Petroleum review

APRIL 2002

Middle East

- Big Three oil producers target gas reserves
- Iran plans switch to petrochemicals exporter

Fuels distribution

- Driving down supply chain costs

Russian Reserves

- Is FSU oil growth sustainable?

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

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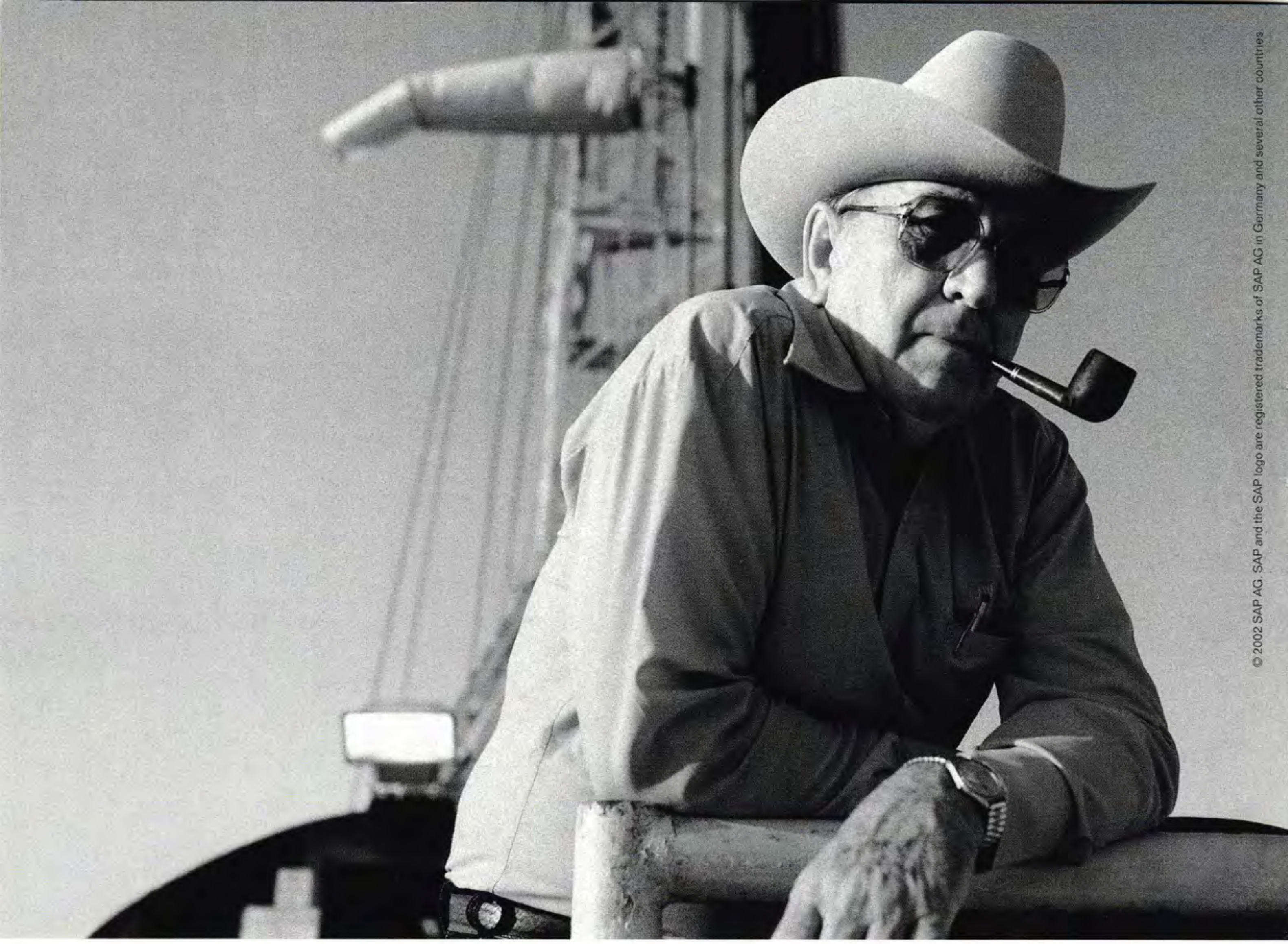

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ABBREVIATIONS

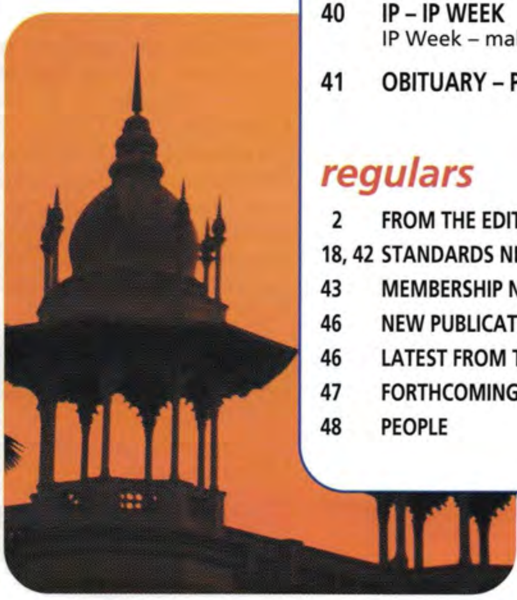
The following are used throughout *Petroleum Review*:

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 Caspian Sea Oil' – Drilling rig in Caspian Sea
Photo courtesy of Lukoil

inside...



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Crude – the high price mystery

Over the last month oil prices have firmed significantly, much to the relief of Opec and the oil companies. Economists and central bankers are somewhat less enthusiastic, seeing reviving oil prices as a possible threat to economic recovery. The obvious, and at one level unanswerable, question is how sustainable are these price levels?

Demand appears very lacklustre with the International Energy Agency (IEA) in its latest (February) *Oil Market Report* revising 2002 demand down by 80,000 b/d to 420,000 b/d. A very limited fourth quarter stockdraw of just 400,000 b/d appears to confirm the demand weakness.

There is mounting evidence of an economic recovery in the US but, so far, there is little impact on oil demand. The IEA, while reporting that fears of a double-dip recession are now fading fast, notes that December deliveries of oil in the US showed the sharpest monthly decline in 12 years – despite a US GDP growth for the fourth quarter that was revised sharply upwards. It continued that 'the same 'disconnect' between oil and the broader economy continued in January, when preliminary data showed oil demand contracting sharply in the key US, Japanese and German markets.'

There is also mounting evidence that the supporting non-Opec production cuts are at best reductions on inflated November and December production levels. However, the market is choosing to focus on reductions in February – Norway (–110,000 b/d), Mexico (–100,000 b/d) and Oman (–40,000 b/d) and Opec 10 output is only 700,000 b/d above its latest quota – evidence that the market is tightening. Hence the firm prices, with Brent now moving back to $25/b.

This in turn has produced a quite dramatic turnaround from a backwardated market with significant short positions to a market in contango with traders rushing to create balanced or even long positions.

Opinions vary amongst traders and analysts but what might be called the 'Iraq war risk premium' is usually assessed at $1–3/b. Following assurances from Opec that they would make up any Iraqi shortfall this 'war risk' premium is likely to erode, but will not disappear while the threat of military action remains. Opec's decision to maintain quotas till June is also supportive.

As we move towards the normal seasonal demand decline in the second quarter and with a notional 7mn b/d of unused Opec capacity we would expect prices to erode. There are, however, good reasons to be cautious and to think that prices may remain relatively firm.

It seems useful to separate the idea of demonstrated capacity from the notion of sustainable capacity. At the end of 2000, most Opec members were operating at very high levels. If we sum the maximum production from each country the total is 29.5mn b/d, which could be called their proven or demonstrated capacity.

Sustainable is capacity that can be accessed within 90 days and sustained for three months. The IEA puts sustainable Opec capacity at 31.9mn b/d. The Solomon Smith Barney (SSB) Group puts it a little higher at 32.25mn b/d.

Since the Opec countries are currently (February 2002) producing 24.9mn b/d what might be called the proven spare capacity is 5mn b/d. If the full Saudi spare capacity is included, this rises to 7mn b/d. That is a truly huge volume potentially overhanging the market.

One has to be very confident of Opec's ability to restrain production to think that current price levels are sustainable over the next quarter. That or be equally confident that a Middle East conflict is imminent.

On page 36 of the April issue it was stated that President Carter was responsible for setting up the Strategic Petroleum Reserve (SPR). It was in fact President Ford.

Peter Ellis Jones 1945–2002

It is with very great regret that we have to report the death of one of the Institute's greatest friends and supporters – Peter Ellis Jones. Peter, who had been a long-serving Member of IP Council and a Vice President of the Institute had worked tirelessly over many years to help and assist the Institute. His great genius was to recognise and to reconcile the interests of all Institute Members from senior oil company executives to ordinary members. Philip Algar, a former Editor of *Petroleum Review* and a close friend of Peter's who worked alongside him on Council and on various IP Committees, gives a personal remembrance on p41.

e-world

APV Products, a subsidiary of Invensys, is launching a heat exchanger enquiry tool – PHE Wizard – on the Internet at **www.phewizard.com** The tool will eliminate the need for customers to invest time in defining the appropriate data required to size a heat exhanger and then submitting it via phone, fax or e-mail to the local APV office, states the company.

A new website designed to serve the needs of the welding industry has recently been launched by TWI at **www.ukwelder.com** The site includes practical information, articles and job vacancies for welders, welding inspectors and welding engineers.

'Atlas Interactive reports that it is the only UK-based company to have been selected by Shell to provide e-learning software modules and custom developments for the Shell Open University based in Holland. The contract has been divided between three e-learning companies due to the scale of the work involved as the oil company moves to delivering learning using more flexible and cost-effective web-based e-learning.

Enterprise Oil has chosen to use Projectplace's Internet-based project collaboration service to enhance communications efficiency between equity partners across a series of global projects.

Projectplace's global pay-per-use web-based project collaboration service enables team members to share documents and files, schedule meetings, carry out project scheduling with to-do items and time charts, and hold online discussions. 'The service makes it possible to create virtual teams, communicate securely independent of geographic distance and also enables the project member to constantly be updated of what is happening in the project,' explains the company. For more information, visit **www.projectplace.co.uk**

Cuno Eruope has launched a new European website aimed at the business of manufacturing and supply of filters, filter housings and turnkey systems. Accessed through its US parent site **www.cuno.com** the new site features hotlinks to various European centres determined by language preference of direct through **www.cunoeurope.net** A range of product literature and systems information is available, together with application and case studies, schematics and technical process data.

Ofgem has published its final proposals for the Information and Incentives Project (IIP), a quality of service incentive scheme for electricity distribution companies that will apply from April 2002. For details, visit **www.ofgem.gov.uk/projects/iip-index.htm**

In Brief

UK

***BP reports that it has reduced its** greenhouse gas emissions by over 9mn tonnes eight years ahead of target and at no net cost to the company.**

***Tuscan Energy is reported to have** renamed the former Argyll field in North Sea block 30/24 Ardmore, after the Scottish whisky. The company and partner Acorn Oil & Gas hope to achieve first oil in mid-2003 via three wells and a floating production vessel. The field is expected to produce some 40,000 b/d.**

The UK Government has launched a** new initiative under Pilot that is aimed at maximising recovery of the UK's remaining 26–34bn boe of oil and gas reserves. For further details, visit* **www.pilottaskforce.co.uk

***Marathon Oil is reported to be plan**ning to build a new 675-km pipeline to carry Norwegian and UK gas production to the UK market. It is proposed that the pipeline serve the Heimdal, Brae, Miller and Britannia fields. Centrica is understood to have signed up as a potential gas customer.*

***UK oil and condensate output is fore**cast to rise by 3% to 2.34mn b/d in 2002, according to a recent report from Wood Mackenzie. The analyst predicts that 15 new fields will come onstream, producing some 80,000 b/d.**

nisus *– **a joint venture between** Aberdeen-based companies RML, GlobalSantaFe, Stolt Offshore and the Wood Group – is reported to have been selected by Phillips Petroleum to undertake the pre-sanction study for*

NEWS Upstream

South Africa's southern Cape Provinces to develop gas industry

The South African Department of Minerals & Energy and Shell South Africa have announced the signing of a Letter of Intent to develop a natural gas industry in the country's southern Cape provinces, reports *Richard Hurst.* The two parties are to jointly evaluate the prospects of introducing natural gas from the Kudu fields in neighbouring Namibia. This assessment will include the transmission of gas, including the possible construction of a pipeline.

General Manager of Shell SA Gas and Power Yiaw-Hin Wee said that the Kudu gas fields' reserves were ample.

The announcement came after the recent news that the US-based exploration company Forest Oil has uncovered what is reported to be commercially viable oil and gas assets off the coast of South Africa after reprocessing old seismic data.

Managing Director of Global Energy Randall Thompson said that the reprocessing of the data had shown the existence of a very large structure in the reservoir sands, which could contain billions of barrels of oil.

Shell SA has meanwhile become the source of a potential rift between the South African Competition Tribunal and the Competition Commission regarding its proposed merger with the black empowerment company Tepco. The split follows the recent ruling from the Tribunal, which gave the merger the go-ahead unconditionally while ignoring the recommendation of the Commission to halt the union.

First production from Jade field

The high temperature/high pressure Jade field in North Sea block 30/2c has come onstream and is currently producing 60mn cf/d of gas and 4,500 b/d of oil via the first development well. Output is expected to plateau at 200mn cf/d and 16,000 b/d by 3Q2002 once the remaining initial development wells have been completed and brought onstream.

The field is being developed at a cost of £225mn using a normally unattended installation, which is connected by a 16-inch diameter multiphase pipe-in-pipe pipeline to the Phillips-operated Judy platform located 17.5 km south of Jade. Following initial processing of Jade production on Judy, gas will be transported through the CATS pipeline to the CATS terminal on Teesside and oil through the Norpipe pipeline to Phillips' Seal Sands terminal on Teesside.

Ultimate recovery from the four initial development wells is put at 380bn cf and 30mn barrels over a 15-year period. However, there is a possibility of a second phase to exploit other potential oil and gas accumulations. Field partners are Phillips Petroleum (operator; 32.5%), BG (35%), Texaco North Sea (19.93%), Agip (7%) and OMV (5.57%).

Radical business changes offshore UK

Radical changes to the way the UK offshore oil and gas industry does business are being brought about as a result of the new cooperative working practices, partnerships and groundbreaking initiatives fostered by Pilot, the innovative joint government/industry programme to boost UK competitiveness – this is the conclusion of Pilot's end of year report for 2001. The report highlights the following achievements:

- Capital investment targets exceeded by £0.5bn at £3.5bn.
- Production of 4.3mn boe/d.
- A record number of oil and gas field development projects approved by the Department of Trade and Industry – up from six in 1999 during the oil slump to 21 in 2001.
- A total of 150 technicians recruited on to industry technician training programmes.
- The launch of the Oil and Gas Sector Sustainability Strategy, one of the first such strategies to be published by a UK industrial sector.
- Some £8mn investment in technology development through the Pilot-sponsored Industry Technology Facilitator programme.
- The launch of the Progressing Partnership work group to identify commercial, behavioural and supply chain barriers inhibiting recovery of Britain's remaining oil and gas reserves.
- The launching of the Stimulating Exploration work group to increase offshore oil and gas exploration.

The full report can be viewed at **www.pilottaskforce.co.uk**

North West Shelf gas sales

The North West Shelf LNG Sellers have signed a gas sales and purchase agreement with Osaka Gas covering the supply of 1mn t/y of LNG from 2004. It is the second sales and purchase agreement signed for the supply of LNG from the North West Shelf's expansion project, currently underway at the North West Shelf Venture's onshore gas plant on the Burrup Pensinsular, Western Australia. The earlier agreement was signed in October 2001 with Tokyo Gas and Toho Gas covering the supply of 1.37mn t/y of LNG from 2004.

The expansion project includes a fourth LNG processing train with a production capacity of 4.2mn t/y and a second trunkline that will link the Venture's offshore gas production and onshore gas processing facilities.

Osaka Gas is one of the North West Shelf LNG project's existing customers, taking about 790,000 t/y of LNG under a 20-year agreement that commenced in 1989. The North West Shelf Sellers also have Letters of Intent with:

- **Tohoku Electric for the supply of 0.4mn t/y of LNG, commencing in 2005; and**
- **Kyushu Electric for the supply of 0.5mn t/y of LNG, starting 2006.**

Key terms agreements have also been announced with:

- **Chubu Electric for the supply of 0.6mn t/y of LNG, starting 2009; and**
- **Shell Gas & Power for the supply of up to 3.7mn t/y of LNG between 2004 and 2009.**

Zamzama project gets the go ahead

Premier Oil has been given the green light to go ahead with the full development of the Zamzama gas field in southern Pakistan at an expected cost of $100mn.

The announcement follows the signing of separate gas sales and purchase agreements and a gas pricing agreement with the Government of Pakistan, the Sui Southern Gas Company and Sui Northern Gas Pipelines covering the supply of up to 320mn cf/d of gas over the expected 20-year field life, commencing mid-2003.

Estimated proven and probable gross reserves at Zamzama are put at 1.7tn cf.

There is also reported to be further gross reserves potential of up to 1.3tn cf outside the core area.

Field development will comprise two additional processing trains located on the existing extended well test plant site and a minimum of three new development wells.

Recent developments upstream Africa

Stella Zenkovich reports on some recent upstream developments in Africa:

- Only four out of 24 blocks in Kenya have been contracted and only 30 wells drilled, equating to one well per 10,000 sq km compared to the world average of one well per 5,000 sq km, according to Kenyan Chief Geologist Don Riaro. Kenya shares the same geological basin with Sudan's oil belt, with Sudanese wells just 400-km from the Kenyan border, he added, pointing out that more prospecting is required before a conclusive view can be given on Kenyan oil prospects.
- ExxonMobil has made a significant oil discovery in Nigeria's deep offshore region. The Bolia field well tested at 6,000 b/d. Esso Exploration & Production holds a 20% stake in the field, Shell 55%, Eni 12.5% and TotalFinaElf 12.5%.
- Global Offshore Oil Exploration has won approval from the South African Ministry of Minerals & Energy and the South African Agency for Petroleum Exploration and Exploitation to prospect in block 3B/4B offshore western South Africa.
- A rand 1.7bn contract has been awarded for the construction of Sasol's 865-km gas pipeline linking Mozambique's Temane field to the Secunda petrochemical plant in Mpumalanga in South Africa. The contract was awarded to a consortium headed by Aveng subsidiary Grinaker-LTD, McConnell Dowell of Australia and CCIC of Greece. Construction is slated to complete by 2004.

In Brief

its Jill and Julia projects in the central North Sea under the Satellite Accelerator programme. Phillips is planning to develop the fields as a subsea tie-back to the Judy platform, also located in block 30/7a.

***Genesis Oil & Gas is understood to have** been selected to undertake conceptual engineering on TotalFinaElf's Glenelg field in the North Sea. Development plans include a new platform to tie-back production to the Elgin facilities.*

***Conoco is reported to be planning to** sell £1.25bn worth of North Sea assets, including interests in the Britannia gas field and the Alba oil field, once approvals for the $35bn proposed merger with Phillips Petroleum have been secured. The company is also understood to be planning the sale of its Jet chain of service stations in the UK, but is expected to retain the Humber refinery as it is the only European operation that Conoco owns outright.*

Europe

***Eni is reported to be selling its 25%** interest in the Gorgoglione concession located in Italy's Basilicata region to TotalFinaElf for an undisclosed sum.*

***TotalFinaElf (42.37%, operator) has** commenced production from an unmanned platform on the K1A field in the Dutch sector of the North Sea. The field is expected to produce some 20,000 boe/d by mid-2003. Partners are Energie Beheer Nederland (43.3%) and NAM (14.33%).*

***Lervik Sveis has secured the contract** to build the accommodation module for BP's West of Shetland Clair project.*

Eastern Europe

***Ramco Energy has secured a new** exploration licence for the B-Golitza block in eastern Bulgaria.**

North America

***The King Kong and Yosemite fields in** the Green Canyon area of the Gulf of Mexico are understood to have come onstream at 120mn cf/d of gas, slated to rise to a target plateau rate of 150mn cf/d. The fields are being developed via three subsea wells tied back to Agip's Allegheny platform.*

In Brief

***PanCanadian Energy is reported to be** hoping to receive regulatory approval for development of the Deep Panuke gas field offshore Nova Scotia in 1Q2003. The company, which is currently in the midst of a C$9.7bn takeover of Alberta Energy, is planning to produce 400mn cf/d in 2005.*

***The US Departments of Energy and** the Interior are joining forces to use oil from federally leased land in the Gulf of Mexico for America's Strategic Petroleum Reserve (SPR), an emergency crude oil stockpile, reports* Philip Fine. *Equiva Trading Company of Houston won the contract to supply additional oil, upping the reserve by 18.6mn barrels.*

***ExxonMobil is understood to have** brought its Gulf of Mexico Madison field onstream as a subsea tie-back to the Hoover spar production platform.*

Middle East

***TotalFinaElf (operator, 40%), together** with partners Gazprom (30%) and Petronas (30%), has brought onstream Phases 2 and 3 of the South Pars gas field in the Persian Gulf offshore Iran. The two phases, costing some $2bn in total, are the first of a planned 12 development phases. At plateau, Phases 2 and 3 are expected to produce 2bn cf/d of gas and 80,000 b/d of condensate from 20 wells tied into two unmanned platforms.*

***Abu Dhabi's oil output peaked at** nearly 2mn b/d in 2000, the bulk of the increase coming from new onshore fields, according to the Abu Dhabi Planning Department's annual report. Total production is expected to exceed 2.5mn b/d in the next decade.**

***Saudi Aramco has awarded Technip-**Coflexip a major lump sum turnkey contract for the expansion of the Berri gas plant to handle additional output of sour gas from the Qatif field that is currently under development and forecast to produce 500,000 b/d of oil.**

Russia & Central Asia

***No sooner had Opec concluded its dis**cussions with Russia, than the Russian Ministry of Energy raised its output forecast for the year 2002 to 365mn tonnes (7.4mn b/d), reports UFG – an increase of 5% on 2001 production.*

NEWS Upstream

Green light for Goldeneye

Shell, on behalf of partners Esso Exploration and Production, Lasmo (TNS), Paladin Expro, and Veba Oil & Gas, has announced that it has received the green light for development of £300mn Goldeneye gas condensate field in the Outer Moray Firth.

First gas is expected by 4Q2004, with production forecast to peak at 300mn cf/d. Reserves are put at more than 500bn cf of gas and 17mn barrels of condensate. Output is predicted to plateau at some 300mn cf/d of gas and 10,000 b/d of condensate. Field life is put at between seven and 10 years.

Goldeneye is reported to be unusual in that the main build will comprise a new processing module onshore at St Fergus instead of offshore, which will be a smaller unmanned platform. At 105 km the full wellstream transfer pipeline will be the longest tie-back in the UKCS, claims Shell, transferring gas and condensate under reservoir pressure from the unmanned platform to St Fergus for processing.

Gas will be delivered to the national transmission system at St Fergus, while natural gas liquids (NGLs) and condensate will go to the Fife NGL plant in Mossmorran through an existing pipeline. In addition, the project marks a technological first for the UK industry – with a jack-up drilling production wells in 120 metres of water as an alternative to subsea completion being a 'completely new territory for the UK.'

Tenders from several UK companies for the construction contract at St Fergus are currently being evaluated and the contract award will be made to a UK company in due course. Tenders for the contracts for the minimum facilities platform, jacket and topsides have been received, with award of the topsides contract expected before the end of March.

According to UK Energy Minister Brian Wilson the Goldeneye project will create around 300 construction jobs in St Fergus as well as providing permanent employment within the venture and securing jobs in the Fife natural gas liquids plant in Mossmorran. In addition, the new infrastructure will open up possibilities for other developments in the area.

Norwegian output

Hydrocarbon production from the Norwegian Continental Shelf in January 2002 was 22.7mn cmoe (cubic metre oil equivalent), with oil accounting for 15.2 cmoe of output, marketable gas 6mn cmoe, and NGLs and condensate 1.5mn cmoe, according to the latest figures from the Norwegian Petroleum Directorate.

Tables detailing the different products for each field/area can be viewed at **www.npd.no/norsk/npetres/prod_tal/produksjon_2002.htm**

Shell NZ asset sale

Shell New Zealand is to sell the McKee and Mangahewa oil and gas fields to its Maui gas field partner Todd Energy for an undisclosed sum. The sale is required to meet conditions set by the Commerce Commission when Shell acquired Fletcher Challenge Energy.

Earlier this year, Shell sold its interests in the Kaimiro field and half of its stake in Ngatoro in Taranaki to New Zealand's Greymouth Petroleum. Shell is also to sell to Todd Energy a 3.7% interest in the undeveloped offshore Pohokura oil and gas field in which Todd already holds a 15% stake.

PDOs put forward for Nini and Cecile

Two new oil fields in the Danish sector of the North Sea – Nini and Cecile – are expected to come onstream in summer 2003, reports DONG. The project partners – Denerco Oil 37%, Denerco Petroleum 24%, DONG 22% and RWE-DEA 17% in licence 16.98, and DONG 40%, Denerco Oil 30% and RWE-DEA 30% in licence 4.95 – have submitted plans for development and operation to the Danish Energy Agency.

It is proposed to develop the fields via unmanned wellhead platforms, connected via pipeline to the nearby Siri platform where the oil will be processed and exported by tanker from summer 2003. Recoverable field reserves for Nini and Cecile are put at 65mn barrels of oil and the total development cost is expected to be in the region of DKK2.5bn.

In addition, DONG is currently negotiating its takeover of the operatorship of the Siri field in licence 6/95 from Statoil from 1 January 2003. If an agreement is reached, DONG will be the operator of a contiguous area in the North Sea, comprising the Siri, Stine, Nini and Cecile fields.

NEWS Upstream

Middle East upstream update

Stella Zenkovich reports on some recent upstream developments in the Middle East:

- With 10tn cm of gas reserves, Qatar is expected to export between 70bn cm/y and 103bn cm/y of gas from 2010, rivalling both Russia and Iran in the gas export stakes. Qatar's 2000 oil exports were worth \$9.2bn, up from \$5.5bn in 1999. Gas exports from 2010 are expected to be worth between \$5.5bn/y and \$8.2bn/y.
- Iran, which boasts the second largest gas reserves after Russia, has officially inaugurated a new gas pipeline to carry Iranian gas to Turkey over the next 25 years. Gas demand in Turkey is projected to increase six-fold over the next two decades.
- Some \$300bn in gas export revenue is expected to be generated by Iran's South Pars gas field in the Persian Gulf over the next three decades.
- Kuwait is planning to import Qatari gas by pipeline in increasing volumes over 25 years from 2005. Initial imports of 22.64mn cm/y will rise to 39.62mn cm over the period. A final sale and purchase agreement is expected to be signed in June.

Green light for Snøhvit project

The Norwegian Parliament (Storting) has approved the plan for development and operation (PDO) of the Snøhvit project in the Barents Sea. The euros 5.2bn gas project involves the development of three offshore fields – Snøhvit, Albatross and Askeladd – and the construction of a LNG plant at Melkoya, near Hammerfest, in north Norway. The Melkoya single-train LNG facility will have a capacity of 4.2mn t/y and is expected onstream in 2006.

The project is the first offshore development in the Barents Sea and said to be the first in Europe to be based on gas liquefaction.

Project partners are: Statoil (operator, 22.9%), Petoro (30%), TotalFinaElf (18.4%), Gaz de France (12%), Norsk Hydro (10%), Amerada Hess (3.26%), RWE-DEA (2.81%) and Svenska Petroleum (1.24%).

UKOOA unveils drill cuttings study results

The conclusions of a £6mn research programme funded by the UK offshore oil and gas industry to find solutions for dealing with historic accumulations of drill cuttings on the seabed have been released by the UK Offshore Operators Association (UKOOA). Launched in June 1998 by a consortium of oil and gas companies, the programme enlisted the help of over 20 research organisations from around Europe. The study included cuttings pile surveys, the development of a model to predict the fate of accumulations over time, the assessment of different management options for technical feasibility and a 10-day lifting trial at BP's North West Hutton platform.

The reports main conclusions are:

- A comprehensive programme of surveying, sampling, analysis and long-term fate modelling is required to select an environmentally sound management option for a cuttings accumulation.
- Management options include covering, retrieval and leaving accumulations in place to degrade naturally.
- A 'one size fits all' approach does not constitute the best environmental option. Selection and implementation of the best environmental strategy for drill cuttings should be part of the consideration of the decommissioning programme of an offshore oil and gas installation.
- Determination of the best environmental strategy will require consideration of the science of environmental impact of the cuttings accumulation on other users of the sea. It will also require 'value' judgements around what is and is not acceptable in terms of the various environmental impacts each management option would have on the land, sea and air.
- These judgements are best made following public consultation.

UKOOA's conclusions are presented in full at **www.oilandgas.org.uk/issues** under 'environment'. Also available are the Scientific Review Group final report and links to reports published by the Environment Council following stakeholder meetings.

In Brief

Russian oil production in 2001 rose by *7.7% to 348.1mn tonnes, or 7mn b/d, compared to a 6% increase in 2000 to 323.3mn tonnes, or 6.5mn b/d, reports* Stella Zenkovich. *Exports grew last year by 4% to reach 133.4mn tonnes. In January 2002 production had reached 30.5mn tonnes, 8.5% more than in January 2001.*

ExxonMobil is understood to have *ceased work at the Nakhchivan-1 exploration well in the Azeri sector of the Caspian Sea after it showed no signed of commercial reserves.**

Asia-Pacific

Kvaerner has secured \$12mn worth of *contracts to provide engineering design and detailed engineering support for a new FPSO and two wellhead platforms destined for the Panyu project in the South China Sea.*

The Papua New Guinea to Queensland *gas pipeline has passed a critical hurdle with the signing up of its first customer. Sydney-based AGL is to take 1,000 PJ of gas over 20 years from the project for distribution in the Sydney market.*

Murphy Oil is reported to be planning *to bring onstream its 30mn barrel West Patricia field offshore Sarawak in 1Q2003 after three appraisal wells drilled on block SK 309 confirmed the commercial viability of the project.*

TotalFinaElf is reported to be planning *to invest \$1bn over the next two years on the additional development of the Paciko and Tunu gas fields in East Kalimantan in a bid to boost gas production to feed the Bontang LNG plants. The fields are currently producing 1.7bn cf/d of gas. It is hoped to raise output to between 2.2bn and 2.3bn cf/d.*

Caltex Pacific Indonesia is reported to *have announced that it expects to produce 610,000 b/d in 2002, less than the 2001 output of 650,000 b/d due to continued security disruptions at operations in the Riau Province in central Sumatra. It is also to invest \$450mn in oil and gas projects in Indonesia.*

A FURTHER 21 OF THE MONTH'S UPSTREAM NEWS STORIES NOT INCLUDED ABOVE CAN BE FOUND ON THE NEWS IN BRIEF SERVICE @ www.petroleum.co.uk

In Brief

UK

***Aminex has rejected an unsolicited** takeover offer from Apple Oil & Gas.**

***Aberdeen-based Torch Integrated** Inspection Services (TIIS) has acquired rival company Northern NDT for an undisclosed sum.*

Europe

***Cambridge Energy Research Associates** (CERA) has created a new German venture following its acquisition of Team Consult, a leading German energy research consultancy which is based in Hamburg. The new venture is called CERA Team Consult.**

***Shell is reported to have announced** that it is to move its Gas and Power business to The Hague in order to be based closer to the company's E&P headquarters.*

***The Finnish Government has recently** given Teollisuuden Voima Oy the go-ahead to build a fifth nuclear reactor, although the Finnish Parliament can either ratify or annul the government decision this spring. Energy consumption in Finland is forecast to rise by over 20% by 2015. Nuclear power met some 27% of Finnish energy demand in 2000.**

***Kvaerner has launched a new company**, to be known as Aker Kvaerner, that is to supply products, services, technology and solutions worth NKr20bn/y to the international oil and gas industry. The new operation, the result of a merger between Aker Maritime and Kvaerner Oil & Gas, employs 18,000 people in 17 countries. Kvaerner earlier posted a pre-tax 2001 loss of NKr5bn.*

***Eni has posted a 2001 net profit of** euro 7.745bn, in increase of euros 1.974bn (up 34.2%), and an EBIT profit of euros 10.388bn (down 3.6%). It is increasing its dividend on 2001 results by 79.6% to euros 0.75/share. The increased pay-out is reported to be equivalent to 37% of earnings.*

North America

***The shareholders of Conoco and** Phillips Petroleum have approved the proposed $35bn merger of the two companies. The new operation is to be*

NEWS Industry

Australian trade deficit

Australia could face an annual trade deficit by 2010 of A$7.6bn on oil imports if new discoveries are not made and brought into production, according to Woodside Energy Managing Director John Akehurst. Addressing the recent Australian Bureau of Agricultural and Resource Economics Outlook 2002 Conference in Canberra, he stated that urgent action was required to reverse the trend which would result in Australia's self-sufficiency in oil dwindling from around 80% to less than 40% by the end of the decade. Critical to reducing the pace of the decline was the need to develop a comprehensive national energy supply strategy and to encourage new investment in exploration, research and the development of new energy supply infrastructure.

'Australia is currently facing the start of a long-term decline in oil and gas liquids production,' he stated. 'Although some good new discoveries have been made recently, these will not be sufficient for the country to continue to meet the majority of its oil requirements from local production. Petroleum demand continues to grow, production from existing fields is declining and the international industry's interest in new oil exploration areas in Australia is at a low level. Many other countries have introduced more favourable terms to stimulate exploration in frontier areas where costs and risks are significantly higher. Projections prepared by government agencies clearly indicate that a "do-nothing" policy will result in rapidly increasing oil imports and significant economic costs to Australia.'

Akehurst said that Australia had several options to attempt to ameliorate the slide. These included:

- Stimulate increased exploration in underexplored frontier and deepwater areas.
- Stimulate development of small, complex and currently uneconomic fields.
- Increase substitution of oil by gas, including through the use of compressed natural gas (CNG), liquefied natural gas (LNG) and gas-to-liquids (GTL) technologies.
- Reduce liquid fuel demand through technology and incentives.

He also stated that, while the energy review initiated by the Council of Australian Governments in 2001 was welcomed, a broader review was required to define a national strategy, policies and plans to provide sustainable, secure and competitive energy supplies for the country over the coming decades. He said that the taxation regime applying to oil and gas was an important driver for stimulating investment in exploration, oil and gas development, transportation infrastructure and new technologies – and that this should be a key focus area for review. Akehurst also suggested that changes to the current Petroleum Resource Rent Tax (PRRT) and the Australian Tax Office's proposed depreciation regime were required if Australia were to attract appropriate investment.

BP outlines Alaska protection plans

BP Exploration has outlined its plan for oil-leak prevention to Alaska state regulators after calls for improvements in its operations, writes *Philip Fine*. The Alaska Oil and Gas Conservation Commission had ordered the company to explain how it would better monitor and maintain the more than 1,000 critical valves at the biggest and oldest oil field at the state's North Slope patch. Last, year the Commission found high failure rates on wellhead valves at six of the 24 production pads.

In a letter dated 1 March 2002, BP Alaska's Operations Integrity Manager Chris J Phillips told the Commission that the company has set up a safety valve management system to improve their record and root out any problems. The system involves small blankets being installed on top of insulation boxes, which will cover valves that have potential for developing hydrate problems in the cold climate. Phillips wrote that the preventative maintenance programmes and improvements to equipment repair have already added up to a better performance record.

Pertamina to cut over 33% of workforce

Indonesian state-owned oil and gas firm Pertamina is to cut its workforce by more than 33% as it moves towards privatisation, reports *Mark Rowe*. Up to 10,000 jobs will go, reducing the workforce to 16,000. Some 2,000 employees will be let go every year even though the company admitted the action was 'a drastic step' with a high social cost.

Under the new oil and gas law that came into force in November 2001, Pertamina will lose its decade-long monopoly in the country's oil and gas sector and must transform to a limited liability company in two years. The transformation process is aimed at making Pertamina more efficient and profitable. For decades Pertamina has been has been dogged with a reputation for being a company that is overstaffed and harmed by corruption.

Meanwhile, Pertamina has also announced that it intends to take part in a tender for oil and gas fields in Egypt in April as part of its expansion programme. Pertamina Upstream Director Iin Arifin Takhyan said the company was interested in bidding for two oil fields in the Nile river area and in the Western desert of Egypt. Pertamina has been expanding its oil exploration and exploitation activities overseas and has also moved into Vietnam, Malaysia, and other countries in the Middle East.

Shrinking employment in global oil and gas

The International Labour Organisation (ILO) has released a report detailing how employment in the global oil and gas sectors has 'shrunk dramatically' over the past 25 years. Citing 'changing corporate structures and privatisation' as key reasons for the change, the Geneva-based UN agency says that in the US alone worker numbers slumped from a peak of 1.65mn workers in 1982 to roughly 640,000 by 2000.

Reductions can happen suddenly, says the ILO, citing the loss of 2,250 jobs in Canada in 1998 when oil drilling activity fell by 10%, a time when large numbers of lay-offs were also being experienced in Norway, China and Britain. For further information, visit **www.ilo.org/public/english/ bureau/inf/pr/2002/5.htm**

Methane hydrate tapped in gas form

A joint venture comprising Japan National Oil Corporation, the Geological Survey of Canada, the US Geological Survey, the US Department of Energy, Germany's GeoForschungsZentrum Potsdam and the Indian Ministry of Petroleum & Natural Gas is reported to have succeeded in tapping methane hydrate in an economically viable gas form for the first time. The experiment – conducted in Canada's Northwest Territories where the ground is permanently frozen – involved pouring water heated to 90°C down three 1,200-metre wells into a methane hydrate layer at 900 metres depth. The resulting slush was warmed to 40°C and the methane gas extracted via pipeline. Previously, methane hydrate could only be extracted in costly solid form before being turned into gas.

Methane hydrate, frosted at low temperatures under high pressure, is thought to be a 'promising' energy source. It is found at depths of between 1,000 metres to 2,000 metres under the seabed near continental shelves, as well as under permanently frozen ground. It could prove to be a major source of energy for Japan, where it is available in abundance under the seabed. It is reported that the team is planning to conduct further tests offshore Japan in 2004.

Floating Venture

UK independent Venture Production has announced the placing of 19.18mn new ordinary shares and 4.35mn existing ordinary shares at 170 pence/share, and admission of the entire issued and to be issued share capital of the company to the Official List and to trading on the London Stock Exchange's market for listed securities.

The net proceeds of the placing will be applied in the short term to pay down a portion of the Group's debt. Subsequently, the enlarged capital will be used to fund ongoing capital expenditure, in particular the development of the Sycamore field in the North Sea.

In Brief

headquartered in Houston, Texas. The European Union and Canadian authorities have also approved the merger; the US Federal Trade Commission is expected to announce its ruling in 2H2002.

***Talisman Energy has posted a 2001 net** income of $786mn. Talisman Energy reports that it increased its proved reserves by 26% in 2001 to 1.5bn boe, with replacement costs averaging C$7.08/boe.*

***ExxonMobil Chairman and CEO Lee** Raymond is reported to have stated that he expects 2002 capital expenditure to rise by 10% compared with 2001, and 2003 spending to increase a further 10% from 2002.*

***Houston-based oil and gas contract** drilling company Nabors Industries is reported to be acquiring Enserco Service Company of Calgary, Alberta, for C$400mn together with C$36.9mn in assumed debt.*

***Marathon Oil is reported to be plan**ning to sell $1bn of debt in a two-part sale split between 10-year notes and 30-year bonds. No information is available regarding pricing or timing of the sale.*

***In the wake of the decline of Enron, BP** is reported to have stated that it is to halt all political contributions. The move is expected to be most felt in the US, where the company donated nearly $1mn last year.*

***US company Benton Oil & Gas is** reported to be selling its 68% stake in Arctic Gas to Yukos for $190mn.**

Middle East

***The Egyptian Minister of Petroleum** Sameh Fahmi is reported to have announced that the Middle East Gas Pipeline linking Jordan, Lebanon and Syria will begin exporting gas in 2003.*

Russia & Central Asia

***Yukos and the Severstal-controlled** Vostochny port in Far East Russia are to jointly invest in expanding the port's oil product export capacity to 7mn tonnes.*

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NEWS Downstream

UK

Phoenix Natural Gas is to implement a *geographic information system (GIS) from ESRI (UK) to aid the company's upgrade of a 2,000-km gas pipeline network in Northern Ireland, acquired in 1996.**

Williams has announced that it will *physically trade power beginning 1 April 2002, having successfully qualified its UK trading systems with Logica. The US company opened its European trading offices in London last July and began trading UK power in November 2002.*

Europe

The proposed merger between *German energy exchanges EEX European Energy Exchange and LPX Leipzig Power Exchange has been approved by both companies' shareholders.*

The European Gas Regulatory Forum *has adopted good practice guidelines on third-party access to the EU gas network, allowing European companies 'non-discriminatory' access 'in order to ease access and allow consumers to benefit from competition,' reports* Keith Nuthall.

Eastern Europe

Predag Drecun, the Montenegrine *member of the Yugoslav Government's expert team on the future of Serbian-Montenegrine relations, has confirmed that Montenegro remains firm on 'divorcing' from Serbia and that the separation of Jugopetrol Kotor from Belgrade-based service station operator Jugopetrol was a first step in this direction.*

North America

Duke/Fluor Daniel has been awarded a *contract by South Carolina Electric & Gas to undertake engineering, procurement and construction services for an 875-MW gas and oil-fired power plant in Jasper County, South Carolina, due onstream in summer 2004.*

Erle Nye, CEO of TXU Corporation and *other TXU firms has stated that the Group plans not just to market in Texas, but also in liberalising wholesale*

Omani gas sales

Oman LNG has signed a sale and purchase agreement (SPA) to sell 0.7mn t/y of LNG over five years to Shell Western that will supply Shell's downstream gas markets in Spain. The agreement is Oman LNG's fourth medium/long-term SPA – the others comprising 4.1mn t/y to Kogas, 0.7mn t/y to Osaka Gas (both 25 years) and Dabhol Power (20 years).

Beginning this year, the LNG will be delivered to Spain by Shell-owned LNG carriers, which Oman LNG has an option to replace with its own ship from 2004 onwards.

Zuata Sweet sales

TotalFinaElf has announced first production of Zuata Sweet syncrude from the Sincor project's Jose upgrader facility in Venezuela. Following this latest milestone, the entire Sincor integrated chain is now onstream and on target to produce at a plateau of 180,000 b/d of high quality, 32° API syncrude with a very low sulfur content from a feedstock of 200,000 b/d, 8°–8.5° API extra-heavy oil produced in the Zuata region of the Orinoco Belt. The Zuata Sweet syncrude is destined for the US market, with regular deliveries slated to begin in April 2002.

Brand manager comments from Q8

Petroleum Review **published its annual** ***Retail Marketing Survey*** **in March 2002. Unfortunately, Q8 Petroleum was omitted from the Brand Managers Comments section and we would like to take this opportunity to present the company's review of the past year's developments in the UK fuel retail sector.**

Miles Mayall, Retail Division Manager of Q8 (pictured) says: 'For Q8, 2001 was a year of improving performance. In the run-up to the General Election we experienced some of the most difficult trading conditions since Esso's Pricewatch campaign began. Since then the pressure has eased and we have stepped up our programme for developing our retail business in the UK.

The year saw our dealer recruitment programme boost our dealer numbers to well over 200 sites. Furthermore, the launch of a new dealer card polling service and the introduction of Q8 Shop Check – a promotional scheme for dealers to improve their shop offer – demonstrated our ongoing commitment to the UK dealer sector.

We also saw the continuation of our highly successful Budgens partnership with the opening of our eighteenth Xpress Budgens site at Windlesham South, and an agreement to develop a further five sites in early 2002.

With all this activity underpinned by our increasingly popular loyalty card scheme Q8GO (see ***2002 Retail Marketing Survey*****), we are moving into 2002 with a clear message that Q8 is a growing brand and is fully committed to the UK retail market.'**

Developments downstream Africa

Stella Zenkovich reports on some recent downstream developments in Africa:

- BG, together with partners Edison and the Egyptian Petroleum Company, is to supply 3.6mn t/y of Egyptian LPG to France over a 20-year period from 2005. Egypt has also contracted to supply some 4.8bn cm/y of LNG, over 20 years to state-owned Gaz de France.
- Nigerian gas sales in 2001 rose by 15% compared to year earlier levels according to Ron van den Berg, Managing Director of Shell Petroleum Development Corporation.
- Kenyan Energy Minister Raila Odinga has stated that upgrading the Mombassa refinery would cost $94mn while building a new refinery could cost as much as $600mn. The government has yet to decide which option to take.

EU promotes waste oil as fuel

A healthy market in the use of waste oil as a fuel to generate electricity is being promoted in the European Union through excise duty exemptions, erected in the face of official EU environmental policy, a new European Commission report says. Its *Critical Review of Existing Studies and Life Cycle Analysis on the Regeneration and Incineration of Waste Oils* points out that Council Directive 75/439/EC on Waste Oils tries to make Member States prioritise regeneration over burning, writes *Keith Nuthall.*

However, in 11 Member States waste oils are exempt from excise duty which, says the report, 'encourages the use of waste oil as fuel.' Britain, for example, uses 85% of collected waste oils for incineration with energy recovery and has recently been threatened by the European Commission with legal action at the European Court of Justice (ECJ) for its alleged failure 'to prioritise the processing of waste oils by regeneration.' The Netherlands, Austria, Denmark, Belgium, Sweden and Ireland have similar records on incineration, but face no ECJ cases.

M. East downstream developments

Stella Zenkovich reports on some recent downstream developments in the Middle East:

- Turkish state pipeline company Botas reports that the first of two pipelines for the 390-km undersea section of the Blue Stream pipeline, which is to carry Russian gas to Turkey, has been completed by Eni and Gazprom. Work on the second is expected to be completed in May 2002.
- Ivan Bambiza, President of Belarus state oil company Belneftekhim, has announced that the country's six largest petrochemical plants are to be converted into joint stock companies. Some \$843mn investment is expected to come from Slavneft, Lukoil, Itera, Amtel and Surgutneftegaz.
- A \$52mn oil refinery is to be built in Russian Yakutia, the Arctic Republic also known as Sakha, by January 2004. Equipment is to be supplied by Petrofac of the US. A leasing agreement has been signed by Yakutgazprom, Avangard Leasing and commercial bank Avangard, the latter committed to investing \$21mn in the project.

FOA help to cut costs

The Futures and Options Association (FOA), in association with Denton Wilde Sapte, has developed a set of multi-energy product, multi-customer standardised documentation for those involved in the energy and oil markets. The initiative is part of the Association's objective to develop more centralised member services on a 'pooled cost' basis.

The documents are specifically designed to assist FOA members reduce the time and cost associated with negotiating contractual agreements with clients complying with the Financial Services & Markets Act (FSMA) and the new FSA Handbook.

The complete documentation suite is available on the FOA website at **www.foa.co.uk**

Replan refinery plans

The Japan Bank for International Cooperation (JBIC) has signed a guarantee agreement for a private syndicated loan of up to \$300mn for the Replan refinery modernisation project to be implemented by Petrobras in Brazil.

The state-owned company is planning to make Brazil self-sufficient in petroleum supply by 2005 by boosting crude oil production and promoting the modernisation of the country's existing refineries. The Replan refinery, located in the state of Sao Paulo, is Brazil's largest refinery. The modernisation programme will allow the facility to refine heavy oil from the Campos Basin and to upgrade the quality of the oil products produced.

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and retail markets outside Texas but still within the US, including the north-east and midwest.

***US companies NirvanaSoft and Energy** Services Group have formed a strategic alliance to provide application service provider (ASP) services to companies that are participating in the competitive energy markets.*

***Duke/Fluor Daniel has been awarded** contracts by Duke Energy North America to undertake engineering, procurement and construction services for three natural gas-fired combined cycle power generation plants with a combined capacity of 2,420 MW. The three projects are the 600-MW Luna energy facility in Luna County, New Mexico, the 620-MW Grays Harbor facility in Grays Harbor County, Washington, and the 1,200-MW Moapa plant in Clark County, Nevada.*

Russia & Central Asia

***Yukos is reported to be planning to** build a new 140,000 b/d capacity oil terminal at the port of Vostochny to develop Far East markets.*

***Sinopec of China has indicated that it** plans to acquire oil fields in Russia, as well as other countries, in order to supply its domestic Chinese refineries, reports UFG.*

Asia-Pacific

***The Sri Lankan Government has struck** a deal with multinational Mundogas for the supply of LPG to customers on the island from May 2002, reports* Swineetha Dias Wickramanayaka. *With retail prices for a 12.5-kg cylinder being between Rs325 and Rs350, it is claimed the agreement will help ensure supplies of reasonably priced fuel in the country.*

***BP is to sell its 21 self-service forecourts** in Japan, to Japan Energy for an undisclosed sum. Japan Energy will integrate the sites into its existing network of more than 4,400 outlets, around 145 of which have been converted to self-service over the past year.*

Africa

***York, UK-based Biocide has been** awarded the Kenyan Institute of Petroleum's East African Award for*

In Brief

Innovation for its work in combating crime associated with fuel fraud. The Biocide anti-fraud programmes – under which export fuels including petroleum and diesel are covertly marked so that field analysis may differentiate fuel products – have been helping to eradicate malpractices and track/trace illegal fuel movements through Kenya, Uganda and Tanzania since October 1998. The award is sponsored by Kenya Shell/BP. (Reported in Petroleum Review's 2001 Retail Marketing Survey.)

Shell is reported to have awarded *Hyundai Heavy Industries of South Korea a $480mn contract to build a 39-km oil pipeline and related facilities in Nigeria by the year 2005. The contract also requires Hyundai to repair and build additional crude terminals on Bonny Island in Nigeria.*

nc sweett – the recently launched *joint venture between construction consultant Cyril Sweett and Spain's professional services business Soluziona – has been appointed as cost consultant and contract administrator for a $1bn LNG export terminal construction project in Damietta, Egypt. Phase 1 of the project is slated to complete in September 2004 and will have the capacity to handle 5mn t/y of LNG. Phase 2 is to follow three years later. The LNG will be transported to regasification terminals under construction in Valencia and Galicia, while the gas will be sold to power generators in Spain.*

A FURTHER 2 OF THE MONTH'S DOWNSTREAM NEWS STORIES NOT INCLUDED ABOVE CAN BE FOUND ON THE NEWS IN BRIEF SERVICE @ www.petroleum.co.uk

Sibneft outlines plans for the year ahead

Sibneft has unveiled plans to raise investment in exploration, production and refining in 2002 by more than one third to $686mn. The company is aiming to boost oil production by 29.2% to a new target of 530,000 b/d from 408,000 b/d in 2001. If successful, this would make Sibneft Russia's fifth largest oil producer.

Sibneft intends to spend $160mn on its 890mn barrel Sugmut field, boosting output from the field by 89% to 155,000 b/d. It is also to spend $137mn at the Palyanovskoye and Priobskoye fields licensed to the Sibneft-Yugra subsidiary. Poduction in 2002 is forecast to average 14,000 b/d from the 1.8bn barrel fields.

The company is also intending to raise investment at its Omsk refinery to $49mn, an increase of 11% from the 2001 total of $44mn. It plans to raise the share of high margin products produced at the refinery while leaving throughput largely unchanged at 262,000 b/d. It is to increase output of A-92 gasoline by 26% to 1.25mn t/y, while cutting production of A-80 gasoline from 1.9mn t/y to 1.7mn t/y and ending production of A-76 gasoline entirely.

Costs awarded in US court case

A Los Angeles court is reported to have ordered ExxonMobil to pay $5.1mn to a former employee who alleged that toxic fumes emitted by crude oil caused his bladder and prostate cancer, writes *Philip Fine*. In a case that could have major implications for petroleum transportation, Dwayne Gregory, 54, who served for seven years on oil tankers, claimed company officials waited 20 months to tell him that a shipboard physical examination had detected blood in his urine – a sign of possible bladder cancer.

His defence lawyer is reported to have said that the jury was most upset over the fact that after chemotherapy and four cancer surgeries the company allegedly refused to relocate him to a non-toxic environment and sacked him. An announcement about any appeal is awaited.

UK Deliveries into Consumption (tonnes)

Products	†Jan 2001	†Jan 2002	% Change
Naphtha/LDF	205,406	70,375	–66
ATF – Kerosene	814,208	741,127	–9
Petrol	1,723,909	1,673,519	–3
of which unleaded	1,640,647	1,624,466	–1
of which Super unleaded	29,565	41,208	39
of which Premium unleaded	1,171,507	–	–100
ULSP (ultra low sulfur petrol)	439,575	1,583,258	260
Lead Replacement Petrol (LRP)	83,262	49,053	–41
Burning Oil	519,222	414,951	–20
Automotive Diesel	1,274,571	1,349,973	5.9
Gas/Diesel Oil	571,645	588,151	3
Fuel Oil	214,942	212,445	–1
Lubricating Oil	73,167	74,598	2
Other Products	615,592	600,305	–2
Total above	6,012,662	5,725,444	–5
Refinery Consumption	470,876	410,116	–13
Total all products	6,483,538	6,135,560	–5

Products	†Dec 2000	†Dec 2001	†Jan–Dec 2000	†Jan–Dec 2001	% Change
Naphtha/LDF	223,601	151,205	2,337,819	1,597,312	–32
ATF – Kerosene	781,119	675,728	10,242,070	10,673,506	4
Petrol	1,892,434	1,730,887	21,270,596	20,204,567	–5
of which unleaded	1,791,776	1,672,836	19,678,027	19,250,766	–2
of which Super unleaded	34,875	44,050	471,509	435,683	–8
of which Premium unleaded	1,756,901	–	19,206,518	5,732,703	–70
ULSP (ultra low sulfur petrol)	–	1,628,786	–	13,082,380	–
Lead Replacement Petrol (LRP)	100,654	58,051	1,592,565	953,801	–40
Burning Oil	350,233	423,146	3,603,361	4,051,115	12
Automotive Diesel	1,174,497	1,391,508	15,341,479	16,244,592	5.9
Gas/Diesel Oil	461,993	520,277	6,820,620	6,202,140	–9
Fuel Oil	161,495	183,169	1,684,864	1,855,881	10
Lubricating Oil	65,514	83,444	823,594	879,399	7
Other Products	701,047	598,250	8,461,492	8,483,375	0
Total above	5,811,933	5,757,614	70,585,895	70,191,887	–1
Refinery Consumption	410,213	456,895	5,133,529	4,754,991	–7
Total all products	6,222,146	6,214,509	75,719,424	74,946,878	–1

† Revised with adjustments

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

The key to successful basin evaluation

The ability to analyse basins and make comparisons on a worldwide basis is increasingly important to oil and gas companies desiring to better manage and optimise their assets on a global, rather than a regional, basis. A new, powerful tool from IHS Energy is now allowing geologists to do just this. *Melissa Manning*, Global PR Manager, IHS Energy Group, explains.

Basin analysis involves many disciplines, which range from achieving a basic understanding of geological processes to assessing the risk and probability of finding hydrocarbons. Opportunities for hydrocarbon discoveries within upcoming basin blocks seem to represent often under-exploited prospects for exploration companies, yet the risks are high. Even if the opportunities are supported by the right seismic data, it would be reassuring for the company to see E&P figures for other areas with a similar geologic profile or to examine the geologic history in more detail as compared to other basins with a proven exploration record.

By understanding the geological setting and history of a lesser-known prospective basin and then comparing its formation history with analogue basins, it is possible to highlight exploration opportunities.

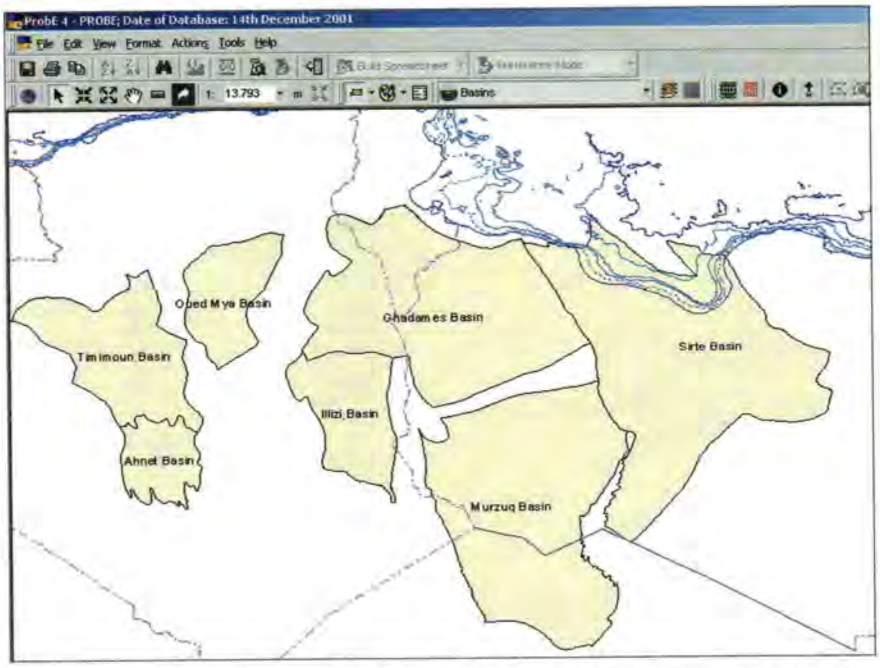
Standardisation lacking

The concept of locating good geological knowledge of a specific area and then comparing that data against the basin-forming processes of lesser-known basins to identify new exploration opportunities, sounds simple enough. Yet such comparisons require a common definition of geological parameters, from age definition to basin classification. To date, a lack of existing standards for these parameters has made it difficult to query data on any of the geological processes between basins at a worldwide or regional scale.

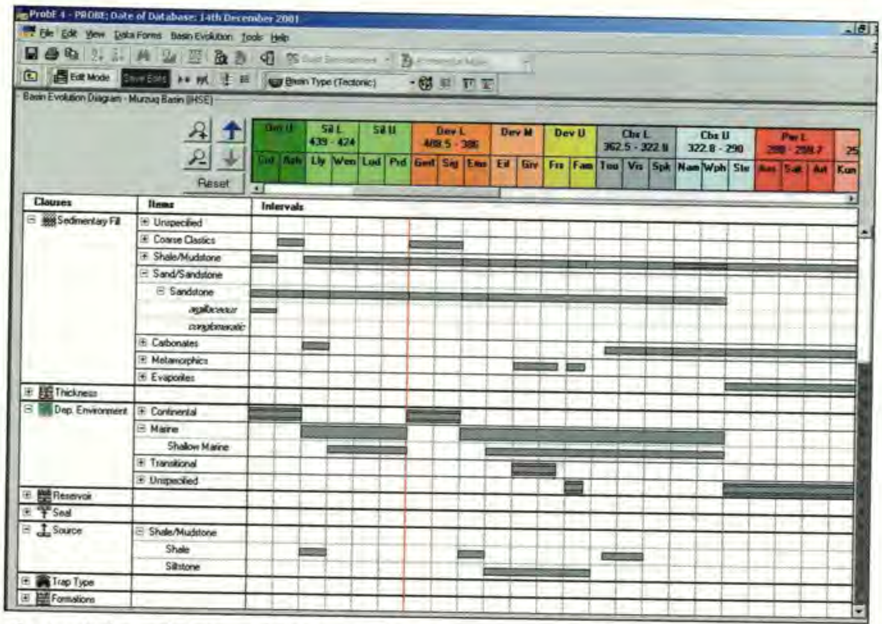
Coherent analysis required

Various tools have been designed for basin analysis, including seismic workstations and basin-modeling software. Until now, however, there were no software programs available to enable coherent analysis of all geological processes, which form part of the basin evolution. Lack of such tools hampers the ability of a geoscientist to compare basins on a regional or worldwide scale. In addition, limited staff resources often aggravate the problem, making it increasingly difficult for E&P professionals to conduct an evaluation of sufficient quality within the limited time frame set by the current business environment.

Until recently, the problems in merging E&P data with geological data have seemed insurmountable – a task that became even more daunting when faced with the lack of a common standard in basin data on a global scale. So, historically, the time and skills base of any in-house team has limited the scope and depth of any evaluation.



Basins selected through the query builder are displayed in the Probe GIS, enabling users to investigate the spatial distribution of basins corresponding to evolutionary criteria.



Geological conditions and basin forming processes are displayed as horizontal geological time lines in the basin evolution diagram (BED).

To the rescue

However, IHS Energy Group has now developed a new module for its proven 'Worldwide Basin Database' that promises to do exactly what geologists have required of basin data – the ability to profile similar characteristics on a global scale and overlay this with detailed E&P data represented in a visual or graphical interface (GIS) format.

In 1999, IHS Energy Group and Eni-Agip began a joint project to develop an application that could form a common, standardised method of visualising and comparing basin attributes and sedimentary environments on a worldwide basis. The product resulting from that effort is called BASE. It forms part of IHS Energy's Probe™ software, an established desktop system that provides a platform for viewing and analysis of E&P and basin data.

While there have been several standards proposed (Bally and Snelson, 1980; Klemme, 1980; Kingston *et al*, 1983; St John *et al*, 1984; Allen and Allen, 1990; and Busby and Ingersol, 1995) the overall lack of a common standard has not only presented problems in evaluation of existing data, but also the entry and handling of new data as it becomes available.

BASE-in analysis

Forming the core of the BASE application, the basin evolution diagram (BED) resembles the basin classification summary form of Kingston (*et al*, 1983), and also shares some similarities to the petroleum system chart. The BED displays the age interval for different geological processes or items on a horizontal age-scale. By visualising the basin evolution and associated attributes of the sedimentary fill in a coherent way, the BED enables a geologic interpreter to quickly identify which processes took place during a certain geological period.

To achieve an analysis, basin data is derived directly from the basin database and plotted in the basin evolution diagram. The interpreter can then add or modify the age intervals and the attributes associated with each item. New interpretations can be saved for future consultation, enabling the geoscientist to create an individual database of basin evolutions.

Importantly, strict validation rules are introduced in the program to force the user to make consistent interpretations. The basin cycle contains a specific set of events and environments in time. For example, depositional environment and sedimentary fill cannot extend over the basin cycle boundaries.

Parts of the lithostratigraphic units – such as source rocks, reservoirs or seals, are assigned hydrocarbon significance. Specific attributes are stored in the basin data set for each item. For example, geochemical data are stored for source rocks and porosity and permeability data are stored for reservoirs. Individuals using the BASE application can also modify the attribute data.

The BASE application contains a built-in query tool called the query builder, which considerably enhances the analysis of the geological evolution of basins within the BED. Using the query builder, the geologist can build a comprehensive understanding of the importance of petroleum forming – and trapping – processes by comparing the events in different geological settings. The result of a query can be viewed in the BED or in a GIS.

Because data is stored in a consistent way in BASE, simple event-queries are possible on a worldwide scale. For instance, an event query can be conducted to find basins containing carbonate reservoirs with certain porosity and permeability ranges. The tool also allows a geoscientist to build complex evolutionary queries. An evolution query interrogates changes in basin-forming processes – for example, the evolution of one basin type into another one. Such a query could select basins that were originally located on an intra-cratonic plate but later became an active-divergent continental margin. To test the occurrence of certain processes on a regional or worldwide scale, several combinations of evolution and event queries are possible.

Basins selected through the query builder can be plotted in a GIS, which enables the interpreter to investigate the spatial distribution of basins through time. A more detailed mapping system is being developed to plot petroleum systems and play characteristics in a particular basin. Using information from the basin evolution diagram in combination with well and reservoir data, particular basin characteristics, such as the occurrence of source rocks, can be plotted on the play map. Then, polygons can be drawn around selected features and, by combining different polygons, interpreters can delineate petroleum plays and areas of interest for further exploration.

As Jan Roelofsen, Vice President–Geneva Operations, IHS Energy Group, explains: 'For Eni-Agip, as for other exploration companies, when identifying new basin opportunities, their main problem is to reduce risk and to speed up evaluation time. Eni-Agip wanted to enable its explorationists to assess a maximum number of different geological settings and to explore and view those settings instantly. This gave Eni-Agip, with the help of IHS Energy, the impetus to design a robust, highly intuitive, yet incredibly detailed program that copes effortlessly with complex basin data on a global level, but it also allows the data to be viewed within a GIS.'

Optimising assets

As a result of the BASE application and its basin evolution diagram, query builder and play-map functions, geologists now have a powerful tool to make a consistent synthesis of geological interpretations, which, ultimately, enables them to analyse basin-forming processes in a coherent manner. The ability to analyse basins and make comparisons on a worldwide basis is increasingly important to oil and gas companies desiring to better manage and optimise their assets on a global, rather than a regional, basis.

For further information on BASE, you can e: ***Sales@ihsenergy.com*** *or contact Danielle Tasker, Product Development Manager on Tel: +44 (0)1273 723773 in the UK or 888-OIL-DATA (toll-free in the US).*

Big Three oil producers target gas reserves

According to the US Department of Energy, the Middle East producers must increase oil production capacity from about 39mn b/d to 70mn b/d by 2020 in order to meet rising global demand. But there is a question mark as to whether the Middle East producers can undertake the scale of investment required as their economies are still subject to the vagaries of oil price fluctuation. In the first of a two-article series, *Mojgan Djamarani* reviews development prospects for the 'Big Three' – Iran, Iraq and Saudi Arabia. Part two, to be published in May, will cover Kuwait, the Emirates and the smaller regional producers.

The high oil prices of 1999 and 2000 sharply increased GDP (gross domestic product) growth rates and helped to maintain the momentum of growth in 2001 despite lower oil prices. However, failure at structural reform of their economies means that the Middle East producers will be operating under increased budgetary pressures that could lead to a slow down of economic growth. Rapid population growth, a burgeoning and largely inefficient state sector, large foreign debts and increased military expenditures in response to internal security problems and political tensions in the region all make demands on the available oil revenues.

A study by the Baker Institute states that Middle East oil wealth is also becoming increasingly limited. The high oil prices, it says, disguise the fact that Opec's oil export earnings have actually been declining from a high of $573bn in 1980 to just $226.6bn in 2000 at a time of high oil prices. Hence Opec's policy in defending the oil price rather than in gaining a market share, as was explained in a speech made by Sheikh Zaki Yamani to the CERI World Oil Conference in January. The expected 33% market share in 1Q2002 – assuming that the Opec member countries largely comply with agreed production cuts of 1.5mn b/d – falls short of Opec's average 39.2% market share over the period 1990–2001. But, according to Yamani, it is designed to prevent the Opec basket price from falling below the floor price band. Opec's official target price range is $22–$28/b for the Opec basket – any fall below $21/b could have severe financial consequences for their economies.

Diversifying economies

Measures aimed at economic restructuring and diversification are being undertaken in a few of the region's oil producers. The United Arab Emirates (UAE) has been by far the most successful in diversifying its economy away from oil and gas. Currently, more than two-thirds of its total GDP contributions come from the non-oil sector and about 30% of its exports. Of the Middle East's oil producers, the UAE is best placed to weather the slowdown in the global economy and the decline in oil prices. It is in a very strong financial position with an estimated $60bn in overseas cash reserves and no domestic debt burdens. Expansion of its private sector (45% of the economy) and non-oil sector is expected to offset any decline in the oil and gas sector in the 2002.

Expanded use of natural gas and LNG exports as well as the petrochemical sector is central to the diversification strategies of Oman, Qatar and Iran (see p19 regarding the latter). This has been accompanied with a build-up of foreign debt that, in the case of Qatar at almost $13.2bn, is almost 80% of its GDP. Qatari investments in the energy sector totalled $25bn in the last five years and, according to the Energy Minister Abdullah al-Attiyah, the next five years should see another $19.2bn. In the last four years two large-scale LNG and three petrochemical projects were completed. The emphasis in the country's development plan now is to shift to medium and light industries that would require smaller levels of investment.

Iran in particular has made significant steps in attracting foreign investment during the last year. Last summer, the Majlis passed the Law on Attraction and Protection of Foreign Investment that, among other measures, streamlines procedures and guarantees repatriation of profits. To reassure foreign investors the government has also agreed to abide by the New York Convention, which is a UN agreement on foreign arbitration awards. Last year the government also set up a stabilisation fund from above budget oil revenues which could serve to cushion the impact of lower oil prices in 2002.

In spite of the possibility of a surplus of LNG in Asia as well as in the Atlantic Basin, all three existing Middle East LNG producers – Oman, Qatar and the UAE – have plans underway for expansion of their LNG capacities. Iran is planning to enter the LNG market soon. Until recently, the Middle East LNG industry was based on long-term fixed route contracts with Asian buyers but last year saw two new developments. One was Qatar's two long-term contracts with two European customers for the first time and the other was the emergence of the Middle East as a swing producer. For the first time they used their surplus capacity to make spot and short-term sales to European and American customers. According to a study by PIRA Energy, the greater the interaction of the swing suppliers with both Asian and Atlantic basin markets the greater the convergence of LNG prices over time. This should be good news to the Asian buyers who, according to the study last July, paid \$4.50–\$5.0/mn BTU compared to a benchmark US Gulf coast natural gas price of \$3.06/mn BTU.

In contrast, in Saudi Arabia, Kuwait and the smaller oil producing economies, the pace of economic reform and market privatisation has been very slow. The outlook for the Saudi economy in particular is rather bleak. For 2002 the government has set a budget deficit of \$12bn. According to Sheikh Yamani, with its Opec quota of 7.2mn b/d for 1H2002, the Saudis require a minimum of \$20/b for their crude sales to reach their targeted oil revenue.

However, Brad Bourland, Chief Economist at the Saudi American Bank, expects Saudi crude prices to slide to \$18/b, further reducing the government oil revenues that stood at \$58.2bn in 2001. The economy, he says, may contract by as much as 1% in 2002. This would be Saudi Arabia's sixth recession in the last 20 years. There is nothing to indicate that this time the authorities will make the necessary economic reforms. On average, the Saudi economy has grown at a rate to 1%/y during the last decade. The long expected opening up of the economy to foreign direct investment has yet to take place with Saudi Aramco and SABIC's hold over the economy still intact. A final agreement with eight international oil companies under the Gas Initiative for three major upstream and downstream natural gas projects worth \$25bn is still pending. The Gas Initiative was intended to open up the economy to competition and boost growth and provide much needed employment. It is estimated that for every \$1bn of foreign investment, 20,000 Saudi jobs would be created.

Iran

Last year's investigations into NIOC and its affiliates, in particular Petropars, by Iran's judiciary, has led to greater control over energy operations by the central government. A Supreme Energy Council has been established to oversee all energy projects and, henceforth, international tenders will only be open to Iranian and foreign contractors who hold a permit from the Economic Council in partnership with Iranian businesses. The foreign operations of Petropars and a number of other government ministerial affiliates registered abroad are to be closed and their assets transferred to Iran. Although the impact of these changes has yet to filter through, it is unlikely that they will divert the current policy of opening up to western investment, although they will make the process more bureaucratic.

According to NIOC, with the implementation of the 12 buy-back projects underway, some 520,000 b/d will be added to Iran's oil production capacity by 2005, bringing the total to 4.5mn b/d. Of this, 1.1mn b/d will come from offshore fields which currently produce 660,000 b/d. Gas condensate production is also expected to increase by 390,000 b/d by 2005. An Iranian economic journal claims that NIOC is to invest \$2bn to revitalise the oil sector with most of the funds going to the southern oil fields that at present produce 3.3mn b/d.

Last year Shell began pumping from the offshore Soroush field at a rate of 50,000 b/d. Its Nowrooz field is scheduled to go onstream in 3Q2003. The heavy oil from Soroush is to be marketed as a separate crude oil grade and at a higher price. The two fields are expected to reach a combined peak production level of 190,000 b/d. Shell has awarded the engineering, procurement, installation and commissioning (EPIC) contract for the \$800mn project to a joint venture of Abu Dhabi's National Petroleum Construction Company and Iran's Naft Sazeh Qeshm who, in turn, have selected France's Technip as engineering partner. Technip is carrying out the design, engineering and procurement for seven offshore platforms and pipelines.

NIOC signed more buy-back projects last year. Eni is to develop the Darkhovin field in the southern Khuzestan Province over a five-year period at a cost of $1bn. PetroIran and Australia's BHP are to triple output from the offshore Forouzan-Esfandiar fields to 130,000 b/d. Forouzan currently produces 45,000 b/d and the Esfandiar field, which Iran shares with Saudi Arabia and Kuwait, is expected to reach production of 25,000 b/d.

Development of the Azadegan field also got underway last year. The Japanese-led consortium (comprising JNOC, JAPEX, Indonesia Petroleum and general trader Tomen), which already had acquired preferential rights to the development of the field, and Shell have agreed to jointly develop Azadegan with an investment of $8bn. Two-thirds of the investment is to be borne by the Japanese and the rest by Shell. The field has 26bn barrels of reserves in place and between 5bn and 6bn barrels of recoverable oil. Production is to start in 2005 with daily output of between 700,000 b/d and 800,000 b/d, most of which is destined for export to Japan. Funding for the project is provided primarily by JNOC and Japan Bank for International Cooperation.

NIOC expects to announce by the end of April the winners of the tender for the South Pars oil field in the Persian Gulf. The field currently produces 5,000 b/d but is expected to see production rise to 35,000 b/d in the first phase and to 100,000 b/d in the second phase of its development.

Earlier this year, Statoil, in conjunction with Iran's Oil Industry Research Centre, was awarded a $10mn contract to prepare a comprehensive plan for boosting production at the Ahwaz, Bibi Hakimeh and Maroun fields in southwest Iran. The three fields currently produce 1.5 mn b/d. Ahwaz, along with the Mansouri and Ab Teymour oil fields, comprise the Bangestan development project. Iran is trying to secure foreign investment through buy-back deals for the project that is estimated to cost $3bn. The three fields have estimated remaining reserves of 5bn barrels and NIOC hopes to see a production rate of 650,000 b/d. TotalFinaElf, Eni and Shell are the front-runners for Bangestan.

NIOC is increasing its presence in the growing markets of India and China. Its crude exports to India have grown at an annual rate of 7%–8% and last year Iran became China's biggest supplier. In 2001, it exported 165,000 b/d to India, a figure that is expected to rise to 180,000 b/d this year. Ties with China have increased. The Chinese are involved in a number of oil projects including the Kashan-Ardestan block where Sinopec is to explore an area of 4,670 sq km over a three to four-year period in the first phase of the project and drill two exploratory wells to a depth of 3,500–4,000 metres in the second phase. Sinopec and CNPC were also awarded the $100mn technical services contract for the construction of the $240mn Neka–Tehran oil pipeline which is expected to carry 175,000 b/d of Caspian oil by the end of 2002. NIOC has also ordered five 300,000-tonnes oil tankers from China, the first of which will be delivered in April.

Iran appears to have given up on an early settlement of the division of the Caspian Sea. It has announced that it is opening up what it considers to be its oil acreage in the Caspian to foreign investment. To lure the international oil companies to the disputed waters, the Oil Minister Bijan Zanganeh has said that Iran is considering offering PSAs rather than buy-backs. The 3D seismic survey of the Caspian, he said, is to be followed by drilling in deep water. Last year NIOC commissioned a joint venture of GVA Norway and Iran's Sadra Company to build an oil rig in offshore Mazandaran Province.

Iran is also going ahead with plans to secure its position as a transit route for Caspian oil and gas. By the end of the year it will start operating the Neka–Tehran oil pipeline which eventually could carry 380,000 b/d of Caspian oil to three northern refineries at Arak, Tabriz and Tehran. According to the Oil Minister, it is possible for Iran to handle 800,000 b/d of Caspian oil produced by Iran and the other littoral states. Plans call for boosting capacity at the northern refineries to 800,000 b/d to process the oil. Currently, only 15,000–20,000 b/d of Turkmen oil is being shipped to the port of Neka on the Caspian.

Iran's regional plans are bolstered by Transneft's plans to go ahead with establishing an oil pipeline corridor through Iran based on the existing pipeline infrastructure. Transneft's plans envisage a pipeline route from Omsk in Western Siberia to Neka, passing through Pavlodar and Shymkent in Kazakhstan and Chardjou in Turkmenistan. According to Transneft boss, Semyon Vainstok, the company is working to coordinate the route with Kazakh state pipeline operator KazakhOil.

Iran has also stepped up its efforts to expand the market for its natural gas. Last October Iran Gas Export Company was established to concentrate and coordinate gas exports. One of its main tasks is to pursue the proposed 66mn cm/d Iran–India gas pipeline. A consortium of Shell, BP, Petronas and NIOC already exists and, according to the Deputy Oil Minister, is negotiating how to export the gas to India.

Both onland (via Pakistan) and offshore routes are being actively considered. In the onland pipeline, estimated to cost $6bn, 70% of the gas would be destined for India and the rest for Pakistan. The offshore pipeline is estimated to cost $10bn. Feasibility studies have been commissioned to Australia's BHP for the onland pipeline and to Snamprogetti for the offshore route. The proposed onland route, the more favoured option, would connect the Assaluyeh gas field in southern Iran to the Gas Authority of India's HBJ pipeline in Gujarat. Of the $6bn capex, 48% would be borne by Iran, 32% by Pakistan and 20% by India. India prefers the more costly offshore route as it would not cross Pakistan. India's fears over supply security, the Deputy Oil Minister says, would be addressed through separate commercial agreements that India and Pakistan would enter into with the international consortia.

Iran is also pursuing a supply agreement with Greece using the gas pipeline to Turkey that came online last December. If an agreement is reached a 100-km subsea connection would have to be built from Turkey to Greece. The Greek market in itself is not significant, but it could lead to Iran's entry into the bigger European markets. However, Iran is up against Russia's Gazprom which already has a strong presence in Greece and two, soon to become three with the completion of the $3bn Blue Stream project (see next month's *Petroleum Review*, May 2002), pipelines to Turkey.

Iran is also not having much luck with gas sales to Armenia. Although the two countries have an agreement for the construction of a 140-km, $120mn pipeline, Armenia has declined to pay the near-world market prices that NIOC is demanding. Turkmenistan, on the other hand, is prepared to supply Armenia at half the price of Iranian gas and Iran is considering supplying Turkmen gas via the Kropche–Kurd Lui pipeline to Armenia.

NIOC is also making a foray into the LNG export market. There are three LNG projects on the cards. Last August it awarded Japan's JGC and Technip a front-end engineering and design

(FEED) contract for an 8–9mn t/y LNG export plant and, last month, a $10mn feasibility study by Foster Wheeler for the construction of a two-train, 8mn t/y LNG plant was due for completion.

The project based on the South Pars gas field (see p19) is estimated to cost $2bn. It is a joint venture of NIOC (40%), BP (25%) and RIL (25%) with NIOC considering awarding the remaining 10% to the Gas Authority of India Ltd (GAIL). The project would deliver gas from South Pars to western India where RIL's planned $250mn, 5mn t/y Jamnagar LNG import and regassification terminal is to be built by 2006. Of the 8mn t/y, RIL will market between 5mn and 6mn tonnes and BP the rest.

Another LNG project being mooted is the Japanese trading company Tomen's plans for a LNG plant in collaboration with major international oil companies. Tomen will fund and procure equipment for the 75,000 b/d LNG plant that would liquefy gas at normal rather than at extremely low temperatures. Gas thus liquefied has components that when mixed with heating oil or gasoil will greatly decrease the emission of harmful substances. Tomen hopes to make a decision on a site for the project by 2004 and begin production in 2006. All of the LNG is to go to Japan.

Japanese investors including Mitsui and Company, Mitsubishi Corporation and Tomen are also negotiating with Iranian Offshore Oil Company (IOOC) in financing the $1bn Kharg island gas gathering and natural gas liquid recovery project. IOOC has already put out to tender three packages for the project.

The first project from Iran's South Pars development came online earlier this year at Assaluyeh. One of four units of TotalFinaElf's $2bn natural gas treatment facility with a capacity of 500mn cf/d became operational and the other three are expected to go onstream within the next six months. TotalFinaElf will transfer operations to NIOC at the end of the year.

However, the completion of the $1bn Phase 1 of the South Pars development which is financed and operated by Iran's Petropars has been postponed again to the end of the current year or early next year. Phase 1 will see production of 1bn cf/d of gas and of 40,000 b/d of condensate. The company is also involved with Eni in Phases 4 and 5, to produce 2bn cf/d of gas, and in Phases 6–8, which should see production of 3bn cf/d of natural gas and 120,000 b/d of condensate, as well as small volumes of LPG. It is negotiating with Statoil for Enterprise Oil's 20% stake in Phases 6–8. Enterprise pulled out of the project on grounds of higher than expected predicted production costs.

Earlier this year, winners for the $2bn Phases 9–10 were announced as South Korea's LG, Oil Industries Engineering and Construction and Iranian Offshore Engineering and Construction.

According to the Oil Minister, the South Pars development, Iran's largest energy project, will over the next 30 years generate revenues of $300bn. South Pars gas is to be used in enhanced oil recovery schemes at the Aghajari field and possibly the Ahwaz and Mansouri fields which make up the huge Bangestan project. South Pars is also to supply Iran's exports of both piped gas and LNG.

The country's natural gas network is also being expanded to transport South Pars gas to the centre and north of the country. Russia's Stroytransgaz last year completed the construction of the 72-km Assaluyeh–Kangan pipeline as part of Iran's IGAT-3 pipeline that is under construction at a cost of $500mn. An IGAT-4 pipeline is also being considered. Germany's Pipeline Engineering is reported to be carrying out a feasibility study for the 700–800-km pipeline that would carry gas from South Pars as well as the onshore Tabnak field and complement IGAT-2.

Iraq

Iraq's policy of deepening economic ties with its regional neighbours paid off handsomely when Jordan, Syria, the UAE, and Turkey, along with Russia, opposed the introduction of 'smart' sanctions on the grounds of commercial considerations and the damage their economies would suffer should Iraq suspend trade with them. In return, Iraq is rewarding them by giving them priority in oil contracts. Already it has granted Russia exclusive rights to develop the Majnoun and Bahr Omar fields located south of Baghdad which it had earlier granted France's TotalFinaElf. It has further invited Russian companies to tender for projects aimed at boosting oil production capacity and awarded Slavneft the development of the southern Luhais deposit. Oil from Luhais is to be exported through the southern port of Umm Qasr and Al Faw. Iraq's Southern Oil Company plans to double its oil production to 400,000b/d from three new fields by the end of the year. Overall oil production for 2002 is to be kept at 2mn b/d.

The introduction of retroactive pricing of Iraqi oil designed to stop illegal payments to the regime through

coninued on p20...

Country	Type of contract	Date	Company	Field	Capex	Status
Iran		Mar 2001	GVA Consultants (Norway) & Iran's Sadra Company	Caspian Sea	$226mn	To build an oil rig.
	Buy-back	Jun 2001	Japanese consortium (JNOC, JAPEX, Indonesia Petroleum, Tomen) & Shell	Azadegan oil field	$8bn	To start production in 2005 and reach output of 700–800,000 b/d.
	Buy-back	Jul 2001	Eni (60%), NIOC (40%)	Darkhovin oil field	five years; $1bn	To reach production of 160,000 b/d.
	Buy-back	Aug 2001	PetroIran & BHP	Offshore Forouzan-Esfandiar oil fields	–	Triple production to 130,000 b/d.
Saudi Arabia	Service contract	–	Technip	Haradh gas development project	–	Engineering and construction of a 245-mile gas pipeline and a 142-mile condensate line to Abquaia. Completion mid-2003.

Table 1: Field development projects in Iran and Saudi Arabia *Source:* Alexanders' Oil and Gas, Technip.com, *EIA*

An alternative method for the determination of aromatics and di-aromatics in aviation turbine fuel

*The following is a report by **Peter David**, BP, and **Ian Roberts**, ITS Caleb Brett, of an IP study into the correlation between IP 436* Total aromatics content and IP 156** Total aromatics content, and between IP 436 Di-aromatic content and ASTM D 1840 Naphthalenes content. Options for adoption of IP 436 and new limits for Defence Standard 91-91 are proposed.*

The current UK Ministry of Defence Standard for aviation turbine fuel – Defence Standard 91-91 (Issue 3) Jet A-1 specification – requires measurement of both total aromatics by fluorescent indicator adsorption (FIA) using IP 156 and naphthalenes by UV spectroscopy ASTM D 1840. The olefins requirement, as determined by FIA, was removed from the Defence Standard specification in 1995. This opened the way for the potential replacement of IP 156 and D 1840 by IP 436, in which total aromatics and di-aromatics contents are determined by high performance liquid chromatography (HPLC).

Background

Historically, the FIA method has shown excellent agreement with other methods such as IP 436 for measuring total aromatics contents, with a small, possibly sample dependent, bias towards underestimating aromatics compared with the other methods. In contrast, detailed compositional analysis of jet fuels has demonstrated that D 1840 underestimates naphthalenes content by around 15% relative because of the way it calculates the average absorptivity of naphthalenes. Both IP 436 and D 1840 include sulfur-containing species in their naphthalenes/di-aromatics definition.

Data source

In 1995, ASTM carried out a round robin exercise to re-establish the precision of D 1840. Ten of the samples, covering the range 0.03% to 4.21% (v/v) naphthalenes by D 1840, were selected for an IP 436 round robin study in 1996. Only limited FIA analyses were performed at that time. Further FIA testing was performed on the 10-sample matrix in 2000 – good agreement was obtained between the 2000 measurements and the earlier results, confirming sample integrity.

Current versions of all three methods allow reporting of results in percent volume. The results generated in the 1996 round robin have been converted into units of percent volume, by taking account of density.

Conclusions

- Round robin data has demonstrated the correlation between total aromatics by IP 436 and IP 156.
- For total aromatics, there is bias between IP 436 and IP 156 that is explained in terms of the definition of an aromatic species. IP 436 represents a more accurate method for measurement of total aromatics and also has better precision. For di-aromatics content, IP 436 currently has unacceptable precision and, if adopted into specification, could result in the introduction of fuels into the market with higher levels of naphthalenes, albeit small, than are currently permitted.
- Eventual adoption of IP 436 into specifications for di-aromatics content measurement is dependent on precision improvement.

Recommendations

It is recommended that IP 436 be adopted as an alternative method for total aromatics content in the next issue of Defence Standard 91-91 (Issue 4). It is proposed that Section 2 of Table A be modified as follows, with inclusion of an accompanying note.

Test No.	Property	Units	Limits	Test method
2.	Composition:			
2.1	Total acidity	mg KOH/g	max 0.015	IP 354/ASTM D 3242
2.2	*Aromatic hydrocarbon types:*			
2.2.1	Aromatics	% (v/v)	max 25	IP 156/ASTM D 1319
or 2.2.2	Total aromatics	%(v/v)	max 26.5 (Note X)	IP 436/ASTM D 6379

Note X: Round robin testing has demonstrated the correlation between total aromatics content measured by IP 156/ASTM D 1319 and IP 436/ASTM D 6379. Details of the investigations carried out may be found in IP Research Report IP 436 November 2001. Bias between the two methods necessitates different equivalence limits as shown. Testing laboratories are encouraged to measure and report total aromatics content by the two methods to assist verification of the correlation.

It is also recommended that IP/ASTM should initiate further round robin testing to verify the precision of IP 436 for di-aromatics. If an improvement, or an equivalent precision to ASTM D 1840, can be demonstrated, adoption of IP 436 into Defence Standard 91-91 for the determination of naphthalenes should be reconsidered.

A copy of the full report is held in the IP Library and is available for study.

For further information on Test Methods please contact John Phipps, Technical Manager–Standards, Tel: +44 (0)20 7467 7130; e: **jp@petroleum.co.uk** *or visit the IP's website at* **www.petroleum.co.uk**

**IP 436 is jointed with ASTM D 6379-99*
***IP 156 is jointed with ASTM D 1319-99*

Iran plans switch to petrochemicals exporter

Iran holds considerable hydrocarbon wealth on which it is planning to build a world-scale petrochemical industry. The immediate aim is to become a net petrochemicals exporter within the next five years. The South Pars project is the key to achieving this target, reports *Priscilla Ross*.

Iran's hydrocarbon wealth is very considerable. It holds the world's fifth largest oil reserves, at 89.7bn barrels, and the second largest gas reserves at 23tn cm (812tn cf). Like other Middle East countries – notably Saudi Arabia, the United Arab Emirates (UAE), Qatar, Kuwait and Oman (see p14) – the Iranians' plan is to establish a world-class petrochemicals industry with a hefty chunk devoted to exports. The country wishes to switch to being a net petrochemicals exporter in the next five years, with state-owned NPC targeting petrochemicals production of between 30mn and 38mn tonnes by 2005.

According to Commerzbank, Iran's petrochemical production has already doubled since 1996 and the plan is to export 60% of production once the 30mn tonne level is achieved. To put this into a Middle Eastern context, Saudi Basic Industries Corporation (Sabic) has a total petrochemical production capacity of around 36mn tonnes and is targeting 50mn tonnes by 2010. Meanwhile, Egypt has invested $3bn in six new petrochemicals projects in Alexandria and the plan is to invest a further $10bn in petrochemical industries over the next 20 years.

Key role for South Pars

Oil and gas accounted for 82% of Iranian export revenues in 2001 and the value of Iran's energy exports are around $24bn/y. According to Mohammad Hadi Rahbari, Managing Director of Petropars and an NPC Board Member, speaking at the 'Investing in Iran Conference' late last year, Iran's South Pars gas field (see **Table 1**) is considered one of the 'most reliable long-term feedstock reservoir[s] for the [development of Iran's] petrochemicals industries'. Sustainable feedstock is a key factor in creating a successful petrochemicals industry, together with low cost of production – both advantages that South Pars can offer.

Rahbari stated that there are 12 field development phases planned, with targeted completion dates between 2002 and 2007. This will provide the feedstock to produce some 6.4mn t/y of ethane and 5mn t/y of ethylene – representing a sustainable feedstock for world-scale olefin projects (see **Table 2**).

Outlining the proposed development plans for Phases 3 and 4 (see **Tables 3 and 4**) of South Pars, Rahbari went on to examine the financing alternatives for the project, with possible sponsors being NPC, the Iranian private sector and foreign investors. (Iran's own financial sector is dominated by 10 state-owned banks but, recently, four private institutions have also been licensed as banks.)

Under foreign investing, various options were mentioned such as BOT (build, own, transfer) and BOOT (build, own, operate, transfer). Other variations were product sharing or joint venture.

Buy-back financing

In 1997/1998 Credit Agricole led the consortium that arranged the first phase of the South Pars financing. A spokesman in the company's structured

Area	3,700 sq km
Gas in place	464tn cf
Condensates	17,100mn barrels
LPG	550mn tonnes
Ethane	560mn tonnes

Table 1: South Pars gas field statistics

	1998	2005
World		
Production share	0.5%	2.1%
Export share	0.6%	3.5%
Middle East		
Production share	14.5%	30%
Export share	8.8%	25%

Table 2: NPC share of world and Middle East petrochemicals markets

Projects	Final products	Capacity (1,000mn t/y)
Olefin-7 (Marun PC)	PE, MEG/DEG,PP, ethylene	1,500
Olefin-9	PE, ethylene	1,400
Olefin-10	PP, MEG/DEG, PE, A-olefins	1,700
Methanol-4 (Zagros)	Methanol	1,000
Aromatics-4	Benzene, O & P xylene	1,300
Urea ammonia	Urea, ammonia	–

Table 3: Phase 3 development of Pars petrochemical project

Projects	Final products	Capacity (1,000mn t/y)
Olefin-11	LLDPE/HDPE MEG	2 x 300 700
Propylene & derivatives	2EH or phenol/acetone	100 180/110
PVC Cholor/EDC/VCM/PVC	S-PVC EDC – (surplus)	300 300
3rd PTA	PTA	400
Acetic/A- VAM	Acetic acid (surplus) VAM	315 250

Table 4: Phase 4 development of Pars petrochemical project

finance team explained that this was not a traditional project financing – it was a pre-export financing with the $300mn loan secured against sales of production. The NIOC (Iranian National Oil Company) provided crude oil as collateral against the loan, which was priced on an oil price of $10/b. However, in the event, Iran benefited from the upside of the subsequent rise in oil prices.

The spokesman from Credit Agricole also explained that, since the 2001 Investing in Iran Conference, investment prospects in Iran are looking more optimistic, with between 25 and 30 phases now being suggested for the South Pars gas field development. He estimated that each of the 25 to 30 phases would involve a capital investment of around $1bn, making a total capital investment of between $25bn and $30bn.

Phases 2 and 3 have already been awarded to a consortium led by TotalFinaElf and including Gazprom and Iranian Petropars in a buy-back contractual arrangement. According to Ian Brown, Manager of Wood Mackenzie's Middle East and former Soviet Union research team, the costs of phases 2 and 3 have come down from the original $2bn forecast to $1.7bn, with each phase costing between $800mn and $900mn. The consortium brought Phases 2 and 3 onstream in mid-March 2002. Brown explained that each phase of development of the 400tn cf field would account for between 15tn and 16tn cf of reserves. Therefore, to fully develop the reserves, between 25 and 30 phases would be necessary.

Phases 4 and 5 have been awarded to a consortium involving Agip, Eni and Petropars, with the western partners holding a 60% stake and Petropars 40%. Phases 6,7 and 8 have been assigned to Petropars, but other foreign partners are being sought. The remaining phases of South Pars are under discussion and a number of Japanese companies are thought to be interested. It is also believed that LNG production is on the agenda from Phases 9 and 10, which could be exported; in the earlier phases all production is for domestic Iranian use.

Credit Agricole believes all the financings will be structured on a buy-back basis, with the foreign investors being repaid for their investment with accrued interest from the proceeds from oil, gas and condensate sales which also guarantees the security of the loans. Brown points out that the buy-back contract pays relatively high interest of about 15% and is repaid over five, six or seven years. 'The creditworthiness of Iran is the risk. There is no exploration or real appraisal risk,' he noted.

Impact of US sanctions

Since US sanctions were instituted against Iran in 1995 it is estimated that around $10bn has flowed into the country from other foreign investors to finance various projects. (The Iran-Libya Sanctions Act prohibits US companies from investing in Iranian projects valued at over $20mn.)

At the conference, Sharie Brown of USA Engage gave a clear message that sanctions are harming US business interests. A former Senior Counsel at Mobil Oil Corporation with responsibility for Trade Sanctions/Export Controls, she co-authored Mobil's application to swap crude oil with Iran. She also developed market pre-positioning strategies for embargoed countries and wrote employee guidelines on corporate compliance and embargoed country restrictions (eg Iran, Cuba, Libya and Iraq).

However, Wood Mackenzie's view on withdrawing sanctions was that it is 'politically too hot to touch', stating that it would be very surprised to see the removal of sanctions this year. The analyst believes that the issue is several years away from resolution.

Despite the disadvantages of US sanctions, Iran is regarded favourably in a macro-economic sense. According to Commerzbank, debt servicing has been declining since 1996/1997. In 2000/2001, total debt servicing was $4bn, which represents less than 14% of exports. Debt servicing and the debt ratio to exports are expected to continue to decrease over the next two to three years. Debt servicing is forecast to drop to $2.8bn, or 11% of exports, in 2002/2003. Foreign reserves are estimated to have increased to $14bn by end 2001, further bolstering Iran's ability to service its debt.

Looking ahead

The unification of the Iranian currency scheduled for March 2002 is seen as a positive macro-economic event, with the establishment of an oil stabilisation fund seen as providing a cushion if there is a further decline in the international oil price.

In addition, fears concerning rising tensions between Iran, the US and Europe in relation to the military situation in Afghanistan have been tempered as President Khatami gave an outright condemnation to the 11 September 2001 terrorist attacks on the US.

...continued from p17

oil purchases has, in the early stages of the 11th phase of the UN oil-for-food programme, led to a decline in Iraqi oil exports. Phase 11 will run out in May 2002. Last year saw Iraq export on average 1.7mn b/d. Exports to the US rose sharply with 79% of Basrah Light and 31% of Kirkuk liftings compared to 58% and 4% respectively in 2000.

Iraq has also started a technical study into building a new gas pipeline to Syria. It is also planning to construct a new 1.4mn b/d oil pipeline to Syria to replace the existing 20-year old one.

Tunisia's ETAP has been given development rights to the Al Kafl field in the Najaf Province which has a production capacity of 40,000 b/d, and a consortium of India's ONGC Videsh Ltd (OVL) and Reliance with Algeria's Sonatrach is expecting to be awarded a contract for the development of the Tuba oil field in southern Iraq which lies between Zubair and Rumaila. OVL already has a contract to develop block 8 in the Western Desert. This year, the Philippine National Oil Company is also to begin a new exploration programme in Area 9 in the southern sector of the Western Desert. In a more controversial move, Turkey's TPAO is to begin exploration for oil in 10 regions in the Barzai region in Kursdish-controlled northern Iraq.

Saudi Arabia

The latest Opec production quota of 7.053mn b/d which, according to the Saudi Oil Minister Ali al-Naimi, may be extended to the end of 2002, leaves the Kingdom with unused excess capacity of 3.5mn b/d. This is likely to slow down Aramco's plans to raise the production capacity by a further 1mn b/d by 2005 that was to be achieved by the development of the $1bn Qatif and $3bn Khurais projects. While the development of Qatif is set to continue, Khurais – which was expected to add 800,000 b/d – seems destined to go on the backburner.

However, Aramco has reportedly earmarked $2bn for spending on new projects in the next five years. Its 2002 plans call for drilling of 292 wells costing $1.2bn. Last year $1bn was spent on drilling 246 new wells. It also discovered a new oil and gas field near its Ghawar field, where an exploratory well tested 1,100 b/d of oil and 1.6mn cf/d of natural gas.

As the Far East has become Saudi Arabia's fastest growing market and where light grades of crude are particularly popular, Aramco in recent years has targeted the development of its high quality super light crude. Light sweet crude fetches the highest crude oil prices as it contains less sulfur and yields higher value refined products. Aramco's flagship project is at Shaybah in the remote Empty Quarter near the border with the UAE, where a $2.5bn facility with eventual production capacity of 500,000 b/d is being developed.

The field contains an estimated 7bn barrels of high-grade sweet oil. The facility will have three gas/oil separation plants and a 395-mile pipeline that will connect to the Abqaiq gathering centre.

The $200mn Haradh 2 gas-oil separation plant for Ghawar field is also aimed at raising the production of high quality crude by 600,000 b/d. The Qatif project is expected to add 500,000 b/d to oil production capacity. It has two mothballed fields, each of which could yield 250,000 b/d of Arab Medium and Arab Extra Light. The US Halliburton Energy Services Group was last year awarded a three-year service contract to drill producing oil and gas fields at Qatif. The Qatif project further involves revamping of the existing GOSP (gas-oil separators) and construction of a new one; construction of a pipeline to Ras Tanura refinery; and the upgrading of facilities at the Berry processing plant.

At the Safaniyeh and Zuluf fields, J Ray McDermott recently completed its fabrication contract which included installation of additional platforms, production decks and pipelines.

The $4bn expansion of the Master Gas System was by the end of last year half completed with the coming onstream of the Hawiya gas processing plant. Located in the Eastern Province near the Ghawar field, the plant – which has a capacity of 1.4bn cf/d – is the first Saudi Aramco facility to process non-associated gas. A second at Haradh, with a capacity of 1.6bn cf/d, is due for completion by the end of 2003.

A final agreement with eight western oil companies on three core ventures under the Gas Initiative was expected in March. Outstanding points of agreement are reported to be definition of Aramco's role within the consortia, agreement on a mechanism for pricing of the gas, and the western companies' concern over the quality and extent of acreage offered to them.

Aramco, which will be an equity holder in all three ventures, is seeking to keep control over the price of gas and extent of gas reserves available to the three consortia. Of the country's 214tn cf of gas reserves, 140tn cf are associated with Aramco's oil, and of the remaining 74tn cf of non-associated gas, 70tn cf are ring-fenced under Saudi Aramco's Reserves Area (SARA). The amount of gas left, the oil companies argue, would not be enough to carry out the downstream projects slated for development. A reversal of SARA is what they are looking for, as well as a western style method of regulatory consultation to set the tariffs for gas.

The biggest of the three core ventures is the development of gas reserves south of the Ghawar oil field and the building of power plants to generate 4,000 MW of electricity, desalination units with capacity of 300mn gallons/d and petrochemical plants. The $15bn project will be led by ExxonMobil, with BP, Shell and Phillips Petroleum as partners.

The second $4bn venture involves the search for gas in the northwest and the adjoining stretch of the Red Sea coast, development of the Midyan and Barqan fields and construction of corresponding power, desalination and petrochemical facilities. Again, it will be led by ExxonMobil, with Occidental and Marathon Oil as partners.

The third venture, also costing $4bn, involves developing gas resources in and around the Shaybah and Kidan oil fields and the laying of pipelines from Shaybah to Hawiya and the Haradh gas processing plants. Shell will lead the project, with TotalFinaElf and Conoco as partners.

Currently, Saudi Arabia produces 5.4bn cf of natural gas that is expected to increase to 7bn cf/d by 2003. By 2025 the country aims to produce between 12bn and 14bn cf/d – of which, the Oil Minister says, 5–7bn cf/d will come from the foreign operators. ●

IP Education student chapter

A meeting of minds

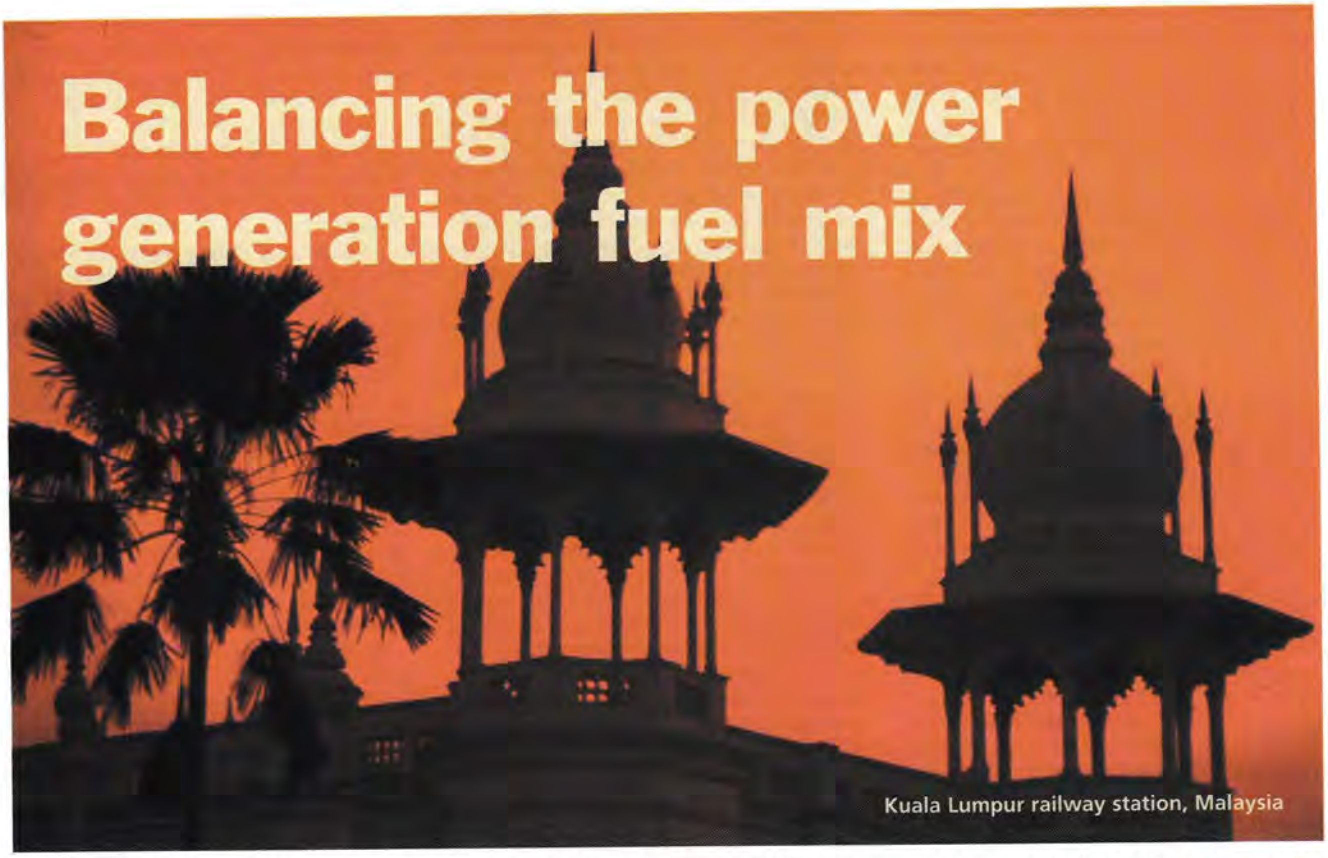
Shell Nigeria's Project General Manager John Stubbs visited Newcastle University on 5 February 2002 to deliver the 'Shell Lecture'. Robert Watts, John Robson and Said Mazaheri – Treasurer, Secretary and Chairman, respectively of the newly-formed IP Student Chapter Committee questioned him and his team about a whole range of oil and gas industry matters and took the opportunity to recruit new members.

All agreed that the IP Student Chapter was an excellent way to increase a wider understanding of the industry, providing networking opportunities and indicating to prospective employers a pro-active attitude. A further benefit is the ability to question older, more experienced people about some of the life skills needed when working with others once outside the university environment.

The Committee gained nine new members during the evening. Since the Chapter was formed in late 2001, one of the major oil companies has already made contact with a view to recruitment. ●

Tom Odell, IP North East Branch Committee Member

***John Stubbs** (left), Shell Nigeria Project, General Manager; **Robert Watts** (second left) is a MEng student of Mechanical Engineering and is hoping to work as a reservoir engineer; **John Robson** (second from right) is a MEng student of Mechanical Engineering and is seeking work as an engineer in the exploration and production sector; **Said Mazaheri** (right) is undertaking a PhD in Offshore Engineering. Once his studies are completed, he is considering seeking a position as a university lecturer or working as an industrial researcher.*



Balancing the power generation fuel mix

Kuala Lumpur railway station, Malaysia

Since the 1980s government policy to utilise Malaysia's large natural gas reserves has led the country to become heavily reliant on gas-fired power generation. While recoverable gas reserves lying offshore Peninsular Malaysia allocated for domestic use are sufficient to last another 20 to 30 years at the current rate of consumption, state-run Tenaga Nasional Bhd (Tenaga) which supplies electricity to Peninsular Malaysia plans to develop a more balanced power generation fuel mix by increasing the proportion of coal-fired and hydropower generation in the future. *David Hayes* reports.

According to Petronas, Malaysia's state-owned oil and gas corporation, about 90% of the total piped gas supplies, over 2,000mn cf/d, consumed in Peninsular Malaysia are used for power generation. At a recent briefing, Tenaga Chairman, Dr Jamaludin Jarjis, revealed that 81% of Malaysia's electricity output is generated by gas-fired stations while coal-fired generation accounts for 8.6% and hydropower schemes 8.3%. Oil-fired units are used to generate just 2% of total power output.

Gas-fired power stations account for about 70% of the Peninsular's total installed generating capacity. At the end of August 2001, power plants with a combined installed capacity of 12,655 MW were operational in the Peninsular, Tenaga gas-fired power stations totalling about 4,400 MW in installed capacity, including 1,571 MW of combined cycle capacity, represented 34.7% of Peninsular Malaysia's total installed generating capacity. Independent power producer (IPP) plants, which sell their power output to Tenaga, are almost entirely gas-fired and total 4,474 MW, accounting for a further 35.3% of the Peninsular's installed generating capacity.

In contrast, coal-fired and hydroelectric stations are much smaller in capacity. At the end of August 2001 Tenaga's installed coal-fired generating capacity stood at 1,564 MW, representing 12.3% of Peninsular Malaysia's total installed capacity. Hydropower plants, meanwhile, totalled 1,873 MW installed capacity and accounted for 14.8% of the region's total installed capacity.

Major gas reserves

With recoverable reserves totalling 82.5tn cf, Malaysia has one of the largest natural gas reserves in Asia. In terms of location, the reserves are divided equally between Peninsular Malaysia, where they lie offshore the Peninsular east coast in the South China Sea, and East Malaysia, where they lie offshore, mostly off Sarawak.

Peninsular Malaysia is the country's main population and economic centre. As a result the government has set aside the Peninsular offshore gas reserves for domestic use. At the current rate of consumption, Peninsular Malaysia's gas reserves are expected to last another 20 to 30 years. Most of the gas will continue to be used for power generation.

Gas reserves offshore East Malaysia have been allocated for the production of LNG and fertilizer for export. LNG markets include Japan, South Korea and Taiwan.

Malaysia operates two LNG plants at Bintulu in Sarawak, where a third LNG plant (MLNG Tiga) is now being built. Petronas is the largest shareholder in all three plants.

Revised power policy

Although Peninsular Malaysia's gas reserves have many years to run, Tenaga recently revised its power generation fuel policy following concern that the electricity industry has become over dependent on gas. One factor prompting a change in Tenaga's fuel policy was Petronas' request to the government that Tenaga pay a higher price for gas supplies in the future as today's heavily discounted gas price is limiting the profitability of the company's gas supply operations. The current subsidised gas price that power plant customers pay is less than half the international price for natural gas.

Tenaga buys gas from Petronas at RM6.40/mn BTU compared with the current international market price of RM16 to RM17. In addition to purchasing gas for its own gas-fired power stations, Tenaga is responsible for negotiating gas prices with Petronas on behalf of all gas-fired IPP power plants which also pay the same price for their gas requirements.

Any change in the gas price paid by Tenaga and IPP power plants to Petronas requires government approval. In fact, the current gas purchase price for supplies to power stations has remained unchanged since the Asian financial crisis hit Malaysia in 1997 as the government has not wanted gas prices and electricity tariffs to increase and damage the nation's economic recovery.

Petronas is understood to have requested a 20% gas price increase early last year. This was refused by the government which extended the current gas purchase price until the end of 2001. However, pressure is growing from Petronas for a more realistic gas price to be set in 2002. Even Tenaga officials realise that buying gas at a heavily discounted price will not be possible over the long term and is considered unfair by other gas consumers in Malaysia that have to pay the full price for their gas energy requirements.

After providing Petronas with a large gas market allowing the development of a piped gas industry in Malaysia, Tenaga is looking to diversify its fuel policy in the

Peninsular Malaysia's gas transmission grid.

future in order to keep generation costs as low as possible. However, any movement in fuel gas prices will not have any impact on Malaysia's gas-fired IPP power plants as the power purchase agreement that Tenaga has signed with each IPP operator treats fuel costs as a pass through cost. Consequently the price Tenaga pays each IPP for electricity is adjusted automatically according to any fluctuation in natural gas or other fuel prices.

Cheaper coal option

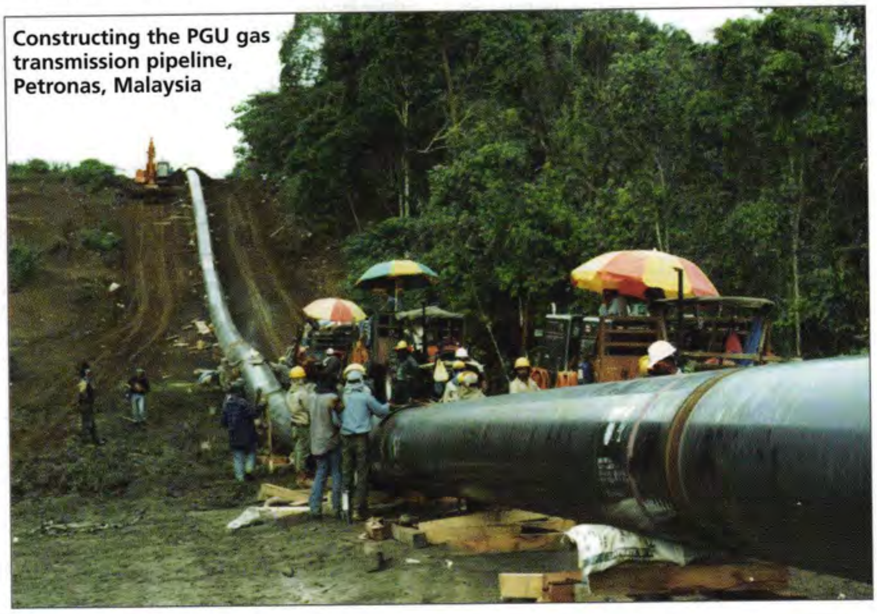
In spite of enjoying a large discount on the price paid to Petronas, Tenaga is keenly aware that imported coal is cheaper even than using subsidised gas. Tenaga's plans call for coal-fired generation to increase to 20% of Peninsular Malaysia's total electricity output before 2010 and for hydroelectric power also to grow to 20% of output, thereby reducing the gas-fired share of generation to about 60%. Hydropower output could be increased by a Tenaga proposal to use off-peak power generated by the currently under construction 2,100-MW Manjung coal-fired station for a proposed pumped storage scheme in Pahang State.

'The price of coal on an energy basis is always cheaper than gas in calorific terms,' commented a Tenaga source, 'even today with subsidised gas prices. However, the kilowatt per hour production costs always depends on the power plant the fuel is being used to fire.'

The source continued: 'Petronas' gas price has been fixed since 1997. The agreement was until the end of 2001. Any change depends on what the government wants.'

Between 2000 to 2009 Tenaga plans to develop coal-fired generation facilities totalling 6,600 MW installed capacity. The corporation recently commissioned two 500-MW coal-burning units at Karpar power plant and plans to start up Manjung coal-fired station in 2003. In addition two coal-burning IPP stations will be built between 2005 to 2009 to supply electricity to Tenaga.

Kapar's two original 300-MW units burn a combined total of 1.5mn t/y of coal for base load generation, while the two new Karpar 500-MW units



Constructing the PGU gas transmission pipeline, Petronas, Malaysia each burn 1.25mn t/y of coal and have increased Tenaga's total coal requirement to 4mn t/y. Coal is imported from major coal producing countries including Australia, China, Indonesia and South Africa.

By 2004, when the Manjung power plant is in full service, Tenaga will increase its coal burn to 10mn t/y. Malaysia's coal import needs will further double to 20mn t/y once two planned coal-fired IPP power plants are fully commissioned by 2009.

According to Tenaga, the 1,400-MW Jimah power plant will need 4mn t/y of coal while the 2,100-MW Pulau Bunting station will burn 6mn tonnes annually. Recently, however, suggestions have emerged that the Pulau Bunting station may be relocated from its originally planned site on Pulau Bunting offshore northern Peninsular Malaysia to Johor in the south. Instead, a 700-MW gas-fired IPP station could be built on the original site, fed with gas from the Peninsular gas pipeline grid.

Growing gas market

Meanwhile, power generation is not the only growing gas market. Petronas' gas supply subsidiary, Petronas Gas Berhad, currently supplies over 2,000mn cf/d of gas to industrial, commercial and residential customers in Peninsular Malaysia. Present consumption is double the 1,000mn cf/d supplied in 1998 and 970mn cf/d in 1997.

Gas demand first reached 2,000mn cf/d in November 2000 due to growing use of gas for power generation. However, city gas consumption also is growing as Gas Malaysia continues to expand its gas pipeline distribution network. Established in 1992 Gas Malaysia is majority owned by Petronas. The city gas utility also benefits from technical support from Tokyo Gas of Japan which has a 20% shareholding in the company.

Gas Malaysia supplies gas to 20 areas of Peninsular Malaysia through various pipeline distribution networks totalling 430 km in length. Gas supplies are obtained from take-off points along Petronas's Peninsular gas transmission pipeline network. Industrial and commercial customers are the largest consumers of city gas.

Customers include Kuala Lumpur International Airport which has the world's largest class of gas district cooling supply based on gas absorbtion chillers. The gas-fired cogeneration district cooling system was installed by a separate joint venture company established by Petronas and Tokyo Gas. Kuala Lumpur City Centre (KLCC), which includes the Petronas Twin Towers, also uses gas-fired district cooling technology.

'Petronas and Gas Malaysia are building more small pipeline spurs which can supply up to 2mn cf/d per customer, a Petronas source said. 'Gas Malaysia is supplying about 65mn cf/d today which is quite significant. We expect Gas Malaysia's sales to grow to about 150mn cf/d, which is the same gas volume as a medium sized 750-MW power station. It all depends on their gas marketing efforts.'

City gas use is growing in Kuala Lumpur where Gas Malaysia is completing a distribution pipeline loop project designed to bring gas to the city centre. Extensive use of mole drilling has enabled the company to complete work installing distribution pipes while avoiding creating traffic jams and negative publicity that digging trenches would involve. 'There is talk now that gas pipes should be installed in new housing development projects,' the source said. 'At the moment Gas Malaysia is focused on supplying industry. Apart from KL Airport and KLCC they have got district cooling systems in the government's Putrajaya administrative centre and Universiti Technologi.'

Gas fuelled vehicles also are helping increase gas use. Petronas has installed gas fuel facilities in about 20 petrol stations in the Klang Valley region including Kuala Lumpur. About 3,000 cars including taxis are equipped for gas use.

In November 2000, Gas Malaysia fur-

continued on p28...

Cutting pipeline costs by over 25%

The principal restraint on the growth of natural gas markets historically was the high costs of transporting it by pipeline, due to its low energy density. The prospect of a big reduction in the capital costs of natural gas pipelines is therefore extremely exciting. Since most of the annual costs of pipelines comprise the amortisation of capital, this will mean, in effect, a similar reduction in the total costs for long-distance pipeline transport of natural gas, writes *Fred Thackeray*.

Results of full scale burst test. *Source: BP*

A project led by BP is expected to yield reductions in the capital costs of large onshore pipelines by more than 25% within the next two to three years. Designated the Pipeline Cost Reduction (PCR) project, the programme was initiated four years ago and is now at an advanced stage. Its progress and revolutionary promise were outlined in a recent paper presented by BP.* As shown in **Table 1**, progress already made offers the potential for cost savings of as much as 15% to 17%.

The project encompasses radical developments in all areas of the engineering and construction of large diameter pipelines, including their design, their materials, and welding and construction practices. BP's main objective is to enhance the economic viability of natural gas in remote fields by cutting the costs of long-distance gas transport. However, it says that many of the technologies developed will be equally applicable to oil pipelines.

The company is working closely with many other interested companies including international contractor and research organisations, as well as industry regulators, and has already employed some of the new techniques on current pipeline projects. In Algeria, for example, on the In Salah pipeline – a 520-km, 48-inch diameter line – BP has successfully worked with local pipe mills to improve productivity, quality assurance and control, and health and safety performance. In Azerbaijan, for the major Shah Deniz project, the costs of bedding and padding material to protect pipeline coatings are to be reduced in the light of research which showed the possibility of reducing the amount of spoil crushing required in the rocky terrain.

Three principal developments will make the dominant contributions to reductions in costs. These are:

- Higher strength pipe
- Improved welding technology
- New construction practices

Higher strength pipe

BP reports that it is 'committed to ensuring that higher grade steels are available for long distance large diameter gas transmission pipelines' and is therefore 'involved in the development of X100 steel.' The current practice is to employ X80 grade steel or, more typically, X70.

The use of higher strength steel allows the pipe diameter and/or the wall thickness to be reduced for a given transmission capacity. As a consequence, costs are cut in two ways:

- the weight of steel produced and transported is reduced; and
- the volume of girth welding is reduced, thus reducing welding time and the materials used in welding.

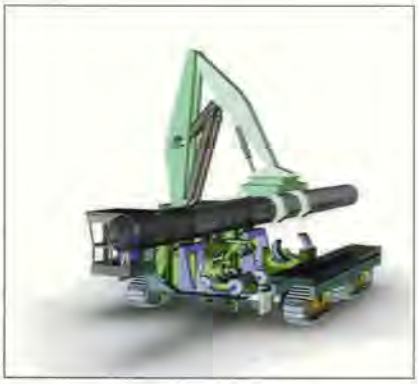
BP's initial three-year development programme on X100 linepipe was completed in 1999, jointly with Shell Global Solutions and Advantica (formerly BG Technology). In 2001, girth welding trials were carried out by CRC-Evans and Serimer Dasa under the management of Cranfield University. Other studies on X100 pipe have included:

- field bending trials by CRC-Evans in Tulsa; and
- a joint project with TransCanada and BG, managed by Advantica, on the resistance of the pipe to propagation of shear fractures.

Welding systems

Currently, the most widely used system for onshore pipeline welding is a single-head GMAW (Gas Metal Arc Welding) technology, in which two single welding torches mounted on bands each travel half the circumference of the pipe. Recent developments of this technology employ dual torches mounted on a single bug. This increases the rate of deposition of weld metal.

At Cranfield University's Welding Engineering Research Centre a 'tandem wire GMAW' has been developed, with computer control to minimise operator involvement. This system uses dual torches each holding two welding wires which are each fed into the weld pool. Its primary benefit is an improved weld deposition rate. TransCanada Pipelines funded initial development by post-graduate students and BP is now funding the further development of this technology known as CAPS



Onshore pipeline construction vehicle.
Source: BP

(Cranfield Automated Pipe-Welding System). CAPS will also utilise a laser vision system to track the welding bevel and adjust the welding torch position as required. The technique is expected to be developed for field application by early 2003.

Separately, BP is also sole funding the development of a hybrid laser/GMAW welding system for pipeline girth welds. The Nd:YAG (Neodymium doped Yttrium Aluminium Garnet) laser has a short wavelength which can be transmitted by fibre optics. This programme is being carried out at UK-based TWI (formerly the Welding Institute) with direct involvement of Tulsa, US company CRC-Evans. Field trials are expected in 2003. Potentially, BP says, lasers offer the opportunity to weld linepipe up to 14 mm thick in a single pass at a welding speed in excess of one metre/minute.

The results of this work will be shared with a joint industry project known as YAGPIPE. This project has attracted wide international interest to the extent that its current sponsorship consists of six operators, two pipeline welding contractors and a pipe supplier. It is being jointly run by EWI (Edison Welding Institute), TWI and Cranfield University.

Construction vehicle

Basic onshore pipeline construction methodology has remained unchanged for 50 years. It is not surprising therefore that BP believes that this is an area in which big cost savings can be made by a 'step-change' in lay rates. The concept is to model onshore pipeline construction on offshore practice, which has achieved major improvements in lay rates and cost reductions in recent years.

In the construction of offshore pipelines, key functions – alignment, welding, examination, cleaning, coating – are completed on a single work platform, or laybarge, up to 300 metres long. In contrast, in onshore construction the various functions require individual platforms. Pipe welding alone may require up to 14 platforms (weld stations) and a pipelay spread can extend over several kilometres.

In pursuit of the potential benefits offered by offshore methodology, BP initiated design studies in June 2000. This led in July 2001 to a contract with RAHCO International of Spokane, Washington State, for the detailed design of an onshore pipeline construction vehicle. Work on this was completed in December 2001.

The key to an enhanced lay rate is an automated welding system. Accordingly, it is proposed to incorporate the CAPS system in the new construction vehicle. The overall construction team required would be considerably reduced in number. Coupled with increased protection against climate extremes for the work force provided by an improved welding cabin, this should make it possible to operate round the clock. On this basis, coupled with the vehicle's capability to handle triple joints of 52-inch pipe, a potential lay rate of 10 km/d is feasible. This is four times the typical rate of about 2.5 km/d – 110 welds per 10-hour shift – using double-jointed pipe.

The potential capital cost savings by using the new construction vehicle and the associated CAPS welding system have been estimated for a phantom gas pipeline project at around \$300mn for a 2,000-km section.

Presenting his paper, Richard Espiner said that BP is considering strategies for further development of the construction vehicle concept, using prototype trials and aiming at commercialisation and implementation in projects. The intention is to establish a joint industry project to pursue further development, an objective in which IPLOCA (International Pipe Line and Offshore Contractors Association) has showed great interest, recently holding a workshop amongst its members to establish the way ahead.

Coating and backfill selection

The sourcing and transport of fine bedding and padding material for backfill to bury pipelines can constitute a significant percentage of construction costs. It is anticipated, however, that a net reduction in costs can be made by using more damage resistant – but possibly more expensive – pipeline coating which enables relaxation of the requirements for fine bedding and padding material.

Working with Advantica and Transco, BP has carried out extensive experimental work, both laboratory and large-scale, to determine the impact, penetration and abrasion resistance of commonly used coatings. Experimental testing is still continuing but BP says that results to date suggest that the size of bedding and padding materials can be significantly increased from current practice without damage to pipeline coating.

Reliability (or risk) based pipeline design

A radical change in the principles of pipeline design is proposed which will reduce costs by justifying operation at increased pressures and throughputs. The traditional approach to pipeline design is to limit the 'hoop stress' (a function of pressure, diameter and wall thickness) to a factor of the nominal material yield, designated the 'design factor.' The factor generally specified in codes is 0.72 or lower. Design based on this factor ensures that the pipeline is safe even if there is third-party damage or external corrosion. It does not, however, give any consideration to the likelihood of such damage or corrosion occurring.

The new approach quantifies the likelihood of pipeline failure due to each credible failure mechanism. This allows the level of safety of a pipeline to be estimated throughout its life. It thus provides the basis for a focused inspection and maintenance programme during operation of the pipeline to ensure its continuing safety. Additional safety measures, such as increased pigging, may also be speci-

	Pipeline A*	Pipeline B*
Design	120	100
X100 steel	390	180
Procurement	65	40
Welding	300	80
Construction	235	100
Engineering costs, owner's costs and contingency	297	134
Total of above	**1,407**	**634**
Percentage saving*	**17.1%**	**15.8%**

**Savings estimated to be obtainable on actual pipeline project proposals by employing innovations already proven in the cost reduction programme. The costs are exclusive of compressor stations and other pipeline-related facilities.*

Table 1: Potential savings* of capital costs of pipelines, in \$mn. *Source: BP*

fied by the designer to ensure pipeline safety at higher stress levels.

The cost savings that this approach can deliver have already been exemplified in practice in the UK, where Transco uprated long sections of its large diameter onshore transmission network, increasing the design factor to 0.78. By doing this, the company avoided the need to install additional pipelines to de-bottleneck the system.

In order to provide general guidance and secure widespread regulatory acceptance of the new design principles, BP is currently working with Canada's C-FER (a unit of the Alberta Research Council) to develop reliability-based methods for onshore pipelines. It plans to develop manuals and software suitable for general use by the pipeline industry. Additionally, it is working on the subject with engineering contractors and ran a training course for contractor personnel in 2001.

Replacing hydrostatic test

A further element in BP's cost reduction programme, also touched upon by Espiner, is a proposal to replace hydrotesting of the completed pipeline prior to commissioning. In order to evaluate the possibility of replacing hydro-tests, BP commissioned studies with participation from the UK regulator and from the European Pipeline Research Group. These studies, BP says, concluded that the removal of the hydro-test is feasible and proposed a strategy to achieve this.

This development would be a particularly valuable innovation in desert environments lacking available water. It would, however, need to be substituted by stringent inspection and quality control procedures from the pipemill through to pre-service in-line inspection.

*Pipeline Cost Reductions, *presented by Richard Espiner of BP Exploration, Upstream Technology Group, at a conference held on 5 December 2001 by the Pipeline Industries Guild entitled 'New Developments in Land Pipelines.'*

Readers interested in obtaining further information on BP's pipeline cost reduction activities should write to the PCR Project Manager, Dr Norman Sanderson, at BP Exploration Upstream Technology Group, Chertsey Road, Sunbury on Thames, Middlesex TW16 7LN, UK or e: **sandersn@bp.com**

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ther expanded its services by launching the supply of liquefied petroleum gas (LPG). A wholly owned subsidiary, Gas Malaysia (LPG), has been established to operate the LPG reticulation business.

Meanwhile, to ensure security of gas supply and support the continuing growth of gas consumption in future, Petronas Gas has completed work constructing the second stage of a two-stage 500-km gas transmission pipeline looping project from Kerteh on the east coast to Meru in Selangor State in the west coast industrial Klang Valley region. The project has allowed the company to double natural gas supplies to Peninsular Malaysia by expanding its gas processing facilities and increasing the volume of gas transmitted to major industrial centres and cities along the west coast stretching from the Thai border in the north to Johor Bahru in the south.

Following completion of the Kerteh to Meru looping project, Peninsular Malaysia's gas transmission grid measures more than 1,920-km in length and consists of 1,750-km of main gas pipelines and 170-km of lateral pipelines (see map, p23).

Thai–Malaysian pipeline project

In the future, Petronas expects to use gas supplies from sources other than the ExxonMobil fields offshore east coast Peninsular Malaysia. It is currently waiting for the Thai Government to approve the Thai–Malaysia Gas Pipeline project that will involve building a gas pipeline to transmit offshore gas from the Joint Development Area (JDA) gas fields owned jointly by Thailand and Malaysia in the South China Sea across southern Thailand to the Thai–Malaysian border.

Construction of the pipeline will provide Peninsular Malaysia with additional security of gas supply. Plans call for a 256-km, 34-inch diameter submarine pipeline to be constructed from the JDA fields to landfall at Songkhla where the pipeline will come ashore and where a gas processing plant will be built. From Songkhla, a cross-country pipeline about 100 km in length will be constructed to run southeast to Sadao on the Thai border with Malaysia. The pipeline route will then cross the border for a short distance and connect at Changlun in Perlis State with the northern end of Malaysia's west coast Peninsular pipeline extension.

The Thai–Malaysia pipeline will be built to transmit Malaysia's 50% share of the JDA gas reserves for Petronas to supply to customers in Malaysia, while the Petroleum Authority of Thailand is planning to use Thailand's 50% share of the JDA gas reserves in future to supply Khanom and Surat Thani power stations in southern Thailand.

For the moment the project plans are in the hands of Thailand's Office of Environmental Policy and Planning (OEPP). At the end of August 2001 a panel of OEPP experts rejected the latest environmental impact assessment study submitted for the Thai–Malaysian gas pipeline project gas separation plant, saying insufficient information had been given about air pollution forecasts during construction of the separation plant and once operations begin.

Petronas is keen to see construction work begin on the Thai–Malaysia pipeline as soon as possible. According to the Petronas source, the project is ready for tendering to begin as soon as Thai Government approval is given.

Construction work on the gas separation plant in Songkhla is expected to take about two years once the contract is awarded. The plant will be designed to process 300mn cf/d initially but will be capable of being expanded in future.

The Thai–Malaysia pipeline and gas separation plant will be built, owned and operated by the Trans Thai–Malaysia (TTM) consortium in which both Petronas and the Petroleum Authority of Thailand (PTT) have equal 50% shareholdings. Construction work originally was due to begin on 1 March 2001, but will now be delayed by at least a year until the project passes its environmental impact assessment hearing in Thailand.

Alternative gas supplies

Elsewhere, Petronas also plans to use offshore gas from Indonesia's West Natuna gas field in the South China Sea to further expand gas consumption in Peninsular Malaysia. Construction is currently underway on a 100-km, 18-inch diameter submarine pipeline to connect the West Natuna gas field with Malaysia's offshore Duyong field operated by ExxonMobil. From Duyong, the West Natuna gas will be transmitted through the existing submarine pipeline grid which comes ashore at Kerteh on the Peninsular east coast. West Natuna gas will be processed by Petronas' gas separation plant in Kuantan before being supplied to gas fuel customers through the Peninsular pipeline grid.

Due for completion in mid-2002 the West Natuna to Duyong submarine pipeline will be capable of transmitting 250mn cf/d of gas when peak supply is reached in about 2005 or 2006. Actual supplies are likely to be smaller initially. The first gas deliveries of about 100mn cf/d are expected to begin in 3Q2002.

Is FSU oil growth sustainable?

Over the last year or so, rapid expansion of Russian and FSU oil production has produced great hopes that the region could provide a counterbalance to Middle East supplies. *Jean Laherrere* takes a closer look at Russian and FSU reserves and the sustainability of production from the region.

The oil revenues on which most Opec countries so heavily rely depend on the interaction of price and volume – both of which have fluctuated widely. At times of low price, Opec governments face the dilemma of cutting production to support price or of using volume to deliver their needed revenues. The recent expansion of Russian production threatens Opec producers by providing an alternative source of incremental supply. The additional production and exports have been welcomed by the US and Europe.

The onset of recession in response to the high oil prices of 2000 underlines the fact that the world's economy runs on energy and is vulnerable to price fluctuations. Oil price has been volatile, swinging from \$10/b to \$30/b over the past four years. Opec did succeed briefly in providing much-needed stability under its declared policy of holding price in the \$22–\$28/b range by the better enforcement of agreed quotas, but geopolitical pressures following the 11 September 2001 terrorist attacks in the US, led it to allow the price of oil to fall once more.

A new element entered the equation when Opec sought support from non-Opec countries, especially Russia that had its own agenda in its relations with the US. Although Russia's production costs are comparable with those of the US-lower 48 in real terms, an adverse exchange means that its exports can undercut Opec.

Opec received assurances that Norway and Russia would cut production in parallel with its own cut on 1 January 2002. However, it is already evident that, in fact, Russia has not respected the agreement – following the precedent of many Opec countries that also fail to respect their quota obligations. But, behind these political acts lie the eternal underlying resource constraints that are immune to politics. It is they that ultimately control the degree to which countries can increase production and for how long.

Discovery trend

It is evident that oil has to be found before it can be produced, meaning that production has to mirror discovery after a time lag. To know the discovery trend, however, calls for valid information on the size of the reserves, which may be either under- or over-reported. In the case of the former Soviet Union the traditional reserves assessment is different from western practise and based on the ability to produce rather than it being economic to produce.

Russia used to classify reserves in five categories: A, B, C_1, C_2 and D. Various attempts have been made to equate Russian classifications with western ones – none wholly satisfactory. Increasingly, Russian companies are having their reserves reassessed on a western basis as part of a move to GAAP accounting standards. Confusion between the two systems still exists in general reserves reporting and in the promotion of Russian oil companies by some of the less scrupulous investment analysts.

One method of resolving the problem is to deflate Russian discovery trends (reserves) to establish the best fit with production trends. A good fit between the discovery and production trends is achieved by reducing the reported reserves by 45% (Laherrere, 2001). Such an adjustment is further justified by Khalimov, the former Soviet Deputy Oil Minister, who first presented the Russian classification in 1979 at the World Petroleum Congress but then noted in 1993 that the FSU resource base was 'strongly exaggerated due to inclusion of reserves and resources that are neither reliable nor technologically or economically viable.'

In fact, reserves of the combined A, B, and C_1 classes in the Russian classification roughly equate with proved, probable and much of the possible reserves

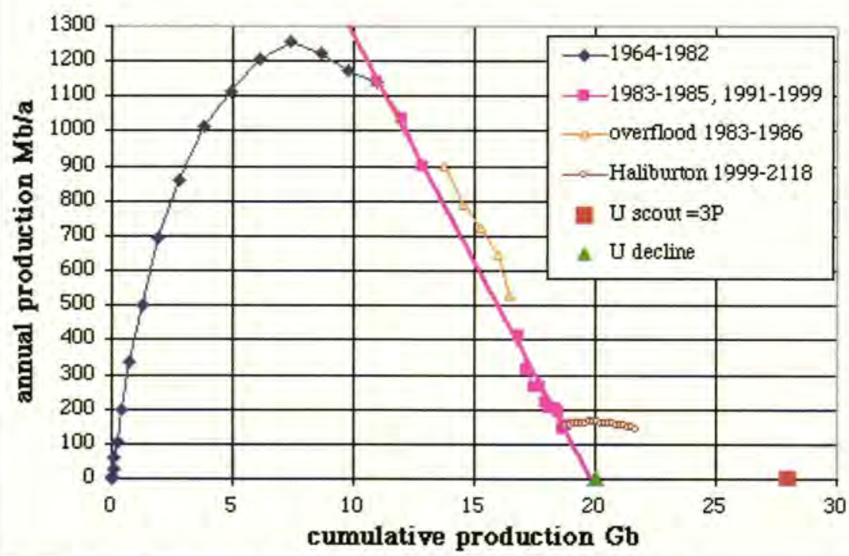

Figure 1: Samotlor field oil decline with Halliburton project (4,583 new wells)

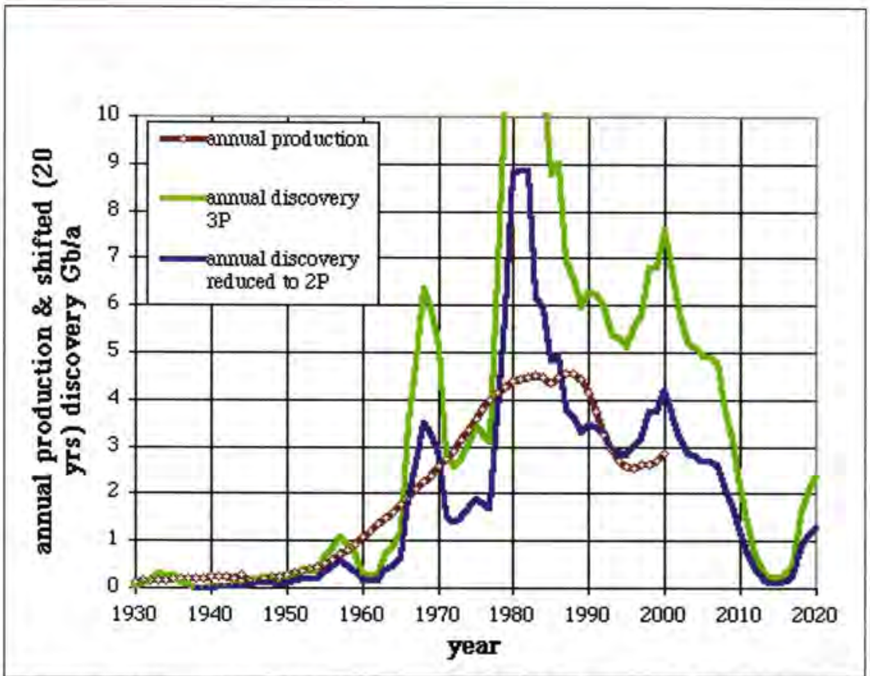

Figure 2: FSU annual production and discovery smoothed on five years and shifted by 20 years and reduced by 45%

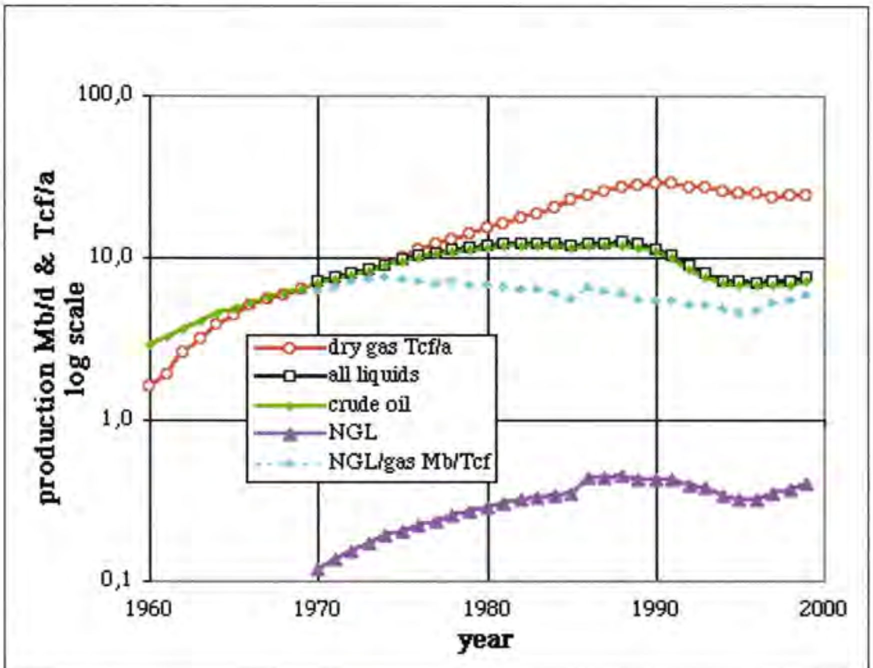

Figure 3: FSU oil, all liquids and dry gas production

FSU fields	Oil (bn barrels)	Condensate (bn barrels)	Gas (tn cf)
In production	250	21	1,800
Developing	10	1	240
Discovery	30	3	360
Total	290	26	2,400

Table 1: Amount of oil discovered in Russia to 2000

(3P) under the traditional western system. Gochenour (1997) has compared the A+B+C_1 reserves of five Russian companies, giving a total of 49.4bn barrels, which are treated as proved reserves in a US sense when in fact only 26.4bn barrels (53%) may so qualify.

Downgrading reported reserves

Further evidence for downgrading the reported reserves comes from decline analysis of individual fields. For example, the largest oil field – Samotlor in Western Siberia – has already produced about 19bn barrels, with production having fallen to no more than 400,000 b/d from a peak of 3.4mn b/d in 1980 (see **Figure 1**). The field is reported to contain 28bn barrels, but extrapolation of the present decline gives an ultimate recovery of only about 20bn barrels. The field was in fact overproduced from 1983 to 1986 to meet the dictates of a Soviet Five-Year Plan. In 1998, Halliburton was brought in to drill more than 4,500 wells, including 3,200 horizontal wells, in the hope of holding production at about 400,000 b/d for around 20 years (Aaland, 1998), but the project has yet to commence despite the committed financing of $672mn (*OGJ*, 11 September 2000).

For these reasons, we have plotted two different discovery curves in **Figure 2**. The 'official' values are shown in green and the 'corrected' values, based on the above evidence, are shown in blue. A good empirical fit between the blue curve and actual production is provided by a 20-year time shift, but, at the same time, it is recognised that the fit may be misleading insofar as the development of fields under the Soviet system may not have followed a normal pattern, being driven by production/supply requirements rather than economics.

The reduction of reserves by 45% partly makes allowance for the Soviet system of classification, but also recognises that there may be as much as 30bn barrels in undeveloped fields, particularly in East Siberia, which do not yet deserve reserve status. The amount of oil discovered to 2000 is given in **Table 1**.

One of the problems in measuring the world's oil production relates to the treatment of condensate, natural gas liquids (NGL) from gas plant, and refinery gains. Data from the US Department of Energy indicates that FSU crude oil represents 94% of the combined production of crude and NGL, without any refinery gain. Approximately 6mn barrels of NGL are produced for every trillion cubic feet of gas when, for the world, the average is 25mn barrels/tn cf. The Russian figure is much lower as Russian gas is very dry. (See **Figure 3**.)

The extrapolation of past liquids production in **Figure 4** showing the percentage of annual to cumulative production versus cumulative production is an elegant method for determining an approximate value of the ultimate production, assuming a 'business as usual' scenario. The relationship for combined crude and gas liquids plots as a straight line from 1964 to 1990, pointing to an ultimate of around 185bn barrels. The trend from 1990 to 1999 is anomalous because it reflects the breakdown of the FSU and can be ignored.

Past production may be modelled with a single Hubbert curve for an ultimate of 185bn barrels, having a peak in 1984 of 12.8mn b/d. It shows a good fit until 1985 before the pattern was distorted by under-production from 1991 to 1999 (representing over 5bn barrels).

Production growth

The new growth in production comes from several sources. First is the restitution of the under-production from the 1990–1999 period. Second, is new production from the Caspian, comprising some 25bn barrels from Kashagan and overcoming the technical difficulties of Tengiz and Sakhalin, 30bn barrels from undeveloped fields (in East Siberia) and an estimated 10bn barrels from new discoveries. But producing discoveries looks to be difficult for some majors, as BP and Statoil withdrew from Kashagan, and Marathon from Sakhalin.

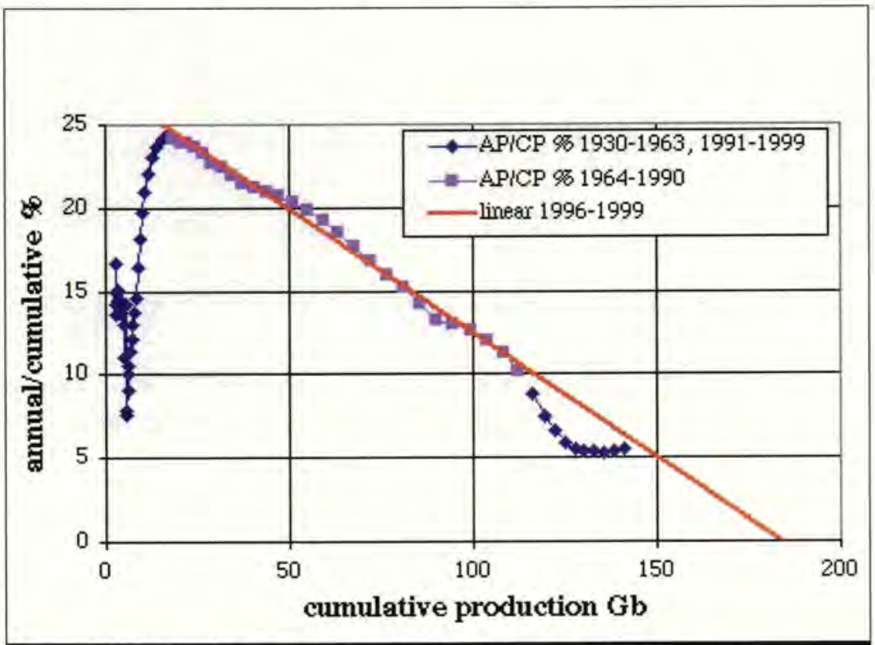

Figure 4: FSU oil production – annual/cumulative versus cumulative

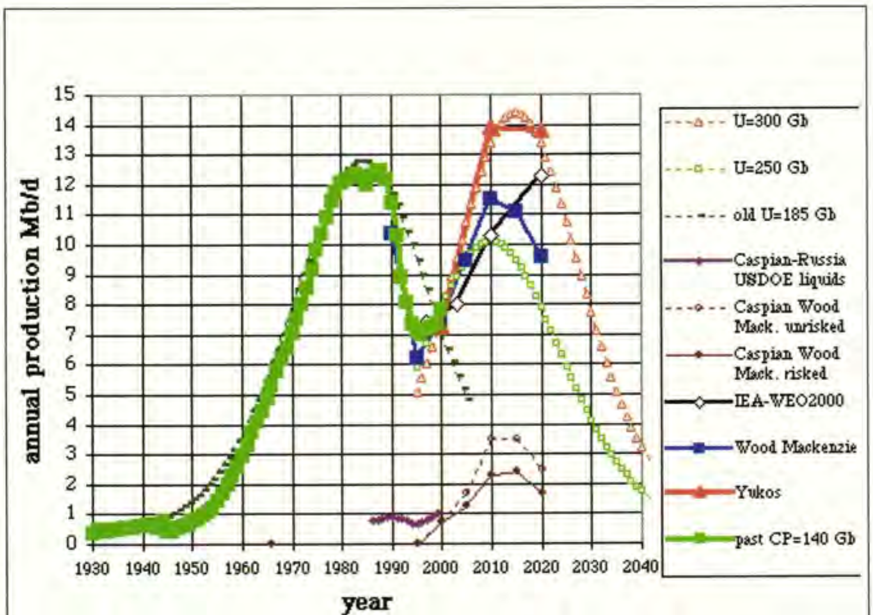

Figure 5: FSU oil production with two cycles – old and new with a likely ultimate of 250bn barrels

This new cycle represents about 65bn barrels which, together with the old cycle of 185bn barrels, gives an ultimate of 250bn barrels. Subtracting the 140bn barrels already produced means that there is 110bn barrels left.

Figure 5 compares the two cycles, with alternative 250bn barrels and 300bn barrels ultimate recovery assumptions, showing past production and various forecasts from the International Energy Agency (IEA, 2001), Yukos (Leonard, 2002), and Wood Mackenzie (2001).

The new Caspian discoveries have been analysed by Wood Mackenzie (McCutcheon & Osbon, 2001), giving an 'un-risked' curve (all will proceed according to plan) peaking at 3.5mn b/d in 2015, and the more realistic risked curve (expect delays and disappointments) peaking at 2.5mn b/d in 2012.

Yukos forecasts a peak of about 14mn b/d in 2010–2020, assuming remaining reserves of 140bn barrels and as much as 50bn barrels undiscovered for the FSU (termed Russia and Caspian), which gives an ultimate of 330bn barrels. It expects that East Siberia will produce 600,000 b/d in 2010 and 900,000 b/d in 2020 thanks to a new pipeline to supply China, which has agreed to pay world prices at the border.

Modelling production on the basis of an ultimate recovery of 300bn barrels is in agreement with the forecast of Yukos, but the evidence discussed above suggests that a model built on 250bn barrels may be more realistic. The forecast of Wood Mackenzie is in between the two. The difference is substantial, having a major impact upon what the region can be expected to produce in competition with Opec.

Russian price war

The Russian companies seem ready to fight a price war as they make adequate profits at \$18/b, but there are also overriding national issues at stake, including international debt servicing (USDOE, December 2001). The evidence suggests that the countries of the former Soviet Union, apart from the offshore, were thoroughly and efficiently explored under the Soviet regime. It follows that the larger productive basins, and most of the giant fields within them, have almost certainly been found, giving a discovery trend that will effectively control future production. How much of this production that is available for export to world markets depends on the growth of domestic demand. It is evident that Opec has little to fear from Russian competition over the longer term, but in the meantime its exports put pressure on price.

In fact, in national terms, Opec, particularly Saudi Arabia, and Russia both need

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China plans rapid gas industry development

The Bund, Shanghai

China is targeting a major increase in gas consumption during the 10th Five-Year Plan as part of a long-term programme to develop gas use in urban areas. *David Hayes* reports.

Currently dependent on coal for over 70% of its primary energy needs – compared with the US where coal represents 25% of primary energy supplies – China is facing problems from severe urban atmospheric pollution as a result of burning about 500mn tonnes of coal annually. Coal-fired boilers and vehicle exhaust fumes are responsible for most urban airborne pollution that has given many Chinese cities the dubious distinction of being among the world's most polluted cities.

Aware of the rapid rise in respiratory illnesses in many cities suffering serious atmospheric pollution, the Chinese Government is keen to develop gas use as part of its clean energy programme. Although using gas is expected to cost substantially more than coal, the government sees gas as an important answer to urban pollution problems as cities are more able to afford gas prices than poorer rural areas.

Apart from Sichuan Province, gas use remains largely undeveloped in China. Most gas supplies currently are used for fertiliser production. Future expansion in gas use will be for power generation, industrial use and by household consumers.

According to official statistics, China's production and consumption of natural gas grew at about 5.7% during the 1990s. In 2000, the country produced 27.7bn cm of natural gas, which increased natural gas use as a proportion of total primary energy consumption to 3% compared with 2.1% at the start of the 1990s.

China's proven gas reserves exceeded 8.4tn cm at the end of 2000, to which was added 220bn cm found in the Sulige area of Changqing gas field, in Inner Mongolia in January 2001. According to official forecasts, gas consumption in China will grow to 50bn cm by 2005 and will reach 110bn cm by 2010 when gas use will account for 6% of total primary energy consumption.

Domestic gas production will represent a major portion of gas supplies in 2010, although China will be using about 3mn tonnes of imported LNG in Guangdong by then, and possibly LNG in one or two other cities. In addition, piped gas imports from Russia could be close to becoming a reality.

Seeking foreign investment

Government plans to develop the gas industry requires foreign involvement to help finance the massive programme as well as provide technical expertise. Foreign oil companies will be involved in developing gas reserves and importing LNG, as well as in building and operating some of the larger gas pipeline schemes.

Opportunities for foreign companies also appear likely in gas reticulation. Closed to foreign investors until now, the development of gas distribution seems likely to involve overseas finance along with foreign city gas technical and marketing expertise. Most opportunities to enter the Chinese gas industry will involve foreign companies in working with local partners. Foreign control of gas businesses does not appear likely for the time being.

Gas pipelines

Plans to develop the gas industry involve constructing a number of major gas transmission pipelines. A gas transmission grid supplying gas from offshore fields in the South China Sea and imported LNG will be built in Guangdong Province, while plans to import gas from Russia will involve constructing a pipeline through Mongolia and crossing northern and northeastern China from where the pipeline route is due to cross the North Korean border en route to South Korea.

Other pipelines due for construction during the 10th Five-Year Plan include the Sebei–Xining–Lanzhou pipeline in northwest China, the Zhongxian–Wuhan and Shaan–Jing looped pipelines in central China, and submarine pipelines transmitting gas from the Chunxiao gas field in the East China Sea to Ningbo in Zhejiang Province and gas from the Dongfang 1-1 field in the South China Sea to Dongfang in the Province of Guangdong.

Focus on East China

East China, with a huge energy requirement and one of China's fastest developing regions, will be another focus of gas industry development in the future. According to Chinese press reports, gas transmission and distribution companies serving Shanghai are poised to invite foreign investment for the construction of local natural gas pipeline networks as well as gas distribution systems. The project is part of preparations to use gas from Xinjiang Province in northwest China. This is due to begin arriving in 2003 through the ambitious West–East gas pipeline scheme.

According to gas industry officials in Shanghai, talks are underway with overseas investors for the construction of gas transmission pipeline and city gas distribution networks to serve the city and surrounding areas. Potential partners include Shell, BP, Gaz de France, and Hong Kong & China Gas. Japanese city gas companies also are believed to be interested in the Shanghai piped gas market.

'Construction of our gas pipeline network will definitely involve a range of investors, though we have to get the go ahead from the government before final decisions are made,' commented Zhang Balong, Chief Engineer of Shanghai Natural Gas Pipeline Network Company, at a recent gas seminar in Shanghai coordinated by the Society of British Gas Industries and Trade Partners UK.

City gas distribution companies including Shanghai Pudong Gas Business and North Shanghai Gas Business also are due to finalise negotiations with foreign partners who are expected to become involved with gas sales and marketing issues as well as providing financial and technology support. Foreign companies also are looking to cooperate with local gas companies in other cities that will receive gas supplies from the West–East pipeline.

At present, natural gas is supplied to Shanghai from the Pinghu oil and gas field in the East China Sea by Shanghai Oil & Gas. According to Shanghai Municipal Gas Management Office, gas consumers in the city, including 3,000 commercial enterprises and 610,000 residential customers, used 283mn cm of natural gas in 2001. If all households could receive natural gas supplies annual consumption would reach 1.8bn cm. However, as only one-third of families can use natural gas, the market potential is limited to about 600mn cm annually.

Residential customers in Shanghai use gas for water heating and cooking. The number of households being connected to gas supplies is growing rapidly each year. According to *China Daily*, in 2001 some 100,000 families in Shanghai's south and north, and a smaller number in the centre, were connected to three gas distribution networks. Meanwhile, two gas pipelines are due to be laid underground to introduce natural gas to outskirt areas including Minhang and Xinzhuang.


Old City, Shanghai

Pioneering gas use

Shanghai's Pudong district has been a pioneer in the use of natural gas, with all of the area's 380,000 families using gas for cooking and heating. Pudong on average consumes 700,000 to 800,000 cm/d of gas. Municipal officials in Shanghai forecast that natural gas consumption will grow more than seven-fold from 400mn cm/y to 3.8bn cm/y in 2005 as city residents convert from burning coal to using gas. By 2010 Shanghai expects to consume 7bn cm/y, of which 40% will be used for power generation, 30% by households, 20% by the chemicals industry and 10% by other users.

Gas prices remain a problem, however. Residents in Pudong, for example, have complained about the high price of natural gas, which currently is twice that of coal.

Equipment and service supply

Apart from investment opportunities available to those cooperating with Chinese gas utilities, foreign companies also, are looking to supply equipment and services to China's gas industry. In 2001, for example, the British and Chinese Governments established the China–Britain Natural Gas Working Group to develop cooperation between British and Chinese gas industries.

'British interest in China is moving into gas project investment, management and pipeline technology,' commented a diplomatic source. 'China's economy is holding up well while other Asian markets are dead. In China it is business as usual. China is in a growth stage where demand for power has not gone away. China is looking for environmentally friendly energy spurred by the 2008 Olympics in Beijing.'

West–East pipeline

In February 2002, Zhang Guobao, Vice Minister of the State Development Planning Commission, announced that China's ruling State Council had approved a feasibility study on the construction of the 4,200-km West–East gas transmission pipeline to bring gas from the Tarim Basin in Xinjiang Province in northwest China to the east coast region.

Studies have shown that there are sufficient gas reserves to provide a stable supply of 12bn cm/y for 20 years, Zhang said, while there is adequate demand for the gas in East China to ensure the pipeline's economic viability. Although the government expects that more gas reserves will be discovered in the Tarim and Ordos Basins, the West–East pipeline is likely to be extended to import natural gas from Central Asia in the future where enormous gas reserves await development.

Exploration in the Tarim Basin continues to reveal additional gas reserves. The Kuqa-Tabei area in the Tarim Basin, which will be an important supply source for the West–East pipeline, had proven reserves of 526.7bn cm and recoverable reserves of 372.5bn cm at the end of 2001 according to China's National Reserve Committee. These reserves will ensure the stable natural gas supply of 12bn cm/y for the West–East pipeline's initial 20-year project contract period. In addition, evaluation explorations are ongoing at Dina 1, Dina 2 and other gas fields discovered last year, with total reserves in excess of 100bn cm. The government is confident that natural gas resources in the Kuqa-Tabei area will be further increased after the completion of ongoing evaluation work.

Meanwhile, substantial progress in gas exploration has been made in the Sulige area in the Changqing gas field that will provide start-up gas supplies to the West–East pipeline. As of the end of 2001, proven gas reserves in Changqing gas field approved by the National Reserve Committee reached 750.4bn cm – making it the largest gas field in China in terms of proven reserves.

The West–East pipeline will run from Lunnan in Xinjiang Province, crossing seven provinces along its eastbound route to Shanghai. Most of the gas transmitted will be used in Shanghai and four nearby eastern provinces in the Yangtze delta region – Jiangsu, Zhejiang, Henan and Anhui. In addition to the main pipeline, plans call for ten branch lines to be constructed to supply local industry and communities along the main pipeline route.

Branch pipeline sections planned include Dingyuan to Hefei in Anhui Province, Nanjing to Wuhu in Jiangsu Province, and Changzhou to Hangzhou in Zhejiang Province. The main markets will be cities with large forecast gas demand and which can afford the higher price of gas compared to coal.

Estimated to cost $5.6bn to build, construction work on the West–East pipeline is due to begin in mid-2002. Various sections of the pipeline will be built simultaneously. The eastern section of the pipeline running from Jingbian in Shaanxi Province to Shanghai is due for completion in 2003 to begin supplying gas to the Shanghai area early in 2004. The Lunnan–Jingbian section will become operational in 1H2005 when the entire pipeline is due to be completed.

Old City, Shanghai

PetroChina has been selected by the government to take a majority 55% stake in the West–East pipeline project. The 45-year project cooperation agreement includes gas field development, pipeline construction and downstream gas marketing. A foreign consortium led by Shell is due to take the remaining 45% shareholding. The Shell consortium consists of Shell, Gazprom, Stroitransgaz, and Hong Kong & China Gas. The other major bidder for the West–East pipeline project was a consortium led by ExxonMobil after BP earlier decided to withdraw from the bidding.

Recent Chinese press reports suggest that ExxonMobil could still participate in the project. In February, PetroChina announced it had received a proposal from Shell and ExxonMobil indicating that they were negotiating to join forces to invest in the project.

PetroChina has agreed to the suggestion, on condition that any further agreement is compliant with the interim agreement signed on 29 December 2001 between PetroChina and the Shell-led consortium. The interim agreement covers equity participation, terms of cooperation, the project business model and health, safety, environmental and social standards for the project. Admitting ExxonMobil to the consortium would involve Shell and the other partners in reducing their shareholdings.

Meanwhile, PetroChina already has signed Letters of Intent with 45 downstream customers to supply gas for power generation, chemical feedstock, industrial fuel to replace coal and as city gas feedstock for piped gas distribution. Based on the Letters of Intent the West–East pipeline is due to supply 800mn cm in 2003, rising tenfold to 8.3bn cm in 2005 and reaching 12.3bn cm in 2008.

Although PetroChina is signing up customers quickly, the price of gas to end users has still to be set. Not every customer expects to pay a high price. According to official estimates gas will cost at least 1.3 yuan per cubic metre while Shanghai Natural Gas Pipeline Networks, for example, has said the maximum price the utility can pay is one yuan to 1.1 yuan per cubic metre.

Power station demand

To create sufficient gas demand to ensure the West–East pipeline project is a success, power generation will be used to establish baseload demand for gas. New gas-fired combined cycle

Old City, Shanghai

power plants totalling 8,050 MW installed capacity are due to be commissioned by 2008 to burn gas from Xinjiang.

According to a rule of thumb used by power station equipment manufacturers, each 1,000 MW of combined cycle generation capacity burns about 700mn cm/y of gas. Some 11 power plants are planned, ranging from 350 MW to 1,050 MW in size. These will require about 5.6bn cm/y of gas and together will use almost half the gas transmitted by the West–East pipeline.

Although three different combined cycle power plant sizes will be built, the power stations will be constructed according to a standard 350-MW block configuration comprising a 230-MW gas turbine and a 120-MW steam turbine unit. The four largest plants will be 1,050 MW each. These are the Shidongkou plant in Shanghai, the Jinlin plant in Jiangsu Province and two plants in Zhejiang Province – the Banshan station and another new plant.

Four 700-MW stations are planned. The Wangting, Qishuyan, Nanjing County and Zhangjiagang plants all will be built in Jiangsu Province. Three 350-MW plants will be built in two provinces and Shanghai. The Zhengzhou plant will be located in Henan, the Caojing plant in Shanghai and the Zenhai plant in Zhejiang.

Shanghai and nearby provinces in the Yangtze River delta region are expected to provide a large market for gas as the region already has to buy between 130mn and 150mn t/y of coal from other parts of China. By 2005 the government forecasts that gas demand in the Yangtze delta region will total 9.5bn cm. Apart from Shanghai, which will need 3.8bn cm, Zhejiang Province will need 3.4bn cm and Jiangsu Province 2.3bn cm.

Gas demand is expected to double in the Yangtze delta between 2006 to 2010. By 2010, the region is expected to need 18.7bn cm/y. Shanghai will need 7bn cm by 2010, while Jiangsu will require 6bn cm and Zhejiang 5.7bn cm.

Meanwhile, residential use of gas is expected to grow rapidly in the future as piped distribution grows. The government forecasts that 17mn families will use 5bn cm/y of natural gas in the Yangtze delta region by the end of 2005. By the end of 2010, at least 34mn families living in the Yangtze delta are expected to use about 10bn cm of natural gas annually. Officials say that gas use could be even larger by then if the present economic boom in East China continues.

Imports required

Rapid growing demand for natural gas eventually will have to be met by imports as China's present gas reserves are insufficient to cope with long-term growth. The government forecasts that by 2010 about 30bn cm will need to be imported, rising to between 50bn and 60bn cm by 2020.

Plans call for a pipeline to be built between 2006 to 2010 to import gas from Russia and East Siberia. The pipeline is expected to cross Mongolia and enter China at Manzhouli and will then pass Daqing, Changchun, Shenyang, Qinhuangdao and Tianjin before terminating in Beijing from where gas will be sent to the Bohai Sea region in South Korea. The pipeline will be built to carry 30bn cm/y, including 10bn cm from Shenyang in China to South Korea.

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prices higher than $18/b. A price war achieved by flouting agreements would be in neither party's best interest. The new Russian oil barons might learn from the experience of their predecessors in capitalist America, where the government had to intervene through the Texas Railroad Commission to regulate over-supply following the discovery of the East Texas field in 1930, when oil fell to 10 cents/b. Cheating against prorationing was widespread ('hot oil', Yergin, 1991) leading to further State intervention – this time at the request of the industry itself.

Opec, too, might remember that its founders sought to extend the principles of the Texas Railroad Commission to world supply, and that cheating on agreements serves rebounds on the perpetrator.

Lastly, the consumers might stop vilifying Opec in its difficult task of managing the depletion of a precious resource and actively contribute to a better solution for the benefit of all.

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Driving down supply chain costs

As the number of players in the business of retailing fuels in the UK decreases, the competition for valuable long-term distribution contracts has intensified and third-party suppliers are having to work harder to win business. In doing so, these suppliers have to respond to the stated needs of the customer but, as the undoubted experts in an area of operations that continues to grow in sophistication, they are increasingly being relied upon to bring their own ideas to the table. *Jon Hyatt*, Business Unit Director for Petroleum Services at Wincanton, reports.

Third-party logistics suppliers have proved that they can deliver a more efficient service.

Wincanton is the largest UK distributor of petroleum products, working with Conoco, Tesco, Texaco, Total and Q8; delivering from 22 locations to retail and commercial outlets nationwide, and running a fleet of almost 300 vehicles operated by 600-plus drivers. The company has benefited from the move towards outsourcing that has taken place amongst fuel manufacturers in recent years and has tailored the services that it offers to the needs of its customers and the wider industry.

Some of the trends that are driving distribution will be clear to anyone in the business:

- the consolidation of the major players through mergers or joint ventures;
- a reduction in the total number of retail outlets; and
- the impact of supermarket retailers that are gaining market share.

Other factors will be less obvious to those not closely involved in distribution. These include:

- a general shortage of drivers;
- technical changes, such as the move to larger 44-tonne trailers; and
- the impact of new technologies.

It is also worth noting the changes that are happening in logistics in other industry sectors that might lead to developments in the fuel market, such as the move to looking at the supply chain as a whole rather than focusing on the individual parts in order to improve efficiencies and drive down costs.

The question, then, is how will all of these various trends finally play out together?

Logistics specialists

Whatever the specific outcomes of these trends, the increasing complexity of the situation and the more pressing need to find efficiencies in this area must lead to a greater role for logistics specialists throughout the supply chain. Some of the changes that will be required might simply be beyond the scope of some existing in-house operations. The need for shared resources, large numbers of skilled personnel and the development of technology and IT will only be possible through third-party suppliers that can leverage the costs across a number of client organisations.

To date, third-party logistics companies have largely been involved in basic resource management, providing vehicles and drivers, whilst the oil companies have retained control of routeing and scheduling. This arrangement gives the oil company full control of service levels as it takes orders, but does place some constraints on the level of integration that can be achieved in the supply chain.

Tough times

There are currently just 12,201 retail outlets for fuel in the UK (see *Petroleum Review's Retail Marketing Supplement*, March 2002), compared with 25,000 in 1980 and 40,000 in 1967, and some forecasts are now predicting a further reduction to just 8,000 service stations by 2006. These changes have come about as the fluctuating price of crude, tightening margins for downstream operations and the levels of duty applied in the UK force companies to review their existing retail owned and dealer operations.

Indicative of the difficult trading conditions for retailers, Conoco recently announced the sale of its owned-retail network to Fuelforce. A further indicator (if one were needed) of the problems of making money from retail fuel sales was the demise of the Save Group after it collapsed into administration in March 2001. The situation has changed to such an extent in recent years that managers of retail sites today often look first and foremost to food, grocery and convenience goods sales to maintain profitability, with fuel sales almost as a secondary consideration.

Reducing costs

In the current environment the main focus of improvement in overall retail performance is by reducing costs through the supply chain. Whilst at first glance it might seem that the falling number of outlets might in itself lead to increased efficiency through greater economies of scale at the remaining sites, this is not necessarily the case.

Oil company fuel retailers have already taken a number of measures to achieve greater efficiencies, introducing new procedures and systems, but they have also been making some fundamental changes – including the closure of some terminals and the setting up of joint ventures at others. At the same time, the supermarkets have been developing their own brands, distribution networks and channels of supply. However, structural anomalies in the distribution systems that currently service filling stations may prove to be more of a factor than changes in the volume of fuel being sold through each outlet.

Fuel stock strategies

Currently, fuel stocks are replenished as the filling station manager dictates – but what might be most desirable for an individual manager might not be best for the network as a whole. In addition, mechanisms designed to promote efficiency, such as penalties for part loads, do not always have the intended effect of bringing efficiency to the distribution system.

As an example, a modern tanker is capable of carrying 42,000 litres of petroleum spirit on a trailer divided amongst six compartments. Typically, a retail site might have up to 30,000 litres of any one fuel stored underground. If that site wants a load of 15,000 litres of unleaded and 10,000 litres of diesel it may also take 10,000 litres of LRP (lead replacement petrol) to avoid a surcharge – even though it already has a month's capacity stored in its tanks. Not only does this system tie up excess fuel underground, but it also limits the ability of the distributor to make multi-drops because tankers are delivering more fuel than necessary for some outlets, whilst not having room for two orders in the same load.

An additional limiting factor is the reliance placed on forecourt staff to operate a demand driven replenishment system for fuels. There is also the problem of the low priority being given to the management of the fuel side of the forecourt business – a problem exacerbated by high staff turnover in the industry and a skills shortage amongst petrol station managers. This has a significant effect on the efficiencies that can be achieved under existing distribution systems.

Holistic approach

One possible solution to the problem would be a move away from a demand driven system to one in which the third-party distributor plays a greater part. Instead of fuel being 'pulled' through to the individual outlets, the distributor, if it took a more active role in load planning and scheduling, would be able to take a more holistic view of the needs of the network. Then, using the IT tools already developed for other industries to predict demand, it could 'push' fuel to where it is most needed, reducing the levels of stock held underground and the total number of vehicle journeys.

Whilst the introduction of such a system would require a certain leap of faith by the manufacturers, many of the previous objections to such a system have already been dealt with. Advances such as DCD (driver controlled delivery) allow the tanker driver to make deliveries 24 hours a day, seven days a week, with no supervision required from station staff. Initially this required the installation of additional monitoring equipment at the filling station, but with the increasing use of onboard telemetry on tankers, the costs involved can be reduced. Deliveries can now be made and stock levels controlled with only the minimal involvement of retail outlet staff.

Making the move

Even without making the transition to a 'push' system of distribution, most of the majors have already benefited greatly through a move to third-party distribution. When outsourcing was first introduced in the 1980s it was partly seen as a solution to the many industrial relations problems that existed at the time. But since then, not only have third-party logistics suppliers proved successful at introducing changes in terms and conditions of their workforce that have been essential to improve productivity, they have also shown that they can deliver a more efficient service. At the time, perhaps the first moves into outsourcing might have been viewed as giving up some control, but today distribution is now almost universally recognised as being a non-core function for oil companies.

Outsourcing has made the move to fuel distribution seven days a week with high levels of double shifting possible as companies such as Wincanton have negotiated appropriate terms and conditions with employees. In addition, spot resources can be much more easily deployed to meet seasonal and project specific demands.

Driving initiatives

Many initiatives, such as the use of on truck computing (OTC), have also been driven by third-party distributors, and these encompass an ever widening range of devices and technologies. In simple terms, OTC uses electronic devices within the vehicle to capture and retain data, which is then held until it can either be downloaded locally or relayed via telecommunications to a central processing point. Wincanton has been using elements of OTC for many of its clients within the petroleum sector for a number of years to give benefits such as consignment management, vehicle tracking and paperless deliveries, and the generation of in-cab proof of delivery notes.

However, developments by third-party suppliers do not come without some cost. One important factor today is that in order to enable a high level of investment by the logistics provider, contracts typically need to be set for periods ranging between three and five years. For example, whilst the introduction of new maximum capacity 44-tonne trailers has increased load size potential and fleet efficiency, many existing trailers currently in operation have insufficient volume to operate at 44 tonnes. Significant investment is required for new fleets, which is best handled with a longer term partnership approach.

Working together

Apart from investment, partnership also brings other advantages. It should be noted that the present driver skills shortage will be worsened by the impact

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Wincanton has benefited from the move to outsourcing and has tailored its services to the needs of its customers and the wider industry.

Transatlantic troubles cloud liberalisation

European Union (EU) officials and Brussels-based industry lobbyists have been reluctant to acknowledge that the collapse of Enron or the Argentine economic crisis could have a lasting impact on the EU's energy liberalisation project, writes *Maria Kielmas*.

The publicly expressed view is that other companies will eventually replace Enron in European energy trading. The European Commission (EC) is expected to issue papers proposing a tightening of accounting rules, but energy trading as such will thrive. In addition, Europe's gas and electricity utilities – who invested so heavily in Argentina's energy market privatisation in the 1990s (see *Petroleum Review*, March 2002) – will ride out the current storm.

However, the EU's three-pillar energy policy of combining energy market liberalisation with security of supply and environmental concerns appears contradictory and French Government moves ahead of the mid-March EU summit in Barcelona to ensure utilities uphold their 'public service' function in exchange for permitting further market opening could pave the way for gridlock.

Enron collapse

Enron's collapse had its greatest initial impact in the energy trading market, most particularly in Germany. The dominant trading entity had been EnronOnline, the world's largest web-based transaction system. Here, utilities could hedge risk through an instrument developed initially by Enron, who was always a counter-party to deals.

As they await settlement of their claims with Enron, companies are now concentrating on optimising their production portfolios. Physical, not virtual, assets are the important factors now – especially grid ownership. But these are creating their own problem with credit ratings and future cash flow.

The existence of large dominant national energy companies in EU Member countries has always been seen as a hindrance to the creation of a truly liberalised energy market. Their merger and acquisition activity over the last few years has not only raised fears about their grip on the market, but has been reflected too in falling credit ratings, increasing their financing costs. Despite the ambitious expansion plans, market analysts feared that there would not be sufficient investment targets in Europe to provide sufficient investor returns. So, the riskier business in emerging markets was a necessity if these companies were to fulfil cash flow ambitions.

Argentinian crisis

Now European company losses in Argentina are piling up as well. Gaz de France (GdF) recently announced plans to sell its 64%stake in Argentine distributor Gas NEA. It had invested \$100mn since 1997 and is making provisions of \$50mn as the cost of pulling out of Argentina. There has been speculation for many years that GdF will be taken over eventually by Electricité de France (EdF), or TotalFinaElf, whenever the French Government gives a green light to energy market liberalisation for domestic consumers.

The model could be the planned acquisition by Italian state power utility Enel of gas company Camuzzi for just over euros 1bn. The deal excludes Camuzzi's troubled Argentine interests, but the joint company will be Italy's second largest gas company and a direct competitor with Eni's Italgas. Such home market consolidation underlines long-standing fears that the future EU energy market will remain a patchwork of 15 Member country fiefdoms.

Spain could witness further consolidation. Repsol-YPF has set aside \$1.12bn from its 2001 pre-tax profits to pay for losses in Argentina. Stock market analysts agree that the company would have been a take-over target were it not for the Spanish state's golden share which protects it from hostile bids. With Barcelona-based Gas Natural (47% owned by Repsol-YPF) and power utility Endesa also facing large losses in Argentina, it comes as little surprise that once more there is speculation that Gas Natural will renew its merger talks, halted over a year ago, with power utility Iberdrola, forcing Repsol-YPF once again on the defensive. In late 2000 and early 2001 Repsol-YPF tried and failed to engineer a three-way merger with Iberdrola and Gas Natural.

Spanish developments

The Spanish Government has been putting a brave face on its stalled attempts to push forward EU energy market liberalisation during the Spanish Presidency in 1H2002. French pressure has limited this to permitting an opening of the electricity market for industrial and commercial, although not domestic, consumers. As well as protecting EdF's market, the French Government is eager to use its state power monopoly in 'public service' functions, such as subsidising renewable energy and cogeneration, and providing electricity at cheaper rates to low income groups. When previous governments in Argentina tried to pressurise utilities into providing cheap rates for low-income users, the European companies howled in protest. But now France wants to make even opening the energy market to industrial users contingent on a strengthened public service obligation for utilities and for this to be enshrined in a directive.

Spanish Economy Minister Rodrigo Rato said after the March EU Finance Ministers' (Ecofin) meeting that he was hopeful France would eventually accede to full energy market opening. Once this happens the EU can move ahead with tax harmonisation, he predicted. In the Commission's view, harmonised energy taxes will make the internal market function more smoothly and help meet the EU's obligation under the Kyoto Protocol, assuming major infrastructure problems such as insufficient international interconnections are solved.

Harmonised energy taxes

Harmonised energy taxes were first proposed by today's Competition Commissioner Mario Monti in 1993, and have been under active discussion since 1997. But they have usually fallen foul of Member countries' internal politics. In June last year the Swedish Presidency's efforts to harmonise taxes were halted by Spain, who insisted that these should be contingent on the opinion of the French market. In 2H2001 the Belgian Presidency's attempts for a pioneer 10 or 11 Member countries to push ahead with 'enhanced cooperation on a harmonised energy tax' disintegrated.

Green groups have been pushing for carbon taxes as a way of promoting inefficient and expensive renewable energy. Renewables are provided with a growing number of incentives in different Member states such as obligations on conventional utilities to buy renewable energy, fixed tariffs and special grid access. But neither they, nor the Commission, are willing to acknowledge publicly the fundamental contradiction in the exceptional treatment of renewables and theoretical liberalisation of the market as well as the increase in energy prices that this will bring about. European industry groups have always regarded energy taxes as an extra fiscal burden. Unlike the US and Asia, there is no discussion within Member and candidate EU states on the scientific validity of the assumptions on global warming which underpin the Kyoto Protocol.

But the EU hopes to move even further with its environmentalist goals and seek a way to halt the access of electricity generated by environmentally unacceptable plants to the EU grid. In recent interviews, Energy Commissioner Loyola de Palacio identified power from Russia's unsafe nuclear plants as an example. But such moves towards a 'command and control' form of EU energy market are just part of the picture. Other ambitions include EU-wide energy regulators and an EU policy on oil stocks.

Today the progress in market liberalisation and taxation is clashing head on with the national interests of the EU's major energy suppliers. Algeria and Russia have both been concerned about the effect that a liberalised EU market would have on what they term 'security of offtake'. The worst-case scenario is that the EU's energy regulators will apply liberalised market rules retroactively to their long-term contracts in the way that North Sea gas producers were obliged to renegotiate sales prices with customers in the liberalised UK market. They are mostly concerned with destination clauses that restrict the reselling of gas in the EU, a provision the EU views as contrary to free market principles. The producer countries have claimed that EU pressure on them to reduce their offtake commitment in order to create greater competition means they, rather than the customer, will have to absorb the price risk. The producers argue that if Europe wants security of supply then they should have security of offtake.

Russia and Algeria were both founder members of the Gas Exporting Countries Forum (GECF), which aims to stall the erosion of long-term take-or-pay contracts in the EU. But it has already raised fears in southern Europe about an over-reliance on gas, whether it comes from the southern Mediterranean or from Russia. Greece, which imports its gas from Russia via a pipeline passing through Bulgaria, has been involved in a dispute for years with Russia who wants to increase prices. Energy officials in Italy are beginning to question the merits of further gas pipelines from the southern Mediterranean and are shifting the focus on to greater imports of coal for power generation.

Looking ahead

Energy market liberalisation is expected to be less of a top EU priority once the Spanish Presidency hands over to Denmark for the second half of 2002. There is little appetite for liberalisation in Denmark as the country is essentially an electricity island, 80% dependent for its power generation from coal imports and increasingly disillusioned with the visual and environmental impacts of wind farms. Danish utilities are quasi-mutual entities, owned by their customers and with little scope for price cuts.

In addition, the EU energy project will be further subsumed in national interests as four countries – Germany Portugal, the Netherlands and France – hold general elections this year.

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of the European Union Working Time Directive, the Compulsory Training Directive, a revision of EC drivers hours, new legislation regarding the achievement of ADR qualifications and the regional impact of consolidated supply points. However, once again, this is a problem that logistics companies such as Wincanton are better prepared to deal with than clients within specific vertical markets. For example, in certain areas of the country, such as southeast England, we have developed links with the Armed Forces Careers Transition Partnership to encourage personnel to join the distribution industry and Wincanton. We have also introduced a 'Driver Apprenticeship' scheme to train and develop existing employees' skills, which also supports the achievement of ADR qualifications.

Safety success

It is also worth noting the significance of safety in operations as key to a successful relationship between distributor and client in the ADR (hazardous goods) and petroleum sectors. Wincanton is a safety professional with health, safety and environmental issues at the top of its agenda. The company has seen improvements year-on-year in managing RTAs (road traffic accidents), contamination incidents and spillages. Effective communication of the company's safety message is the key to success, with a commitment to the creation of safe working practices from top to bottom in the organisation.

Our policy clearly allocates responsibilities for all levels of management and staff, but once again the company is able to add additional value through the use of shared resources. A practical example of this is the establishment of a nationwide emergency response capability, with highly trained response 'incident teams' supported by specialist equipment providers, to deal effectively and safely with fuel and gas fuel vehicle incidents.

Opportunities ahead

Whilst there have been many changes in the distribution of retail fuel over recent years, third-party logistics providers see even greater opportunities for the future. As experts in their sphere of operations they are willing to move forward as fast as the petroleum distribution industry requires and to work with the industry to develop new systems and methods in an increasing climate of partnership. At the same time, they recognise the many constraints on the industry and aim to meet the specific problems of today with effective action.

IP Week – making it happen

Friday 22 February 2002 and 61 New Cavendish Street is quiet. Many of the staff are tired, but there is a collective sigh of relief as people acknowledge that IP Week is over for another year… except that it's not! As a guest or delegate, what you see over the four days of IP Week represents a fraction of the IP Week process, and a small proportion of the ten or 11 months' work that goes into making IP Week such a success.

Around 3,000 people attended in 2002. There were three full-day conferences, five half-day seminars, an evening London Branch discussion meeting, a Lunch for 350 people at the Dorchester Hotel, and the Annual Dinner which fills the Great Room at the Grosvenor House. In addition, a parallel exhibition at 1 Great George Street and, for the first time, an association with the AAPG APPEX show, made IP Week 2002 bigger than ever. As recently as 1996 it comprised only six events.

Window to the world

IP Week's importance cannot be exaggerated. It represents the Institute's annual shop-window to the world and is a hugely important revenue-generator. Outside our own programme, the oil and gas industry chooses IP Week to run many additional events. This is sometimes, but not always, to our advantage. It is frequently and incorrectly referred to as 'International' Petroleum Week in the press. On the basis that imitation is the sincerest form of flattery we should not be too hurt by the International Bunker Industries Association who run an event on the Monday evening following their AGM that is billed as 'Not the IP Dinner'. Another organisation has now launched the 'Alternative IP Dinner' on the same day as ours.

Planning

Most of the events of the third week of February have their origins some 11 months before. By the middle of March 2001 ideas and suggestions for speakers for the Lunch and the Dinner were canvassed and venue bookings confirmed while, in the case of the Dinner, the Grosvenor House has been booked three years ahead. In April or early May a small group comprising of the Conference Department and other staff from the IP, plus volunteers, get together. Led for many years by the late Peter Ellis Jones, today's IP Week is very much his legacy to the Institute. This planning meeting sets the shape and themes for the following year.

Individual programmes are developed within the IP and with collaborating organisations such as OGP and sponsor partners like Wood Mackenzie through the period until the end of June. The summer months (the timing could not be worse) are spent securing speakers.

There are always refusals and constant changes, but the larger part of the programmes will be finalised by early/mid-September so that the brochure and advertising materials can be printed, the marketing campaign planned and the promotion to additional sponsors and exhibitors started, ready for the first major marketing thrust at the beginning of October. Marketing then continues right through until IP Week itself.

From October onwards there is also work in terms of speaker liaison, obtaining papers, finalising details with venues, and preparation of documentation. Speaker arrangements seem never to be completed. This year the keynote speaker for the major Monday conference cried off at 3 pm on the previous Friday! In this case we were grateful to our Vice President Wolfgang Schollnberger who not only filled this gap but did so in a way that undoubtedly outshone what we might have expected from our absentee.

Sitting our guests down to Lunch and Dinner is even more complex and demanding, with special booking arrangements to sell tables, VIP guests, menus to be fixed, private cocktail arrangements, seating plans, attendance lists, and placecards. There is a myriad of detail that must be right if the process is to run smoothly.

The last two or three weeks before IP Week are frenzied for the Conference & Events team. Twelve to 14-hour days, seven days a week with so much to be done at the last minute, it was almost a relief when Monday 18 February arrived. After that, the staff keep going on a surge of enthusiasm and adrenaline until it is all over.

Aftermath

But of course, it's not. Next follows the period of both physical and metaphorical clear-up, with an exhibition to be dismantled, materials to be returned and sorted back in the office, thank-you letters to be written and despatched, accounts to be sorted out and reconciled, bills to be paid, revenues to be counted and credited to the right place, and articles to be written for *Petroleum Review* and for the website.

How is this done with such a small team in the Conference Department when they also have many other events to organise and run, particularly in the busy period of the fourth quarter of the year with conferences, the IP Awards and an Autumn Lunch? In the run-up to IP Week they are augmented by temporary staff and are well supported by staff from other departments before, but particularly during, IP Week itself. By the middle of March, apart from paying the final bills and sorting out the outstanding financial matters, IP Week 2002 is history, but… here we go again… IP Week 2003 is only 11 months away!

Team players

The three-strong team in the IP Conference Department makes IP Week happen.

- *Conference Manager* **Marta Kozlowska** – veteran of three IP Weeks, having joined in December 1999, just two months before her first.
- **Laura Viscione** – 2002 was her second IP Week when, amongst other things, she took the prime role in organising the Lunch.
- **Andrea Fulton** – a debutante this year, having joined just last October, she led on the Dinner.

Each of the three members of the Conference Department takes the lead role in specific events, the whole managed and coordinated by the Conference Manager, supported by temporary staff and with almost 30 other IP staff contributing in their different ways.

PETER ELLIS JONES
MA, ACIS, MIPD, FInstPet, Barrister-at-law
1945–2002

1965–1970	*Oxford, studying law, followed by postgraduate degree in industrial relations.*
1975–1980	*Mobil Oil, employee relations, then Senior Corporate Planning Advisor.*
1980–1988	*Premier Oil and other independent oil companies. Finance and Operations Director.*
1988–2002	*Managing Director, Tawe Oil Managements Ltd. Chairman, Tawe Shipping Ltd, Avia Fuels (UK) Ltd, Avia Petroleum Ltd and Cedar Petroleum Ltd.*
1975	*Joined Institute of Petroleum (IP).*
1988	*Wrote and published* OIL: A Practical Guide to the Economics of World Petroleum.
1979–1999	*Member of IP Council.*
1991–1999	*Vice President of the IP.*
1995	*Awarded the Institute of Petroleum's Eastlake Medal.*
1999	*Made an Honorary Fellow of the Institute of Petroleum.*
1997–2002	*Treasurer of the World Petroleum Congress (WPC).*

The following is a personal tribute from Philip Algar, a former Editor of* Petroleum Review, *who worked closely with Peter on the IP Council and various IP Committees, and counted him a close friend.

'I was devastated to learn of the premature death of Peter Ellis Jones. It is of little consolation to me that hundreds of people across the oil and gas industry will be feeling the same sense of loss, desolation and injustice. With Peter's sudden death, I have lost not one richly-gifted friend, but many, for he was articulate, well-informed and more able to discuss a variety of topics than anyone I have known. He could make you laugh and stimulate you intellectually all in the same comment. Peter was a rare man of impressive learning and great modesty.

I had the privilege of working with him on many oil economics courses in Oxford, at the IP and overseas, and his ability to change mental pace and approach to suit his audience was the mark of a true, but unassuming, professional. He could conduct sensible conversations on almost any topic raised by different nationalities and he probably taught them more about their own countries than any other foreigner they had met.

Peter was an excellent travelling companion, whether visiting temples in Bangkok or having a formal dinner in Oxford. He could regale colleagues with genuinely humorous tales from different parts of the world and different times of his life. He never flaunted his versatility and was always happy to share his truly huge knowledge.

Throughout his long and totally devoted dedication to the Institute of Petroleum, not least on the-then Publications and Information Committee (P&I) and the IP Council, he never wavered in his understanding of complex issues or in his ability to cut through to the key points. Whether at a committee meeting or presenting a paper or chairing a conference, he was able to puncture pomposity with a gentle but well-aimed shaft of humour that was sometimes so gentle that the recipient smiled with the audience. His unrivalled experience of the IP, communicated so freely and not always adequately acknowledged in recent years, allied with his vast range of contacts, was of inestimable value to our Institute. He was a consistently outstanding ambassador at home and overseas.

He always championed the cause of individual members, without alienating corporate members, and found a way to reconcile apparently different stances. He had a rare diplomatic skill and one source of regret must be that it was not used on a wider stage. The IP was indeed most fortunate in being able to rely on Peter to solve problems, organise conferences and find top-class speakers at the last moment. He did all this because he believed in the organisation and its objectives as enshrined in the original constitution all those decades ago. In the 35 years during which I have been a member of the IP, nobody, but nobody, has done more for the IP than Peter. We shall never be so fortunate again.

Peter was one of those rare individuals who managed to ignore any unfair treatment or inadequate recognition, especially from those who had most for which to thank him. He delighted in pondering the absurdities of contemporary life and this doubtless allowed him to be pragmatic and to sustain his individuality in a world that rates conformity so highly. I still recall seeing him striding through an airport in a hot Papua New Guinea, wearing his overcoat because he was en route to Switzerland and did not want to pack the coat, whilst carrying a bow and arrow given by a grateful course leader.

I mourn the loss of a true friend, but rejoice for having known him for some 25 years. Would that it could have been decades longer.'

Evaluation of the performance of meters in loading gantries

This IP Technical Development Project, conducted by SGS Redwood, looked at the performance of various types of meters in loading gantry installations. Such installations are notorious for the restricted space available for the meter and its associated components, and for the fact that batch volumes are relatively small. These features compromise the performance of many types of meter and mean that the positive displacement (PD) meter remains the most popular choice for gantry metering applications.

In recent years a number of companies have, because of cost, installed turbine meters as an alternative to the PD meter – but these changes have met with limited success. There is, nevertheless, continuing pressure to reduce equipment costs without compromising performance. With progressive improvements in the performance of alternative types of meter, the need was perceived for an objective comparison of the main contenders.

Meter evaluation

The following meters were selected for evaluation:

- Positive displacement (PD) meter of the type installed in many UK gantries.
- Straight bladed turbine meter of the type used to replace some PD meters.
- Helically bladed turbine meter.
- Coriolis mass meter.

All the meters were tested on motor spirit, kerosene, ultra-low sulfur diesel (ULSD) and gas oil.

Various types of installation evaluated

- An 'ideal' installation with 20 diameters of straight pipe upstream and 10 diameters downstream of the meter. This provided a basis for comparing the performance of meters in the other installations.
- A simulated gantry rig with the bends and components copied from a real gantry.
- A second simulated gantry rig, the orientation and positioning of the bends differing from the first.

Project findings

The main findings from the project were:

- All the meters showed some installation effect.
- All the meters showed some sensitivity to product viscosity.
- The installation effects on the PD meter were most apparent on the lower viscosity products in the middle range of flow rates. However, operational experience of these meters demonstrates that, since they are normally proved in situ, these effects do not significantly compromise their ultimate performance.
- The straight bladed turbine meter did not perform well. Its linearity and repeatability were poor, and although it performed better on the lower viscosity products, it was not considered acceptable. The results for this meter were in line with experience of other straight bladed turbine meters in the field.
- The helical turbine meter showed its greatest installation effects with motor spirit, producing an unacceptable linearity in one test. Its repeatability also increased with this product, although remaining within acceptable limits. However, the meter's performance was satisfactory with all other products and, subject to a cautionary note regarding motor spirit, it can be considered for gantry metering applications.
- The greatest installation effects on the Coriolis meter were seen at low flow rates. Nevertheless its linearity and repeatability remained acceptable at all but the lowest flow rate with gas oil and, subject to a note of caution on this point, this meter can also be considered for gantry metering applications.
- None of the meters showed any obvious performance effects due to the small batch volumes involved in the tests. Although the repeatability of the helical turbine meter increased on motor spirit, it is unlikely that this is related to batch volume.

Product calibration

The test results from this project were analysed in conjunction with the calibration data for six PD reference meters. The analysis demonstrated that the practice of calibrating a reference meter using gas oil and applying a fixed meter factor 'correction' to establish its performance for ULSD can lead to significant errors. All the meters behaved differently and errors up to 0.07% were noted at 2,250 litres/min, with even larger errors at lower flow rates.

Similar problems occur when fixed corrections are applied to a reference meter's performance to account for viscosity differences between products.

The implication is that reference meters must be calibrated on the products with which they will subsequently be used to prove gantry meters.

John Miles
Consultant and Chairman of the IP Dynamic Measurement Sub-Committee

The two reports arising from this project are available for study in the IP Library.

For further information on the work of the Petroleum Measurement Committee please contact John Phipps, Technical Manager–Standards, Tel: +44 (0)20 7467 7130. Alternatively, e: **jp@petroleum.co.uk** *or visit the IP's website at* **www.petroleum.co.uk**

Membership News

NEW MEMBERS

Dr I.M Abbass, Petroleum Training Institute
Mr C Acuna Allen, Manchester
Dr Y Akoto, Tema Oil Refinery Limited
Mr P Allen, Blandford Forum
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Mrs S Anikina, c/o Targetpoint Services Limited
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Mr T A Yew, University of Newcastle

IFEG

INFORMATION FOR ENERGY GROUP

Cool Sites for Hot Energy Information

Thursday 9 May 2002
2 pm – 4.45 pm (1.00 pm buffet lunch)
Institute of Petroleum, 61 New Cavendish Street, W1G 7AR
Attendance FREE for IFEG Members, £25 to non-IFEG Members

This seminar provides an insight into the upgraded and improved websites of the DTI and the Institute of Petroleum, plus the Free Pint site – a site providing researchers of business information the opportunity to ask questions and get answers from fellow information workers. Speakers will be Danny Stocker, DTI; William Hann, FreePint; and Aideen Mooney, Institute of Petroleum.

The seminar is sponsored by Energy Day
www.energyday.com

Andy Dawson, Lecturer of Information Studies University College London will chair the seminar.

For more details, contact: Sally Ball, IFEG Secretary, 61 New Cavendish Street, London W1G 7AR
Tel: +44 (0)20 7467 7115; Fax: +44 (0)20 7255 1472
e: **ifeg@petroleum.co.uk**

London Branch Activities

23 April, 18.00 hours
Fuel Cells – Panacea or Pipedream?
by John Dean (at the Institute of Petroleum)

21 May, 18.00 hours
Why Recycle?
by Cleanaway Ltd (at the University of Surrey, Guildford)

Contact:
Ian K Robinson,
Tel: +44 (0)1932 783774

Super-duplex solution for an exotic North Sea problem

***Jim Cuthill*, FD Alliance's Development Manager reports on its new composite repair system that was recently used for the first time on superalloys.**

Exotic materials started to appear in oil and gas installations several years ago with carbon steel, always the metal of choice, being increasingly relegated in favour of alloys like CuNiFe and super-duplex steel. The alloys' greater strength meant that for any given pressure a thinner wall could be used than that needed in steel, thereby reducing total weight. Both also offered greater resistance to corrosion – the big problem for carbon steel offshore.

However, the adoption of new materials has also brought with them a range of new characteristics and defects. Super duplex stainless steel, for instance – a family of different alloy grades containing varying proportions of chromium, molybdenum and tungsten – suffers in particular from a condition known as sigma-phase crystallisation.

Metals have a structure that exists as one or more 'phases'. Modern duplex stainless steels have a two-phase structure, namely austenite and ferrite. Most cast and wrought products will have an approximate 50/50 by volume split of ferrite and austenite, although each manufacturer has a preferred balance – generally 35% to 55% austenite.

Heat treatment causes structural changes in duplex steel, predominantly in the ferrite stage – its body-centred cubic crystal structure is less compact and therefore more mobile. The presence of chromium and molybdenum in the ferrite stage also causes the formation of structurally unfavourable 'inter-metallic phases'. The precipitation of this phase within the metal is called sigma phase.

However, the formation of such phases can be prevented if sufficient precautions are taken during heat treatment, involving rapid removal from the furnace followed by quenching. The inter-metallic precipitates dissolve following bright annealing at 1,070°C – but timing between the heating and cooling zones is critical, if sigma-phase creation is to be avoided.

Small volume fractions of sigma phase can have serious effects on the impact toughness and corrosion resistance of the material, with tensile and hardness properties also suffering. In a pipeline situation this has little direct effect on pressure containment or structural strength – until the pipe receives a significant impact, which could result in it shattering.

This was the situation on a platform of one of the North Sea's leading operators, where NDT systems had identified an area of internal corrosion at a bend on a 30-inch diameter seawater line. A minor through-wall defect, a 20-mm crack, had occurred – which if left, would have affected line velocity and compromised platform capacity. Because NDT had also identified sigma-phase crystallisation in the damaged section, engineers were wary about using the traditional solution of a clamp; in any case, it would have been too big and would have proved difficult to bolt in its position on the bend.

Super-duplex steel is very difficult to repair and repair systems are not yet fully validated. Additionally, the section in question was due to be switched out within six months during a planned shutdown. Therefore, the recent launch of the FD Alliance's composites repair system aroused significant interest.

An alliance between DML, the Plymouth-based engineering consortium, and onsite online specialists Furmanite, FDA was called in after Furmanite's Norway office was approached, having previously worked on projects for this operator.

Repair of the seawater line was completed using carbon fibre and epoxy resin – materials usually seen in the aerospace and defence industries.

High-tech materials require a careful approach – one reason why FD Alliance provides a full service, from assessment, through design and appraisal to the actual installation of the material itself. Installation is no simple task – surfaces must be carefully prepared, using either a grit or water-blast process, in order to remove oxidation from the metal surface and provide a key for the composites. An SA2.5 finish (75 mm) is usually specified, with the repair starting within four hours of its completion, to prevent re-oxidation.

In the North Sea case, the company actually used a water-blast process because of concern about the effect that grit-blasting could have on the brittle material. It also used a proprietary surface pre-treatment cleaning to ensure that oxidation did not set in so quickly and to increase the durability of the bond. Preparation really is key – without a good start, the longevity of a repair is extremely unfavourable.

Further precautions are taken during the next stage, when a glass fibre tie coat is applied to the prepared surface. Not only does this provide a high-quality interface between the pipe and the layers of carbon fibre, but it also provides a degree of electrical insulation to guard against the risk of galvanic reaction. Although no such cases have ever been recorded, it forms a vital part of the AEA validation process and an integral part of FDA's quality control.

Layers of carbon fibre are then built up, according to a calculated design thickness. Commonly this will be as little as 5 mm; one of the main attractions of the composites material is its strength and low density. At ten times the strength of steel, twice the stiffness and only one-quarter the density, the repair it creates is very often stronger than the original structure itself. Indeed, when the design specification is calculated, FDA engineers actually ignore the presence of the original pipe, creating a repair with an in-built extra factor of strength.

A final sacrificial peel coat over the top layer of carbon fibre – removed once the resin has cured – serves to remove excess resin from the carbon fibre layers and creates a textured final coating on the repair, ready for the application of paints or other finishes if required.

This particular repair marked the first time that one of the superalloys had been repaired using the new procedure. Since then, however, the company has dealt with CuNiFe too, which will boost even further the operator confidence about composites.

Tel: +44 (0)870 241 5065
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Precision locator finds buried pipelines

Bristol-based Radiodetection recently launched its new precision pipeline locator on the UK market. Designed to use very low frequency signal processing technology, the system is said to be capable of accurately locating and identifying a buried pipe from the ground surface, providing a depth of cover reading without the need to pothole or penetrate the ground.

The advanced digital signal processing technology is also reported to allow the system to compensate for interference, enabling it to be used in areas where previously it was not possible to use electronic locators, states the company.

The locator comprises a sensor array and associated digital signal processing electronics within a portable housing. The unit is placed on the ground and receives a signal radiated from the buried pipe. Sophisticated vector analysis software determines the position of the pipe relative to the unit and then transmits the information via a short-range radio link to a handheld data viewer (HDV). The HDV allows the user to view target position, depth and electronic confirmation data on a Palm V device.

Tel: +44 (0)117 988 6499
Fax: +44 (0)117 976 0088
www.radiodetection.com

Compact level switch for 'solids'

A compact, vibrating rod level switch which is said to be suitable for level detection on 'solids' such as powders with densities as low as 0.05 km/dm³ or any granular media with a diameter up to 10 mm is the latest addition to the Magnetrol International portfolio.

The Solitel switch is reported to operate safely in applications where pressures are up to 25 bar and temperatures to a maxiumum of 160°C. It has an aluminium housing which makes it suitable for use in hazardous areas (Dust EX Zone 10).

Vibrating rod level probes can be prone to media build-up which, if left unchecked, can impair reliability and cause problems of false alarms. However, as the Solitel switch incorporates features such as self-cleaning probe and polished sensor as standard, these problems are claimed to be eliminated.

The switch is designed to respond within less than 2 seconds (or 5 seconds following field selectable setting) by means of an integrated 8A SPDT relay or a 'solid state' output and is field selectable to high/low failsafe alarm. The solid state output means it can be connected directly to a PLC (programmable logic controller) or to an external load such as a pump, light bulb or to any logical voltage input. The status of the output is visible by means of an LED built into the cover of the unit.

The switch is supplied with either a standard probe length of 235 mm, a rigid extended rod up to 3 metres, or cable extended sensor up to 20 metres. It is line powered and offers separate cable entry for signal output/input power.

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Perforation flow lab

Halliburton Energy Services recently commercialised a new element of its PerfPro™ process – its Perforation Flow Laboratory, which is designed to simulate a wide range of well conditions and flow measurement options to accommodate low permeability hard rock and high permeability unconsolidated sand samples. Developed to address deficiencies in validation data, the laboratory provides detailed instrumentation and controlled-laboratory conditions that can allow insight into physical phenomena occurring in the reservoir during complicated perforating and multi-phase flow events.

According to Jody Powers, President of Halliburton Energy Services, the addition of the Perforation Flow Laboratory to the PerfPro process 'allows us to provide operators with the information needed to make better, more knowledgeable decisions when perforating a well to optimise production.' The PerfPro process allows technical advisors to improve the design and optimisation of perforating systems and to optimise well inflow performance using standardised process and analysis tools. A three-pronged approach, using laboratory tests, theoretical models and field tests, provides operators with a process that can quantitatively determine the optimal perforating system design for a given reservoir formation.

The Perforation Flow Laboratory, based at the company's Jet Research Centre in Texas, is reported to have conducted more than 80 perforating flow lab tests to date. The lab includes a pressure chamber, a wellbore section mounted against one face of the core, and a flow loop. The pressure chamber applies in-situ stress to a reservoir or outcrop core. The flow loop applies pore and wellbore pressure to appropriate core sample boundaries. After the shaped charge is detonated to create perforation, the flow loop pressures can be changed to induce flow from or into the perforation.

The laboratory can quantify the impact of different perforation design variables (tubing versus wireline-conveyed, charge size and type, under- versus overbalanced), fluid type, and skin source on completion efficiency, therefore, on well productivity, explains the company. When linked with reservoir characterisation analysis, the design of the perforating system and the well completion can be tailored for specific application in the reservoir of interest.

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NEW Publications

The Skeptical Environmentalist: Measuring the Real State of the World*

Bjorn Lomborg (Cambridge University Press, The Edinburgh Building, Shaftesbury Road, Cambridge CB2 2RU, UK. Tel: +44 (0)1223 312393; Fax: +44 (0)1223 315052.) ISBN 0 521 01068 3. 515 pages. Price (paperback): £17.95.

This book sets out to challenge widely held beliefs that the environmental situation is getting worse and worse. The author, a former member of Greenpeace, is critical of the way in which many environmental organisations make selective and misleading use of the scientific evidence. Using what is said to be the 'best available statistical information from internationally recognised research institutes', the book systematically examines a range of major environmental problems that feature prominently in headline news around the world. Arguments are presented in non-technical, accessible language, and are backed up by over 2,900 notes allowing readers to check sources for themselves. Concluding that there are more reasons for optimism than pessimism, the author stresses the need for clear-headed prioritisation of resources to tackle real, not imagined, problems.

The Promotion and Licensing of Petroleum Prospective Acreage

Michael A G Bunter (Kluwer Law International, PO Box 858889, 2508 CN The Hague, The Netherlands. Tel: +31 70 308 1552; Fax: +31 70 308 1515.) ISBN 90 411 1712 1. 400 pages. Price: £83 (euros 132; $121).

This book is based on more ten years' experience in conducting tenders for the licensing of petroleum prospective acreage on behalf of a number of governments in Europe, Africa and the former Soviet Union. It explains the processes of licensing from the points of view of the two main protagonists – the government bodies and the international oil companies – and also looks at the interests of the host communities and the environment, as well as those of the neighbouring states and other participants that may be affected by the licensing process.

How Did That Happen? Engineering Safety and Reliability*

William Wong (Professional Engineering Publishing, Northgate Avenue, Bury St Edmunds, Suffolk IP32 6BW, UK. Tel: +44 (0)1284 763277; Fax: +44 (0)1284 718692.) ISBN 1 86058 259 8. 256 pages. Price (hardback): £29 (+10% delivery outside the UK).

This publication uses lessons learnt from real engineering problems to highlight what good engineering practice should be. It includes extensive analysis of well-known disasters where events have not gone to plan; explanations of the underlying issues, processes, procedures and regulations; and case studies and examples to show the use of statistics and the application of HAZOP, FMEA and FTA. Illustrated with photographs, diagrams and tables, the book also includes a directory of centres for information and organisations providing services to this sector.

The Legal Regime of Offshore Oil Rigs in International Law

Hossein Esmaeili (Ashgate Publishing, Gower House, Croft Road, Aldershot, Hampshire GU11 3HR, UK. Tel: +44 (0)1252 331551; Fax: +44 (0)1252 368595; e: **dfattore@ashgatepub.co.uk** *ISBN 0 7546 2193 6. 320 pages. Price (hardback): £60.*

This book reviews and examines the relevant portions of all international treaties, cases and the national law and practice of states, in relation to international aspects of offshore oil rigs to offer an understanding of the legal regime surrounding oil rigs and formulate an

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New editions to library stock:

This is just a small selection of what we have added to our Library stock in recent months. Please see the IP website (**www.petroleum.co.uk**) for a complete list of our holdings. Members are also welcome to suggest potential purchases – please contact Catherine Cosgrove (see contact details below).

- *Annual book of ASTM standards 2002. Section 5: Petroleum products, lubricants and fossil fuels. Volume 05.05: Test methods for rating motor, diesel and aviation fuels; catalysts; manufactured carbon and graphite products.* American Society for Testing and Materials (ASTM) Pennsylvania, US, 2002.
- *Code of practice 19: Liquid measuring systems for LPG. Part 1: 2001: Flow rates up to 80 litres per minute in installations dispensing road vehicle fuel.* 2nd Edition. LP Gas Association (LPGA), Ringwood, UK, 2001.
- *Downhole equipment for petroleum and natural gas industries – Progressing cavity pump systems for artificial lift. Part 1: Pumps.* BS EN ISO 15136-1: 2001. 1st Edition. British Standards Institute (BSI) London, UK, 2001.
- *The energy report: market reforms and the environment.* Department of Trade and Industry (DTI), London, UK, 2002.
- *Environmental consultancy directory.* 9th Edition. Environmental Data Services (ENDS), London, UK, 2002.
- *The fuel tax protests in Europe, 2000–2001.* Mitchell, John V; Dolun, Muge. RIIA, London, UK, 2001.
- *The misuse and smuggling of hydrocarbon oils. Report by the Comptroller and Auditor General: HC 614 Session 2001–2002: 15 February 2002.* HM Customs and Excise, London, UK, 2002.
- *Neighbourhood retailer & forecourt technology: Yearbook 2002.* Craig, Tara, Ed. Penton Publications, Dublin, Ireland, 2002.

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

EVENTS Forthcoming

APRIL 2002

3–5 **Greenwich**
The World's Oceans & Seas
Details: The Greenwich Forum, UK
Tel: +44 (0)1444 416678
Fax: +44 (0)1444 441162
e: **enquiries@conferencebusiness.co.uk**

4–5 **Antwerp**
Dangerous Goods Conference
Details: Pira International, UK
Tel: +44 (0)1372 802046
Fax: +44 (0)1372 802243
e: **kateg@pira.co.uk**

6–11 **Qatar**
Middle East Oil and Gas Week
Details: The Conference Connection, Singapore
Tel: +65 226 5280
Fax: +65 226 4117
e: **info@cconnection.org**

8–9 **Aberdeen**
Subsea Pipeline Technology Conference
Details: Pipeline Industries Guild, UK
Tel: +44 (0)20 7235 7938
Fax: +44 (0)20 7235 0074
e: **glenister@pipeguild.co.uk**

8–9 **Connecticut**
Connections to Commercialism
Details: Business Communications Company, USA
Tel: +1 203 853 4266 ext. 309
e: **publisher@bccresearch.com**

8–10 **London**
ERTC Environmental Conference
Details: Global Technology Forum, UK
Tel: +44 (0)1737 365100
Fax: +44 (0)1737 365101
e: **events@gtforum.com**
www.gtforum.com

8–10 **Noordwijk**
Gasification: The Clean Choice for Carbon Management
Details: Institution of Chemical Engineers, UK
Tel: +44 (0)1788 578214
Fax: +44 (0)1788 534407
e: **mroyce@icheme.org.uk**

8–10 **York**
International Conference on Fluid Sealing
Details: BHR Group, UK
Tel: +44 (0)1234 750422
Fax: +44 (0)1234 750074
e: **eabson@bhrgroup.com**

8–12 **London**
OH&S Management Systems Auditor Course
Details: Training International, UK
Tel: +44 (0)1323 832939
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www.training-international.co.uk

8–13 **London**
Flexible Management Training Programme
Details: Training International, UK
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9–11 **Paris**
Global Retail Technology Forum
Details: RMDP, UK
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e: **r.elliott@rmdp.co.uk**

9–12 **Paris**
International Petroleum Economics Seminar
Details: ENSPM, France
Tel: +33 1 47 52 71 09
Fax: +33 1 47 52 72 93
e: **josee.foucault@enspmfi.com**

10–12 **Durham**
Maritime Boundary Delimitation
Details: International Boundaries Research Unit, UK
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Fax: +44 (0)191374 7702
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www.ibru.dur.ac.uk

14–19 **Oxford**
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15–16 **London**
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www.smi-online.co.uk/asset.asp

15–17 **Bahrain**
GEO 2002
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e: **jamila@aeminfo.com.bh**

15–17 **Dubai**
Land Tank and Shipboard Measurement
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e: **register@abacus-int.com**

16–17 **London**
The Middle East: What Does the Future Hold After 9/11?
Details: IBC Global Conferences, UK
Tel: +44 (0)1932 893851
Fax: +44 (0)1932 893893
e: **cust.serv@informa.com**

17–18 **Harrogate**
FPS 2002
Details: Federation of Petroleum Suppliers, UK
Tel: +44 (0)1565 631313
Fax: +44 (0)1565 631314
e: **vc@fpsonline.co.uk**

21–24 **Adelaide**
2002 APPEA Conference & Exhibition
Details: Australian Petroleum Production & Exploration Assoc, UK
Tel: +(02) 6267 0907
Fax: +(02) 6247 0548
e: **jhood@appea.com.au**

22–23 **Amsterdam**
Subsea Tie-Backs
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24–25 **Belgrade**
Investing in Serbia
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www.ibcenergy.com/serbia

24–26 **Aberdeen**
Subsea Pipeline Integrity Management
Details: Trevor Jee Associates, UK
Tel: +44 (0)1892 544725
Fax: +44 (0)1892 544735
e: **admin@tja.co.uk**
www.tja.co.uk

25 **London**
Improving Productivity and Performance
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MOVES *People*

BJ Process and Pipeline Services has announced that it has appointed **Carl Mook** as Base Manager of its operational facility in Dubai, United Arab Emirates. In his new role, Mook oversees all financial and operations management for the division in the Middle East region. He is also responsible for driving BJ PPS business development efforts, and maintaining existing relationships with clients operating in Turkey, the Arabian Peninsula, Indian Sub-continent and Caspian region.

Cairn Energy has announced that **Normal Lessels** CBE has advised his intention to stand down as Chairman and as Non-Executive Director at the next Annual General Meeting of the company. He will be succeeded as Chairman by **Norman Murray**, who was appointed a Non-Executive Director of Cairn Energy on 4 October 1999.

William J Sember has been appointed Vice President Offshore Development for ABS. During his 26-year career at ABS, Sember has held a succession of progressively senior positions after starting as a field surveyor. These include head of the Offshore Engineering Department and Vice President of Operations for the Eastern Region of ABS Europe.

Oil-On-Line, the industry-driven electronic oil trading initiative, has announed the appointment of **Rupert Marks** as Chief Executive Officer. The appointment of Marks is an important milestone for Oil-On-Line in its quest to create an independent, neutral electronic marketplace for the trading of physical crude and oil products.

Leiv L Nergaard has been appointed President of Norsk Hydro's holding companies in Germany, including those formed to accommodate the VAW acquisition. Nergaard will focus on optimising the company's corporate presence in Germany and the European Union. **John O Ottestad** joins the Corporate Management Board as Executive Vice President and Chief Financial Officer. The Corporate Strategy Team, Finance, Tax, Investor Relations, Mergers & Acquisitions and Accounting staffs will report to Ottestad, as will the Petrochemicals, Pronova and Hydro Business Partner divisions.

In order to ensure the smooth operation of its new bases, BJ Services has appointed long-term Well Services Manager ***Brian Forgie*** as West Africa Area Manager. Forgie is responsible for business development activities, project integration and management, cost control initiatives, equipment and allocation of personnel to serve clients operating in each of the respective countries.

IP THE INSTITUTE OF PETROLEUM

IP TRAINING COURSES 2002

Advanced Process Control

The oil refining and petrochemical businesses are becoming increasingly competitive, with every plant manager seeking to produce the best quality products at the lowest operating and investment cost. This **four-day course** looks at Advanced Process Control (APC) and how it now forms an essential part of this effort. Small differences in refining performance can have a major impact on profitability: get it right and profits continue to grow – get it wrong and operating losses quickly materialise.

In association with enspm FORMATION INDUSTRIE

Course Dates:
9 - 12 April 2002

Course Venue:
Institute of Petroleum, London

Registration Fee:
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Non-Member: £2000 (£2350.00 inc VAT)

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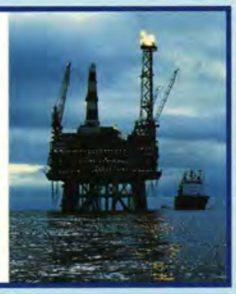
Course Dates:
16 - 19 April 2002

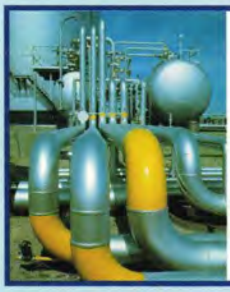
Course Venue:
Institute of Petroleum, London

Registration Fee:
IP Member: £1800 (£2115.00 inc VAT)
Non-Member: £2000 (£2350.00 inc VAT)

Overview of the Natural Gas Industry

This **four-day course** will provide participants with an overview of the economic and contractual aspects of the natural gas industry. The peculiar features of natural gas will be highlighted in order to explain the economic differences between a crude oil chain and a natural gas chain. Gas chains can become very complex, rigid networks which penetrate deep into energy markets and the associated, broad range of crucial economic, marketing, and legal issues of the gas industry will be examined. Discussions will cover a number of questions, including problems of gas projects' structuring, upstream sales' contracts, take-or-pay issues, and gas markets' liberalisation.





Custody Transfer of Crude Oil - Trading and Loss Control Issues

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

In association with SGS

Course Dates:
25 - 26 April 2002

Course Venue:
Institute of Petroleum, London

Registration Fee:
IP Member: £900 (£1057.50 inc VAT)
Non-Member: £1100 (£1292.50 inc VAT)

In association with INVINCIBLE

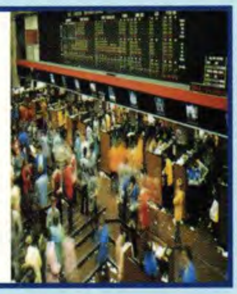
Course Dates:
13 - 17 May 2002

Course Venue:
The Møller Centre, Cambridge

Registration Fee:
IP Member: £2600 (£3055.00 inc VAT)
Non-Member: £2800 (£3290.00 inc VAT)

Trading Oil on the International Markets

During this **five-day course** delegates become part of Invincible's fictional trading team, taking decisions about the company's activities to maximise profits through an understanding of the economics of trading and the management of inherent price risks. Delegates trade the live, crude oil and refined product markets worldwide under the guidance of an expert team of lecturers reacting to events and using real-time information from Reuters and Telerate screens and daily price information from Platt's and Petroleum Argus. The course expects a high degree of participation from delegates.



Environmental Impact Assessment and Management

This new **three-day course** is designed to give delegates real practical training in the assessment and management of critical environmental issues relevant to the upstream oil and gas industry. It is essential for the industry to be able to assess, manage and minimise its impacts, and to demonstrate continuous improvement with respect to its environmental performance. Companies need a thorough understanding of environmental issues not only to meet regulatory requirements but also to win stakeholder approval and achieve internal project sanction.

In association with BMT BMT Cordah Limited

Course Dates:
15 - 17 May 2002

Course Venue:
Institute of Petroleum, London

Registration Fee:
IP Member: £1300 (£1527.50 inc VAT)
Non-Member: £1500 (£1762.50 inc VAT)

In association with enspm FORMATION INDUSTRIE

Course Dates:
21 - 24 May 2002

Course Venue:
Institute of Petroleum, London

Registration Fee:
IP Member: £1800 (£2115.00 inc VAT)
Non-Member: £2000 (£2350.00 inc VAT)

Fundamentals of Petroleum Refining Processes

The **four-day course** examines the composition, main characteristics and new trends of petroleum products, examining the roles of the different refining units and their process characteristics.

Participants will gain an understanding of the main manufacturing schemes encountered in the oil refining field and look at the overall economic context of this industry.

For more information, see enclosed inserts or contact Lynda Thwaite at IP Training or visit: www.petroleum.co.uk/training

Tel: + 44 (0)20 7467 7154 Fax: + 44 (0)20 7255 1472 E-mail: lthwaite@petroleum.co.uk

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