reflects energy away from the satel-

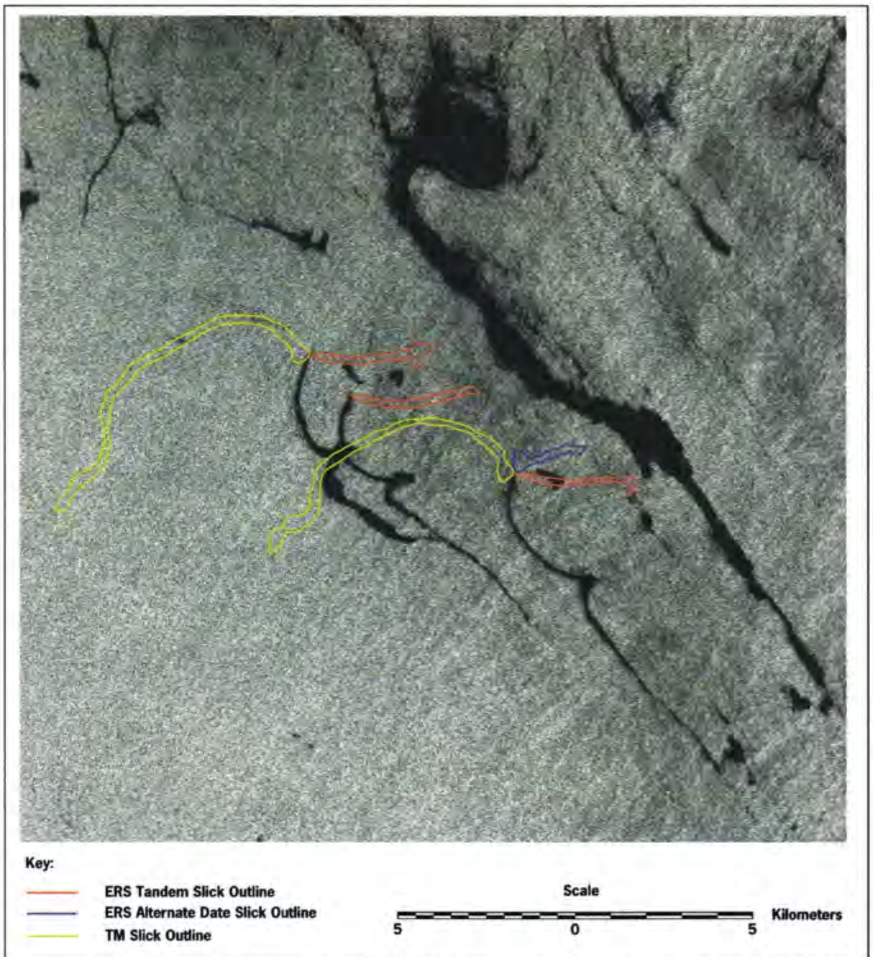


Figure 2: South Caspian Basin – example of repeat seeps (multi-temporal)

lite detector, an effect known as 'backscatter reduction'. Oil slicks are therefore seen on satellite images as dark features which contrast with 'normal' sea-water which reflects some energy back to the sensor to produce a typical grey, speckled image. Slicks are therefore easy to spot on satellite radar images. However, the key to success is being able to distinguish seepage slicks from pollution slicks and other false positives.

This is achieved quite simply by analysing a minimum of two satellite passes of each area. Pollution slicks left by illegal bilge cleaning, an alternative application for this technique, will be displaced from their original location by the combined effects of wind, currents and tides, whereas slicks produced from seeps show a repeatable source point. Sceptics can also point to the fact that leaking rigs or production platforms will also produce 'source-point' slicks, but these form obvious bright targets on the imagery and thus avoid confusion.

Satellite seep detection has many advantages over the more traditional airborne or boat-borne methods, principally as satellite data is classified as 'free-skies' data and obviates the need for expensive and time-consuming permitting and mobilisation. Its real lead over competing technologies is the fact that it offers multiple-pass observation of the same area. This is achieved by the polar orbiting patterns of each satellite (at approximately 800 km above the earth's surface) which have a revisit period (repeat coverage time) of 24 or 35 days for the two most widely-used platforms: the Canadian Radarsat or the European ERS satellites.

In the case of ERS, an extensive archive has been built up since its launch in 1991, providing a wealth of available data for all the world's sedimentary basins. Data is collected digitally in swaths which (for Radarsat) vary from 50 km to 500 km and with resolutions ranging from 10 metres to 100 metres. For most regional offshore studies, a swath width of either 100 km (ERS) or 165 km (Radarsat Wide 1 mode) provides an optimal resolution of 25 metres or 30 metres.

However, not all satellite radar data is useful for offshore seep detection and NRSC geoscientists have developed a comprehensive seep screening methodology which incorporates a rigorous analysis of the wind and wave data for each survey area. Only data which has been acquired in the optimal weather window of 6 knots to 15 knots wind-speed is purchased. Scenes below this threshold typically show confusing false positives (such as natural organic films, wind shadow effects) and scenes above the threshold run the risk that any oil slicks present are effectively destroyed. A classic example of this effect was the large, potentially calamitous *Braer* tanker oil spill (85,000 tonnes) off the Shetland Islands in 1993 where high winds broke up and dispersed the slick before it had drifted ashore.

South Caspian success story

Optimal satellite coverage for the Caspian is provided by both ERS and Radarsat. This has been supplemented by some older, cloud-free images from the Landsat Thematic Mapper (Landsat TM) satellite to either infill gaps or provide repeat coverage of key areas. The NRSC study used a combination of over 40 satellite scenes, predominantly ERS which also provided 400 km long strips of tandem data (ERS-1 and ERS-2 operating in orbits 24 hours apart) covering the central part of the basin. This proved to be very informative in tracking the amount of drift of major pollution slicks from the fixed installations on the Aspheron Peninsula and in confidently discriminating these from natural seeps which showed no drift over the same period.

Over 150 potential seep targets were identified in the South Caspian basin, 25% of which had repeating point sources and which therefore must represent active seeps, leaking from oil-filled traps. The seeps are distributed widely across the deepwater Azeri and western Iranian sectors and demonstrate the existence of a much larger black oil fairway than previously thought. An example image showing multiple seepage slicks from the deepwater Caspian is shown in **Figure 1** (red circles define the source points). **Figure 2** shows a close-up of seepage slicks that have been observed repeating over a period of 10 years; the TM slicks (yellow outlines) are from data acquired in 1986 and exactly overlay seeps on 1996 ERS data (base image and red and blue outlines).

Seep interpretation

The significance of these remarkable data will only become apparent when they are integrated with surface geochemistry results and subsurface data (especially seismic). Published geochem-

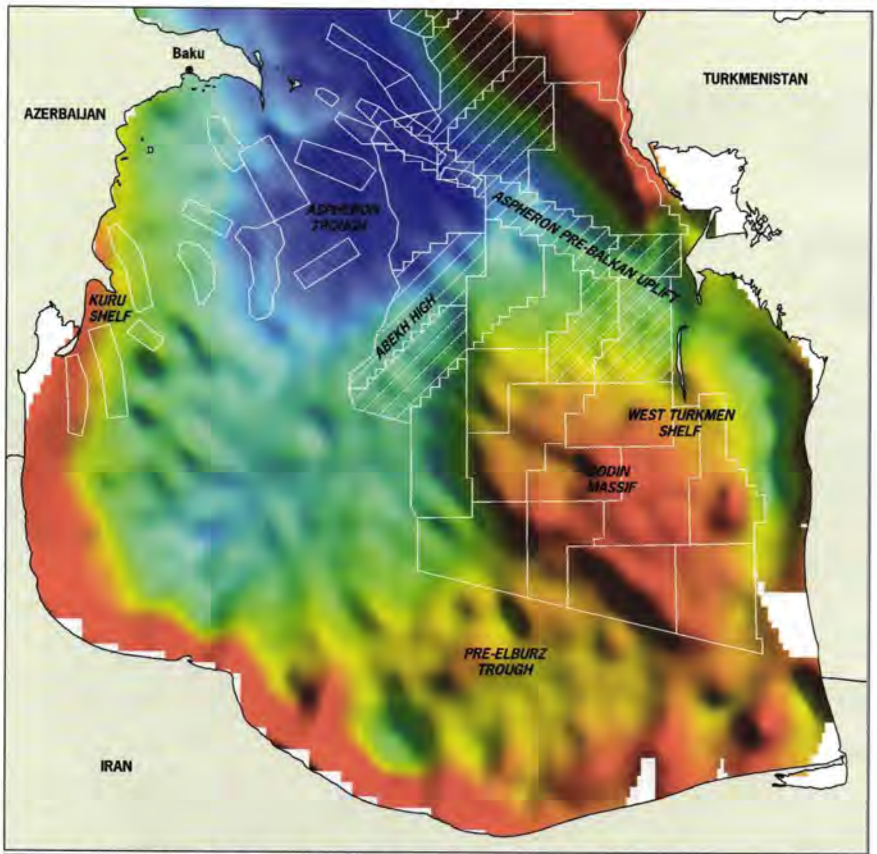


Figure 3: Free air satellite gravity image of the South Caspian Sea

ical data has confidently correlated reservoired oils to both of the principal source rocks and it seems highly probable that the observed oil seeps will also derive from similarly charged traps. Correlation of our results with published prospect maps and deep seismic profiles have also shown some interesting correlation of seeps to undrilled structures and to major leakage pathways (shallow-cutting faults, mud volcanoes, etc).

In a more regional context, the density of seepage slicks falls off dramatically as one moves both eastward in the basin over the Godin Massif into Turkmenistan and northwards of the Aspheron Flexure. The lack of success of recent drilling in this area may be partly attributed to a lack of present day oil charge as seepage slicks were not observed in this area.

Besides oil seep and pollution monitoring, satellites can also provide valuable information on gravity, bathymetry and nearshore environment. Altimetry data collected by a number of satellites can be processed to produce gravity data. A global dataset (incorporating declassified Geosat naval data) is available on the Internet from Scripps Institute in the US (referred to as the Sandwell Dataset). This provides Free Air gravity data for all the world's ocean basins and has a 'ground' resolution of approximately 10 km at the equator which improves to around 5 km at 40°N. The data can be combined with marine (and/or) airborne gravity and processed to generate derivative products such as Bouguer and Isostatic Residual maps.

Satellite gravity maps provide an excellent overview of the regional geology, especially in under-explored regions. An example of the Free Air gravity map of the South Caspian Sea (with licence information overlaid) is shown in **Figure 3** and clearly shows the contrast of the deep South Caspian Basin (blue colours) in Azerbaijan and Iranian waters with the prominent basement high (red colours) of the Godin Massif underlying the Turkmenistan sector. This also seems to be controlling the pattern of active seepage in this region (as detected by the radar satellite study) which is mirroring these regional trends.

Data from the optical satellite, Landsat TM can also be analysed for offshore seep detection but has another application in shallow (25 metres water-depth maximum), clear-water areas. With suitable ground control, TM can generate bathymetry maps at 2-metre contour intervals and map coastal environments such as mangrove swamps or coral reefs. In poorly chartered areas such information can be an invaluable aid for planning seismic and other marine surveys, particularly in ecologically sensitive areas.

The final word

Satellite exploration has reached a high level of sophistication and can provide explorers with low-cost, high-coverage information of any sedimentary basin in the world. In offshore frontier basins such as the South Caspian, seepage data acquired by NRSC Exploration Services has already contributed to a much better understanding of the regional oil generation and migration patterns of the unexplored deepwater areas and, together with satellite gravity, will help explorers in their search for the sleeping oil giants still awaiting discovery.

IT fuelling the search for energy

Western Geophysical is at the cutting edge of developments in the oil exploration industry's never-ending global search for energy reserves. Its crews operate in some of the most inhospitable locations on the planet, conducting land and marine surveys that help oil companies reduce the risks and costs of exploration, and improve the management and control of their reservoirs. Technology is intrinsic to the company's success and in recent years it has exploited the power, scalability and ruggedness of IBM RS/6000 SP supercomputing solutions to drive its business.

Above: ***The Western Monarch***

When it comes to discovering and exploiting hydrocarbon reserves, computer technology is one of the most valuable tools available to the oil industry today. On the geophysical side of the business in particular, a new generation of supercomputers is revolutionising seismic data processing.

Previously, seismic companies such as Western Geophysical relied on mainframe technology and teams of experts based in major processing centres to resolve the complex raw data acquired during offshore seismic surveys. Today, with the emergence of powerful UNIX-based parallel processing technology – known as supercomputers – data is increasingly processed at the point of acquisition, improving the cost effectiveness and turnaround of survey projects.

Headquartered in Houston, Texas, US, and with more than 5,000 employees globally, Western Geophysical is part of oilfield services specialist Baker hughes (formerly known as Western Atlas prior to the recent merger with Baker

Hughes). The company is using powerful IBM RS/6000 SP-based solutions to create what it claims is an unrivalled seismic processing capability across its operation.

One of Western's main reasons for selecting the IBM solution was the scalability and processing power of the RS/6000 SP. Its flexibility in configuration while maintaining supercomputer processing power was also a factor. The SP can be configured from two to 512 nodes and can be equipped with a variety of tape, disk and other peripherals. The fact that it can also be installed on marine seismic acquisition vessels too, makes it the ideal match for the growing requirements of onboard computing.

More bang for bucks

According to Chris Usher, Western Geophysical's Vice President of Data Processing in Europe Africa and Middle East (EAME), the company recognised the potential of UNIX technology when the first RISC workstations – powerful enough to cope with the seismic industry's processing volumes – were introduced.

The company took the strategic decision to port its proprietary seismic processing software, known now as OMEGA, to the UNIX platform. But the most significant change happened in 1994. 'We were considering an upgrade to our existing mainframe and then IBM announced the RS/6000 SP,' explains Usher. 'The timing was perfect. With UNIX and parallel processing, we knew we could get more bang for our bucks, not to mention all the benefits of scalability and increased flexibility.' The OMEGA software was ideally suited to the IBM RS/6000 SP as the software is designed to efficiently run both serial and parallel work concurrently.

Since then, thanks to the 'grow with you' ethos of the IBM RS/6000 SP – its expansion capability is said to be virtually unlimited – Western has increased its SP implementation across EAME to match business needs. Recent years have seen an annual quadrupling of CPU (central processing unit) power in London, resulting in a current system providing 35 times the capacity of the centre prior to implementing the RS/6000 SP.

At the seismic company's London Euro-centre in Isleworth, Middlesex, (also serving the Bedford, UK, and Stavanger, Norway, sites), the RS/6000 SP part of the centre rates around 80 GigaFLOPS. Smaller SP implementations are deployed in the 11 regional centres and remote sites around EAME, making it one of the largest IBM RS/6000 SP users in Europe. The Cairo centre and all of the company's deepwater vessels maintain multi-frame

Seismics – setting the scene

Bill Miller (right), General Manager of Western's Process & Petroleum Industry EAME, offers an insight into the seismic market.

Q. What are the current trends in the seismic market?

A. The seismic acquisition marketplace continues to be very strong with increased activities around the world. We are seeing an increase in the deployment of new technologies such as 4D and 4C. [4D is time-lapsed 3D used to provide data on fluids flow within a reservoir. 4C is a four component data acquisition system comprising three geophones and one hydrophone. The geophones are orthogonally arranged and measure both shear waves and P-waves. In certain conditions, such as gas chambers, shear waves can show up a greater degree of seismic detail than do the P-waves on which conventional acquisition systems rely.]

Q. What are your predictions for the future of the global market in terms of size, and investment in seismic acquisition?

A. Historically the statistics tell us that if the price of oil stays below $20 per barrel, annual growth (year-on-year basis) tends to be small, as oil companies generally are conservative with their IT expenditure. However, statistics over the years have also shown that when oil price is around or above $20 per barrel oil companies (and the whole industry in general) tend to invest hugely on IT and you see a tremendous growth in the marketplace.

Q. Are there any particular regions that are providing a particular focus of interest – what are they and why?

A. Working closely with our customers in the oil companies and seismic services companies, the areas/regions of continued interest are in the North Sea and Gulf of Mexico. There is also a continued interest in Latin America, particularly in Venezuela and Brazil. The areas of growth that we are seeing across the industry are the Caspian region as a whole, the South America coast and the West African coast. All the regions have growing oil countries/provinces investing in onshore and offshore exploration.

Q. What changes are taking place within the offshore seismic industry at present?

A. The trend in the market place seems to be for seismic services companies conducting surveys in deeper waters and generally places where they have not been before. The survey sizes tend to be significantly larger due to newer and bigger seismic vessels, some capable of towing 14 streamers and with the capability of processing onboard during data collection. The increase in computer power, while at a substantial lower $/megaflop, has enabled 3D technology to deliver a drilling success ratio above 60% and repeated collections and processing (4D) is driving production rates upward. The capacity to conduct larger surveys needs more computing power as the customer demands faster turnaround.

Q. How are Western/IBM planning to meet these demands?

A. IBM is planning to meet and exceed the demands from new technologies in this industry by continuing to provide acceleration in computer power available to the geophysicist. With IBM's commitment to delivering a multi-teraflop computer to the US Department of Environments ASCI (Accelerated Strategic Computing Initiative) to manage the US nuclear stockpile, the ability to do 3D prestack depth migration with ever increasing data sets and more stringent turnaround times will become more attainable.

The seismic industry has always demanded supercomputing power that has linear scalability, increased flexibility (the IBM RS/6000 SP is the only supercomputing platform to provide the ability to reconfigure and redeploy capacity on a when-you-need-it and where-you-need-it basis). IBM has also provided the systems management capability that customers expect to provide workload balancing, job scheduling, backup and recovery in large supercomputing installations; all this leads to improved systems availability. The seismic industry demands not only the highest performance supercomputers but also the highest performing sub-systems (tape and disk) to move the data. It achieves this by using IBM's high-density 3590 Magstar drives and IBM 7133 SSA disk. What this provides our valuable customers with is flexible, scaleable computing and improved turnaround time on seismic processing.

Nearly 1mn km of data has been processed by Western's onboard processing systems in the last two years

RS/6000 SP systems and rank as some of the largest computer centres in the company.

Seismic processing needs the highest performance sub-systems (tape and disk) to move the data, and to complement the RS/6000s, Western is using robotic tape silos, with IBM 3590 Magstar high-density drives and IBM SSA disk technology. It has approximately 1,000 IBM 3590 Magstars across its organisation and upwards of 17 terabytes of installed disk space. For systems management, it is using proprietary job scheduling systems, as well as IBM Load Leveller for workload balancing and IBM ADSM for backup and recovery.

From SP to software products, Western's total solution from IBM is ensuring that it gains maximum benefit and flexibility from its IT investment, with high levels of automation in both processing and systems management.

Responding to customer needs

One of the main benefits for Western in having an integrated SP platform is the possibilities it creates for reconfiguring and deploying computer resources as regional needs dictate. Usher explains: 'As well as eliminating compatibility issues, having a universal SP-based solution means we don't have to worry about over-capacity or not having enough power for a project when we need it, where we need it. The SP's scalability gives us a much more nimble operation. We simply add or move nodes and storage capacity from one location to another to match the size and complexity of projects.'

The result is that the company is actually winning more contracts because it is able to mobilise processing capacity quickly and cost-efficiently – essential in a business with aggressive timescales imposed by oil companies and where every second costs money. 'For a big contract, we can move into, say, Saudi Arabia, install a processing centre, complete the project, then demobilise the centre and recycle the computer resources elsewhere,' Usher adds.

The company is also making advances in real-time data processing aboard its fleet of seismic vessels. 'We have to process the data we acquire as quickly as possible to meet customer timescales,' Usher says. 'And the only way we can do that is by processing data as it's recorded.'

Western's solution to this is claimed to be unique in that it is processing acquired data in real-time using the same technology aboard its fleet as in its data centres, with a remote log-in satellite configuration. 'Of course, it would have been possible to pump seismic data from our vessels straight back to a land-based data centre via satellite for processing,' Usher acknowledges. 'But we believe this method is risky. Compressing can affect the quality of data for a start. Then there are job scheduling issues. Our solution is more elegant. With dedicated supercomputer resources onboard vessels, coupled with remote job submission by expert London-based teams, top class real-time processing is a reality.'

All aboard for success

In fact, Western's largest vessel – the Western Monarch – is one of the company's biggest computer facilities with processing capacity said to exceed that of many commercial organisations. The vessel is equipped with an IBM RS/6000 SP system with a base system of 28 nodes, providing the power for fully automated marine data acquisition, navigation and onboard processing. Like the land-based data centres, this ship-based package is complemented by a robotic tape library complete with IBM Magstar drives and satellite data communications, making the processing centre accessible from any Western site in the world.

'In practice, this means that our seismic experts don't even have to be aboard ship to oversee processing,' says Usher. 'So we can have all our experts located on dry land. Robotic tape systems mean we don't need operator shifts either. Jobs submitted from London, via dedicated satellite link, are simply lined up and processed overnight with minimal intervention, keeping support costs at very acceptable levels.

'It's convenient for our customers too,' he adds. 'They can visit our data centre in London and gain a comprehensive view on any number of projects we're working on for them.'

In the last two years, nearly 1mn kilometres of data has been processed by the company's EAME onboard processing systems. There are many examples of how the integrated solution is making a big impact on turnaround time and cost-effectiveness of services in the demanding marine environment. For example, using the RS/6000 SP and processing system on the Western Regent vessel, the company claims to have processed data acquired for an area of over 1,000 sq km, including full 3D DMO (dip moveout) and final stack, within 30 hours of last shot. Migration tapes were produced in London and available to oil company clients within 30 days. A few years ago – and without onboard processing – such a project would have taken in the region of six months.

On the *Western Monarch*, the company processed data acquired for a 2,500 sq km area, through a hi-tech, compute-intensive processing sequence including Radon demultiple, in order to significantly reduce project turnaround time.

With remote processing, the onshore finalisation is handled by the same team that processes the data with the onboard system. Hence the technology available from IBM today gives advantages in project continuity in addition to the project turnaround time reductions that are so vital to the oil exploration business.

Usher concludes: 'Just as our oil company customers want to get maximum yield from their reservoirs, we're looking to leverage our IT investment to full potential. We'll continue to work closely with IBM as our technology partner to achieve this.'

Unlocking the wealth of oil sands at the wellhead

***Priscilla Ross* takes a look at how the use of enhanced recovery techniques is helping to give heavy oil projects, in particular Canadian developments, a new lease of life.**

The two largest steam-floods in the world are operated by Texaco at Kern River, California, and the Duri field in Indonesia with Caltex Pacific Indonesia (CPI). These mature heavy oil fields have a normal extraction rate of about 65% to 67% of the oil in place. However, by using the new Texaco 3D visualisation supercomputer in Houston, which allows five times more data to be viewed in cinema auditorium-like conditions than could previously be looked at on a conventional workstation, the extraction rate from Kern River has been lifted to 80%. This vastly improved recovery rate will enable another 300mn barrels to be extracted during the field's life time.

Proposed SAGD drilling at Lak Ranch
Source: Derek Resources Corportion

The Kern field was discovered in 1899 and is currently celebrating the billionth barrel of oil output. Only a handful of the world's fields can lay claim to equalling such prolific output and the next hurdle being contemplated is production of the second billion barrels.

The heavy oil beneath the surface at Kern River includes original oil in place estimated at over 3.5bn barrels with most of the current reserves under Texaco ownership. The field is abundantly productive – the Kern river steam-flood producing 100,000 b/d – but in size it is a modest 10,000 acres.

Key developments

During the 1990s Texaco has initiated two key developments to bolster production. The first was multi-zone steam-flooding. Instead of using steam in the nine layers of sand in the field on a one-off basis, the steam-flood was applied to multiple layers across the field. Production was boosted from 80,000 b/d to 95,000 b/d. Purchasing Monterey Resources pushed Texaco's production to 100,000 b/d in 1997 and in 1998 the company has drilled Kern county's 100,000th permitted well.

The second breakthrough is the inauguration of Texaco's first field visualisation centre at Kern River, which is similar to the Houston cinema-like visualisation auditorium. The Californian field visualisation enables hands-on interpretation of data at a field site. The centre can generate 3D maps and visualisation of the field above and below the ground in microscopic detail. Information has been gathered from over 10,000 wells and data has been periodically captured from selected observations wells.

World record

Texaco's second major heavy oil project is the Duri field in the Rokan block in central Sumatra. Claimed to be the world's largest steam-flood since 1985, output averaged 284,000 b/d of oil in 1997.

The massive Duri project, which is divided into 13 phases, reached phase eight of the steam injection programme in 1996, ahead of schedule. Above the massive P/K reservoir of the Duri field lies the shallow Rindu reservoir and there has been a pilot steam-flood there since 1994. CPI is currently in the process of a multi-year 3D seismic effort to evaluate oil and gas potential in the under-explored areas between current producing fields.

The world's largest reserves of oil sands, however, are to be found in Canada and Venezuela. Canada's Alberta tar sands contain 2,500tn barrels of oil in place and at least 300bn barrels are in the recoverable category using current technology. Advanced technology, however, such as horizontal wells could double recoverability to 30%.

These oil sands contain more recoverable oil than all the proven reserves of Saudi Arabia, and the Canadians have barely begun to develop them with only 2bn to 3bn barrels produced to date.

Early in 1997 Natural Resources Canada forecast that between 1995 and 2020 production from oil sands will double to 850,000b/d. By 2020 oil sands are projected to contribute 36% of Canada's total oil production compared to the current 20%. But based on announced investments of C$24bn, output from the oil sands could rise to 1.7mn b/d. Except for the Husky and NewGrade upgraders, which are now operational, no other stand-alone or refinery add-on upgrader projects were assumed over the projection period. The Shell SCO project of 150,000b/d by 2002 is not included in the analysis – Shell has 9bn barrels of recoverable oil.

Canadian upgrader

A number of stand-alone upgraders were proposed in the early 1980s. Only the Lloydminster BiProvincial Upgrader made it past the proposal stage (excluding upgraders outside of Alberta, ie the NewGrade Upgrader in Saskatchewan). The first 1mn barrels of high quality synthetic crude oil were produced in September 1992 from heavy oil and bitumen from Alberta and Saskatchewan. In 1994 the governments of Canada and Alberta withdrew their financial support for the upgrader and sold their interests to Husky Oil. More recently the government of Saskatchewan sold its interest in the project leaving Husky the sole owner. At the upgrader large amounts of coke and sulfur are removed and hydrogen is added to the bitumen to produce synthetic sweet oil.

The heavy oil and bitumen reserves of Canada are located in the Lloydminster area of Saskatchewan and four major areas in Alberta: Peace River, Athabasca, Wabasca and Cold Lake. The Athabasca region in Alberta is estimated to host three-quarters of Canada's heavy oil reserves and became the site of Canada's first two commercial plants. Suncor established its first oil sands operation in 1967 and Syncrude followed in 1973. Conventional heavy oil (other than bitumen) occurs mostly in the Lloydminster area.

Canada, with its cold climate, vast distances and highly industrialised economy, is the largest per capita consumer of oil in the world. Conventional crude oil production in Canada's western sedimentary basin is declining gradually and without new production the country could become a net importer of oil. Canada wants to avoid this possibility and heavy oil exploitation and East Coast production may be the solution to maintaining the country's hydrocarbon self-sufficiency.

Holding the advantage

An average of only 10% of the original heavy oil reserves in place is included in the present recoverable category using existing production methods. However, a number of advances (horizontal drilling and thermal technologies) could enhance the average recovery rate to over 30% of the oil in place.

The advantage the Canadians have in bitumen extraction is that cheap, high volume, strip mining techniques can be used on the vast reserves which occur at relatively shallow depths at Fort McMurray, Athabasca in Alberta. There is no need to inject heat into the formation as at the in-situ (well) operations at Cold Lake in Canada or the Orinoco deposit in Venezuela.

The developing of bitumen and heavy oil upgrading plants in Canada to make the end product more acceptable to Canadian consumers could create the right economics for more expensive enhanced techniques to be used effectively.

Probing further

Probe Exploration produces heavy oil from the Kitscoty project in Alberta. Steve Gibson, Chairman, says that in the last six months in Canada the differential between light oil and conventional heavy crude dropped from $9/b to $4/b. During that period the Canadian dollar depreciated from 72 cents against US$1 to 65 cents. Probe has put a hedging programme in place which locks up the $4/b differential to preserve future cash flows.

Probe sells all its production to the Husky Oil upgrader. Essentially Canadian production is competing with Venezuelan output for refinery capacity in the US. However, the Venezuelans have vertically integrated by owning refinery capacity, and Canadian output can only compete on cost structure. Around 80% of Canada's output is exported to Chicago and, of the two refineries that the Venezuelans owned there, one has been sold. Most of Venezuela's exports are delivered to the Gulf Coast.

There are significant bitumen reserves in the Orinoco deposit in Venezuela and the magnitude of the oil in place and recoverable reserves are roughly equivalent to the Canadian bitumen profile. The Venezuelan heavy oil has two distinct advantages: it is closer to water and it is cheaper to transport via tanker than pipeline. Also the Venezuelan heavy oil is naturally heated, because it lies over a natural fault, which has the advantage of lower lifting costs than less accessible reserves found in Alberta.

Hamaca study

Texaco has a 20% stake in the Hamaca Heavy Oil Project, which has been studied for the past two years in order to assess the possibility of developing a heavy oil field whose production could eventually be diluted and transported to an upgrader which would produce a lighter oil. It is hoped that the planned process will make the heavy oil more appealing to the refining market.

Chris Avenius of Texaco's small new business group operating in Caracas says: 'The process could remove the high sulfur and heavy metal content of the fuel [crude], making it more attractive to refineries.' In 1999 the study on the project will be presented to the boards of the joint venture partners and will include potential profitability and the long-term outlook.

The life-span of the project is expected to be around 35 years with reserves of 2.6bn barrels of oil. The project would begin with 36,000 b/d of extra-heavy crude (bitumen) for blending with lighter fuel for direct sale. The upgrader, when completed, would increase production to 165,000 b/d for upgrading to a 25° API syncrude.

Increased assets

Ranger Oil, the Canadian group with North Sea oil interests merged with Elan Energy Inc to add heavy oil to its asset base in September 1997. Elan added 5bn barrels of oil in place and production of 21,424 b/d in the 4Q1997. However, output fell to 14,802b/d for the 2Q1998 with production levels continuing to decline because of uneconomic wells being shut-in as a result of low prices. The sale of a non-core asset in the 1H1998 shaved 1,000 b/d off heavy oil output. About 4,000 b/d of output is shut-in.

Most of Ranger's heavy oil production comes from two fields: Lindbergh and Cold Lake. Both fields were extensively drilled in 1996 and early 1997. Expertise in a cold production technology was one of the assets acquired by Ranger. Elan was the first company in Canada to use single well steam assisted gravity drainage (SAGD). This thermal technology has the potential to significantly increase the recovery of bitumen and conventional heavy oil if applied to suitable reservoirs.

Ranger also has a 50% interest in the ECHO pipeline which provides a secure source of transportation of the company's heavy oil. This innovative heated pipeline transports heavy oil from Lindbergh to Hardisty without condensate diluent.

For the December 1997 year-end Ranger's heavy oil operating costs were reported as being under $5/b.

Company President, F J Dyment, believes that in the longer term future growth in the Canadian Western Sedimentary Basin will be primarily from natural gas and heavy oil.

Three successful evaluation wells were drilled at the Wolf Lake thermal project in East Central Alberta during the 1Q1998, confirming the quality of the heavy oil reservoir. The commercial potential of the project is under evaluation, but full development is on the backburner until a sustained recovery in heavy oil prices is apparent.

Notable development

A junior Canadian company called Derek Resources is noteworthy because its Vice-President – Engineering, Dr John Donnelly, has recently been working on recovery technology at the Blackrock property in the Cold Lake oilsands of Alberta and has consulted for various governments. He is now an adviser to Shell's SAGD project at Peace River. Derek Resources itself has a pilot plant on the Lak Ranch property located on the Powder River Basin of eastern Wyoming, US, and is interesting because it provides some salient figures.

Other companies have attempted to produce heavy oil from the Lak Ranch. Conoco tried 'huff-and-puff' for a limited period in the 1960s. Parrent Engineering attempted solvent recovery, and a Surtek pilot scheme in the 1980s using chemical methods arguably failed because of the withdrawal of its Japanese partner following the 1986 oil price collapse.

The WTI spot price averaged $27.99/b in 1985 and had slumped to $15.05/b in 1986.

All these attempts proved that oil production on a commercial scale was technically feasible if not necessarily rendering an appropriate return on investment to shareholders.

Some insight into both the potential and the drawbacks of conventional recovery techniques can be gleaned from a vertical well on the eastern side of the property completed as recently as 1990 but suspended as uneconomic.

The current C$5mn pilot project will begin steam generation in the final quarter of 1998 with first production in 1999 between 12 and 15 months from the commencement of the project. The oil is comparatively light at 20° API compared to others at Cold Lake of between 8° to 10° API which have encountered separation problems.

Derek claims lifting costs will be US$4/b or less, substantially lower than other Canadian and US projects. Compared to Blackrock, the topography of the Lak formation requires that horizontal sections will be shorter at 1,600 feet and only one generator will be required rather than two. Derek asserts that Lak Ranch oil is suitable for jet fuel and, with its higher gravity, it will sell at no discount for quality (gravity) or transport to WTI – compared with a discount of up to US$8/b for Athabasca aromatics and US$6 for Kern River oils.

The base case for the Lak Ranch project is for 70mn barrels to be produced over a 15 to 20 year life span.

For the Lak Ranch project to be profitable it is based on a WTI price of US$14/b less full lifting costs of $6/b including royalties and capital amortisation. Pilot lifting costs are estimated to be about $9.40/b. Third-party engineering has now been completed to support these assertions and access to their reports is available on request.

Derek says Texaco has guaranteed in writing as of May 1998 a price of WTI for Lak Ranch oil. It is napthenic and makes an excellent jet fuel. The price is for delivery to tanker trucks FOB the Lak Ranch well-site. Refining and distribution facilities are within 4 miles of the Lak Ranch site. Derek claims over 100mn barrels of oil with the potential for 150mn barrels of 20° alkaline sensitive, low sulfur oil.

Heavy oil and tar sands – definitions

- **Heavy oil:** a depleted crude oil of high viscosity in which most of the light ends have been lost. Usually refers to a material with an API gravity of 10 or above (sometimes 15° API or even 20° API). In virtually all oil producing basins there are some heavy oil fields. The two largest producers are Kern River in California and Duri in Indonesia.
- Below 10° API the material is usually referred to as bitumen, asphalt or tar, and the source as **tar sands** or **oil sands**. The two largest deposits are the tarsands of Athabasca in Canada and the (misnamed) heavy oil deposits of the Orinoco area in eastern Venezuela. Each area is estimated to have 1tn barrels in place.
- Canadian deposits are usually worked by stripping the overburden and extracting the bitumen with steam, hot water and caustic soda. The bitumen is then upgraded by coking to yield a low gravity, low sulfur synthetic crude oil. The Orinoco deposits (gravity 9.5° API) are extracted by steam stimulation and chemical diluents and then sold for refining.
- **Orimulsion:** the name given by the Venezuelans to a commercial boiler fuel consisting of 70% bitumen, 30% water and 2000 ppm surfactant which forms a stable, pumpable emulsion.

Cutting costs

The key to unlocking the wealth of the oil sands at the well-head is science and technology. With over C$100mn being spent annually on science and technology the Canadian oil sands industry has been able to dramatically cut operating costs. Ten years ago it cost C$30/b to produce a barrel of upgrade crude oil. It now costs C$14/b (US$10/b). For mining operations using large truck and shovel equipment combined with a hydro-transport system further reductions of C$2/b are expected.

The National Task Force on Oil Sands Strategies of the Alberta Chamber of Resources believes science and technology will be the lever to reduce operating costs for integrated mining operations to between C$8/b and C$10/b (US$6/b–US$7/b) and total costs to US$15/b by 2010.

SAGD technique

SAGD is the latest and most efficient technique for the exploitation of oils of low gravity and/or in low-energy reservoirs. Its use also qualifies for royalty relief as it is classed as 'experimental' production.

A single or a pair of wells is drilled, usually both horizontal and parallel but a vertical and horizontal combination may also be used. Steam is injected into the top of the formation through the upper well to create a steam chamber thereby reducing the viscosity of the oil, which then sinks due to the gravitational force to be collected by the lower (horizontal) well drilled close to the base of the reservoir.

The technique was successfully introduced a decade ago by the Alberta Government operation UTF (Underground Test Facility) and followed up with highly productive results by Sceptre Resources at Tangleflags. Sceptre's first horizontal well in 1988 at Tangleflags initially yielded 150 b/d – a vast improvement on the 20 b/d return from a typical cold vertical producer. A year later its productivity had bulged to 1,500 b/d and this has proved to be a sustainable rate.

Productivity varies from project to project but Suncor's in-situ (well) operation at Cold Lake has three well pairs in operation that render 650 b/d a piece as opposed to its massive strip mining operation at Fort McMurray.

At the Blackrock property in the Cold Lake, where oil sands began production in September 1997, output is currently exceeding expectations at 400 b/d from the first well pair.

Risk analysis

Essentially there are three components to consider in the risk analysis of heavy oil (bitumen) projects – geology, engineering and commodity price. Geology favours Canada and in particular Alberta with its vast heavy oil (bitumen) reserves. Modern recovery techniques such as SAGD, especially with a royalty break for experimental production, favours heavy oil. The overriding risk factor at the moment is the commodity price risk, namely the US dollar price of oil. But in Canada, with the depreciating currency against the US dollar, some advantage in preserving cash flow can be derived from locking into hedge programmes which have seen the differential between conventional crude and light oil derived from heavy oil decline from $9/b six months ago to $4/b.

New lease of life

In the US, Kern River's heavy oil field has been given a new lease of life with multiple layer steam-floods, and the visualisation techniques of supercomputer technology have enhanced recovery rates to 80% from a previous 65%. The second billion barrels of oil production are now being slated for production.

In Indonesia the Duri field, the world's largest steam-flood has been in production since 1985. It had output of 284,000 b/d in 1997 – enhanced oil recovery methods will help Duri maintain this level beyond 2000.

Living dangerously

Those involved in today's international oil and gas business, be they workers on the ground or top-level executives, are increasingly having to operate in countries troubled by local political and cultural disturbances and face the ever-present threat of terrorist activities, including kidnap. *John Burke* recently learned how to survive such threats, taking part in a training course that could save oil multinationals from paying out to kidnappers or compensating staff's next of kin.

The oil industry might well ponder Sinatra's line about 'how nice it is to go travelling but so nice too to come home'. In a troubled world, each week brings news of an attack on someone working or going abroad. Worse still, experience shows that the top targets for kidnappers are in oil and energy, while the prediction is that the Latinos are turning away from landowners to the blackmail of multinational companies instead. (The risks to oil personnel are confirmed by a recent report from Control Risks Group, see p48.)

Financially, there are few statistics on such attacks. But one quirky comparison is that while Shell probably spends about £15mn/y on business travel, there is an immediate facility for $50mn of ransom cover at Lloyd's although overall capacity is not stated.

Among the special insurers, AIG puts the basic premium around £500 to cover kidnap and ransom up to £1mn with additional weighting for areas such as Latin America and the Middle East. The Hiscox syndicate reports that known cases of kidnapping rose from 1,367 to 1,407 last year, followed by a surge to 784 up to June this year.

To encourage cover against violent criminal or political risks and also to limit the likelihood of payout by those with deep pockets, be they oil multinationals or overseas millionaires, a quick course has been designed by Special Contingency Risks Ltd (SCR) of Leadenhall Market, UK, for anyone whose business could be in a hot-spot. Entitled 'Executive Security Awareness', the course is divided into seven lectures and seven hours of practical training during which I counted well over 100 tips for the prudent traveller, including several things to do and buy even before the day of departure.

Since 1976, SCR (which is owned by insurance broker Willis Corroon) has combined its expertise in insurance broking with security advice and training to protect firms and their staff from all kinds of violence and extortion. Having seen several hundred cases of commercial blackmail, the group acts for 850 corporate and individual clients around the world. These include oil and gas companies, although the company refuses to divulge names.

It is an open secret that the course is run by former members of the Special Air Service (SAS) with more than 40 years of military service between them. Although they do not encourage discussion about their past, all the trainers seem to have served in the Middle East. Having also helped to protect British embassies, they now advise and protect wealthy clients in many countries – not least by recommending various grades of armoured vehicles with a top price of £80,000.

The training actually took place between Hereford and the Brecon Beacons at the kind of country-house where wartime agents were trained. The course, costing £2,900, attracted about a dozen executives who were not too publicity-shy to reveal that they came from the oil and other industries not only in the UK, but also Scandinavia, Benelux and the Mediterranean. However, the absence was noted of certain western and oriental nationalities whose attitudes often lay them open to organised crime.

Prime targets

The course's director, Aubyn Stewart-Wilson, outlines the dangers: 'Attacks on oilmen and others abroad, especially conspiracies for ransom, have shown a marked increase over recent years. Desire for quick gain will be aggravated by the global economic crisis that is affecting emerging markets in particular.'

He says that there are two endemic reasons why oilpersonnel come top of the kidnapping list instead of those in the contracting industry or financial services. 'In the same way as pin-striped bankers, they are seen as being backed by big money. Unlike them, however, but in common with engineers and constructors, they work and live at sites remote from the forces of law and order. Besides all that, a lot of oil comes from what were always unstable areas of the world.'

Top ten hot-spots

According to Stewart-Wilson (who joined Willis Corroon from the Royal Green Jackets), kidnapping generally has long been worst in Latin America. That is why SCR has its own safe-house located somewhere between Acapulco and Monterrey out of which its consultants can operate in comfort and safety.

Mexican kidnappers tend to target local businesspeople whereas the hated 'gringo' is more likely to be targeted in countries like Guatemala and Peru. The worst place of all remains Colombia (7,800 cases since 1989) where kidnapping goes hand in hand with other organised crime based on narcotics. According to SCR, oilpersonnel face their greatest risk there, followed by Venezuela and Peru, although they are far from the only targets.

Dangerous too are the Philippines and the Indian sub-continent as well as the former Soviet Union where there have been six cases of kidnap so far this year. The going rate for ransom is $1mn in Chechnya, but in Russia hostages are more likely to be taken for cash on the premises.

The top ten areas for kidnapping also include Yemen, although Nigeria and South Africa are looming large for personal attacks of all kinds. Most kidnappers are criminally rather than politically oriented, but the distinction is irrelevant to SCR. Terrorists too need to raise money, and the techniques for evading capture (such as altering routes and routine) are much the same.

Taking care of number one

The first day of the course dealt mainly with planning one's trip abroad and learning how to identify hot-spots or troublesome situations. There was also advice about how to get out of a tight corner. One instructor advised: 'Guidebooks like the *Gulf Handbook* or *South American Handbook* will give you the low-down about local hazards, but you should also get updates from a source such as the Foreign Office or Control Risks.' Following is an extract from the latter's briefing on Peru: 'Sophisticated criminal gangs in Lima indulge in contract killings, extortion, drug-trafficking and opportunistic kidnapping to raise money'.

Among other vital advice, course participants were told about handling money and about secure, but discreet, luggage as well as about security in hotels. The point was made that today's business traveller must also be aware of fraudsters – for example, in West Africa – who will not only try to con them but also use any information or documentation they can grab to plan a long-term scam at long range.

We were also advised to avoid anything, in conversation or clothing, to suggest that one was worth killing (as happened recently in Cyprus) between airport and hotel. According to one instructor, nine kidnappings out of ten occur when the target is in a vehicle, often close to the destination. Nearly all of them succeed, which is why most of the second day of the course was dedicated to defensive and evasive driving.

Our trainer, whose next assignment is in an African oil-state, sat in the passenger seat as we took it in turns to drive along the Welsh border and anticipate whatever surprises might be in store. Then we went onto a deserted airfield for thrills and spills straight out of the James Bond films: fast turns ... breaking and reversing ... ramming a car that crossed our path ...

Before the final debriefing, there was a basic course on first-aid and minor surgery/dentistry. The trainer for this section (whom the army seconded to casualty hospitals) quoted cases where travellers had survived through taking such equipment as their own sterile needles. At this stage, there was a commercial break. Special Contingency Risks can take orders for medical kit, including roll-up stretchers, invented by ex-SAS men. Also recommended were *The Survival Book* and *Urban Survival* written by 'Lofty' Wiseman, a Borneo veteran. And since it is hard to absorb everything in two days, each participant leaves with a 50-page manual.

The final word

Having myself reported from places as far apart as the Andes, Emirates and Philippines, I would not only recommend the scheduled courses in Herefordshire but encourage SCR to take seminars or videos to oil companies and other relevant organisations such as the Association of Insurance & Risk Managers in Industry & Commerce (AIRMIC). Some of its members are in the oil and energy business and place their risks through such brokers as Willis Corroon.

Self-defence

Students study roll-up stretcher

Oilpersonnel are hostages to fortune. How sensitive the industry is to kidnapping and ransom can be gauged from the fact that when I called Shell to ask a very simple and harmless question, its press department said that the security officer did not discuss the subject under any circumstances.

Netherlands Conference

Delegates to the Recommissioning Conference gathered for a group photograph at the Netherlands Energy research Foundation (ECN) facilities at Petten. This successful two day event was organised jointly by the Institute, the IP's Netherlands Branch and ECN. The speakers focused on the opportunities to re-use or recycle the facilties and structures from redundant offshore steel platforms in the North Sea, concepts which are now entirely in line with the thinking of the European Commission and the outcome of the July OSPAR meetings in Portugal. There was a lively participation in the technical sessions by delegates from Norway, Netherlands, Germany and the UK.

NEW Publications

Natural Gas in Italy

David Lane (FT Energy, Maple House, 149 Tottenham Court Road, London W1P 9LL, UK). ISBN 1 85534 895 3. 176 pages. Price: £395 ($632).

This report provides analysis of Italy's natural gas industry and highlights the key areas for investment. It outlines the latest developments in this market sector, such as the increase in gas-fired electricity power plants and the growing influence of the largest municipal utilities. The report also includes detailed profiles of the industry's key players and analysis of industry prospects.

Western European Cross-Country Oil Pipelines: 25-Year Performance Statistics*

(CONCAWE, Madouplein 1, 1210 Brussels, Belgium). 38 pages.

This report (No. 2/98) contains 25 years of performance data relating to western Europe's cross-country oil pipeline system which currently comprises 30,600 km of pipeline carrying 634mn cm/y of crude oil and oil products. It indicates that most European pipeline spillages are small and the effects generally localised and temporary. Spillage frequency is also shown to have fallen over the period from 1.2 to 0.4 spillages per 1,000 km of pipeline.

Prospects for the World Offshore Oil and Gas Industry 1998–2000

(Mackay Consultants, Albyn House, Union Street, Inverness IV1 1QA, Scotland). 196 pages. Price: £850.

This report provides a comprehensive overview of the economics of the offshore oil and gas industry. It provides detailed forecasts of offshore activity in 114 countries, grouped into eight regions. These forecasts cover seven key variables: offshore oil production, offshore gas production, exploration and appraisal wells, total offshore expenditure, exploration expenditure, development expenditure and production expenditure. The report takes into account the recent falls in oil prices and the economic crisis in Asia.

Corruption and Integrity: Best Business Practice in an Imperfect World*

(Available from Control Risks Group Ltd, 83 Victoria Street, London SW1H 0HW, UK). Price: £95.

Corruption is a universal phenomenon with far-reaching implications for business. This report defines the different forms of corruption, including 'grand' and 'petty' corruption, systematic corruption, collusion and extortion. It analyses the current corruption debate, and the consequences for business. Drawing on the international experience of Control Risks Group and on interviews with business people worldwide, the report is intended to help senior executives understand the problem, anticipate future trends, and implement strategies to address the corruption issue.

Energy in Ukraine

Heiko Pleines (FT Energy, Maple House, 149 Tottenham Court Road, London W1P 9LL, UK). ISBN 1 84083 000 X. 201 pages. Price: £395 ($632).

This book provides an overview of Ukraine and the political, economic and sociocultural factors shaping the country and their implications for the energy sector. The report also addresses the availability of oil, gas, coal and uranium resources; the plans for the restructuring of the individual energy industries; geological and environmental issues impacting energy developments; changing attitudes to foreign investment and the regulatory framework involved; and Ukraine's role in the Eurasian oil and gas transportation network.

Trading in Oil Futures and Options*

Sally Clubley (Woodhead Publishing Ltd, Abington Hall, Abington, Cambridge CB1 6AH, UK). ISBN 1 85573 387 0. 140 pages. Price: £45 ($80) plus p&p (£3.75 UK, £5/$9 rest of Europe, £11/$20 rest of world).

This publication explains the intricacies of futures and options in the world oil markets. It introduces the concept of price risk management and provides numerous practical examples. The book concentrates on all the risk management tools currently available to those involved in the industry, from crude oil producer to refined product consumer, and explains the theory of futures, exchange options and over the counter trading.

* *Available from IP Library*

On-line searches

The IP Library provides access to both *Dialog* and *Questel-Orbit* as well as *Reuter's Business Briefing* for carrying out on-line searches on behalf of IP members. Contact Chris Baker or Sue Tse for more details.

Hot off the press

- *UK Petroleum Industry Statistics. Consumption and Refinery Production: A Ten Year Cumulation 1988 – 1997.* This valuable statistical publication will be mailed to all subscribers to the IP Statistics Service. Non-subscribers can purchase copies at £12 each (£9 for IP Members). Please make cheques payable to the INSTITUTE OF PETROLEUM.
- *IP Annual Statistics 1998/99.* One copy free, extra copies £5 each.

Contact Chris Baker or Sue Tse for either publication.

Information for Energy Group (IFEG)

IFEG members and prospective members are invited to the AGM and Wine and Cheese party on Thursday 10 December at 5.30 pm. Do not be put off by the AGM – it only lasts 15 minutes! Please let Catherine Pope know that you are coming.

Just walk through the door

Have you every wondered what we hold in the IP Library or what services we offer? As a member you are welcome to visit us from 9.30 am to 5 pm, Monday to Friday. If you phone in advance we will set aside some time to show you around. Non-members are also welcome to see what benefits they would gain from joining. Contact Catherine Cosgrove to arrange an appointment.

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Alternatively, read all about the Library, the Institute of Petroleum and what it can offer you on our web page **www.petroleum.co.uk**

New software aids valve management

US company Neles Controls recently unveiled version 2.1 of its Valve Manager™ software.

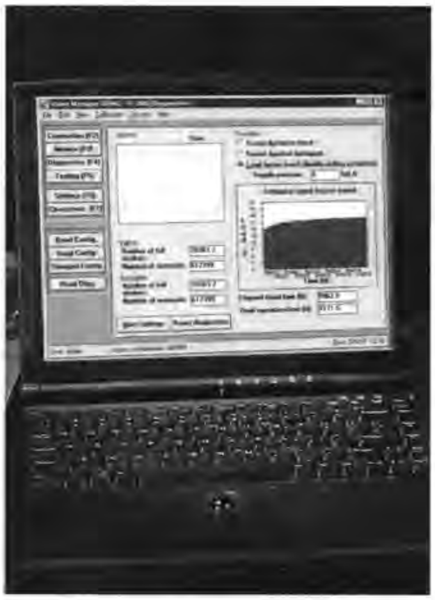
Used with the company's microprocessor-based ND800 Position Controller, the updated software provides PC-based tools for configuring and monitoring control valves from a single remote location. It has also been designed to interface with the manufacturer's family of life cycle management electronic and software products.

The Valve Manager software monitors valve performance online, accumulating trends on critical parameters and automatically recording any deviations from acceptable performance. This information allows users to identify and trouble-shoot valve and/or process problems.

The system also facilitates the implementation of predictive maintenance schedules designed to improve run times and reduce the total cost of valve ownership, states the manufacturer.

The system's remote configuration capabilities make it simple to calibrate the valve as well as change settings and operational parameters, claims the company. Automatic calibration takes only a few minutes.

Valve Manager is also said to allow the user to linearise the valve's installed flow characteristic so that the opening and closing response is directly proportional to the control signal across the entire band. This can be done either by entering corrections manually or by importing the installed flow characteristic curve from Neles Control's NELPROF® sizing software and initiating Valve Manager's automatic linearisation feature.



A multiplexer network version of the new software, which allows the connection of hundreds of valves to a single computer, is also available.

Tel: +1 358 204 80 150
Fax: +1 358 204 80 151

Deepwater mooring installation package

A new software system designed to make the installation of deepwater moorings easier and safer has been unveiled by marine consultant ASCo Marine and Underwater Services (AMUS) and BMT Fluid Mechanics.

The Deploy system contains BMT's latest mooring line analysis routines, which are claimed to be capable of coping with the most complicated mooring line combinations of wire, chain, support buoys and sinkers etc. The system also takes into account the effect of seabed friction on the installation.

'The installation of moorings in deep waters poses particular technical problems and risks', explains Andy McCluskey, Marine Services Manager of AMUS. 'Deploy enables customers to carefully plan the use of their resources and to use them more efficiently. In particular, it allows them to ensure that the selected anchor handling vessels are suitable to complete their task. The user is then in a position to charter the most appropriate vessel, and not necessarily the largest or most expensive. The detailed plan will also reduce the risk that the mooring installation will meet unexpected problems or expensive delays.'

The Deploy software is a Microsoft Windows® application with easy to understand user interface and a high resolution graphical display of the planned deployment.

The software also delivers a graphical and tabular deployment plan report which can become a key component of a rig move or mooring installation procedure.

Asco Group – Liz Davis
Tel: +44 (0)1224 564706
Fax: +44 (0)1224 57617

BMT Fluid Mechanics – David Owen
Tel: +44 (0)171 735 8366
Fax: +44 (0)171 793 0425

Cutting completion costs

The Expro Group has developed two subsea bore selector systems which it claims reduce the costs associated with deepwater completion and tree installation programmes where traditional dual-bore systems are required. The completion and open water bore selector systems provide dual-bore access from a monobore riser, eliminating the need for a dual-bore riser which is an expensive element of subsea operations.

The Completion Bore Selector System is designed to be run as part of the tubing landing string providing wireline access to both the annulus and production bores of the tubing hanger. The tool can be controlled from surface in parallel to the company's tubing hanger running tool (THRT) control system and directs toolstrings to one or other bore as required via a hinged gate actuated by a sliding sleeve.

The tool is designed to interface either directly with the THRT or with the company's dual-bore subsea completion tree (DBSCT) which provides dual-bore well control and an emergency disconnect (and subsequent relatch) facility in the landing string during completion and clean-up operations.

The completion bore selector system is modular in design. The potential for a string circulation path has been retained through the use of a side-port in the annulus bore of the DBSCT accessed via the blowout preventer choke/kill lines.

The tool was recently used to install eight subsea completions in the North Sea, with no attributable downtime, states the company. These were installed in 500 metres of water utilising a hydraulically actuated tubing hanger requiring suspension plugs in both annulus and production bores. Similar dual-bore riser requirements have traditionally existed for conventional tree installation operations, with monobore systems requiring a round-trip to surface to realign the riser for annulus bore access, explains the company – an operation that can be expensive from a high-specification rig in deep water. However, application of the bore selector concept is said to deliver capital and potential operating cost savings by interfacing with the existing lower riser package (LRP) design. The tool is positioned in the string immediately above the emergency disconnection package and below the riser stress joint. Selection functions are controlled hydraulically via a workover control system – a position indicator, viewable with an eyeball ROV, has been incorporated to provide feedback.

Tel: +44 (0)1224 214600
Fax: +44 (0)1244 770295

New look for Greek service stations

Service station designer Minale Tattersfield & Partners has developed a new identity and petrol station network for Greek fuels retailer Elinoil.

The operator wanted a new design for its 350 outlets, which would 'reflect both its Greek origins and friendly approach' to fuels retailing.

As part of the new look, Minale Tattersfield decided to focus on the use of clean lines and colours which are suited to the sunny climate, breaking away from the yellows and reds traditionally associated with service stations in the region. It also dropped the word 'oil' from the logo, using only the word 'Elin' (meaning Greek) in Greek characters.

The two bands of blue from the old identity were retained, but brightened for a more modern and vibrant effect, while the extensive use of white aimed to emphasise the clean, sweeping lines, explains the company. The design includes a white sail with the pennant at its top doubling as the accent of Elin.

The designs have been created on a modular system to allow them to be easily applied to the existing service station structure. A single logo panel can be applied to the canopy whatever its size, providing complete versatility. New spreader panels above the pumps are designed to carry abstract images reflecting Greek culture.

Mobile service station

The designer has also recently updated its Mintat G2 transportable petrol station (see *Petroleum Review*, March 1997). Developed to serve motorists in remote rural areas of Russia and eastern Europe, the entire facility fits into two international standard steel shipping containers – one holding the fuel storage tanks and the other the rest of the station, including a small shop and toilet. Claimed to cost 20% of a 'normal' outlet, the mobile facility can be installed and operational on a prepared site within 48 hours.

Minale Tattersfield believes that its mobile station could play an important role in the uptake of alternative automotive technologies such as hybrid vehicles and LPG autofuel, the success of which will be largely dependent on the development of a good refuelling infrastructure. 'If this infrastructure is mobile, it reduces the cost and time of implementation', states the design company.

The company points to a number of other advantages of the transportable service station. 'One aspect of LPG is that there are very strict guidelines for its storage – it cannot be stored in the same area as petrol. A mobile could provide a solution to this problem.

'Electrical recharging is slightly different as each test market is using a different system to recharge. However the transport and storage of such power is relatively easy and could be suited to the mobile station.'

Integrated UK oil and gas well log information

Warwick-based Centra Technology and Spectrum Energy and Information Technology have developed a new, integrated system for storing, accessing and retrieving UK Continental Shelf well log information. The new system is part of a major project currently being managed by Common Data Access Ltd (CDA) on behalf of over 30 companies with interests on the UKCS. Supported by the UK Department of Trade and Industry, this project is designed to rationalise and improve the management of the UK's oil exploration information resources and will eventually result in a common, high quality store for all UKCS data.

The Centra 2000 engineering document management (EDM) system provides the underlying electronic document archiving, management and distribution facilities for the well log information. In a two-year project which started late 1997, Spectrum is extending the existing digital well data and online index which is maintained for CDA by QC Data, in order to create a common, high storage and access system for all primary geotechnical data required by geoscientists in their day-to-day work. New well log information includes that recently made available by Llandudno-based Robertson Research.

For an industry which currently requires between 3,000 and 10,000 copies of well log data every month, the new database is expected to provide major benefits, explains Centra Technology. 'It will do away with the current need for oil companies to store their own copies of well log data, thereby eliminating duplication and providing faster access to higher quality information, better data exchange facilities and greater security against data loss and deterioration.' It is also expected to result in lower data management costs for its users.

Using many of the standard features of Centra 2000, the new single, integrated solution provides data access for users via a standard Internet/intranet web browser. It also integrates with Microsoft Office applications and can support both structured and unstructured data. The system can also accommodate Centra Technology's petroleum GIS (geographic information system) as a front-end to enable users to request data for specific areas by identifying those regions on digital maps of the UKCS.

Centra Technology
Tel: +44 (0)1203 537102
Fax: +44 (0)1203 537032

Resistant touch-screen

Kingshill Electronic Products' Orbit touch-screen LCD panel has been built for use with equipment operating in severe environments in the oil, gas and defence industries. The panel is said to be resistant to temperature, humidity, drip, vibration, shock, radiated emissions, radiated susceptibility and audible noise.

Processing can be configured to satisfy application-specific tasks, although the panel will also run commercial operating systems. Up to 4096 colours can be generated within a display area of 5.2 inches by 3.9 inches. There is a choice of solid state drive or rotational media (up to 2.4 Gig) and up to 32 Mbytes of RAM.

Tel: +44 (0)1634 821200
Fax: +44 (0)1634 821222

Storage tank valve sizing software available free of charge

Whessoe Varac has released a free Windows-based valve sizing programme which automates the calculation and selection process of valves for above-ground storage tank venting applications. The new software is designed to ensure that venting systems are correctly sized and to speed the selection of pressure and vacuum relief valve, pilot-operated valves, regulators and end-of-line or detonation flame arrestors.

Supplied on a CD-Rom for use with Windows 3.1 or higher, the menu-driven programme has been developed for use by tank designers, installers and operators. After entering project information, the user may select two ways of sizing and specifying relief valves.

One method determines the tank venting requirements according to the API 2000 standard. The user is presented with screens to enter the required data for different types of components, such as pump in/out rates, tank dimensions or capacity, set points and maximum allowable pressure and vacuum for relief valves, and the programme automatically calculates the required sizes.

Alternatively, appropriate accessories may be specified by entering the venting parameters provided by the tank manufacturer or supplier.

Result are presented complete with pictorial and mechanical data, and all information necessary for ordering units. A flow chart and specification sheet for each project can also be produced to document the process.

To ensure that the latest version of Whessoe Varec's valve sizing programme is always used, a timer is built into the software. On 1 June 1999 the programme will display a message prompting the user to call the factory to receive the latest version of the tool.

Tel: +44 (0)1325 301100
Fax: +44 (0)1325 300840
e-mail: **sales@whessoevarec.com**

Microsoft first for Coggins Systems

SCADA (supervisory control and data acquisition) systems supplier Coggins Systems has become a Microsoft Certified Solution Provider (MCSP). MCSPs are independent organisations working with Microsoft to offer customers a full range of services, including customisation for vertical industry applications and client/server implementations.

Coggins Systems, part of the Whessoe Varec group of companies, claims to be one of the first SCADA companies to offer solutions based on the 32-bit Windows NT platform, after starting development in 1992 and installing a beta release version of its FuelsManager package the following year. The company provides SCADA solutions for the management of liquid and gas processing, storage and distribution.

Tel: +1 770 447 9202 Fax: +1 770 447 5767

New software upgrade supports energy trading

Saladin recently released Version 2.3 of its EnergyServer software which acts as a central repository of energy market prices, providing support for spot prices, forwards, futures, forward curves and swaps in the crude oil, refined products, gas and power markets. The new release adds support for exchange traded energy options. In addition to fully automatic daily updates of settlement prices, volumes and open interest, the new options module also includes an implied volatility calculator which automatically calculates implied volatility using the options settlement price, its strike price, the underlying futures price, the time to expiry and the relevant interest rate.

The module also allows traders to view options data as calendar month or contract month, as well as viewing the strike prices as absolute prices or as in the money, at-the-money or out-of-the-money strikes.

The software module comes complete with at least two years' worth of history for IPE and NYMEX energy options contracts. 'This provides one of the only available sources of complete quality checked options pricing' states Saladin.

Release 2.3 includes an additional module enabling EnergyServer to produce configurable output formats suitable for feeding a wide range of external applications such as SAP/IS-Oil, Triplepoint Technology's Tempest 2000 and many other third-party applications as well as internally developed trading systems, explains the manufacturer. This is said to allow EnergyServer to be integrated into an existing environment faster than was previously possible, enabling customers to see the benefits of a central price repository without the need for large, complex re-engineering projects.

Release 2.4, which will be available at the end of 1998, will include full Year 2000 compliance, an interface to the new Platt's FTP service and further data handling features. It will also include greater integration with the various data access products developed by FAME Information Services, who acquired Saladin in July 1998.

Tel: +44 (0)1932 243233
Fax: +44 (0)1932 244786

Torque technology

Elfab has developed a scored reverse disc that is claimed to be non-sensitive to torque. Some bursting discs used for process plant over-pressure safety relief have been shown to be sensitive to under or over-torquing, which can result in the disc failing to burst at its specified set pressure, explains the company.

Multi-Guard will always relieve at set pressure regardless of the variations in torque that can reasonably be expected, states the company, thereby eliminating the need for special pre-torqued disc holders which are expensive and only compensate for the under-torquing, not over-torquing, of flange bolts.

Tel: +44 (0)191 258 1188
Fax: +44 (0)191 296 0219

If you would like your new product releases to be considered for our Technology News pages, please send the relevant information and pictures to:

Kim Jackson
Deputy Editor, *Petroleum Review*
61 New Cavendish Street, London W1M 8AR, UK

EVENTS Forthcoming

DECEMBER

3–4 **London**
New European Pollution Control Technologies: Limiting the Environmental Impact of the Hydrocarbons Industry
Details: Jane Kennedy, CMPT, UK
Tel: +44 (0)870 608 3440
Fax: +44 (0)870 608 3480
e-mail: **j.kennedy@cmpt.com**

4th December
London: *Dispute Resolution in the International Oil and Gas Industries*
Details: Pauline Ashby, The Institute of Petroleum

4–7 **Buckinghamshire, UK**
The Mechanics and Operations of Oil Trading
Details: Petroleum Economist
Tel: +44 (0)171 831 5588
Fax: +44 (0)171 831 4567

7–8 **London**
New Development Opportunities in the South American Oil & Gas Industry
Details: Penny Richards, IBC UK Conferences
Tel: +44 (0)171 453 5491
Fax: +44 (0)171 636 6858
e-mail: **cust.serv@ibcuk.co.uk**

7–8 **Oslo**
Controlling Hydrates, Waxes & Asphaltenes
Details: Jinnie Hung, IBC UK Conferences
Tel: +44 (0)171 453 5447
Fax: +44 (0)171 453 2058

7–9 **Prague**
Developments and Challenges for Syndicated Learning in Central and Eastern Europe and the CIS
Details: Ian Bell, IBC UK Conferences
Tel: +44 (0)171 453 5494
Fax: +44 (0)171 636 6858

8–9 **London**
Investment Opportunities in Kazakhstan
Details: Euroforum, UK
Tel: +44 (0)171 878 6886
Fax: +44 (0)171 878 6885

8–10 **South Africa**
Marina 98, Planning, Design and Operation
Details: Liz Kerr, Wessex Institute of Technology, UK
Tel: +44 (0)1703 293223
Fax: +44 (0)1703 292853

8–10 **Cyprus**
Refurbishment of Submarine Pipelines and Risers
Details: Energy Logistics International, UK
Tel: +44 (0)1628 671717
Fax: +44 (0)1628 671720

10–11 **London**
Safe & Reliable Control Room Operations
Details: IBC UK Conferences
Tel: +44 (0)171 453 5491
Fax: +344 (0)171 636 6858
e-mail: **cust.serv@ibcuk.co.uk**

JANUARY 1999

13–14 **London**
New Technologies in Offshore Oil and Gas in West Africa
Details: International Quality and Productivity Centre
Tel: +44 (0)171 430 7333
Fax: +44 (0)171 430 7303

14–15 **London**
Opportunities for Oil and Gas Development in the South Atlantic
Details: Spearhead Exhibitions, UK
Tel: +44 (0)181 949 9222
Fax: +44 (0)181 949 8186
e-mail: **southatlantic@spearhead.co.uk**

14–15 **London**
Offshore Abandonment and Removal Conference
Details: Spearhead Exhibitions, UK
Tel: +44 (0)181 949 9222
Fax: +44 (0)181 949 8193

14–15 **London**
13th Annual Conference: Floating Production Systems
Details: IBC UK Conferences
Tel: +44 (0)171 453 5491
Fax: +44 (0)171 636 6858

14–15 **Hungary**
Hungarian Energy
Details: SMI Ltd, UK
Tel: +44 (0)171 252 2222
Fax: +44 (0)171 252 2272

18–19 **London**
E&P Data Management
Details: SMi Ltd
Tel: +44 (0)171 252 2222
Fax: (0)171 252 2272

26–27 **Aberdeen**
Advances in Solving Oilfield Scaling
Details: Jennie Hung, IBC UK Conferences
Tel: +44 (0)171 453 5447
Fax: +44 (0)171 453 2058

26–27 **Paris**
Libyan Oil and Gas
Details: SMi Ltd, UK
Tel: +44 (0)171 252 2222
Fax: +44 (0)171 252 2272

28–29 **London**
Electronic Commerce for Oil and Gas
Details: First Conferences, UK
Tel: +44 (0)171 404 7722
Fax: +44 (0)171 404 7733
e-mail: **confdesk@firstconf.com**

29 **London**
Negotiating & Structuring Profitable & Stable PSAs to Access New Hydrocarbon Frontiers
Details: Euroforum, UK
Tel: +44 (0)171 878 6886
Fax: +44 (0)171 878 6885

FEBRUARY 1999

20–23 **Bahrain**
MEOS 99, Managing The Future Challenges for People, Resources & Technology
Details: The Society of Petroleum Engineers
Tel: +44 (0)171 487 4250
Fax: +44 (0)171 487 4229
e-mail: **wmartin@london.spe.org**

22–23 **Aberdeen**
Best Practice Compliance with Environmental Regulations for Offshore Drilling
Details: Anita Bath, IIR Ltd, UK
Tel: +44 (0)171 915 5032
Fax: +44 (0)171 915 5000

MARCH 1999

15–17 **Oman**
Improved Measurement of Bulk Liquids
Details: Abacus International, UK
Tel: +44 (0)1245 328340
Fax: +44 (0)1245 323429

22–24 **Singapore**
Improved Measurement of Bulk Liquids
Details: Abacus International, UK
Tel: +44 (0)1245 328340
Fax: +44 (0)1245 323429

29–31 **London**
International Conference on Separations for Biotechnology
Details: Society of Chemical Industry, UK
Tel: +44 (0)171 235 3681
Fax: +44 (0)171 235 7743
e-mail: **conferences@chemind.demon.co.uk, sci.mond.org**

Membership News

NEW MEMBERS

Mr M Q Al Ansari, Abu Dhabi National Oil Company
Mr A R Al-Obaidly, London
Mr M Appolus, Ministry of Mines and Energy
Mr R C Ashton, Parsons Energy & Chemical
Mr D H Atkins, London
Mr I Avdos, Environment & Resource Technology
Mr D Baldwin, Bekay International
Ms C M Bisset, BP Exploration & Operating Company
Mr J Blackall, Aylesbury
Ms S Blank, London
Mr A P Bradley, Schroder Securities
Mr K J Breeze, ITS Caleb Brett (UK) Limited
Mr B Bronowski, Veba Oil Supply & Trading GmbH
Mr B Brummitt, PanCanadian North Sea Limited
Mr A E Campbell, Spain
Mr N Carroll, Live Oil
Ms F S Cranmer, Arthur Andersen
Mr N Dicker, Maidenhead
Mr J M Donachie, Aberdeen
Mr A Eggerton, Aberdeen
Mr I Esau, Reading
Mr J D D Evans, Norton Rose
Mr M Freydefont, European Investment Bank
Mr J Getliff, Schlumber Eval & Prod Services
Mr W R Hamm, Conoco Limited
Mr K B Harris, Wickford
Mr R Herrera, London
Mr E J Hikmet, Uxbridge
Miss F F Hussain, ANZ Investment Bank
Mr R W Irvine, Langdon Hills
Mr W H Kaufman, Aberdeen
Ms H A Kelly, Hayes Montrose International
Mr G H Kerr, Aberdeen
Mr S D J Kerr, Wayne-Dresser UK Limited
Mr H Kirkpatrick, Rimkus Consulting Group Inc
Ms G Kjeilen, RF-Rogaland Research
Mr W T Lawrence, Epsom
Captain A C Luck, HM Forces
Mr W F MacDonald, Fuel Pump & Tank Services
Mr N Milne, USA
Mr K Nagel, Germany
Mr P R C Nowell, Nolwest Holst Eng (Holdings) Limited
Mr T Pearson-Young, Putman Hayes & Bartlett
Ms P Phillips, Sandhurst
Mr F A Pogorzelec, Dundee
Mr A S Pollard, Cornwall
Ms C M Pullen, Ramsgate
Mr M Quraishi, Pakistan
Mr P Rock, Huddersfield
Ms L-A Russell, Aberdeen
Ms S C Salmon, EDS UK
Mr P Smith, SGS Gulf Limited
Mr A J Smith, Barrow upon Humber
Mr I J Smith, Texaco Ltd t/a Team Flitwick
Mr I S C Spark, Aberdeen
Mr A Spring, Arthur Andersen
Mr D Taylor, Velcon Filters Inc
Ms H Tucker-Moore, Tyne & Wear
Mr U N Ukpong, African International Bank Limited
Mr P E Washbourne, Dickinson Dees
Ms I S Whitley, London
Mr B J Williams, Williams Caldal Limited
Ms M L Wilsch, Uxbridge
Mr J M Wood, Corex UK Limited
Mr R Woolven, Norway

NEW STUDENTS

Mr A R Abdul-Rahman, Centre for Petroleum Studies
Mr T S Abouargub, Centre for Petroleum Studies
Mr R J Adam, Centre for Petroleum Studies
Mr H Al Moallem, Centre for Petroleum Studies
Mr M Al-Gharhi, London
Mr H S Al-Hadhrami, London
Mr S S Al-Harthy, Centre for Petroleum Studies
Mr A A Al-Lamki, London
Mr W Ali, London
Miss A I Alouache, London
Mr R I Ball, Luton
Mr F N Botchway, University of Manchester
Mr C Bqezq-Guinez, Angus
Mr G Buonaffina, Centre for Petroleum Studies
Mr B A Burke, London
Mr N A Chuck-A-Sang, Bishop Stortford
Mr R Concha, London
Mr S Dey Chowdhury, Centre for Petroleum Studies
Mr M J Dias Tavares, Centre for Petroleum Studies
Mrs L A Doble, Brailsford
Mr B C Esparcieux, London
Mr J V Evans, London
Dr G Falcone, Centre for Petroleum Studies
Mr A Gbo, London
Mr T Goh, Centre for Petroleum Studies
Mr J J Hastings, Centre for Petroleum Studies
Mr N J D Jethwa, Centre for Petroleum Studies
Mr K C Liew, Centre for Petroleum Studies
Ms H E B Love, Leeds
Mr M F Malik, Parkistan
Mr M Mansoori, Tyne & Wear
Mr T Martin, Centre for Petroleum Studies
Mr M J McQueen, London
Miss M Michael Lalak, Royal School of Mines
Mr S H Modi, Halesowen
Mr R J Muda, Centre for Petroleum Studies
Mr J Mvzi, London
Mr M B Ngah, Centre for Petroleum Studies
Mr K A Nutley, Centre for Petroleum Studies
Mr A Rafi, Woking
Mr D J Reynolds, London
Mr R Ridzuan, London
Mr S Z Sadollah, Centre for Petroleum Studies
Mr O A Solanke, Centre for Petroleum Studies
Mr I H Stewart, University of Liverpool
Mr K W R Tee, London
Mr C Tzinieris, London
Mr A Velasco, Centre for Petroleum Studies
Mr S S Wong, Royal School of Mines
Mr J A Wylie, Hemel Hempstead
Mr M Yousuf, London

STUDENT PRIZEWINNER

Ms C L Ball, Texaco North Sea (UK) Limited

IP Discussion Groups & Events

The Institute of Petroleum Discussion Groups have been combined to form

The IP Discussion Group: Energy Economics, Environment

The Group is chaired by Dr Roger Cairns, formerly Managing Director of Hardy Oil & Gas

The IP Discussion Group debates the motion

'This House believes that cost-effective precautionary measures should be taken, starting now, to address the climate change risk, with the requirements of the Kyoto protocol providing a sensible next step in the process'

Monday 14 December 1998, 17.00 for 17.30–19.30

Chairman: John Mitchell, Chairman of the Energy Programme, Royal Institute of International Affairs, Chatham House

Proposed by Michael Jefferson, Director of Studies and Policy Development, World Energy Council
Opposed by William O'Keefe, Senior Vice-President, The American Petroleum Institute

IP Contact: Jenny Sandrock (Prior registration essential)

The IP Discussion Group jointly with British Institute of Energy Economics

'Oil Markets in 1998 and the Outlook for 1999'

Thursday 7 January 1999, 17.30

Mark Lewis, Managing Director, Energy Market Consultants

Venue: Britannic House, London EC2

Contact: Mary Scanlan, BIEE, +44 (0)181 997 3707

All meetings are held at the Institute of Petroleum unless otherwise stated. Please tell the IP contact if you plan to attend any of these free meetings. Tel: +44 (0)171 467 7100 Fax: +44 (0)171 255 1472

Membership News

NEW CORPORATES

DERA Pyestock, Fuels and Lubricants, Building 442, Room G24, Farnborough, Hampshire GU14 0LS, UK.
Tel: +44 (0)1252 374760 Fax: +44 (0)1252 374791

Representative: Dr C Bartlett, Principal Consultant

DERA Pyestock fuels and lubricants centre carries out research, development and in-service support on fuels, lubricants and hydraulic fluids for the Ministry of Defence and industry. It comprises 80 staff situated in dedicated office laboratory, rig and engine test facilities at Farnborough, including equipment and expertise in tribology, microbiology and condition monitoring.

Brackno Ltd, 28 Woodford Drive, Swinton, Greater Manchester M27 9UA, UK.
Tel: +44 (0)161 794 5614 Fax: +44 (0)161 793 1422

Representative: Mr Eric Knott, Managing Director

Brackno Ltd delivers focused training packages specifically designed to meet client training objectives. Courses can be delivered worldwide and can attract internationally recognnised qualifications.

Integrated Intelligence Networks, 19–21 James Street South, Belfast BT2 7GA, UK.
Tel: +44 (0)1232 246300 Fax: +44 (0)1232 246200

Representative: Mr C Maclean, Chairman

Integrated Intelligence Networks is involved in electronic publishing, oil and gas, and energy news databases in Perth, Stavanger, Germany and Aberdeen. It is the world's first online community to the global energy industry and can be visited at **www.iinoil.com**

Hayklan Concept Ltd, 17–18 Picton Place, London W1M 5DE, UK.
Tel: +44 (0)171 224 1740 Fax: +44 (0)171 224 1776

Representative: Ms N Sidorour, Director

Hayklan Concept Ltd is a management consultancy with a track record of providing services and advice for east European companies in downstream oil distribution and petrol filling stations, management, including training, and technology transfer.

IP Conferences and Exhibitions

IP Week 1999: London 15–18 February

Monday 15 February

International Conference on

Financing the International Oil Industry – The Challenge of Major Projects

Keynote Address: Stephen Hodge, Group Treasurer, Royal Dutch/Shell Group

Tuesday 16 February

Annual Luncheon

Guest Speaker: Sir John Browne, Chief Executive, The British Petroleum Company plc

Knowledge Management in the Oil and Gas Industry – Trends and Case Studies

organised in association with ARTHUR ANDERSEN

Arthur Andersen will facilitate this Workshop designed to educate, inform and provoke thinking on the topic of Knowledge Management in the Oil and Gas industry.

The prime objective will be to ensure that as a senior executive you are well briefed in this emerging area, you understand examples of applications others are implementing in your industry, and you have a basis to assess your own organisation's progress in capitalising on your employees' knowhow.

London Branch Evening Discussion Meeting

Sakhalin Oil & Gas Exploration of the East Sakhlain Shelf

Wednesday 17 February

The 12th Oil Price Seminar and Exhibition

Supported by New York Mercantile Exchange

The Institute of Petroleum Annual Dinner SOLD OUT SOLD OUT

Thursday 18 February

International Conference on

The Caspian Region: The Major Oil and Gas Play for the Next Decade

Opening Address: Sir Malcolm Rifkind, Director of International Strategy, BHP Petroleum Ltd

Please refer to page 19 for further details.

1999 Programme of Events

International Retail Conference and Seminar

organised in association with Forecourt International

NEC, Birmingham: 9–10 March

Second International Conference on Emerging Markets for Emissions Trading

London: 26–27 April

This conference will address the implications of the Kyoto Protocol, explain the various emissions abatement mechanisms, show how to develop and incorporate a trading and hedging strategy and suggest ways of maximising the opportunities presented by emissions trading and Kyoto Protocol.

Course on Introduction to Oil Industry Operations

London: 16–18 June

and

Course on Introduction to Petroleum Economics

London: 21–23 June

International Conference on Offshore Marine Support (OMS 99)

Southampton: 12–13 October

For programmes and registration forms please write or fax:

Pauline Ashby,
Conference Administrator,
Institute of Petroleum,
61 New Cavendish Street,
London W1M 8AR, UK

Tel: +44 (0)171 467 7100
Fax: +44 (0)171 255 1472
e-mail: pashby@petroleum.co.uk

MOVES People

The UK Offshore Operators Association (UKOOA) has appointed two new senior members of staff. **David Odling** succeeds **Michael Knowles** as Assistant Director–Policy. Odling has worked with GEC and, since 1977, with AOC International (now Brown and Root AOC), where he is currently Business Development Director. A leading player in the Crine initiative, he is currently on the Board of the Offshore Contractors' Association. **Nigel Essex** succeeds **Chris Volk** as Company Secretary. He has spent 29 years with Amoco, latterly as Treasurer and Economics Manager, and is also a past Chairman of the UKOOA Fiscal Committee and Legislation Committee.

The Board of Directors of Kvaerner has elected **Kjell E Almskog** as the company's new President and Chief Executive Officer, effective from 1 January 1999. Almskog is currently Executive Vice-President and a member of the Group Executive Committee of ABB Ltd in Zurich.

Per Møller-Hansen has stepped down from his position as Managing Director of Aker Maritime subsidiary Maritime Hydraulics' whihc developed the RamRig lightweight drilling derrick. He is replaced by **Jan Roger Olsen**.

David McManus has been appointed as the new Managing Director for Arco British Ltd, following the promotion of his predecessor **Stephen G Suellentrop** to a new position as Arco's Vice-President of Technology and Operations Services, based in Texas. McManus was previously with Shell, Ultramar and Lasmo before joining Arco in 1994. He has been Project Director of the company's Rhourde el Baguel project in Algeria since July 1998.

Gambica, the trade association for the UK instrumentation, control and automation industry, has appointed **John Hemming**, Managing Director of Unicam Atomic Absorption, as its Vice-President and President-Elect. Hemming has held a number of senior managerial positions at Philips and associated companies. Gambica President **Michael Gutteridge**, Group Chief Executive of Blackburn Starling & Company, will continue in office for another year.

Gerald Wingrove, former Vice-President of Enron Europe, has joined London Electricity as the company's Finance Director. He replaces **Alan Towers** who is retiring. Wingrove has much experience working in Eastern Europe and Central Asia, developing investment opportunities in the energy sector. Prior to joining Enron, he was Group Financial Controller for Premier Oil.

Peter Maude has taken up the position of Sales and Marketing Director of Pipeline Engineering. He has around 20 years' experience, mainly in overseas assignments in the Middle East and Far East, where he was directly involved in establishing and operating sales, marketing and manufacturing activities to service the growing oil and gas industries in the region.

***Carl Clump* has been appointed Group Chief Executive of Card Clear plc. He joins the company from his position as Managing Director of the Harpur Group, and brings with him from Texaco extensive experience of the petrol, retail and point-of-sale systems industries.**

Montgomery TankServices Ltd, a subsidiary of Ballyvesey Holdings Ltd, has announced that *David Mills* has joined the company as Business Development Manager. Formerly with P&O Trans European, Mills has many years' experience having previously worked within the bulk liquid storage and lubricants section of the oil industry.

Philip Prow has joined Veeder-Root as Sales Manager for UK and Ireland with additional responsibility for the launch of Simplicity Petroleum Data Services across Europe. He was previously with PetroVend Inc where he was responsible for promoting the company's range of tank gauging systems, and with PetroVend (Europe) as Sales Director.

Foster Wheeler Ltd has appointed **Christopher Holt** as its Deputy Chairman. He also retains his existing position as Group Financial Director. In his new position Holt has overall responsibility for the Fired Heater Division of the company, and for Foster Wheeler subsidiary FW Management Operations Ltd.

***Graham Stewart* has joined the Board of Dana Petroleum plc as Commercial Director. He was previously Commercial Director of the UK's National Petroleum Institute where he worked on the development of new petroleum technologies.**

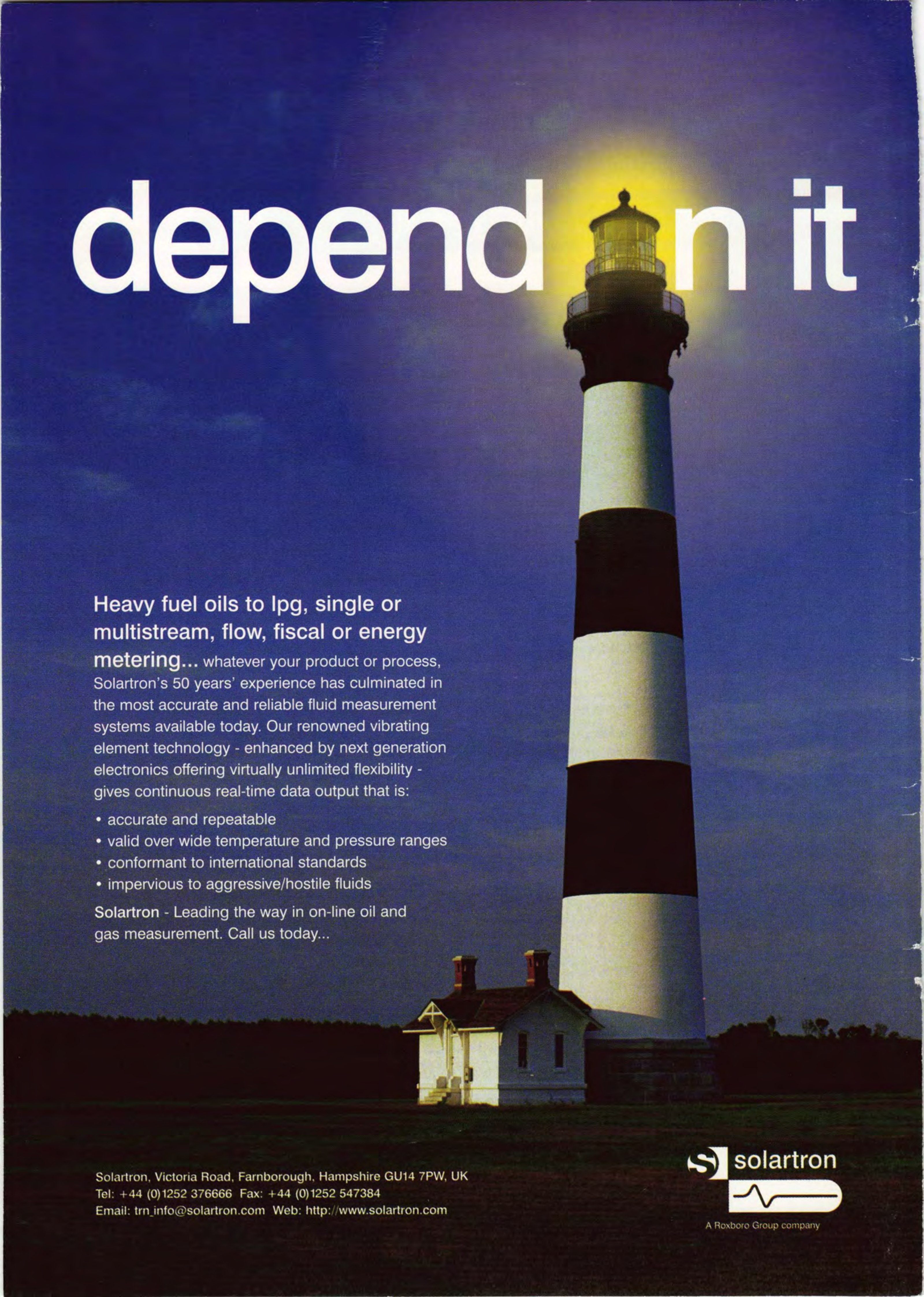
Paul Anderson, President of US oil and gas corporation Duke Energy, this month becomes BHP's new Chief Executive. He is the second non-Australian in 113 years to run BHP.

Global Marine has announced that **Edward A Blair** has been elected to its Board of Directors. Blair has 40 years' experience in the domestic and international oil and gas industries, and retired earlier this year as President of BHP Petroleum (Americas) Inc.

Following the merger between British-Borneo and Hardy Oil & Gas, British-Borneo has announced the following appointments of directors of Hardy to its Board: **Douglas Baker**, Non-Executive Deputy Chairman; **Peter Hill**, Technical Director; **Jim Ellis**, Non-Executive; **Robert Norbury**, Non-Executive; **Sir Eric Parker**, Non-Executive. The responsibilities of the Executive Directors of British-Borneo have been reassigned as follows: **Alan Gaynor**, Chief Executive; **Bill Colvin**, Finance Director; **Peter Hill**, Technical Director; **Steven Holliday**, International Director; **Dr Ian Thornley**, Human Resources Director.

Artur Chakhdinarov is now in charge of Purchasing Operations at Wingas GmbH in Kassel. He succeeds *Iouri Viakhirev*, who is to take over the post of Deputy Director-General of Gazexport, the marketing arm of Russian gsa company Gazprom.

Asco Group, the oil and gas logistics provider, has appointed **Steve Marples** as a Director of the company. Marples joined the company in January 1998.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