FEBRUARY 2005

Petroleum review

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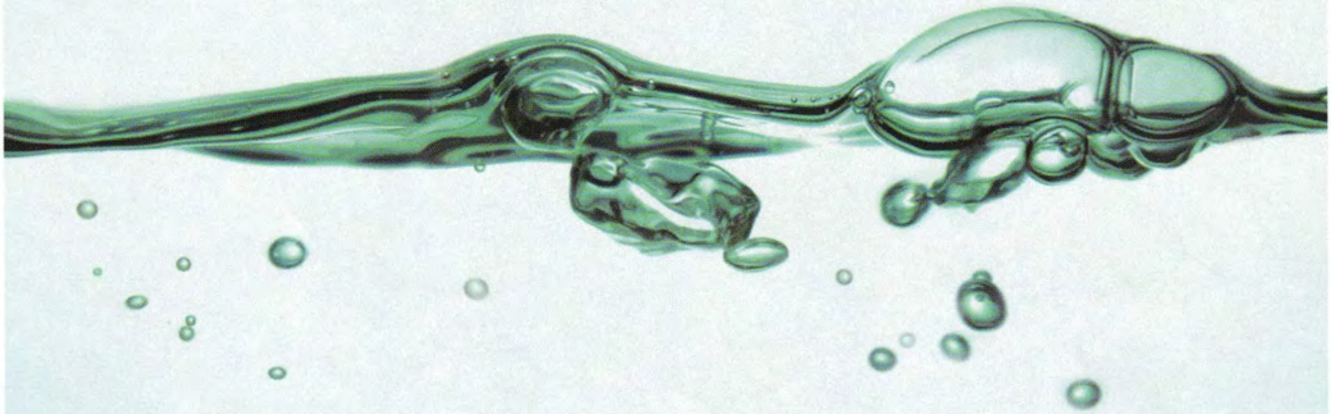

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energy INSTITUTE

61 New Cavendish Street, London W1G 7AR, UK

Chief Executive: Louise Kingham, MEI

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

Editor: Chris Skrebowski FEI

Associate Editor: Kim Jackson MEI

Design and Print Manager: Emma Parsons MEI

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

e: petrev@energyinst.org.uk

www.energyinst.org.uk

ADVERTISING

Advertising Manager: Brian Nugent
McMillan-Scott plc
10 Savoy Street, London WC2E 7HR

t: +44 (0)20 7878 2324 f: +44 (0)20 7379 7155
e: petroleumreview@mcmslondon.co.uk
www.mcmillan-scott.co.uk

SUBSCRIPTIONS

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

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ABBREVIATIONS

The following are used throughout *Petroleum Review*:

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

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

Front cover picture: Metering flows to Belorussia at the Smolensk compressor station
Photo: Chris Skrebowski

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The Energy Institute as a body is not responsible either for the statements made or opinions expressed in these pages. Those readers wishing to attend future events advertised are advised to check with the contacts in the organisation listed closer to the date, in case of late changes or cancellations.

FROM THE EDITOR

IP Week – a networking opportunity

International Petroleum (IP) Week is almost upon us. From 14 February large numbers of senior oil and gas industry figures will gather in London for an exciting week of conferences, dinners, seminars and informal gatherings.

The real strength of IP Week, however, is the way that it facilitates networking, allowing the industry to informally discuss many of the challenges facing it.

So, what are the challenges that face the oil and gas industry in 2005? These fall into three broad groups: access to resources; the maintenance and development of production flows; and the political, social and environmental costs and constraints involved in refining and selling products to consumers. All these challenges will be covered and discussed in the course of this year's IP Week.

There is little doubt that the results of the Iraqi election and its aftermath will have profound consequences not just for Iraq but for the whole Middle East region. For the international oil and gas companies it may well determine how welcome or unwelcome their investment ambitions for the area are in the short to medium term. On Tuesday 15 February a morning conference at the Dorchester will address just this question under the title 'Future opportunities in the Middle East and North Africa'.

The opening one-day conference – The Peter Ellis Jones Memorial Conference – on Monday 14 February is a not-to-be-missed global perspective on the most pressing of industry concerns and developments. Industry leaders will provide key insights, talking to the title 'Fighting for energy: geopolitics of oil and gas'.

Facilitating further conversation and networking is a drinks reception at the end of the conference. In addition, there will also be an opening night drinks reception at a separate venue. A key feature of IP Week is the social activities and the networking opportunities they provide. They are also very enjoyable.

Russian reconstruction

One of the key developments this last year has been the slow, semi-legalistic destruction of Yukos. Russian government intentions have been pretty opaque, but it is now becoming clear that the intention really is to reconstruct a massive state-dominated energy company, to be based around the merged Gazprom and Rosneft with generous helpings of ex-Yukos assets. Another clear implication is that all other companies operating in Russia will in future be beholden to, dependent on, or directly involved with the new Russian state energy behemoth.

The hope that operating in Russia would be like operating anywhere else, or that western-style private energy companies were evolving, has clearly been crushed, at least for the moment. A recent press visit to Russia (see p18) clearly shows the way that Gazprom rewards western consumers with reliable supplies because they pay on time, but is prepared to punish those who are tardy in paying (Belorussia, Ukraine) while retaining its strong social obligations to Russian consumers. In short, a corporation that seeks to maximise revenues from reliable exports but retains the primary objective of advancing Russian interests.

However, the sheer scale of Gazprom/Rosneft's investment requirements, now for oil as well as gas, means that close involvement with western corporate interests is inevitable – the challenge being for companies to negotiate terms that are in line with western business requirements. On Tuesday 15 February an all-day conference will address all aspects of 'Exporting oil and gas from Russia and the CIS' and will provide first hand experience of the challenges of operating in the region.

The final conference of the week, on Thursday 17, addresses another key area of industry activity – transportation by pipeline and tanker.

This listing of IP Week's attractions is by no means comprehensive, but hopefully will encourage readers to log onto **www.ipweek.co.uk** to view a comprehensive run down of all that will be going on.

However, no mention of IP Week could ignore the Annual Dinner at the Grosvenor House Hotel on the evening of 16 February. This year the Guest of Honour and Speaker is Lee Raymond Chairman and Chief Executive of ExxonMobil. His company has over recent years been, publicly, very clear about the challenges facing the industry (see p4) and his speech promises to be most interesting.

Chris Skrebowski

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

E-DATA

The Supplementary Compensation Fund to the International Oil Pollution Compensation Fund 1992 will enter into force on 3 March 2005. This follows the ratification of the Supplementary Fund, adopted in May 2003, by eight states – Denmark, Finland, France, Germany, Ireland, Japan, Norway and Spain. The Supplementary Fund will raise the maximum compensation for any oil pollution incidents in signatory states from $314mn to $1,159mn. IOPC Funds has also issued a product database and calculator to help states and potential contributors in the identification and reporting of contributing cargo under the HNS Convention. The Secretariat is planning to set up a dedicated website for the system where users will be able to access relevant parts of the system. More information will be available at **www.iopcfund.org**

The UK Trade and Industry Select Committee has published its first report of session 2004–2005 – *The Electricity Distribution Networks: Lessons from the Storms of October 2002 and Future Investment in the Networks* – at **www.publications.parliament.uk/pa/cm/cmtrdind.htm**

The Global Training and Education Partnership (GTEP) is a new body that aims to increase the UK's share of the international market for training and education in the oil, gas, petrochemicals and associated industries. Quality control and accreditation schemes guarantee that the training available from UK providers is of the highest standard. Supported by UK Trade & Investment, GTEP is an industry sector partnership between the Association of British Offshore Industries (ABOI), the British Oil Spill Control Association (BOSCA), the Energy Industries Council (EIC), the Pipeline Industries Guild (PIG) and the Society of British Gas Industries (SBGI). For more information, visit **www.gtep.org.uk**

With the UK energy market at its most dynamic it is worth shopping around to find out whether or nor you have the best deal for your home energy. The actual differences in price between the lowest and highest suppliers can be substantial. If you wish to compare the energy prices of every single gas and electricity supplier in the UK, visit **www.energylinx.co.uk/energycalc.html?db=dual**

www.energylinx is a free, impartial online and phone-based domestic energy comparison service. Domestic consumers are able to view the whole energy market in a transparent form from their own home. They can compare by price, green energy rating, electricity label, customer service standard or any combination.

UK

ExxonMobil subsidiary Mobil North Sea Limited (MNSL) has produced first gas from the Arthur field in block 53/02 in the UK southern North Sea.

A total of seven licences have been awarded under the second Faroese licensing round, to eight oil companies organised in five groups or as individual companies. Included among the successful bidders are ChevonTexaco, Statoil, OMV, Dong and Shell.

North Sea rig utilisation ended 2004 up 13.1% from a year earlier at 81.7% in December, close to the September high of 84.1% and with every prospect of making further gains, according to Platts' North Sea Letter *data.*

Dr Alison Goligher, Vice President of Production, Schlumberger, was awarded an OBE in the 2005 New Year's Honours List for services to the oil and gas industries. MBEs were awarded to Robert Creswell, Corporate Affairs Manager, Coolkeeragh Power, for services to the energy industry, and Roger Dangerfield, for services to health and safety in the offshore industry.

Wingas of Germany has acquired Saltfleetby, the largest onshore gas field in the UK, from the Australian Roc Oil Company for £44mn.

BP has been given permission to develop the Farragon oil discovery in North Sea block 16/28.

EUROPE

ExxonMobil (32%) has participated in an extensive upgrade programme at the Statoil-operated Sleipner West field that will boost estimated recoverable resources by approximately 350mn boe and help keep Sleipner West's gas production at its plateau level of around 775mn cf/d.

Lundin Petroleum is to sell its 12.5% participating interest in the Seven Heads gas project and certain other offshore Irish oil and gas assets to Island Oil & Gas.

ConocoPhillips has signed a memorandum of understanding with Gazprom that will allow the two companies to undertake a joint study on the development of the Shtokman gas field in the Barents Sea. The Shtokman field is estimated to contain more than 100tn cf of gas.

North American first for Anadarko

Anadarko Petroleum has completed a complex natural gas transportation project beneath the Buckinghorse River in north-eastern British Columbia, which is currently delivering 9mn cf/d of previously stranded gas.

Two wells were drilled horizontally to a depth of 4,600 ft (1,400 metres), beginning nearly two miles apart on opposite sides of a 1,000 ft-deep, steeply sloping and unstable river gorge. The wells intersect beneath the river and were guided by data from a magnetic source on the drilling assembly in the south well and a magnetic receiver on the drilling assembly in the north well. The distance between the wells and the depth to which they were drilled make this project the first of its kind in North America, reports the company.

A conventional pipeline crossing either under the river or across the top would have been a significant technical and economic risk, with little chance of success due to slope stability issues on either side of the gorge.

In addition to making the crossing feasible, drilling horizontally beneath the river also required less of a footprint on the land than a conventional crossing, as no pipeline right-of-way was required.

Since 1999, Anadarko has drilled five exploration wells on the north side of the Buckinghorse River and plans to drill four exploration wells in the upcoming winter drilling season. The company holds approximately 60,000 net acres in the Buckinghorse area with an estimated 200bn cf of potential resource. The newly completed river crossing has the capacity to transport up to 30mn cf/d of gas. Current volumes go to the nearby Caribou gas plant in Jedney, which has another 42mn cf/d of existing gas processing capacity available. On the south side of the river in Anadarko's Jedney area, the company plans to drill three exploration wells this winter that would also flow to the Caribou plant.

Green light for Alpine satellite fields

ConocoPhillips (78%) and Anadarko Petroleum (22%) have approved the development of two Alpine satellite oil fields on Alaska's North Slope. The project will include two satellite drill sites – CD 3 on the Fiord oil field, and CD 4 on the Nanuq oil field. Both will be located within an 8-mile radius from the ConocoPhillips-operated Alpine oil field on the border of the National Petroleum Reserve in Alaska.

Plans call for the drilling of approximately 40 wells, with first production scheduled for late 2006 and peak production of approximately 35,000 b/d in 2008. The satellite oil fields will be developed exclusively with horizontal well technology and employ enhanced oil recovery, similar to the Alpine field.

The oil will be processed through the existing Alpine facilities. Originally estimated to produce 80,000 b/d, the Alpine field is currently producing an average of 115,000 b/d. Combined production from the Alpine field and these two satellites is expected to peak at 135,000 b/d in late 2007.

***Petro-Canada has awarded the main** fabrication and installation contract awards for the De Ruyter oil field development in North Sea blocks P10 and P11b on the Dutch Continental Shelf to Heerema Zwijndrecht and Allseas. First oil is expected in 2H2006. Peak production of around 25,000 to 30,000 b/d is forecast for 2007.*

EASTERN EUROPE

***The International Finance Corporation** (IFC), of the World Bank, is investing $25mn into London-based Melrose Resources to support its oil and gas operations in Galata, Bulgaria, and El Mansoura, Egypt, writes* Keith Nuthall. *Galata is Bulgaria's first private upstream oil and gas project.*

NORTH AMERICA

***Eni has made a new oil discovery with** the Allegheny South exploration well in Green Canyon block 298 in the Gulf of Mexico. Reserves are put at 20mn boe.*

***Talisman Energy has commenced pro**duction from the Brazion deep natural gas well in the Monkman area of north-eastern British Columbia. It is currently producing sales gas at rates of up to 66mn cf/d.*

***Woodside Energy (90%) has formed** an alliance with Explore Enterprises (5%) of Louisiana to jointly conduct exploration, acquisition, development and production activities in the US Gulf of Mexico.*

MIDDLE EAST

***OMV (34%) has made its first oil dis**covery in Iran's western region of Zagros. The well, drilled in the Mehr exploration block in Khuzestan Province, tested at 1,040 b/d of 22° API oil.*

***Shell has signed agreements with the** Government of the Sultanate of Oman which extend the term of Petroleum Development Oman's (PDO's) block 6 concession for a further 40 years to 31 December 2044.*

RUSSIA/CENTRAL ASIA

***Lukoil-Perm has secured the rights to** develop the Alexandrovskoye field located in Russia's Kungur district (southern part of Perm region). Peak production of 70,000 b/d is planned as early as 2006.*

ExxonMobil looks at new resources

ExxonMobil Senior Vice President Stuart McGill recently told financial analysts in New York that the company is uniquely positioned to meet the challenge of adding new resources and reserves to address an increasing global energy demand. McGill cited ExxonMobil's financial strength, largest resource base among international companies, and technological expertise as characteristics that will enable the company to continue to outpace the competition.

McGill noted that world demand for oil and gas is expected to increase by 1.7%/y, while the world's oil and gas fields on average are declining in production at a rate of 4% to 6% annually. This base decline, coupled with the growing demand for oil and gas, means that the amount of new daily production needed in 2020 is nearly equivalent to replacing all of today's daily production. 'This is both an enormous challenge for the energy industry and an opportunity for those companies with the right capabilities,' McGill said.

All work stops on Greater Sunrise project

It seems unlikely that the 7.8tn cf of gas reserves in the $5bn Greater Sunrise project in the Timor Sea will be developed for at least a decade after project operator Woodside said that no more money was being committed to the development and that employees working on Sunrise had been reassigned. The company called a halt to work on Sunrise after the East Timorese government refused to present to its parliament for ratification an agreement it signed with Australia in 2003 covering legal and fiscal terms for the Greater Sunrise development. The agreement would have split revenues from the project 80:20 between Australia and East Timor.

However, since the initial agreement, East Timor has been pushing for a higher percentage of the revenues. Resolution of the dispute became even more difficult after revenue sharing at Greater Sunrise was linked to determining a maritime boundary between the two countries. The argument came to a head in October 2004, when East Timor called for the facilities to develop the gas to be located within its borders rather than in Australian-controlled territory as proposed by the Greater Sunrise partners Woodside, ConocoPhillips, Shell and Osaka Gas.

More than $200mn has been invested to date on Greater Sunrise. However, without an agreement with the East Timorese guaranteeing legal and fiscal certainty the partners are unable to sign long-term supply contracts that would underpin development costs.

In other news, East Timor is reported to be planning to set up a national oil company that will participate in the licensing round for several onshore oil blocks that is scheduled in April. It is understood that the final decision as to whether the new energy company will be a state or private operation has yet to be made. The East Timorese Parliament passed a new petroleum law at the end of 2004, which is aimed to encourage foreign companies to bid for oil and gas exploration licences in the areas in which it has exclusive jurisdiction. The licensing round will not include the area under dispute with Australia.

Malaysia-Thailand gas sales deal

Amerada Hess reports that an agreement has been reached to secure future natural gas sales from block A-18 of the Malaysia-Thailand Joint Development Area (JDA). The agreement also provides for the acceleration of natural gas sales from the block. Amerada Hess and Petronas Carigali each own a 50% interest in the block A-18 production sharing contract (PSC). Under the agreement, initial natural gas sales will be accelerated to commence during 1Q2005 and will average 200mn cf/d for 2005. In 4Q2005, gas sales are expected to increase to 390mn cf/d, when the buyers' gas separation plant is completed. Phase 1 gas sales of 390mn cf/d commence on 1 January 2006 for a period of 20 years. Phase 2 natural gas sales, involving the delivery of an additional 400mn cf/d, will commence in 1H2008 for a 20-year period. Under Phase 3, the sellers have an option to deliver additional natural gas volumes commencing between 2010 and 2012, subject to further drilling success on block A-18.

Amerada Hess estimates that net production from block A-18 will exceed an average of 55mn cfe/d in 2005 and 140mn cfe/d in 2006.

In exchange for the acceleration of additional phases of natural gas sales, the sellers have agreed to release the buyers from prior take-or-pay obligations and to reduce the base price associated with Phase 1 production by 5%.

***Caspian Holdings has identified seven** new wells to be drilled in a bid to optimise production from the Zhengeldy oil field onshore Kazakhstan.*

ASIA-PACIFIC

***China National Petroleum Corporation's** (CNPC) Chuanyu field is reported to be the first field in south-west China to produce more than 10bn cm/y of gas. Production is forecast to rise to 13bn cm in 2007 and 15bn cm in 2010.*

***The Indian government has put out to** tender 20 oil and gas blocks as part of a drive to increase oil production to meet its burgeoning economy. Oil Minister Mani Shankar Aiyar is reported to have said that he expects a strong response from foreign companies.*

***India is understood to have proposed a** wide-ranging alliance with Malaysia to explore and develop oil and gas fields in Iran, Russia and elsewhere as part of a plan to build an Asian partnership on energy security.*

***CNOOC has completed its acquisition** of an equity interest in the North West Shelf Gas Project in Australia, which is to supply LNG over a 25-year period to the Guangdong LNG terminal in China, beginning in 2006. CNOOC now holds a 25% stake in the China LNG joint venture, a new joint venture established within the NWS Gas Project, as well as a 5.3% interest in certain production licences.*

***Amerada Hess has finalised an agree**ment for the sale of gas from the Ujung Pangkah field, located in the East Java area of Indonesia. The agreement provides for the supply of 440bn cf of natural gas from the Pangkah field over a 20-year period at an expected plateau rate of 100mn cfld (gross). First gas is expected to be delivered at the end of 2006.*

***The Indian Petroleum Minister is** reported to have stated that India has oil reserves to last only until 2016 if no new discoveries are made and production remains at 2001–2002 levels. As on 1 April 2004, recoverable oil plus oil equivalent of gas reserves were put at 1,658mn tonnes.*

LATIN AMERICA

***A farm-in agreement has been signed** between Statoil and Total Oil and Gas Venezuela for block 4, part of the Plataforma Deltana area of the Venezuelan continental shelf, giving*

Norwegian licensing round awards

The Norwegian Ministry of Petroleum and Energy awarded 21 companies offers to rights and operatorships in a total of 28 production licences in the North Sea, Haltenbank in the Norwegian Sea, and around the Snøhvit field in the Barents Sea. The companies received offers for participation stakes in a collective total of 55 blocks and parts of blocks.

Among the successful bidders, Norsk Hydro has been granted five new operatorships in the Norwegian government's round of licence awards in mature offshore areas.

Petroleum Geo-Services' wholly-owned subsidiary, Pertra, secured operatorship and 45% participation in production licence (PL) 337, including blocks 15/11, 15/12 (part) and 16/10 (part); 20% participation in PL 332, including block 2/2 stratigraphic division; 35% participation in PL 343, including blocks 29/9, 30/7 and 30/10 (part); and 35% participation in PL 349, including blocks 6407/11 and 6407/12 (part).

PGS reports that it is particularly pleased that Pertra was awarded operatorship of PL 337, which is located north of the Varg field in block 15/12. Pertra is currently the operator of Varg, holding a 70% interest; co-venturer Petoro holds the remaining 30%.

Lundin Petroleum was awarded interests in three exploration licences –100% of production licence (PL) 338 in block 16/1 (part); 18% in PL 335 operated by BG), containing blocks 7/4 (part), 7/7 (part) and 7/10; and 15% in PL 340 (operated by Marathon), containing block 24/9 (part) adjacent to the companies' 2004 Hamsun discovery and the ongoing Alvheim development.

West Salym first oil

Salym Petroleum Development (SPD) has commenced oil production from wells in West Salym, the largest of the Salym fields in Western Siberia – a year ahead of schedule. The oil produced from the initial wells will be exported by road tankers from West Salym to Upper Salym for further shipment to customers. This will continue until the central processing facility (CPF) in West Salym and the oil export pipeline have been commissioned.

SPD is a 50:50 joint venture between Shell and Evikhon, the latter controlled by Sibir Energy. SPD holds production licences for all three of the Salym fields – West Salym, Upper Salym and Vadelyp – which are located in the Khanty-Mansiysk Autonomous Okrug in Western Siberia. Production from Upper Salym has already begun, while Vadelyp is due onstream in 2006. West Salym output is expected to peak at some 120,000 b/d by 2009.

Middle East news

Stella Zenkovich writes that Kuwait will invest around $10bn in oil projects within its strategic plan that expires in 2020, according to Minister of Energy Sheikh Ahmad Al-Fahad Al-Sabah.

In other news, Canada's Dublin International has signed a $22mn, 20-year contract to drill eight oil wells in two phases and relaunch 14 others in Hasaka Province, 700 km north-east of Damascus.

Meanwhile, Saudi Arabia plans to raise its oil production capacity to 12.5mn b/d from the current 11mn b/d over the next few years, according to Petroleum and Mineral Resources Minister Ali Al-Naimi.

Mumbai-based Reliance Industries of India has set its sights on acquiring deepwater oil and gas blocks in the Gulf of Oman and is looking for oil assets in Qatar. Petroleum Development Oman, which is 34% owned by Shell, expects Omani output of crude oil to fall by 2% this year to about 635,000 b/d, continuing the past three years of decline.

ConocoPhillips pulls out of Arctic Power

ConocoPhillips has dropped out of Arctic Power, the single-issue lobbying group that promotes opening the coastal plain of the Arctic National Wildlife Refuge (ANWR) for oil and gas drilling. The decision by the Houston-based company means that the two largest operators on Alaska's North Slope – BP and ConocoPhillips – are no longer members of the Arctic drilling lobby group.

Over the last two years, ConocoPhillips' shareholders and environmentalists have pushed the company to address the risks associated with drilling in the coastal plain of the Arctic Refuge. An Arctic Refuge shareholder resolution filed by Green Century received more than 9% of the shareholder vote in May 2004. Green Century refiled the Arctic Refuge resolution in December 2004, but offered to withdraw the resolution if the company dropped out of Arctic Power.

BP dropped out of Arctic Power in November 2002, after a similar campaign by the PIRG Arctic Wilderness Campaign, the World Wildlife Fund and Green Century.

Total a 49% equity interest. Statoil will remain operator, with 51%. Upon declaration of commerciality, state oil company PdVSA has the right to back-in to an interest of up to 35% in the project.

***Talisman Energy reports that the** Angostura field offshore Trinidad and Tobago has come onstream. The company is to drill its first onshore wells in Trinidad and Tobago later this year, on the Eastern block where it holds a 65% working interest. Work will also continue to commercialise the Angostura natural gas reserves.*

***Repsol YPF has reached an agreement** with the Venezuelan Ministry of Energy and Mines and PdVSA to increase natural gas production at the Quiriquire block, in the state of Monagas, by 20,000 boe/d, up from the current 240mn cf/d.*

***BP Trinidad and Tobago (bpTT) has** made a significant gas discovery off the east coast of Trinidad. The well, located in East Mayaro licence area, penetrated 1,400 ft of gas bearing sands in four main reservoirs. According to an announcement by RepsolYPF the discovery holds 360mn boe and is called Chachalaca.*

AFRICA

***Lundin Petroleum is to acquire a** 22.5% interest in oil mining lease (OML) 113 offshore Nigeria containing the Aje oil and gas discovery. Partners are YFP, Syntroleum, Palace Exploration, Challenger Minerals, Providence Resources and Howard Energy. It is planned to drill the first appraisal well, Aje-3, in the second or third quarter of 2005.*

***ChevronTexaco (55%, operator) has** discovered oil in four exploration wells in offshore Cambodia block A.*

***As Nigeria's countdown to a new bid** round for oil blocks begins in 1Q2005, the federal government is to reduce the size of 27 deepwater blocks that are to be put on offer in the continental shelf of the Niger Delta, Benin, Anambra, Chad Basins and Benue Trough, reports* Stella Zenkovich. *The block sizes are to be reduced to 1,250 sq km from the original 2,500 sq km.*

***Of the 122 companies that registered** to apply for oil and gas exploration permits under the latest Libyan government licensing programme, 63 have been given the green light to submit bids, writes* Stella Zenkovich. *The list includes BP, Shell, ChevronTexaco, ConocoPhillips and ExxonMobil.*

Another fall in UK oil production

UK oil production of 1,532,502 b/d in September 2004 represented a significant decline with production down by 5.5% on the month and 22.1% on the year, according to the December Royal Bank of Scotland *Oil & Gas Index*. September's oil production was the lowest monthly average since May 1991.

Gas production, at 9.017mn cf/d, was up 2.5% on the month but decreased by 5.5% on the year.

Year Month	Oil production (av. b/d)	Gas production (av. mn cf/d)	Av. oil price ($/b)
Sep 2003	1,966,800	9,546	26.81
Oct	2,018,972	10,075	28.93
Nov	2,036,012	12,641	28.76
Dec	2,056,469	12,642	29.84
Jan 2004	2,014,906	12,689	31.12
Feb	1,972,891	11,220	30.89
Mar	2,006,160	11,787	33.72
Apr	1,964,905	12,181	33.36
May	1,778,979	9,218	37.72
Jun	1,776,246	10,192	35.21
Jul	1,758,312	10,269	38.15
Aug	1,621,582	8,800	42.99
Sep	1,532,502	9,017	42.92

Source: The Royal Bank of Scotland Oil and Gas Index

North Sea oil and gas production

First production from Bomboco field

ChevronTexaco's Angolan subsidiary, Cabinda Gulf Oil Company (CABGOC), has achieved first oil from the Bomboco field in its operated block 0 concession offshore Malongo, Cabinda province. Bomboco is expected to reach an average daily production of 30,000 barrels of oil within the next year and is an integral component of CABGOC's Sanha condensate project.

The Sanha processing facilities first received condensate from surrounding fields in December 2004 and first gas injection is expected to occur in late January. Condensate production from the Sanha field is scheduled to start early in 1Q2005 and first LPG production from the Sanha FPSO vessel is forecast for early in the second quarter. Combined Sanha and Bomboco peak production of an estimated 100,000 b/d of oil and LPG is anticipated in 2007. Of particular importance, Sanha operations will significantly reduce gas flaring in block 0, reports ChevronTexaco, by up to 50%.

UK government moves forward with e-agenda

The first digitally signed chemical consent for the Shell Shearwater platform was completed on 11 January 2005. In a major step forward for the UK government's e-agenda, the whole process was conducted electronically between Shell, the DTI and all other interested parties using the UK Oil Portal. The final consent is held digitally in legally admissible form within DTI.

The UK government has set challenging targets for making all government services available electronically by 2005. The Licensing and Consents Unit of the DTI intends to implement these targets via the UK Oil Portal – **www.og.dti.gov.uk/portal.htm** –using the Internet. Oil companies will be able to apply for all their consents online and will also be able to deliver regular reports online.

The Portal will introduce a significant change to all business processes in that all the work will be completely paperless. There will be a number of advantages for the oil industry. It will be the focus for all government interaction for approvals and consents and these should be processed more efficiently and quicker than at present. It will also significantly reduce the need for physical storage and handling of paper.

One element of this involves the need for authenticated communication in and out of the UK Oil Portal in a number of associated electronic transactions. As an example, the scope of the UK Oil Portal will allow companies to apply online for permission to conduct oil related activities in the UKCS and to receive their legal consent via the UK Oil Portal. These electronic consents are authenticated with a digital certificate on behalf of the Secretary of State and stored automatically within the DTI's electronic document filing system, accredited to the correct level to be legally admissible.

UK

Foster Wheeler subsidiary Foster *Wheeler Energy has formed a new oil and gas division, headquartered in Reading, UK.*

EUROPE

BP has begun construction of a 9-MW *wind farm at its oil terminal in the port of Amsterdam, The Netherlands. The project will have capacity to provide sufficient electricity for some 5,000 Dutch homes and displace 5,000 tonnes of carbon dioxide.*

Shell and Repsol YPF have signed a sale *and purchase agreement relating to the divestment of Shell's LPG business in Portugal for an undisclosed sum. Shell will continue to operate in Portugal through its lubricants business and the Madeira distribution terminal (Madeira Praia Formosa). The divestment includes the assets of two LPG filling plants, more than two million cylinders, supply, distribution and customer contracts covering mainland Portugal and the islands of Madeira and Azores. The deal gives Repsol YPF a 21% market share.*

Fortum has acquired an additional 6% *of shares in Finnish company Gasum Oy for 40mn, increasing its overall stake to 31%.*

NORTH AMERICA

Freeport LNG Development has *awarded Technip, in a joint venture with Zachry Construction and Saipem, an EPC contract for a new LNG receiving terminal to be built on Quintana Island, near Freeport, Texas in the US. The terminal will have a capacity of 1.5bn cf/d and is due to be commissioned in 2008.*

Vancouver-based Ivanhoe Energy is to *buy Boston's Ensyn Group for $85mn, resulting in Ivanhoe gaining full ownership of Boston-based Ensyn Petroleum International, of which it already owns 15%, reports* Monica Dobie.

The US Federal Energy Regulatory *Commission (FERC) is reported to have given construction approval for the Sabine Pass LNG receiving terminal at Cameron, near Port Arthur, Texas, following an environmental impact study.*

Sempra Energy has awarded the Aker *Kvaerner and Ishikawajima-Harima*

Key peace agreement in Sudan

Lundin Petroleum reports that a comprehensive peace agreement has been signed that puts an end to the 21-year long war in Sudan. The main terms of the agreement are that, immediately upon the signing of the agreement, an initial six months pre-transition period will come into effect, a period which is to be used to put in place measures necessary to execute the agreement. A transition period of six years will follow during which the South will enjoy autonomy. At the end of this period, the South will decide by referendum whether it wants to secede or remain within a united Sudan.

A power and revenue sharing scheme has also been agreed to, whereby resources will be shared on a 50:50 basis, while power will be shared on a 70:30 basis in favour of the central government (55:45 in the formerly disputed areas of Abyei, Blue Nile and Nuba Mountains). There have been indications that the resource sharing scheme will take place immediately, which means that 50% of oil revenues should accrue to the South straight away.

The agreement is also understood to contain provisions to exempt the South from Sharia law (the status of Khartoum to be decided by the elected assembly) and to merge the armies at the end of the six-year period, should the South choose to remain within a united Sudan.

Oil spill alliance first

Petroval, a leading Swiss-based oil trader for crude and refined products originating from the Russian Federation, and Oil Spill Response Limited (OSRL), the world's largest international oil spill response company, have signed a landmark agreement confirming Petroval as a full participant member and shareholder in the Global Alliance.

The agreement, which guarantees 24 hour, 365 days-a-year global response to an oil spill incident covers Petroval and also embraces Yukos and its subsidiaries, including the Lithuanian oil refiner Mazheikiu Nafta. Through this membership Yukos becomes the first Russian oil company to join the OSRL/EARL Global Alliance.

The OSRL/EARL Global Alliance – which provides expertise and equipment to help prevent, or help with cleaning up, oil spills on land or sea – is operated as a not-for-profit cooperative owned by 27 of the major international oil companies covering all parts of the globe.

Caspian pipeline plans

The five countries planning to build a crude oil pipeline linking the Romanian Black Sea port of Constanta to Italian Adriatic ports have declared the initial route changed and have increased the annual transport capacity from 10mn to 60mn tonnes, reports *Stella Zenkovich*. Representatives of Romania, Serbia, Montenegro, Slovenia, Croatia and Italy said that, following a feasibility study, the link with the Croatian crude oil terminal of Omisalij has been dropped amid environmental issues. A direct route through Croatia and Slovenia to the Italian port of Trieste has been selected in preference. At that point, the pipeline will fork in to two, with one route to be connected to the Trans Alpine Pipeline fuelling Austria and Germany, with the other arm going to Venice to supply oil refineries located in northern Italy.

The 1,360-km pipeline – named 'The Pan European Pipeline' – is seen as the shortest route for getting Caspian crude oil to western markets.

Certified emissions reductions in 2004

New York-based Natsource reports that it has finalised commercial terms for over 10mn certified emission reductions (CERs) created by candidate clean development mechanism (CDM) projects in late 2004. The CERs were created from five different activity types – hydro, wind, HFC destruction, landfill and waste heat recovery – and are located in India, South Korea, Bolivia and China.

The transaction structures incorporate a mix of different risk management techniques to address credit counter-party and carbon-related delivery risks in a way that achieves buyer and seller objectives. The deals provide a range of financial arrangements, including pre-payments, payments on delivery and a blend of each.

Natsource has also unveiled plans for the first close of its Greenhouse Gas Credit Aggregation Pool (GG-CAP), also known as the Buyers' Pool. This pool is claimed to be one of the world's first private sector carbon investment vehicles. It will purchase low-cost, high-quality emission reductions that buyers can use to comply with mandatory greenhouse gas reduction obligations from 2005 to 2012. At present, Natsource has commitments from six companies in Europe, Japan and Canada to participate and is in negotiations with several other businesses.

Heavy Industries (IHI) consortium (AK/IHI) a contract for the engineering, procurement and construction of the Cameron LNG regasification terminal in Louisiana, US. The $700mn facility will process 1.5bn cf/d of gas.

MIDDLE EAST

Iran and South Africa have reached a *preliminary agreement on the price of gas needed for a GTL (gas-to-liquids) facility that is part of the development project for phase 14 of South Pars gas field in Iran, writes* Stella Zenkovich.

Technip, in consortium with Al Jaber *Energy Services, has been awarded a $62mn lump sum turnkey contract by Dolphin Energy for a new terminal to receive and distribute gas from Qatar to the United Arab Emirates.*

RUSSIA/CENTRAL ASIA

ConocoPhillips has increased its stake *in Lukoil to 10%.*

Lukoil has closed a deal to acquire Eni *Group's 50% interest in LukAgip.*

ASIA-PACIFIC

China's National Development and *Reform Commission is reported to have approved PetroChina's proposal to build a 3.5mn t/y LNG import terminal at Rudong, in East China's Jiangsu Province, at a cost of some $2.4bn. The terminal will receive up to 3.5mn t/y of imported LNG.*

CNOOC has signed an agreement with *Shenergy Group for the development of a 6mn t/y capacity LNG import terminal in Shanghai.*

LATIN AMERICA

ChevronTexaco has been awarded a *permit from the Regulatory Energy Commission for a proposed natural gas import terminal off the coast of Baja California, Mexico. The terminal will be designed to have an initial capacity of 700mn cf/d of natural gas.*

FPL Group has agreed an option to *buy development rights to El Paso's proposed South Riding Point terminal, while Tractebel has announced that it will drop its Freeport terminal plan for a holding in the FPL site. The projected capacity is some 6mn t/y, with start-up planned for 2008.*

Qatargas II project developments

Qatar Petroleum (70%) and ExxonMobil (30%) have commenced a number of significant activities to advance the $12bn Qatargas II project, which will supply LNG from Qatar to the UK by the winter of 2007/2008. The gas will be sourced from Qatar's giant North field, which has estimated recoverable natural gas resources in excess of 900tn cf.

Several milestones have been reached that are critical to the implementation of the project, which is the largest integrated LNG project ever undertaken. These include:

- **Letters of authorisation have been signed with engineering, procurement and construction (EPC) contractors for the construction of platform topsides, pipelines and two 7.8mn t/y LNG trains at Ras Laffan Industrial City in Qatar that are claimed to set new standards for scale and efficiency.**
- **Qatargas II and South Hook LNG Terminal Company have signed financing documents securing funds to execute the project. Qatargas II entered into funding agreements totalling $6.5bn of debt and South Hook LNG Terminal entered into funding agreements totaling £600mn. In total, $7.6bn has been raised from 57 institutions – reportedly the largest energy project financing ever and the first ever financing on a full LNG chain-integrated basis.**
- **Two new companies have been formed to manage the LNG importation, terminal operations and sales of natural gas to ExxonMobil Gas Marketing Europe for sale, in turn, to UK markets.**
- **A $700mn EPC contract has been awarded to Chicago Bridge & Iron of Texas, US, to construct the first phase of the receiving terminal at Milford Haven in South Wales.**
- **Twenty-five-year time charters for eight LNG transport ships (209,000–216,000 cm) have been signed with two consortiums – ProNav-Commerzbank-Qatar Gas Transport Company and Overseas Shipholding Group-Anglo Eastern-Qatar Gas Transport Company. These state-of-the-art vessels will be 50% larger than conventional LNG ships, providing additional project economies.**

News from the European Union

While discussions continue over how to ensure the security of energy supplies to the European Union (EU), Brussels institutions are sinking money into one sure bet – eastern Europe and the former Soviet Union, writes *Keith Nuthall*. The European Bank for Reconstruction and Development (EBRD), for instance, is lending $170mn to Socar, the state oil company of Azerbaijan, to fund two Caspian gas projects. Some $110mn will help develop the Shakh Deniz gas field and $60mn the South Caucasus gas pipeline that is being built alongside the Baku-Tbilisi-Ceyhan oil pipeline.

Meanwhile, the EBRD is also securing a 2% stake in Romanian oil giant Petrom, converting debt into equity. The company is 51%-owned by Austrian oil and gas company OMV. More is being sold off and the bank said its presence should ensure 'continued transparency of the privatisation process'. Further east, the EBRD is trying to conserve Russian gas supplies with its largest energy conservation loan – $160mn to chemical giant TogliattiAzot. The company consumes 1% of Russia's domestic gas supply for fuel and ammonia production. Energy efficiency improvements funded by the loan would, said the bank, save gas equivalent to the monthly consumption in Switzerland or Greece.

In other EU news:

- Belgium, Britain, Greece, France, Italy, the Netherlands, Austria and Finland are being taken to the European Court of Justice (ECJ) for failing to implement EU legislation on vessel traffic monitoring and information systems framed following the *Erika* tanker accident.
- The Commission has cleared sole control by BP of HDPE, its high-density polyethylene joint venture with Belgian chemical company Solvay.
- Norway has notified the European Free Trade Area (EFTA) Surveillance Authority that it intends to cut its carbon dioxide taxes on mineral oils and basic heating oil for the paper and pulp industry until 2011.
- Brussels has issued a web database on EU legislation harmonising rules on appliances burning gaseous fuels – **www.europa.eu.int/comm/enterprise/newapproach/standardization/harmstds/reflist/appligas.html**
- The EFTA Court has clarified how EU employment law applies to complex deals amongst oil and gas companies operating within the Norwegian and British sectors of the North Sea. The court, for instance, said that a company had duties under transfer of undertakings directive 77/187/EEC towards staff transferred to another business, even where employees had opposed a takeover or sale.

UK

RWE npower is reportedly planning to *build a 2,000-MW natural-gas-fired power station at Pembroke in South Wales.*

Foster Wheeler has been awarded a *contract by Total UK for detailed engineering, procurement services and construction management support to debottleneck and improve the energy efficiency of Total's refinery at Milford Haven in the UK.*

Centrica has signed a long-term *power purchase agreement with NM Renewable Energy, a joint venture between Macquarie Bank and Novera, which will deliver approximately 300 GWh of green electricity to British Gas customers every year, enough to supply around 60,000 homes. The agreement, commencing in April 2005, will run for more than ten years, meeting approximately 5% of Centrica's rising renewables obligation. Electricity supplied to British Gas customers will be delivered from a diverse range of renewable sources including hydro-electric, landfill gas and an onshore wind farm.*

ScottishPower increased its online *domestic electricity and gas prices on 7 December 2004. This latest price increase came within a week of ScottishPower announcing that was to commence charging 135,000 gas customers who are on a non-Transco gas network an extra £40/y. Although ScottishPower does have to pay this additional charge to the Independent Gas Transporters (IGTs) it will, however, net the company a further £5.4mn/y.*

EUROPE

The Norwegian Ministry of Petroleum *and Energy has granted Statnett a licence to organise and conduct power exchange between Norway and the Netherlands. Statnett and the Dutch state-owned system opertor TenneT plan to build and operate a high-voltage interconnector between Norway and the Netherlands. The NorNed cable will boost the Norwegian electricity import and export capacity by 20%, according to Thorhild Widvey, Norwegian Minister of Petroleum and Energy.*

VBi Retail Solutions, which supplies *fuel management systems and retail solutions to forecourts and conve-*

Safety on the forecourt

Left to right: Gillian Black, Commercial Development Manager; David Allan, Deputy Principal; Gareth Bourhill, Maintenance Manager for D H Morris Group and Chairman of the APEA Scottish Board; and John Dallimore, Chairman of the Energy Institute/APEA Electrical Installations Working Group

Monday 29 November 2004 saw the official opening of Falkirk College's new Comp'EX' 07 and 08 Centre in central Scotland – recently accredited to deliver training and assessment to contractors operating in hazardous service station environments. The Centre was officially opened by John Dallimore, Chairman of the Energy Institute/APEA Electrical Installations Working Group, who said: 'With the introduction of the course here at Falkirk College, the number of electricians trained in forecourt work will begin to reach a level where oil companies and private operators will be able to insist on Comp'EX qualifications for those working at their sites, whether it be on new installations, maintenance or inspection and testing.'

Over the last few years there have been major steps taken in the downstream retail industry to prove that all those working on forecourts in the UK are 'competent' as far as possible. With the NICEIC delivering its own UKAS accreditation scheme for electrical contractors working in potentially explosive atmospheres, and listing 07/08 as the minimum standard of training, it is becoming a pre-requisite for many duty holders, particularly with the second edition of the APEA/IP Design, construction, modification and maintenance of filling stations guidance due early 2005.

This qualification can be included in the Electro Technical Certification Scheme (ECS), which will allow employers to ascertain that electrical and instrumentation technicians have achieved technical competence and training in the installation and maintenance of electrical equipment and apparatus in petrol station environments. The course, which is certificated by JTL, the national training agent of the electrical contracting industry, takes five full consecutive days and aims to raise awareness of operative competence and assesses candidates in a simulated, state-of-the-art service station environment.

The UK Health and Safety Executive has supported the College throughout its development. A spokesman commented: 'The necessity for well constructed, properly operated and maintained electrical installations at petrol filling stations is paramount. The possession of a valid Comp'EX certificate will give assurance that the technician has been assessed as to his core knowledge and practical ability to enable him to work safely on electrical equipment used at petrol filling stations. The recently introduced Dangerous Substances and Explosive Atmospheres Regulations emphasised the ongoing need for people to be competent to work in this highly specialised environment.'

Falkirk College is not only the second centre in the UK to offer this training course – the other is run by P&R Hurt, in Yeovil, Somerset – but is also claimed to be the only centre in the UK to offer all eight Comp'EX' units.

For further details and course start dates e: **biz@falkirkcollege.ac.uk** nience stores, has signed an exclusive agreement with County Down-based Forecourt Systems. The new agreement makes Forecourt Systems the exclusive distributor and agent for VBi technology for Northern Ireland and the Republic of Ireland.

EASTERN EUROPE

The Slovak government wants to buy *back its 49% stake in Czech holding Unipetrol to Polish refiner and fuel retail group PKN Orlen, writes* Stella Zenkovich.

Lukoil Europe Holdings, a 100% sub- *sidiary of Lukoil, has made a tender offering to buy 28.89% shares of Lukoil Neftochim Bourgas refinery in Bulgaria. The company already holds a 58% stake in the refinery.*

NORTH AMERICA

BP is to close its linear alpha olefin *(LAO) production facility in Pasadena, Texas, by the end of 2005. The company will continue the manufacture of linear alpha olefins at its other two facilities in Alberta, Canada and Feluy, Belgium. Closure of the Pasadena site will reduce BP's global linear alpha olefin capacity by 500,000 t/y.*

MIDDLE EAST

Foster Wheeler has been awarded *a front-end engineering design (FEED) contract by ENOC Processing Company (EPCL) to upgrade its condensate refinery located in the Jebel Ali Free Zone, Dubai, UAE. The new facilities – which include a new 70,000 b/d per stream hydrotreater, a continuous catalytic reformer and ancillary processing units – will allow EPCL to upgrade its existing naphtha product to a low-sulphur petrochemical naphtha product stream, provide a 102 RON reformate product stream and operate the plant at full capacity using sour condensates. Other new products will include LPG, butane and sulphur.*

Technip has been awarded by Al- *Jubail Petrochemical (Kemya) – a 50:50 joint venture between Sabic and ExxonMobil – a contract for an additional cracking furnace at its ethylene plant in Al-Jubail, Saudi Arabia. The new furnace will enable Kemya to increase its ethylene and propylene production by 110,000 t/y.*

Fuelling recommences at Night Owl truck stops

Independent fuel management company CH Jones has taken over the management of fuel provision at Night Owl's five truck stops, which are some of the UK's key sites for overnight parking and rest facilities.

Night Owl operates five large sites, providing facilities for more than 1,000 trucks each night. These are strategically located along major trunk routes, serving Carlisle, Newcastle, Rugby, Wolverhampton and Alconbury. The sites aim to provide everything a trucker might need on an overnight stop, including motel facilities and restaurants. The fuel pumps had been out of use since the beginning of 2004. However, thanks to this new deal with CH Jones, the company is once again able to offer refuelling facilities to its customers.

BP agrees hydrogen refuelling deal

BP has signed a memorandum of understanding (MoU) with JTC Corporation to cooperate in the development and installation of hydrogen refuelling technology. The MoU marks BP's second hydrogen refuelling station in Singapore. The first was opened at a retail site on Upper East Coast in July 2004, utilising hydrogen produced from natural gas at the local Jurong Island refinery.

The second facility will be located within one-north development, an innovation and research hub. It will differ from the first site in that it will be a stand-alone operation. It will consist of a hydrogen production facility utilising electrolysis technology by Singapore Oxygen Air Liquide (SOXAL) for onsite hydrogen production, compression equipment and a vehicle refuelling dispenser unit located under a canopy. The project should be completed by 2Q2005.

The agreement supports BP's involvement in the Clean Cars for Clean Cities project – a collaborative effort between BP and DaimlerChrysler to support the introduction of pre-commercial hydrogen fuel cell cars and hydrogen fuel infrastructure in Singapore, Los Angeles and Berlin. The initiative started in 2004 for an initial period of up to three years.

IPE volumes continue year-on-year growth

The International Petroleum Exchange (IPE) reports that Exchange volumes during 2004 rose 6.6% over 2003 to 35,540,758 lots. This marks the seventh consecutive year-on-year volume increase for IPE.

IPE's Brent Crude and Gas Oil futures contracts saw overall trading records of 25,458,259 and 9,355,767 lots respectively during 2004, with both contracts establishing new levels for electronically traded volumes.

The Exchange added nine new members with the addition of exclusive electronic Brent Crude trading in the morning session from 1 November 2004. Approximately 26% of the Brent Crude futures volume was traded electronically from 1 November through year end.

RUSSIA/CENTRAL ASIA

Lukoil is to aquire Balt-Trade's 37 ser*vice stations in St Petersburg and Leningrad, increasing its network of outlets in the region to 79. Among the filling stations acquired is Europe's largest site – located on Primorsky Highway in Leningrad – which is equipped with 18 fuel dispensers.*

ASIA-PACIFIC

Shell has announced that it is *progressing to the next phase of its proposed world-scale cracker and derivatives project in Singapore. This phase will result in a detailed design and engineering package for construction to begin in 2006 and start-up in 1H2009. The project will include modifications and additions to the existing Bukom refinery owned by Shell Eastern Petroleum (SEPL), a new world-scale ethylene cracker on Bukom Island and a new world-scale MEG plant utilising Shell's proprietary technology on Jurong Island. Both the cracker and the MEG plant will benefit from integration with Shell's existing investments in Singapore. The project is planned to be a collaboration between Shell and the Singapore Economic Development Board. Detailed discussions will take place in 2005.*

AFRICA

The Indian Oil Corporation (IOC) has *submitted an expression of interest (EoI) to acquire a 51 % stake in the Nigerian government-owned Port Harcourt, Warri and Kaduna refineries in Nigeria, reports* Stella Zenkovich. *Nigeria has spent about \$700mn since 1999 on refurbishing the refineries, which have a combined nameplate capacity of 445,000 b/d. However, problems such as fire, sabotage, poor management, inter-ethnic violence and lack of turnaround maintenance have resulted in the plants operating well below capacity. The Nigerian government now plans to privatise them.*

Honeywell has received a \$60mn con*tract from Algerian oil company Naftec Spa for an automation project at its refinery in Arzew, Algeria. Honeywell plans to modernise the refinery's instrumentation systems with the goals of improving production and optimising operational efficiency. Work is to complete by 2009.*

ChevronTexaco expands Caltex branding

ChevronTexaco reports that Caltex South China Investments Limited (CSCIL) and CITIC Resources Holdings (CITIC) have entered into a preliminary agreement in which CITIC has agreed to invest a majority stake in CSCIL.

This preliminary agreement is part of ChevronTexaco's strategic direction to focus on enhancing and managing three world-class brands – Chevron, Texaco and Caltex. As part of this strategy, Caltex is engaging with local partners such as CITIC to grow its presence in the burgeoning China market. Currently, China has the fastest growing automobile market in the world with double-digit growth expected over the next few years.

President of ChevronTexaco Global Marketing, Shariq Yosufzai, said: 'Partnering with a major business leader like CITIC will allow us to expand our retail network in the world's fastest growing economic region while exploring growth opportunities in commercial and industrial segments.'

CSCIL currently operates a network of more than 40 Caltex-branded service stations in South China through a number of joint venture partnerships.

Petronas acquisition

Petronas is to acquire Kuwait Petroleum (Thailand) (KPTL) from Kuwait Petroleum International, paving the way for the Malaysian oil company to further expand its presence in the retail and marketing sector of the Thai oil and gas industry.

Under the terms of the sales and purchase agreement, Petronas will take over KPTL's retail service station and lubricant businesses, including 117 operational service stations located in major cities in Thailand. About 70% of the stations are located in the Bangkok metropolitan area, while the rest is spread out in other areas of Chiangmai, Nakorn Rachasima and Pattaya.

The acquisition, expected to be completed by the end of January 2005, does not include KPTL's aviation business, which will be handed over to Kuwait Petroleum Aviation (Thailand).

Shell expansion plans

Shell has announced that it is progressing to the next phase of its proposed world-scale cracker and derivatives project in Singapore. This phase will result in a detailed design and engineering package for construction to begin in 2006 and start-up in 1H2009. The project will include modifications and additions to the existing Bukom refinery owned by Shell Eastern Petroleum (SEPL), a new world-scale ethylene cracker on Bukom Island and a new world-scale MEG plant utilising Shell's proprietary technology on Jurong Island. Both the cracker and the MEG plant will benefit from integration with Shell's existing investments in Singapore.

The project is planned to be a collaboration between Shell and the Singapore Economic Development Board. Detailed discussions will take place in 2005.

Dealing with climate change

'Kyoto is an important step, but we need more efforts to promote energy efficiency and new technologies to cope with climate change,' said Claude Mandil, Executive Director of the International Energy Agency (IEA), in Buenos Aires at the UN Conference of Parties on Climate Change (COP 10) in December. 'The entry into force of the Kyoto Protocol is a success for ratifying countries, yet the targets – if they are met – are only a very small contribution towards global climate change mitigation, which requires much stronger worldwide carbon dioxide (CO_2) reductions.' According to IEA statistics, world energy-related CO_2 emissions are now 16.4% above their 1990 level. In 2002 alone, they increased by 2%.

The IEA acts as an advisor for its 26 member countries on energy policies. It projects in the *2004 World Energy Outlook* that measures adopted up to the year 2003 cannot prevent a rapid increase in CO_2 emissions. In a business-as usual scenario, developing countries' emissions are projected to more than double between 2002 and 2030 (from 8.2 Gt to 18.4 Gt CO_2).

IEA analysis of an alternative policy scenario shows that emissions can be curbed, mainly through a strong push on energy efficiency policy, support to renewables and further use of nuclear, for those countries choosing to do so. A 16% reduction in emissions from business-as-usual levels could be achieved worldwide by 2030, with energy efficiency contributing to 60% of this reduction. In this alternative scenario, IEA countries would start a declining emissions trend in the 2020s. But even this alternative scenario does not bring emissions to sustainable levels worldwide in the future.

New LNG terminals – already white elephants?

Photo: © ConocoPhillips

The rush to create LNG regassification plants in North America shows no signs of letting up. But will they arrive only to be too late? **Petroleum Review** *plays devil's advocate.*

Economists have a ready answer for the high price of natural gas currently gripping the North American market – conventional supplies are dwindling and consumption is soaring.

All the numbers seem to back their argument. In a report issued in 2004, Cambridge Energy Research Associates (CERA) noted that North America consumes about 71bn cf/d. Most of this is produced in mature exploration basins, such as the Gulf of Mexico and Western Canada Sedimentary Basin, where fields are in decline. Current production of dry gas from the US's lower-48 states is expected to fall from around 53bn cf/d in 2004 to 50bn cf/d by 2010.

At the same time, long-term demand is rising. A study by the Interstate Natural Gas Association of America (INGAA) shows that US gas consumption will grow from 21.5tn cf in 2003 to 29.7tn cf by 2020. The Energy Information Administration (EIA) expected prices to have averaged \$6.24/1,000 cf by the end of 2004 and forecasts an average price of \$5.95/mn cf in 2005, hovering comfortably thereabouts for the better part of the following decade.

Industry response

The energy industry has responded to the price signals in a variety of ways. Unconventional gas, including coal bed methane (CBM) and tight gas (low permeability reservoirs) are being exploited, deep plays in the Gulf of Mexico are being pursued, and pipelines are being planned to deliver huge stranded reserves from the Arctic.

However, unconventional gas alone will not replace declines in conventional fields, and Arctic gas will not arrive until 2009 at the earliest. In the meantime, a new source will be needed to plug the gap.

That new source is liquefied natural gas, or LNG. At a liquefaction facility, natural gas is run through a succession of refrigeration levels until it reaches approximately –160°C, where it turns into liquid under normal atmospheric pressure. It is then loaded onto insulated carriers and shipped to market. A regassification facility returns it to gaseous form, and it is then injected into the conventional distribution system.

For the last three decades, LNG has been used to move stranded gas from isolated fields (like those in Qatar) to consuming countries that have no indigenous supplies (such as Japan). Typically, the arrangement involves a dedicated chain of liquefaction plants, carriers and regassification facilities, built under long-term contracts.

Formerly, LNG could not compete on price with conventional gas in North America. The cost of liquefaction, transportation and regassification has dropped dramatically in recent years, however, bringing the point of profitability down to as low as \$3/mn Btu – well within the new base price range. Even long-term contracts are no longer seen as necessary to create LNG chains. 'There's a new business model being used by super-majors like Exxon and BP,' says Robert Ineson, CERA's Director, North America Natural Gas. 'They are taking the risks, but their business plans are to envision a situation where LNG starts to look like [the international market for] oil.'

There are four regassification terminals currently operating in North America – Cove Point, Maryland; Elba Island, Georgia; Lake Charles, Louisiana; and Distrigas terminal, Boston Harbor. Together, they have a capacity of approximately 3bn cf/d, with expansion plans to push this total to 5.7bn cf/d.

However, it is the proliferation of proposed regassification plants for North America that has everyone's attention.

Natural Gas Intelligence recently reported 43 greenfield projects in play. The locations fall under three main areas – The Gulf of Mexico, the Pacific Coast, and the north-east US and eastern Canada. Most are sited onshore near major refinery and petrochemical centres, like ConocoPhillip's Freeport development in Texas. Some, such as BHP Billiton's Cabrillo Port near Los Angeles, are planned for offshore. Several, like Sempra Energy's Costa Azul in Baja, Mexico, and Irving's Canaport facility in New Brunswick, Canada, have already been approved. 'Right now, they're lining up upstream to downstream, and it's falling into place, but it takes a good three years and we won't see them until 2008,' comments Ineson. By 2010, there could be 6.9bn cf/d of LNG flowing into the North American system.

Bankers' coronories

But what if they're already too late? What if the window of opportunity is already closing?

In spite of the glowing prospects for natural gas in North America, a doomsday scenario is not too difficult to construct. The classic economic theory of supply and demand has another side to the coin – when prices go up, demand goes down. Power producers, for instance, switch to coal, while petrochemical plants move offshore. When prices remain high too long, this shift becomes known as 'demand destruction' – a permanent loss of market. Evidence for this already exists:

- In 2000, when the price for gas was low, the EIA reported that the US consumed 23.3tn cf/y. By 2003, however, as higher prices took firm hold, consumption had dropped by over 5%, to 22tn cf. The vast majority of this loss, over 1tn cf, was in the industrial sector, which closed petrochemical, fertiliser and other plants that relied heavily on natural gas.
- TXU, a Texas energy supplier, recently announced the closure of 16 older natural-gas fired plants – a total of 3,100 MW of capacity.
- EPCOR, an electrical generating company headquartered in Alberta, is spending C$700mn to add 450 MW of generating capacity to its coal-fired Genesee plant near Edmonton.

Could a combination of several factors produce a 'perfect storm' to swamp LNG? For those who think it can't happen, one merely has to recall the 1970s, when similar supply and demand forecasts resulted in the first wave of construction of LNG regassification plants in North America. New sources of natural gas were tapped by

Photo courtesy of www.lngoneworld.com

pipeline, however, and prices fell to the point where the LNG facilities at Cove Point, Elba Island and Lake Charles were mothballed.

Maybe not

Experts within the industry beg to differ. 'They are not going to be white elephants,' says Ed Kelly, Vice President, North America Gas & Power, Wood Mackenzie. While all of the above complications are indeed pertinent, other factors will combine to dampen and negate any dilatory effect upon the growth of liquid natural gas in North America.

First of all, no one doubts that conventional supplies in North America are dwindling, and that increased drilling won't stem the tide. 'Between 1999 and 2001, oil companies increased the [natural gas] rig count by 195%, but production went up by 3%,' comments Ineson. 'You can wring the sponge a whole lot harder, but there's not much left.' As for demand destruction, while the effect is real, data from the EIA indicates that the impact from the initial price rise in the early part of the decade to the $5/mn Btu level has largely run its course. 'What surprises us is that there hasn't been a little more,' notes Ineson.

The reasons for the relatively modest demand destruction are complex, reflecting the interaction of regional and global markets, regulations and usage. Natural gas is consumed by three main groups:

- residential and commercial, which consumes around 40% for heating needs;
- industrial, which uses about 33% for petrochemical and other feedstock purposes, and
- power, which converts slightly over 20% into electricity.

Residential and commercial consumption can respond to higher prices through increased efficiency or switching to other fuels. While large businesses can invest in dual-burner heating systems, individual homes have less flexibility and the effect is muted. Efficiency reduces consumption, but that trend has been proceeding apace for the last three decades – CERA notes that North Americans use almost 40% less natural gas per home than they did in 1971. Continued efficiency gains will counteract natural growth in heating needs, keeping consumption growing modestly for the next decade.

Power generation would, at first glance, seem to be a stellar candidate for switching to alternate forms of fuels. While oil prices in the $50/b range exclude using crude, coal is still relatively cheap and in abundance in North America, and is still the largest fuel for electricity generation in the US. Could not existing facilities be expanded and new facilities built? Unfortunately, political and environmental concerns limit coal as an option. 'Coal is considered a dirty fuel, a political pariah, and it will be difficult to approve,' explains Ineson. The new plants that are currently being built are insufficient to make an impact. 'It [the use of coal] is not going to materially change the picture until well into the next decade.'

Another problem is the recent investment trend in power generation in North America. Some 200,000 MW of new plants have been installed since 2000, 94% of which are gas-fired and very little of which can burn alternative fuels. The current power grid is over-

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Place your bets please

One of the most enduring and increasingly popular policies adopted by the governments of oil-producing countries has been to create a 'stabilisation fund'. Known also as a 'rainy day fund', the reasoning behind this policy has been that national budgets should be protected from oil price volatility and that oil export revenues should be invested over the long-term to provide for a return for future generations. Maria Kielmas *takes a closer look at whether governments might choose to hedge their oil price risks in the future.*

Hedging oil price risks has never been treated as a serious undertaking, outside of a brief and very modest programme undertaken by the US state of Texas. However, on various occasions over the past decade and a half, multilateral institutions such as the World Bank and IMF (International Monetary Fund) have published working papers about the possibility that governments should hedge their oil or other commodity price risks. However, these have remained cocooned in a world of theoretical economics and politely disregarded by the non-economists at both institutions as something not applicable to the 'real world'.

The hedging idea was revived in November last year at an International Policy Workshop in Berlin, which was organised by the World Bank, the German Ministry of Economic Co-operation and Development, and the German Development Institute. The workshop addressed the vulnerability of low-income countries to external shocks such as commodity prices. 'In such a volatile environment, there is a need for improving sovereign risk management supported by appropriate policy reforms, institutional development and international financial support on appropriate terms and using suitable financial instruments,' concluded the meeting.

The workshop took place just a few months after the World Bank suggested to the Indian government that it should consider hedging the price risk of its oil import bill by investing in oil price-linked bonds whose returns increase when oil prices increase.

So, is it time for governments to start betting?

Stabilisation funds

To date, stabilisation funds have reigned supreme. Over the past decade Venezuela, Colombia, Ecuador, Chad, Azerbaijan, Kazakhstan and Russia have created such funds, the models for which have been those of Norway and the US state of Alaska.

The most important aspect of their management has been that the funds are transparent and not corrupt, says Øystein Noreng, Professor of Petroleum Economics at the Norwegian School of Management in Oslo. This was not the case in the past for Kuwait, which established its Fund for Future Generations in 1960. Administered by the Kuwait Investment Administration (KIA) and Kuwait Investment Office (KIO), the fund famously bought 24.9% of BP stock in the mid-1980s. It was later obliged by the British government to dispose of most of its BP holdings at a loss. This contrasts with the Norwegian fund, which is not permitted to hold more than 1% of its assets in one security. At end-2004 the Norwegian fund held over $160bn in assets. At the time of Iraq's invasion of Kuwait, the Kuwaiti fund held just $13bn, from an estimated $60bn five years earlier. The remaining assets were used in the reconstruction effort and the fund has since been stored.

More recently, President Hugo Chávez of Venezuela ordered the withdrawal of over $2bn from the country's Macroeconomic Stabilisation Investment Fund (FIEM) to finance a variety of election campaigns and social welfare programmes. In November 2004 the fund held just $706mn, although the Venezuelan authorities were predicting that this amount would rise to $3bn by end-2005.

Meanwhile, Russia's initiative in setting up a rainy day fund drew praise from the IMF. The Russian fund topped $19.7bn by end-2004, when the government announced that it would use part of it to pay down foreign debt. The Russian government later announced that in 2005 it would raise defence spending by 26% on 2004 levels.

No restraint

Such government actions are the practical problems associated with stabilisation funds, says Randall Dodd, Director of the Washington DC-based think tank Financial Policy Forum. In theory the fund can work to stabilise government budgets and prevent a too rapid appreciation of a currency. But this is all conditional on the fact that the years of plenty must come first. Unless the fund can borrow against future income, it cannot exercise a stabilising influence on government budgets.

The political problem here is that it has to be a burden on the economy before it acts as a stimulus. All this comes before the even greater problem that the fund is often unlikely to act as a restraint on government spending in the first place. According to a number of IMF studies, the reason why Norway's fund is successful is because it does not interfere with fiscal policy or the budgetary process. In addition, Norway's transparency, accounting and governance standards are of great importance. The IMF doubts that other countries would be prepared to use this approach.

Alaska's Permanent Reserve Fund (APRF) – with about $28bn in assets as of late-2004 – has worked well because there has been a second financial cushion in place against fluctuating oil prices. This is the Constitutional Budget Reserve Fund (CBRF), created a decade ago to fill the gap between a fluctuating revenue source and the ongoing need for social spending. The Alaskan authorities are now worried about what will happen when the CBRF runs out and the state may have to take a serious look at the hedging option.

The downsides

Outside of the world of hedge funds and media punditry, betting on oil prices has always been deemed a fool's game, not least in the oil industry. Hedging strategies adopted by oil companies have often resulted in a zero-sum game and have been criticised by investors. The investors are there in the first place because of the price risk and do not want see their earnings cut by hedge, observed one Wall Street investment banker. But even he thinks that governments should not be betting on oil prices. They could try to lock in above an acceptable floor price, for example. Dodd thinks likewise: 'The upside of prices is not as beneficial as the downside is costly. You need to protect the downside.'

This view was expressed in a May 2004 report from the Paris-based International Energy Agency (IEA). Opec's policy of cutting production to maintain high oil prices is storing up problems for the future, it noted. The impact of higher oil prices on economic growth in Opec countries depends on a large variety of factors, particularly on how the latest windfall revenues are spent. However, in the long term, Opec oil revenues and GDP are likely to be lower as high oil prices do not compensate fully for lower oil production, the report concluded.

But price hedging by government faces more problems. How does a government explain the costs of such an under-rating, and any subsequent price losses, to its citizens? A study by the Alaskan state government's Department of Revenue estimated that hedging all of the state's royalties and production taxes through a futures programme could cost between $18mn and $20mn in upfront transaction fees over three years. A three-year options programme could cost $300mn. In addition, who would be the counterparty to such a hedge and how would the counterparty's credit risk be estimated?

Texas and Australia tried

The state of Texas launched a successful hedging programme for its royalty revenues in 1991 as part of the state's treasury operations, rather than a stand-alone project. However, in order to limit political opposition to the scheme it was funded from unclaimed royalties rather than departmental budgets.

State legislators and department staff were trained in the issues involved and experienced professionals were hired to manage the operations. There were monthly and quarterly reporting requirements and stop loss limits on the amounts of money that could be risked in one day ($500,000) and for the total loss in one year ($2.5mn). In addition, the choice of financial instruments was limited to exchange traded options. Peter Nance, President and Principal of Austin, Texas-based Teknecon Risk Advisers (TERA), says that there was nothing complicated about the programme – the major task was to set appropriate objectives and then to stick to them.

At present, financial markets are neither deep nor liquid enough for such a scheme to be expanded to accommodate a middle-income national government hedging its risk. The opportunity for fraud is vast. In the US alone there is an enduring lack of confidence in the financial markets following the collapse of Enron, various corporate scandals, the mutual funds debacle, and now the latest insurance industry investigations, notes Dodd. However, one saving grace has been that the futures exchanges have emerged as well-managed throughout these scandals. So, the exchanges, rather than the over-the-counter (OTC) market, would be the starting point for any such future scheme.

Success and complications

It works in Australia. The Australian Wheat Board has used a hedging strategy to guarantee farmers a minimum price for their crops. The Board gave put options to farmers and hedged its exposure on the wheat futures market on the Chicago Board of Trade. Stijn Claessens, Senior Adviser, Operations and Policy Management, at the Financial Vice-Presidency of the World Bank in Washington DC thinks that the market for such oil price transactions is there. It wasn't 10 years ago, Claessens believes, that governments have not chosen to use such financial instruments because they don't see any advantage in doing so. This reasoning, he says, is not applicable to the major oil producing countries because the volumes these governments may be required to hedge are too high and could raise questions about any government's objective in doing so. But the middle- and lower-income countries could benefit from hedging.

One of the reasons for government reluctance to consider hedging is the complication of public sector risk management where various public institutions – central banks, ministries, state-owned enterprise – have to coordinate their actions. The governments have to decide whether a state-owned enterprise hedges on its own – as Mexico's Pemex has done in the past – or whether the operation is centralised. Such decisions are usually hostage to the political ambitions of the various national officials involved.

The World Bank has been mulling over a scheme that would allow debtor countries to repay their loans using petroleum. If such a loan were to be arranged for an infrastructure programme, then a country's oil revenues would be used directly for development. The precise structure of such a mechanism is still under development, but repayment could be based on a certain number of barrels of oil at an average price over a given period. Floor and ceiling prices could be set, and the transaction rolled over on a regular basis. The World Bank would hedge its own oil price risk. The real question would be the cost of such a transaction on the market.

Claessens believes that such risk management by sovereigns will still remain difficult until governments start thinking of how they allocate their risks between the public and private sectors. This kind of allocation will vary from country to country. It may imply liberalisation, privatisation, altering the nature of public social security obligations or assuring a proper institutional environment in the banking system that limits moral hazard.

Whose risk?

An IEA official in Paris, speaking in a private capacity, observed that there is a difference between the oil price exposure of a country and that for a government. Furthermore, this depends on the degree of liberalisation of its energy market.

In the European Union, where high fuel taxes mean that pump prices do not fluctuate as dramatically as in the US, the issue of oil price risk management takes on a different character. And to the degree that there is a price risk, these price fluctuations are in any case passed on to the consumer. Even in the US, future oil price shocks are likely to cause less disruption than in the past. US oil intensity (the relationship between oil consumption and GDP) has declined by about 50% over the last three decades – even though the proportion of imports in oil consumption is projected to rise to 70% over the next 20 years.

Ian Parry and Joel Darmstadter, both senior researchers at Washington DC-based think tank Resources for the Future (RFF), think that eventually a US government will have to adopt oil taxation. This would be better than an outright tax on gasoline, which accounts for 45% of oil use in the US. Although this seems like a hopeless cause right now, Washington will have to address one or other of its various deficits at some stage in the medium term – crude oil taxes equivalent to between $3 to $5 per barrel could be the answer.

Ultimately, sovereign risk management against oil price shocks is a political matter. Among the consequences of such shocks have been countries' defaults on international loans, as in the case of Russia in 1998 and Argentina in 2002. A corporation is forced to pay up on its liabilities through a bankruptcy filing. There are no bankruptcy procedures for countries, so a government need not pay up on its obligations if it doesn't want to, even if it can, observes Claessens. As a result, the incentive to adopt risk management techniques is not there.

Looking ahead

In the future, countries opting for a hedging programme probably would have to enact legislation authorising such a strategy and spell out its objectives and parameters. For most developing countries, this could involve constitutional change. The same would apply to any liberalisation of their economies.

Today, in contrast to the liberalisations of the 1990s, developing country governments are more concerned with re-asserting their control over their economies. Dodd thinks that the greatest political challenge could be the widespread lack of understanding of the costs of doing nothing.

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built, and operators are loath to invest in alternatives in a soft market. 'Coal doesn't help tomorrow or next year, it has a long-term aspect,' says Kelly.

Industries that consume a large amount of gas – ammonia, methanol, petrochemicals – have an incentive to shift to areas of low-cost, stranded gas. In fact, that's what happened, with US consumption in the industrial sector dropping from 7.6tn cf in 2002 to 7tn cf in 2003. That trend has largely abated, thanks to strong international demand keeping marginal plants open. 'China is buying everything,' says Ineson. 'Last year, the petrochemical producers were unhappy, but now they have pretty good profits and they are hitting the limits of global capacity.'

Even if North American gas production remains stable and industrial consumption declines, the need for electricity will still create significant demand for natural gas. 'We have other energy choices we could make – nuclear, coal, renewables – but you need lead time,' says Ineson. 'The only thing right now that can redress the energy shortage is LNG.'

LNG shake out

Currently, worldwide production of LNG stands at around 16bn cf/d. Major LNG exporting nations include Indonesia, Algeria and Qatar, although Australia, Brunei, Nigeria, Abu Dhabi, Oman and Trinidad & Tobago also have significant production. Some 40mn tonnes of additional capacity (around 5.6bn cf/d), is being built, primarily through expansion of facilities in Nigeria, Australia, Qatar and Malaysia.

In addition, many other jurisdictions, from Peru to Yemen, are considering building liquefaction plants. An IEA report notes that global production could double to 31bn cf/d by 2010 and reach 51bn cf/d by 2020. A recent study by the Interstate Natural Gas Association of America estimated that the US might need around 18bn cf/d of LNG by that time. While Japan, Korea and newcomers like India and China will account for a significant percentage of the rest, might there end up a glut of LNG, resulting in price battles for producers? 'LNG dumping is quite unlikely,' comments Kelly. He notes that, because the liquefaction portion of the LNG chain is the largest portion of investment, producers look very carefully at market conditions before committing to construction. He states: 'I don't believe we will overbuild production.'

What about all the proposed regassification facilities in North America? With an estimated total capacity of 47bn cf/d, might too many plants be constructed? Once again, Kelly sees the process evolving step-by-step, in a manner that will weed out the majority of contenders – 'An oil company considers liquefaction first, then considers shipping and regassification.' The few regassification plants built will be those that can get a firm agreement with liquefiers, he says.

Still, two factors on the supply side weigh heavily on LNG's prospects in the next decade – the Mackenzie gas pipeline (1.2bn cf/d), scheduled to come onstream around 2009, and the Alaskan gas pipeline (4.5bn cf/d), proposed to begin shipments around 2015. 'Mackenzie gas won't alter the situation as the volume is not sufficient to lower the overall price level to a point that discourages LNG,' states Kelly. He adds: 'Alaska is different; 4.5bn cf arriving instantaneously is likely to slow LNG development.'

Slow, but not kill. A huge slug of gas coming on market typically depresses the price, but once the floor of $3.50–$4/mn Btu is breached, Ineson believes the market would respond to restore equilibrium. 'The marginal cost of domestic gas production is over $3.50. North American producers would stop drilling below that, and LNG would pull out of the market and move to Europe or Asia.'

'We think that LNG will arrive a little bit late because greenfield sites are not under construction yet,' says Ineson. 'It takes a good three years, and we won't see them until 2008.' After that, North America imports, currently around 2bn cf/d, will swiftly rise. 'We see 6.9bn cf/d by 2010 and 10–12bn cf/d by 2015,' says Kelly.

Which regassification facilities will be built first? Sempra Energy has regulatory approval to build in Baja, Mexico, as well as long-term agreements to receive LNG. Various proposals on the US eastern seaboard have been rejected, but two have been approved further in Canada. 'A lot of people are looking to Canada, there is a sense that they are more rational regarding approval,' says Ineson. In the end, the bulk of regassification may end up in the Gulf of Mexico. 'Texas and Louisiana, are receptive. Even if just these two move forward, there will be enough capacity to rebalance the market.'

And while it may never reach the point of oil, the growth of LNG in the US will go a long way to creating an international market for natural gas. 'The entry of the US as a large LNG consumer creates a very liquid natural gas market where you get a clearer price signal,' comments Ineson.

1bn cm of gas = 37.3bn cf = 0.73mn tonnes of LNG

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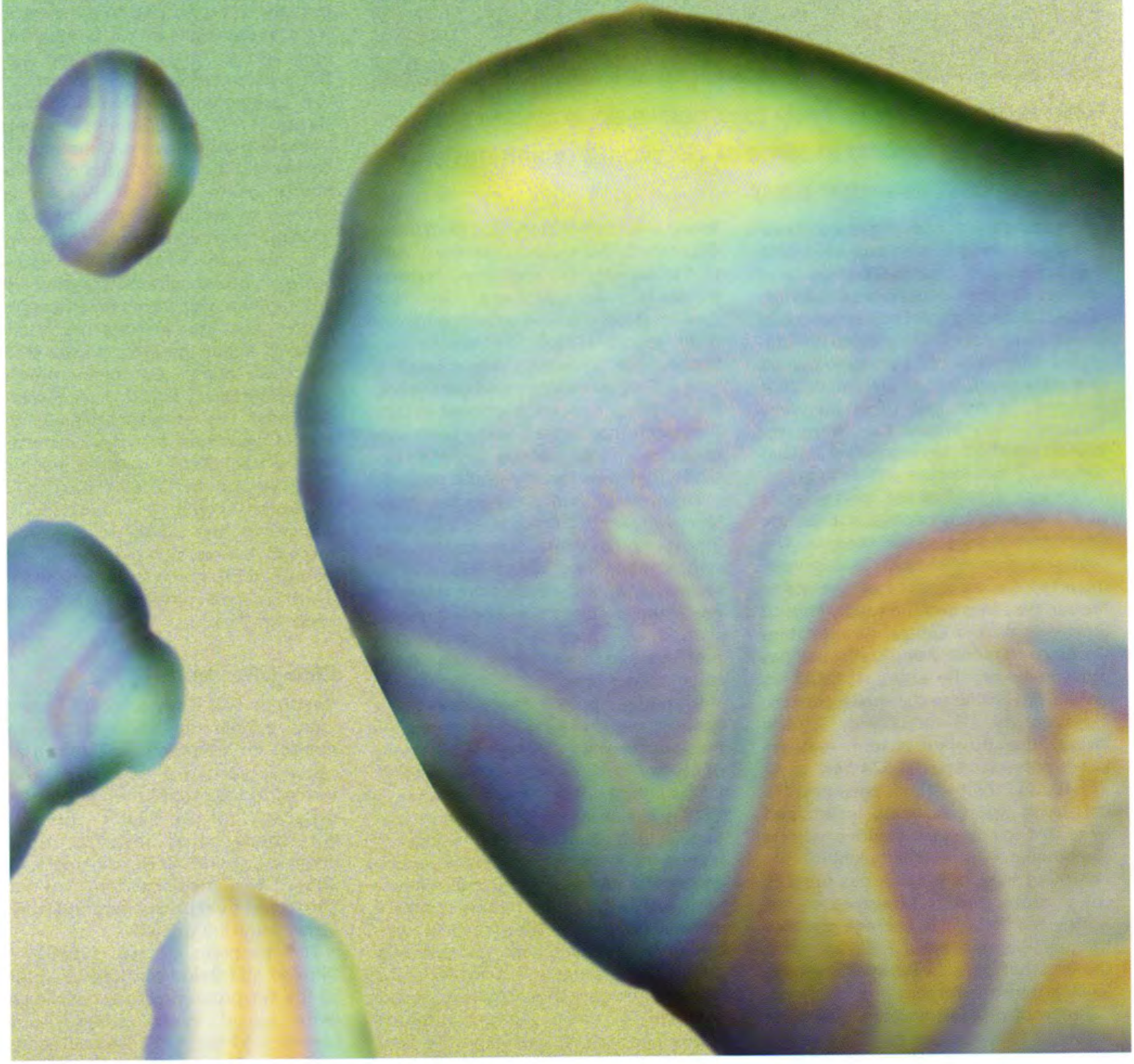

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Energy giant awakes

Metering flows to Belorussia at the Smolensk compressor station

Petroleum Review *recently took part in an extended press visit to Russia, looking at some of Gazprom's operations and learning about its export plans.*

Gazprom is already the world's large gas company, with projected 2004 production of 542bn cm and reserves of (Russian definition) 28tn cm of gas, 1.28bn tonnes of condensates and 0.57bn tonnes of oil. The soon to be completed merger with the state-owned Rosneft – which, in late December 2004 acquired the principal Yukos subsidiary Yugansk – will ensure that Gazprom-Rosneft now becomes a major oil and gas company... possibly the world's largest.

The visit started at the control room of the dispatching departments at the Gazprom headquarters in Moscow. The central control room, with its vast wall-mounted display map of all the major Russian pipelines and the supply links to Europe and from Central Asia, enables Gazprom to monitor and control all gas movements on the entire 154,000 km system. According to the spokespersons, although the US network is actually larger, the Russian system features larger pipe diameters (1,024 mm, or 42 inches) and higher line pressures (75 bar), with pressures being maintained by a 264 compressor stations with a combined power of 43.8mn kW.

Around 90% of Russian gas supplies come from the Yamburg area of northern Siberia. The average distance the gas flows is around 2,500 km, with the gas that goes to Europe travelling 5,400 km to the border.

The central control room was completed in 1995 at a cost of $65mn and is equipped with Sun systems with full data integration allowing 24-hour monitoring and control of the 2bn cm/d being dispatched. Although confronted with all the usual sorts of problems – terrorist incidents, an accident in the Zapolyarnoye gas field – Gazprom's aim is to ensure reliable delivery to customers. The company's proud boast is that in Gazprom's 30 years of experience, the customer had never suffered. In fact, it boasted that while Russian customers might be without water or without electricity, they were never without gas.

The company had, however, had problems with both Belorussia and Ukraine 'borrowing gas without permission'. The central monitoring system was able to see and account for every cubic metre of gas – the problem had been ensuring that it was paid for, although this problem had now largely been overcome, they claimed.

Gazprom reported that winter peak deliveries were roughly double those of the summer, which was when the 75bn cm of gas storage came into its own, allowing fairly constant offtake from the producing fields while deliveries to customers featured a large summer/winter swing. It quoted the example of Moscow, where winter demand reached a rate equivalent to 127bn cm/y while summer demand was only 50bn cm/y. It was explained that even with gas travelling down the pipelines at around 35 km/h, it took three days to reach Moscow and between five and seven days to reach France and Italy. Deliveries to the new market that Gazprom is expecting to develop in the UK will take over seven days from the Siberian fields. In terms of the overall system a temperature change of ±1°C depresses or elevates demand by 40mn cm.

Plans in the pipeline

In the course of an extended press conference with three Gazprom directors – Sergei Kupriano, Yuri Komarov and Alexander Ryazanov – a number of plans were revealed. Confirming that Gazprom was seeking a vertical integration of its business from field to end consumer, the directors drew attention to plans to export LNG to the Americas from a new plant in the St Petersburg area and to China, Korea and Japan from Sakhalin. Similarly, the company was seeking a closer involvement with Gazprom's final consumers by developing distribution assets. Germany is the company's biggest customer, taking nearly one-quarter of Russian gas exports to Europe (29.6bn cm out of 132.9bn cm in 2003). Recent talks with the German Chancellor, Gerhard Schroder, had sought to strengthen links and facilitate Gazprom's involvement in power generation projects in Germany.

Asked about the likely impact of the proposed North European pipeline (under the Baltic, directly from Russia to Germany), the directors explained that current plans were to expand exports to Europe from 2004's projected 140bn cm to 180bn cm by 2010. This 40bn cm expansion could be achieved by expanding the Yamal-Europe route through Poland or the southern route through the Ukraine, or by building the North European pipeline or some combination of these.

LNG prospects

Gazprom will gain a direct involvement in Sakhalin LNG capacity via its merger with Rosneft. Sakhalin II and other projects are to provide 10mn tonnes of LNG supply, while new LNG capacity to be built near St Petersburg could facilitate up to 20mn t/y of LNG to North America by 2010. The development of the Shtokman field is expected to provide up to 14mn t/y of LNG.

The problem of gas supplies to Ukraine and Belorussia had, according to the Gazprom directors, now largely been solved, with agreements on Ukraine's $1.6bn debt and agreement by Belorussia on price (see box, p22).

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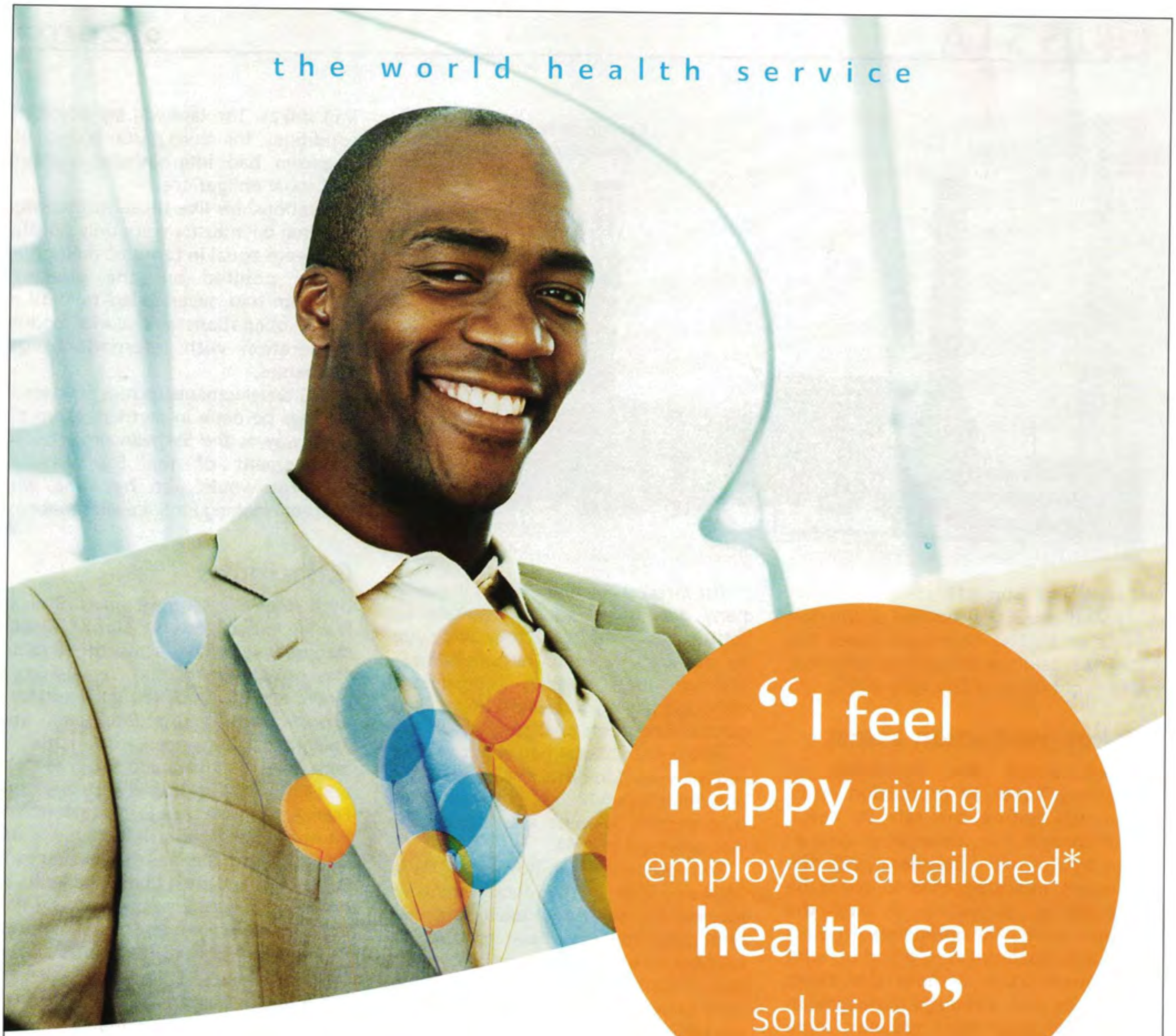

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Compression units on the Yamal-Europe pipeline at Smolensk

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Asked about the removal of the ring fence on trading Gazprom's shares, the directors said the indications were that this might occur in late June 2005.

Yukos production assets

Asked about the possibility of acquiring Yukos oil production assets (this was before the sale to Baikal Finance and the subsequent acquisition by Rosneft – see box, p22), the directors indicated that it could be interesting, providing it was the 'proper price'. The immediate problem was that Gazprom would end up with too much crude without the Yukos refineries and, although the Bashkiari plant had some spare capacity, more would be needed to cope with production approaching 100mn t/y (2mn b/d). They did suggest that buying the rest of Yukos was a theoretical possibility.

Turning back to the gas market, the directors noted the merits of traditional long-term contracts, noting that Gazprom had already sold two-thirds of a trillion cm of gas on take-or-pay contracts.

In 2004, Gazprom anticipated selling around 176bn cm to Europe (140bn cm to central and western Europe), rising to around 200bn cm by 2015. By this date the company envisaged selling up to 20bn cm/y into the UK, accounting for 25% of UK imports by 2010. Germany remains the largest export destination for Gazprom gas, however, taking some 36bn cm in 2004 and an anticipated 40bn cm by 2010.

Gazprom currently accounts for around 25% of European gas supplies and the directors stressed that to ensure suitable levels of investment in new production they needed long-term take-or-pay contracts to give the stability and reliability that customers expected. An important new sources of supply would be LNG exports, targeted at the US and possibly UK markets.

The directors confirmed that the company was targeting a 12% rate of return, but noted that they were 'up to our ears in social responsibilities', stating that Russian consumers, although paying subsidised prices, had outstanding debts of slightly over $1bn – although this total had reduced over recent years. Moldova also owed $1bn and Belorussia $120mn, but settlement is in process. Ukraine debt settlement was achieved in 2004.

Price rises for gas in Russia of 20% in 2004 and 23% in 2005 would improve income for sales in Russia, but gas remained the cheapest of fuels – leading to a range of problems from lack of incentives for energy saving, 3bn cm/y growth in consumer demand and gas taking 66.7% of the Russian primary energy market in 2003. Gazprom was pressing for free market prices, at least for Russian businesses. The largest business user – the United Electricity Service (UES) – takes 145bn cm/y of gas, but only 15% of the electricity it generates is sold at market prices, while tariffs to consumers and key utilities were fixed for an extended period. [Gazprom derives two-thirds of its income and virtually all of its profits from the one-third of gas production that its exports. Ed.]

Third-party access

Asked about third-party access to the gas supply grid, the directors described it as a 'big challenge' and claimed that a single export channel was 'in the national interest'. They pointed out that independent suppliers were much stronger in the internal market. They believed that Gazprom's export monopoly should be maintained and that social responsibilities had to be taken on by any new suppliers. New suppliers had an obligation to supply what they can sell, but it was also important that they get back controlling stakes. The law will lay down the conditions for third-party access, but Gazprom had international contracts and social obligations.

Relationships like those in the international oil industry were only possible if all were equal in terms of their obligations, pointed out the directors. Gazprom had never failed to fulfil its supply obligations and works in close cooperation with international gas companies.

LNG developments such as Shtockman will also be done in partnerships in the same way as the Sakhalin projects. The development of the East Siberian resources would also be done with Gazprom looking for 'win-win situations'.

Gas exports

Until relatively recently, up to 90% of Russian gas exports to Europe flowed through export lines across the Ukraine. The completion of the Yamal-Europe pipeline in 2004 opened up a northern export route across Belorussia and Poland to the German trunk network, with links to Austria and south to Italy, and a link to Aachen and then west into France. If the projected Northern European Gas Pipeline is built, it will link Gryazevets on the main Yamal line to St Petersberg and then under the Baltic to northern Germany where it would link into the main German trunk networks. A possible extension could cross northern Germany and the northern Netherlands before crossing the North Sea to a landfall in East Anglia.

On the existing Yamal-Europe line, the westernmost compressor station is at Smolensk, close to the border with Belorussia. In the so-called Belorussian corridor, there are five main gas supply pipelines. The first was built in 1965, followed by two more in 1982–1983, with first gas supplies to Europe in 1987. In 2004 the Yamal-Europe lines were completed – these are twin 1,400-mm diameter line (56-inches) with an 18- to 20-mm wall thickness; the three earlier lines are 1,200-mm (48-inches). Trunk lines operate at pressures of 55–83 bar.

The decision has recently been taken to make the Yamal-Europe pipelines dedicated export lines and, in late December 2004, all links from the Yamal-Europe lines to Belorussia were cut off. This decision was largely the result of earlier pricing and supply disputes, which led Gazprom, in February 2004, to cut off all supplies to Belorussia for three days – a move that led to rapid repayment of outstanding accounts, according to a spokesman for Lantrangas, which operates the Smolensk facility. Planned throughput

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of 60mn cm/d in 2004 will rise to 90–100mn cm/d in 2005, according to Lantrangas – at which point gas passing through Smolensk could account for one-third of Russian gas exports.

A similar compressor station at St Petersburg supplies gas to Finland, the city of St Petersburg and all consumers to the north of the Neva in Karelia up to the Finnish border. Gas supply to Finland started in 1973 and Russia remains Finland's sole supplier. The largest single customers are in the paper and pulp industry, and power generation. Finnish demand has built up steadily and has now reached the point where peak winter demand is 20mn cm/d, while demand from St Petersburg stands at 20mn cm/d.

There are two 810-mm (32-inch) pipelines supplying Finland, the second completed in 1998. Finland has become a partner with Lantrangas for technical support and will probably have an involvement in the North West Gas Project. Although still at the feasibility study stage, the new 610-km high pressure (100 kg/cm^2) line will be of 1,200 mm (48-inch) diameter and will require four compressor stations to deliver 19bn cm/y.

The directors noted that Gazprom was currently negotiating with the US about LNG supplies from a plant to be built in the St Petersburg area. The Zarpolyarnoye gas field, which came onstream in 2003, will provide initial supplies, but the development of supplies from the Shtokman gas field in the Barents Sea will be developed by joint ventures, possibly including one with ConocoPhillips, to provide long-term supplies. The LNG facility is likely to be built at Ish-Lugar, taking some three years to complete. It will be capable of delivering 5–6bn cm/y. In addition to targeting LNG supply to the US, probably via a Canadian regasification facility, there are also possibilities for sales into Europe, they suggested.

Overall view

Gazprom's overall view was that it had an exciting future ahead, with both the debt problems and the problem of low prices in Russia slowly being resolved. There was now active cooperation in the transiting of gas supplies from Tajikistan, Uzbekistan, Turkmenistan and Kazakhstan. President Putin was determined to increase gas connection in Russia, extending the benefit of gas supplies to more of the population.

While the resource remained plentiful – noting that preparation work was already beginning for the development of the Yamal gas fields – the investment demands would be large, which was where international collaboration could help.

Russian gas to Belorussia

Russia is reported to have stated that it is ready to supply 20.5bn cm of gas to Belorussia in 2005 at a preliminary price of $46.68/1,000 cm. Some 18.5bn cm will be supplied by Gazprom, and 600mn cm from independent suppliers.

It is also reported that the Belorussians have proposed increasing supplies to 21.5bn cm, but at a price of $39.56/1,000 cm. However, it is understood that this proposal is not acceptable to the Russians.

Rosneft/Gazprom merger unaffected by Yugansk sale

On 22 December 2004, state-owned Rosneft purchased 100% of Baikal Finance Group, the mystery bidder that purchased at auction a 76.6% stake in Yuganskneftegaz – Yukos' production arm. According to Gazprom's press service, Rosneft's new acquisition will not prevent Gazprom from proceeding with plans to merge with Rosneft, which will give the state a majority stake in Gazprom.

The news about Rosneft's purchase of Baikal Finance Group confirmed many analysts' predictions that Yukos's former prize asset would eventually belong to the state or a company loyal to the state. It has become obvious that Baikal Finance Group served as a front at the Yuganskneftegaz auction, writes *Nina Kulikova*, Economic Editor, RIA Novosti. Gazprom will now get control over the asset through a merger with Rosneft. The deal will also protect Gazprom from possible lawsuits from former Yuganskneftegaz shareholders and make Gazprom appear like a good faith purchaser. President Putin has said that Rosneft's purchase of Baikal Finance Group conformed to free market principles.

However, Gazprom will have to pay a higher price for Yuganskneftegaz. The purchase of Yugansk has made Rosneft the nation's second largest producer of crude oil, after Lukoil. According to Georgy Shmal, President of the Oil and Gas Industrialists' Union, Rosneft could become one of the top 15–20 oil corporations in the world.

Gazprom and Rosneft are already cooperating on projects to develop the Shtokman gas condensate deposit and the Prirazlomny oil and gas deposit in the Barents Sea, as well as the Kharampursky oil and gas field in the Yamal-Nenets Autonomous Area and other deposits. The creation of a large oil and gas company may help reduce production costs, facilitate technology sharing, and raise the efficiency of management.

In earlier reports, Rosneft was understood to have sold Gazprom its stake (about 70% of shares) in Sevmorneftegaz for $1.7bn – the same amount had been deposited by Baikal Finance Group to participate in the auction for 77% of the shares of Yuganskneftegaz. It is understood that Rosneft returned the proceeds from the deal with Gazprom to Surgutneftegaz, which had given money to Baikal Finance Group through Sberbank so that it could bid in the auction for Yuganskneftegaz.

Sevmorneftegaz was established on a parity basis in 2002 by Rosneft-Purneftegaz and the company Rosshelf, which was founded by Gazprom. Rosneft owns about 40% of the shares in Rosshelf. Sevmorneftegaz holds licences for the development of the Prirazlomny oil field and the Shtokman gas condensate field, both of which are located in the Barents Sea. Prirazlomny is estimated to hold some 83mn tonnes of recoverable oil; Shtokman some 3.2tn cm of gas and 27mn tonnes of oil.

• As *Petroleum Review* went to press, it was reported that ONGC Videsh, a subsidiary of India's Oil & Natural Gas Corporation, is in discussions with Rosneft regarding a possible $2bn acquisition of a 15% stake in Yuganskneftegaz. However, Rosneft is reported to have denied any negotiations are taking place.

Following the market speculation, Yukos is understood to have said that any bid by ONGC, or anyone else, could be added to its $20bn damages claim in Houston against those involved in the forced auction of Yuganskneftegaz on 19 December 2004. Yukos has stated that any additional transactions relating to Yuganksneftegaz would be in breach of a US court order freezing its assets following Yukos' bankruptcy filing in Houston in late December.

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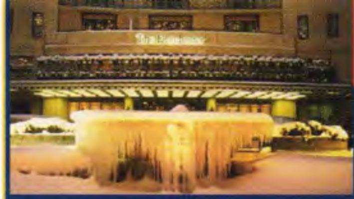

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Wolfgang Schollnberger (left), receiving his Outstanding Individual Achievement Award from sponsor Jon Glesinger, Norman Broadbent in 2004

Energy resources, substitution and efficiency

There are few subjects as important or more controversial than the idea that oil supplies may be approaching a production peak, with all the obvious implications for future energy supplies. Wolfgang Schollnberger *(above) – who won the Energy Institute's Outstanding Individual Achievement Award in 2004 and recently retired from BP where he had been Technology Vice President – explained his optimism about future energy supplies in an extensive discussion with* Chris Skrebowski, *Editor,* Petroleum Review.

Schollnberger started by explaining that he had had a very keen interest in the subject for many years and had published on the issue. The most comprehensive paper had been one presented in Vienna in September 1997 to celebrate 150 years of the Austrian Academy of Sciences (a shortened version has since been published in English).

Resources

Schollnberger recalled that when attempting to examine what the economic supply of hydrocarbons over the next century would look like, he thought it was important to examine and graph the resource in terms of total hydrocarbon demand, ie oil and gas together (see **Figure 2**). He felt it was important to stress that it was the consumers who held the trump card, and in his view it was the demand side that was decisive.

He went on to question the relevance of the heated discussion about running out of conventional oil – we are already producing and selling large amounts of unconventional oil (from deep and ultra-deep waters, tar sands, etc). The usage of natural gas was rapidly rising. In addition, many products such as diesel, which are now mostly made from oil, could be made from natural gas or coal – for a price. He stated that we are not running out of natural gas or coal for a long time.

The relevant question then, is: For how long are consumers willing to pay the price for fossil fuels – the price in terms of money and in terms of impact on the environment (which could also be expressed in terms of money)? If nobody wanted to use coal, coal reserves would dwindle. The same would be true for oil and gas. If nobody wanted to purchase them, the money for exploration, production, and the development and application of new technologies would simply be not there. Then even plentiful physical resources of fossil fuels would never be converted to reserves (**Figures 1a–c**).

'It is quite clear,' he continued, 'that, as long as a resource is as plentiful as hydrocarbons are for the next decades, there will be a demand driven elasticity of reserves – as demand increases and as more consumers are willing to pay, the larger the reserves will be.' This elasticity of reserves also was the reason why those currently so popular one-line predictions of future oil or gas supplies are inadequate. They do not take into account the elasticity of reserves in relation to economic conditions. With this in mind Schollnberger estimated in 1997 that ultimate recovery of oil and gas, not including oil shales and gas hydrates, might fall somewhere between an outrageously high and a low estimate (**Table 1**).

When graphed, these give **Figure 2**. Schollnberger plans to update the estimates in 2007.

A narrow focus on conventional oil only, he claimed, effectively excludes the areas where reserves/resources are being added through the application of new technologies, such as deep and ultra-deep water and in existing fields. It was probably true that, for light sweet crude from conventional sources, production had possibly already peaked, commented Schollnberger. This was interesting, but hardly relevant to the prediction of ultimate hydrocarbon recovery. He remarked that even with a renewable product like milk there was a conventional supply (hand milking) that was exhausted in Europe and the US, but another (machine milking) that was in plentiful supply. He suggested that we should stop staring at peak conventional oil (ie Hubbert-type curves for conventional oil) like a rabbit frozen in front of a snake, and should look at hydrocarbons 'in the round' – meaning the availability of oil and gas together.

End of cheap oil?

Asked if he felt that we had seen the end of cheap oil, Schollnberger countered with the question: 'What is cheap?' He noted that the cut-off point might be around \$15/b for some consumers, so for them we were probably already in a higher cost era and might stay there.

Future potential

Asked about potential new areas for large new oil and gas discoveries, Schollnberger said that he saw very considerable potential in the Russian Arctic, particularly in the Lena Delta and from northern Eastern Siberia and from the Laptev Sea to the Bering Sea as well as in Sakhalin and the Timan Pechora area. There were also many deep and ultra-deep water oil plays along the coastlines of the Atlantic, the Pacific, the Indian Ocean, the Gulf of Mexico and the Caribbean (eg Cuba). An area of notable potential was the Perdido fault belt in the Gulf of Mexico. Oil and gas plays below disputed national boundaries were promising once the access problems were resolved. Examples included the Empty Quarter on the Arabian peninsula and the offshore area disputed between Malta, Libya and Tunisia. The world was generally under-explored for gas, for which there were many more prospective areas.

He also stated that a lot more oil and gas would be squeezed from existing fields.

Substitution

According to BP's report on world energy for 2003, the world was 87% dependent on fossil fuels – oil, gas and coal – for primary energy. The actual figures were oil 37%, gas 24% and coal 16%. The remaining non-fossil fuel – 14% – was dominated by nuclear (6.15%) and hydro (6.11%), with all the other renewables – wind, solar and biomass – accounting for just 1.51%.

Schollnberger commented that for consumers the question is: If there was no immediate threat to availability of fossil fuels, why change the energy mix? For the moment it appeared consumers like the current energy supply package and economics also favour the current situation. Seen from this perspective there are few, if any, obvious changes or substitutions to be made. There is, however, a trend to minimise carbon and increase hydrogen in the fuel mix, in a progression that has already been established for over a century – a trend that can be seen in the move from wood to coal, to oil to gas and can be expected one day to continue on to hydrogen as the predominant energy carrier (see **Figure 3**).

Figure 1a: Reserves/resources vs hydrocarbons in place (as of 1 January 2101) – 'High' scenario – another hydrocarbon century *Source: Schollnberger 1998*

Figure 1b: Reserves/resources vs hydrocarbons in place (as of 1 January 2101). 'Medium' scenario – energy mix *Source: Schollnberger 1998*

Figure 1c: Reserves/resources vs hydrocarbons in place (as of 1 January 2101). 'Low' scenario – end of the internal combustion engine *Source: Schollnberger 1998*

Consumer power

So what then may lead to the much talked about substitution of fossil fuels? Developing his earlier theme about the sovereignty of the consumer and the way that change was driven by consumers rather than suppliers or the governments, Schollnberger believes that consumers consider six elements when making an energy purchasing choice – price, convenience/reliability of supply, performance, safety, environmental

Estimate	Produced by 2101 (in bn boe)	Ultimate recovery (as estimated in 2101 in bn boe)
High	7,748	11,985
Medium	5,665	8,766*
Low	3,703	5,150

*of which oil 3,330bn boe

Table 1: Ultimate recoverable reserves and production to 2101

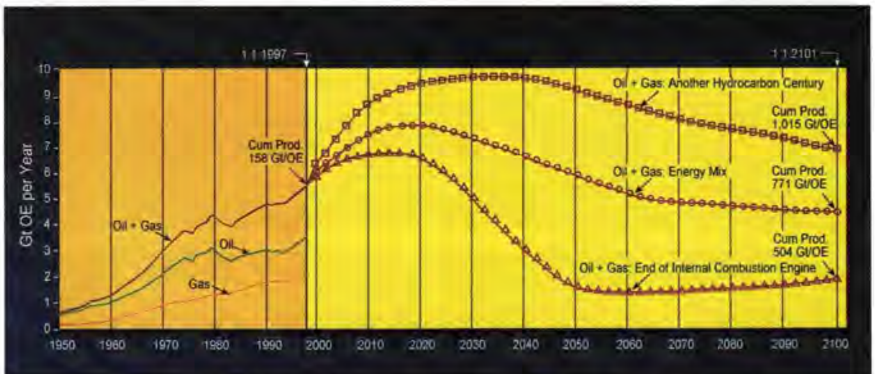

Figure 2: Worldwide production of oil and natural gas – the three future scenarios *Source: Schollnberger 1998*

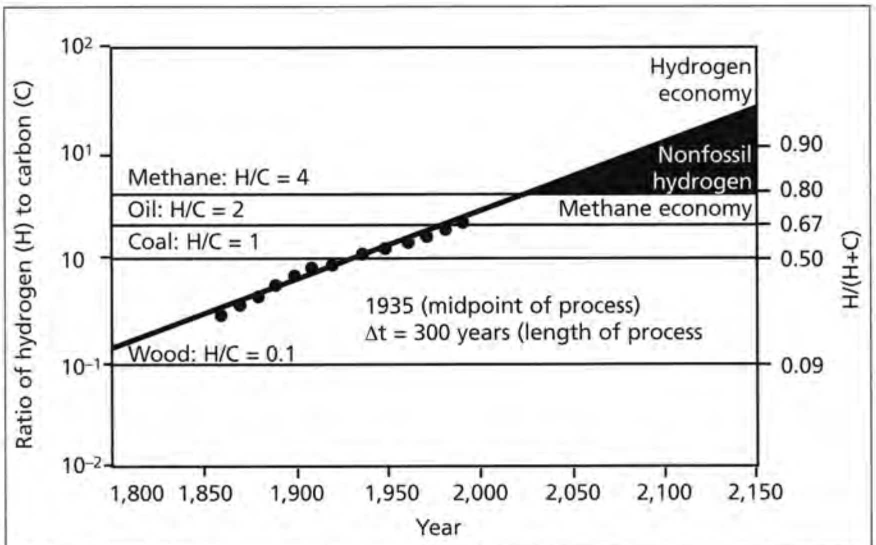

Figure 3: Ratio of hydrogen (H) to carbon (C) for global primary energy consumption since 1860 and projections for the future *Source: Ausubel 1996*

impact and social impact. 'The best energy mix would take care of these six points,' he says. 'It's not always price that dictates consumer choice. In Germany, the Netherlands, the UK and elsewhere, it's been shown that some people will pay more for cleaner energy.' Large-scale replacement of fossil fuels in an open market would only occur, according to Schollnberger, when a large segment of consumers in that market believes that an alternative energy source or a combination of alternative energy sources clearly outperforms fossil fuels on one or several of the mentioned six elements. By actually purchasing the alternative package the consumer has the vote, which is the trump card.

Government – with its array of powers – also holds a strong hand. Business, he felt, has to play in between.

Clarifying the human factor in substitution choices is an area in which Schollnberger sees an important role for research guided by the Energy Institute. 'Why not make it an all-around pleasant experience to use more renewables?' he asked.

Climate change concerns

The discussion then focused – not surprisingly – on the environmental impact of various energy sources as a driver for substitution of fossil fuels. Increasing concerns over man-induced rapid climate change made minimisation of carbon emissions desirable, claims Schollnberger, and that could lead to the replacement of fossil fuels even as they are plentiful. Three key players – the consumer, business and government – each would have an important role to play in the substitution process.

Studies of human behaviour showed that individuals react to threats or problems when they were clear and immediate, and when elimination of the threat or problem had positive consequences for the individual. Schollnberger believes that this also applies for individual consumers. Business had the responsibility and ability to deliver economic and profitable solutions to everyday problems, thereby giving consumers choices and options. Government was able to induce behavioural changes via rules and regulations, taxation policies, education and basic research. He felt taxation policies are most successful when they incentivise a changed behaviour, while high taxation in the UK for instance had not broken the trend to use ever more oil and gas.

Concerns about climate change were already motivating many governments – some 126 have signed on to the Kyoto Protocol – some from the business sector, and certain consumers. However, concern or a signed protocol did not by itself produce change, he said. It is when concern translates into human action that rapid change can be achieved.

Schollnberger then noted that since the beginning of the earth its climate had been changing, long before humans were around to trigger climate change or to do anything about it. What we needed to worry about now were the short-term and long-term consequences of rapidly increasing greenhouse gas (GHG) emissions from human activities. If we acted on GHGs introduced by man to the natural environment, we may over several generations mitigate their impact on climates. But, he pointed out that we had to recognise that taking precautionary actions is, in effect, a huge physical and economic experiment with highly uncertain outcomes.

However, stated Schollnberger, for most people, the problem of climate change was not clearly defined or immediate, and there was no common understanding of the threats or the benefits of changed behaviour. In fact, for 80% of the world's population

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Bottom: *EI Awards 2004 winners on stage with Matthew Pinsent (centre).*

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there were other, more pressing issues – poverty, genocide, corruption, access to healthcare, access to education, ethnic and religious intolerance, nuclear proliferation. These and other concerns competed consciously or unconsciously in the minds of people with concerns about climate change. More needed to be understood and made known about the named concerns, which were to various degrees interrelated and at the same time compete with each other. Then we might see how concerns about the climate may lead to the large-scale substitution of fossil fuels. Schollnberger sees lots of opportunities for the Energy Institute to contribute to the solution through research, education and communication. A somewhat discouraging analogy, however, is smoking where the information about its harmful effects are well known, but have not led to a change of behaviour by a significant segment of the population.

Cutting emissions

In contrast, large petroleum and petrochemical companies and many others in business have been reducing GHG emissions from their internal operations. BP's emissions were already 10% below 1990 levels, pointed out Schollnberger, and this was achieved in 2002 – some two years ahead of the group's own target. Much had been achieved simply by good housekeeping – plugging leaks and holes, and using energy more efficiently. He felt that Lord Browne's leadership in advocating precautionary actions had really broken the mould in the petroleum industry and shown that GHG emission reductions were both possible and economic. Now petroleum companies were turning their attention to reducing GHG emissions caused by the use of their products outside of their refineries and plants. In this context, Schollnberger notes, it is important to remember – as a rule of thumb – that if the carbon dioxide (CO_2) emissions from coal were set at 100, then the emissions for oil were roughly at 75 and for natural gas at 50 for the same amount of labour.

Meanwhile, most governments were already having difficulties meeting their recently established Kyoto targets. Governments relied on economic growth to achieve their social and political objectives. However, economic growth produced growth in emissions, so the challenge was to reconcile the various objectives and ambitions of governments.

Schollnberger felt we now had to leave Kyoto behind and target an acceptable level of CO_2 in the atmosphere instead. Levels had already moved from the pre-industrial 270 ppm to the current 370 ppm. The aim currently under discussion was to stabilise at around 500–550 ppm – a level that in the opinion of some scientists and economists may mitigate man induced climate change and, at the same time, allow for the economic growth needed to ensure the health and well being of future generations.

Efficiency

He then turned to the potential emissions reductions and other benefits possible by using fuels more efficiently. Noting that overall fuel efficiency in motor vehicles is still low, at around 19%, he pointed out that a change in technology had revolutionised power generation. Whereas coal-fired generation achieved overall first cycle efficiencies of around 30–40%, the latest gas-fired combined-cycle gas turbines (CCGT) were generating electricity with efficiencies up to 60%.

Schollnberger then went on to point out that air-conditioning was very inefficient, with considerable potential for improvement. On the vehicle side, a number of positive trends were already underway. We already had ultra-efficient diesels and direct gasoline injection was approaching large-scale commercialisation. Hybrid cars were another route, and there were new fuels with the potential to double current mileages. However, to drive the changes and ensure they were taken up would require profound changes in consumer attitudes and suitable regulations and tax incentives for consumers and business, he commented.

Emission reduction needed to be complemented by GHG separation, capture and sequestration. There was increasing cooperation between government and business in research and pilot studies. Schollnberger cited the Sleipner CO_2 sequestration project in Norway as a good example. There was a clear need for economic CO_2 disposal routes to be developed and it was encouraging that Chinese scientists were finding ways to strip CO_2 from coal combustion.

Alternatives for electricity

Turning to alternative sources for electricity, Schollnberger explained that, for photovoltaic solar, the challenge continues to be the conversion efficiency – although considerable progress had been made. Similarly, wind generation was much improved, with rapid growth on a small base, notably in Spain, Denmark, the UK and Texas. So far, the potential for locating windmills offshore had barely been tapped, but was a development with great potential. The long-distance transportation of electricity was also a challenge, but one where large progress had been made in bringing down the costs of the conversions between alternating current (AC) and direct current (DC). And there were considerable opportunities for further efficiencies, which would make it more economic to link windy or sunny regions with consuming centres. Once again, to really drive the move to non-fossil fuel generation, large-scale credits are needed or other forms of 'infant industry' subsidy.

Turning to biofuels and extenders, Schollnberger noted that getting the energy balance (fuel in, fuel out) right was of great importance. At the moment biofuels were all too often used as a means to justify agricultural subsidies rather than being economic fuel options.

Hydrogen was still relatively costly and was currently mainly manufactured from natural gas. It still had to overcome distribution, storage and safety of use issues. 'But,' he exclaimed, 'we might be moving towards a hydrogen economy. The big question is: When?'

Gradual transition

Increased energy efficiencies would result in lower energy intensity. The consultant Wood Mackenzie was predicting prices of \$30/b in 2010, anticipating a further rapid fall in energy intensity. While Schollnberger did not believe that the price would get that low, he noted that a 50% fall in energy intensity had already occurred in the US between 1973 and the early 1980s and he believed that as economies evolved there was considerable further potential for reductions.

He advocated smooth change to allow the necessary choices to be made in developing future energy mixes. The dream was a sustainable energy mix, but, as he quickly points out: 'The content of the mix will change over time.' He remained optimistic about the role and position of oil and gas in the mix for many decades to come. While agreeing that there was no time to waste, there was no need for irrational or precipitate action. 'By the way,' he said, 'the evolution of a new energy mix is already underway.'

Schollnberger concluded: 'I firmly believe not only that a sustainable energy mix is achievable, but that we shall attain an abundance of sustainable energy.' Few, however, would doubt the challenges ahead in converting the potential of a resource into the physical fuels the consumer uses.

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t: +44 (0)20 7467 7151 f: +44 (0)20 7255 1472 e: nwilkinson@energyinst.org.uk

www.energyinst.org.uk

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Longer life for ESPs

Electrical submersible pumps (ESPs) have largely replaced 'nodding donkeys' to boost oil field production, but premature failure can prove very costly. To address this problem operators are now working closely with manufacturers to achieve greater reliability, using advanced digital telemetry systems to ensure that pump speed is regulated to suit prevailing conditions. Some operators are also using a more complex pumping configuration for subsea wells, so that a single failure does not cause loss of artificial lift. Jeff Crook *reports.*

A typical ESP comprises a multi-stage pump coupled to a high power electric motor in a long package that is robust and slim enough to run into the well as part of the production tubing string. The technical limits for pump capacity were recently pushed back by Shell when it deployed a dozen 1,250 horsepower (HP) pumps to 'back-produce water' on the Brent field. These were the highest power pumps used offshore to date – an achievement which won the EI Award 2004 for Technology, sponsored by Eni (see *Petroleum Review*, January 2005).

Protecting the electrical systems from harsh downhole conditions is one major challenge for ESP design, another is the design of rotating components which can resist abrasion from solid particles entrained in the well stream. The use of hard-wearing materials has greatly improved pump reliability, with Zirconia bearings now used on some top-of-the-range pumps.

Further benefits have been achieved with real-time monitoring and pump speed control. Modern ESP systems permit downhole data to be transmitted to the surface over the power cable, even when the pump is switched off. Performance data may then be fed to the field control centre and to the equipment manufacturer. Inlet pressure and motor temperature are the most commonly monitored parameters, while the provision of a control system allows the motor speed to be regulated to suit the prevailing downhole conditions.

Many operators also recognise that the successful operation of ESPs is dependent on taking a whole system view of an installation, rather than simply focusing on the performance characteristics of individual components. This approach can be fostered by involving the equipment supplier with the operations team, as was illustrated by Wytch Farm, where Schlumberger REDA ESP Systems has a management presence on the BP-operated site.

Wytch Farm first

Wytch Farm is the UK's largest onshore oil field, with recoverable oil reserves originally put at 41.1mn tonnes. Development has been complex, however, because the field lies underneath Poole Harbour and extends out into Poole Bay. This has been designated an Area of Outstanding Natural Beauty, with protected habitats for wildlife, public beaches and pleasure boat activity.

Strict planning rules demanded that the drilling centre be restricted to small secluded sites, of around four acres each, with all process equipment hidden beneath the tree line. These tough restrictions meant that only 2.6mn tonnes of the oil had been produced by 1989, after its first decade of operation, with oil production running at around 5,000 b/d.

However, the field prospects were transformed with the drilling of extended reach wells and the installation of ESPs, in the early 1990s. As a result of these technical innovations, production rose sharply – peaking at 95,000 b/d in 1995.

Amongst the achievements at the site was the world's first 10-km step-out well – drilled from the Goathorn Peninsula in Poole Harbour into the Sherwood Triassic reservoir that lies under Poole Bay. Another achievement was the drilling of tri-lateral wells in the early 2000s, which led to a 20-fold production increase from each main well bore.

Thanks to this new technology, production reached a cumulative total of over 61mn tonnes by the end of 2003. Annual production is currently running below its peak – totalling 1.9mn tonnes in 2003 compared to 4.7mn tonnes in 1996, according to DTI figures – while BP now puts the recoverable reserves at 500mn barrels (67–69mn tonnes) of oil. Wytch Farm has, meanwhile, become a valuable test bed for well technology.

The ESPs on the site were supplied by Schlumberger, who claimed a UK record when one of its units achieved a 10-year continuous pumping life, thus outperforming comparable equipment by about five years. The company estimated that the 10-year run time of this ESP saved over $1.1mn in work-over costs in comparison to other systems currently on the market. The record-breaking REDA GN4000 ESP was installed in well F8SP in 1990 and has produced over 2.6mn barrels of oil during its decade of operation. It continues to run at the time of writing.

Schlumberger says that the exceptional performance of this ESP could be attributed to a combination of factors, including the equipment quality, the stable environment of Wytch Farm and the manner in which the equipment was initially installed, then subsequently operated and maintained.

The company also states that careful monitoring of ESP efficiency means potential problems are diagnosed early and remedied quickly, thus maintaining optimum production and extending the pump life of installations such as that at Wytch Farm.

Offshore and subsea applications

Intervention costs are particularly high on small offshore platforms, which lack permanent drilling facilities, or on subsea developments. The deployment of an ESP in a subsea well presents an additional challenge since it is necessary to transmit high voltage electric power through the pressure casing of the subsea wellhead tree on the seabed. Whilst technical solutions have been found to this challenge, there are relatively few applications thus far, largely due to the high cost of well intervention.

Retrieval and replacement of an ESP from a subsea well involves pulling the production string by means of a mobile drilling unit whose charter rate is likely to be over $100,000/d. These operations were simplified with the development of horizontal trees, since the string can be pulled whilst the subsea wellhead tree remains in place – but these operations remain extremely costly. Nevertheless, a small number of ESPs have been deployed in subsea wells, with the most notable application being the Liuhua 11-1 field, located 220 km south-east of Hong Kong.

Liuhua 11-1 was jointly developed by CNOOC, Amoco and Kerr-McGee at a cost of over $600mn. It was commissioned in 1996, being the largest oil field under Sino-foreign cooperation in Chinese offshore waters. The reservoir, which contains 1.3bn barrels of oil, is characterised by limited reservoir drive and heavy 21° API crude. The complex geological nature of the reservoir meant that it was only possible to achieve economic production rates by drilling horizontal wells and installing ESPs for artificial lift. The development was further complicated by the 310-metre water depth, as well as often adverse climatic conditions, including typhoons.

The Liuhui development consists of an FPSO vessel connected to 20 subsea wells, supported by a floating production system (FPS). The FPS is a converted semi-submersible drilling rig that is designed to support the ESPs. The permanently moored FPS feeds electric power to the ESPs and can perform well intervention for ESP maintenance. The performance of the 400 HP ESPs is vitally important for the project and expertise has therefore been provided by Schlumberger (formerly Lasalle Engineering) as a member of the integrated project team. The procurement contract contained incentive clauses, the aim of which was to maximise ESP run-life.

It is also possible that large numbers of ESPs could be installed in subsea wells for the Marlim oil field offshore Brazil at some stage in the future. This massive field produced over 650,000 b/d in 2002 and is currently being developed by eight floating production units. It has 129 subsea wells (86 producers and 43 water injectors) in water depths ranging from 650 to 1,050 metres. The operator, Petrobras, is currently studying methods of extending economic field life from 20 to 40 years and has indicated that ESPs may have a role to play in this plan.[1] The company has already gained operational experience of using an ESP in a satellite well in water depths of 3,600 ft. The REDA GN5200 pump with a Model 562-270 HP motor has run trouble-free for four years and is notable for the first use of a subsea electric transformer connected to a horizontal subsea tree.

Dual ESP configuration

It would be uneconomic to provide permanent facilities for ESP support on a small subsea development. As a result, operators have adopted an innovative approach on some subsea projects to enhance the reliability of the artificial drive system by installing two ESPs in the same well. TotalFinaElf (now Total) first adopted this dual pump solution for the Otter development in the North Sea. This subsea satellite consists of three production wells and two water injection wells, tied back 21 km to the Eider platform. It came onstream in September 2002.


Wytch Farm has become a valuable test bed for well technology

Photo: Schlumberger

This artificial lift concept has been developed further for the Mutineer development by Santos and its partners[2] in the Carnarvon Basin off the north-west coast of Australia. Here, dual ESPs are to be supplemented by seabed booster pumps and by water injection. The Mutineer-Exeter fields lie in 160 metres of water, 150 km due north of Dampier, in a cyclone-prone area. The development is due onstream in July 2005.

An existing Suezmax double-hulled tanker is being converted by MODEC to act as the FPSO; it will have a capacity of 930,000 barrels of oil. The turret mooring will allow the vessel to be disconnected easily when a cyclone approaches so that it can temporarily leave the field. Production is expected to reach 100,000 b/d of oil at plateau, initially from seven subsea production wells drilled through two templates. There is provision for drilling a total of 14 wells.

The electric power for the artificial lift system will place considerable demands on the FPSO's power generation, which consists of a 31.5-MW diesel power plant supplied by the Wärtsilä Corporation. The diesels will run on treated crude oil.

Each of the wells will be provided with dual ESPs and a seabed multiphase pump. Santos explains the need for this complex artificial lift system by saying that the 'oil has an unusually low gas oil ratio (GOR) and therefore the typical NW Shelf option of using associated gas lift source was not possible'.

Subsea booster pumps are able to reduce back-pressure at the wellhead and thus boost production, although, strictly speaking, they cannot provide artificial lift. The reduction in back pressure could be a useful way of boosting flow from deepwater wells, or from long tie-back satellites. The subsea booster pumps are less costly to maintain than ESPs, since the complete pump mechanism can be retrieved from the seabed from a support vessel, utilising simple lifting equipment.

Subsea boost

Subsea booster pumps have proved a successful method of boosting production from subsea oil wells. There are now plans to use this technology to enhance production on the Schiehallion FPSO, in the UK's Atlantic Frontier. One of the first applications of this concept was Lufeng 22-1, a small oil field development 250 km south-east of Hong Kong in around 330 metres of water. This field was developed by Statoil Orient, in partnership with CNOOC, by means of subsea wells connected back to an FPSO – the converted multi-purpose shuttle tanker *Munin*.

The Lufeng crude has an API gravity of 31.1°, with a high wax content, and requires artificial lift if production rates are to be maintained at economic levels. Framo Engineering supplied the entire subsea booster system, including 400-kW multiphase pumps, umbilical and topside power supply system. The subsea manifold incorporates five pump receiver barrels, one for each well. One spare booster pump cartridge is also held. The pump cartridges may be deployed into the receiver barrels from the FPSO.

With the use of its subsea booster pumps, Lufeng has achieved much greater recovery rates than originally expected. It has produced 32mn barrels of oil to date, considerably greater than forecasts when production began in December 1997 that total output would be about 25mn barrels. Even higher recovery is expected following a recent decision to drill side-tracks, thus increasing the production rate from 6,000 b/d to 10,000 b/d and extending field life to 2008.

Notes

1 'The Marlim field development: Strategies and challenges', paper presented by R A Lorenzatto, R Juiniti, J A T Gomes and J A Martins of Petrobras at OTC 2004, Houston.

2 Mutineer partners are Santos 33.3977% (operator), Kufpec 33.4023%, Nippon Oil 25.00% and Woodside 8.20%

A taxing change

From 1 January 2005, the UK Oil Taxation Office (OTO) has changed the way in which it calculates the value of the Tax Reference Price (TRP). The TRP is the price at which equity producers of UKCS crude oil are taxed on the oil they sell from UK oil fields. The tax rates that apply to UKCS production can be anything from 0–70% depending on the vintage and profitability of the field in question. This did not change on 1 January. What has changed is the price to which this marginal rate is applied, reports Liz Bossley.

UK oil producers are faced with three main taxes:

- Petroleum Revenue Tax (PRT) at a rate of 50%
- Supplementary Tax (ST) at a rate of 10%
- Corporation Tax (CT) at 30 %

PRT was abolished for all fields whose first development consent was granted on or after 16 March 1993. All fields given a first development consent on or after that date fall into the 30% CT-only band, as do many older and smaller fields kept out of PRT by various allowances. Fields developed after 1 April 1982 were exempt from marginal rates of up to 12.5%, but then royalties were abolished for all fields on 1 January 2003. From 17 April 2002 a supplementary charge of 10%, similar to CT, was applied to profits 'inside the ring fence' (IRF).

The effect of a ring fence is that production 'profits' from upstream activity are held separately from normal corporate profits for taxation purposes. Any costs or losses from other activities, such as trading or refining, cannot be offset against petroleum production taxes. In other words, an oil field pays tax, even if the company as a whole is making a loss.

Hence, individual companies can have production taxed at 0–70% inside the ring fence. A tax rate of zero can be achieved for barrels taxed at high IRF rates, if profits can be moved 'outside the ring fence' (ORF) and other losses are available to cover profits made on oil trading.

Tax reference price

When sales of cargoes of oil by UK producers are made at arms-length, ie the 'contract is for a cash sale between unconnected parties without any other complexities', PRT can be levied on the actual contract price. But, in order to qualify as an arms-length sale the transaction must be nominated.

The UK Tax Nomination scheme is an anti tax avoidance measure introduced in 1987 by the British government. It is administered by the Oil Taxation Office (OTO) and applies to all spot sales and some term contract sales.

Penalties for making an invalid nomination within 24 hours of making an arms-length sale, or to amend a nomination within the time period allowed or for the strictly proscribed reasons allowed, are that cargoes are taxed at the higher of actual price or a non arms-length tax reference price.

In the case of sales (or 'disposals' in OTO terminology), which are not at arms-length – eg transfers between group companies, oil taken by the participator for refining, commodity swaps, barter arrangements etc – PRT is applied to the OTO's assessed market value, which is computed for each month in each chargeable period. This is the tax reference price (TRP). A chargeable period is a six-month period beginning in January and July of each year. The TRP is applied to all non-arm's length disposals in that month, regardless of the actual sale price. It is the OTO's method of calculating the TRP that changed on 1 January.

New methodology

Hitherto, the TRP has been computed to represent a '... price at which oil... might reasonably have been expected to be sold under a contract of sale...' under stringent conditions including that the contract is at arm's length to a willing buyer and is for delivery of oil (ie a physical cargo rather than a derivative forward or future price).

The TRP value was arrived at by taking a volume-weighted average of Brent deals done for each business day in the valuation reference period (VRP), which is the first day of M-1 to middle of M, where M is the delivery month to which the TRP applies. For other grades a differential is applied to the base Brent value. This needs contract information and deal evidence for each business day, which OTO get from PRT returns submitted to it.

According to the OTO: 'We do not have sufficient data to support [the old] method. We have increasingly been forced to rely upon interpolations to fill the gaps in the data. This situation can only get worse, probably in the short- rather than the long-term.'

The legislation provides alternative rules for these circumstances 'if or in so far as the Board are satisfied that it is impracticable or inappropriate to determine... the price of oil in any month ...'. Reasons can include insufficient information to calculate a value on this basis, or the nature of the market, or for any other reason. The legislation provides for two other methods:

- using other contracts so far as it is practical and appropriate to do so;
- otherwise the OTO can determine values '... in such other manner as appears ... appropriate in the circumstances'.

The new methodology is based upon

Price Reporting Agency (PRA) assessments using a daily average of the prices produced by three pricing agencies – Platts, London Oil Report (LOR) and Argus. This daily average is then used to calculate the average price over the VRP.

Before changing to this new basis, the OTO experimented by running the old system and the new system in parallel during the two chargeable periods of 2H2003 and 1H2004. The results are shown in **Table 1** and suggest that the OTO has cut down on its calculation and reporting workload without a significant impact on the bottom line of tax take.

$/b	Old method	New method	Difference
Jul-03	27.92	27.79	0.13
Aug-03	28.93	28.88	0.05
Sep-03	28.73	28.97	–0.24
Oct-03	28.16	28.12	0.04
Nov-03	29.14	29.13	0.01
Dec-03	29.24	29.24	0
Jan-04	30.37	30.34	0.03
Feb-04	30.72	30.66	0.06
Mar-04	31.86	31.86	0
Apr-04	33.1	33.08	0.02
May-04	34.57	34.58	–0.01
Jun-04	36.95	36.96	–0.01

Table 1: The OTO experimented by running the old system and the new system in parallel during the two chargeable periods of 2H2003 and 1H2004

Mark consequences

The UK oil producers have raised no significant opposition to the change, but there may be some knock-on effect for market practice. At the moment the hedging market for North Sea oil is based on Brent forwards (21-Day Brent/Forties/Øseberg) and CFDs (dated to paper contract for differences) as reported solely by Platts. The three publications report contracts inconsistently, which means that a hedge based purely on Platts quotes will be an imperfect hedge of a tax position based on Platts, LOR and Argus.

Equity producers in the UK sector anxious to avoid basis risk now have an incentive to hedge based on an average of Platts, LOR and Argus quotations. **Table 2** shows that in a month where volatility was low, such as the delivery month of July 2003, the correlation between the prices reported by the three publications was high. However, even in that month with low volatility, the consequences for a UK producer of a 600,000 barrels cargo of a hedge based solely on Platts or a TRP based on an average of Platts, LOR and Argus was $89,000. In more volatile months, such as we saw during 2004, this basis risk could easily reach $500,000.

The change by the OTO is regarded as a sensible move. Despite industry efforts to shore up declining Brent production by the inclusion of Forties and Øseberg volumes in the dated Brent benchmark price and the introduction of 21-Day forward BFO (Brent/Forties/Øseberg) contract to replace 15-Day Brent, Brent is suffering the death of a thousand cuts as an international reference price. Further market changes are likely and a debate is warming up to replace Brent as the international benchmark with a Mediterranean-based grade. The OTO's move has put the onus of benchmark pricing squarely on the shoulders of the oil price publications.

Correlation July 2004	Platts/LOR	Platts/Argus	LOR/Argus
	0.97	1.00	0.96
Average $/b	Platts	Argus	LOR
	27.64	27.83	27.73
Difference from TRP $/b	Platts	Argus	LOR
	0.15	–0.04	0.06

Table 2: Correlation of forward prices as reported by Platts/LOR/Argus for July 2004

Other regimes

The erosion of Brent as a benchmark has consequences internationally. An estimated two-thirds of international oil production is priced by reference to Brent. Most international production sharing contracts (PSCs) contain a clause that describes what is meant by 'market price' – the price which physical oil ought to achieve in the market – in the regime in question. Many PSCs are priced by reference to Brent, not just for taxation purposes but for determining the cost recovery price and the host government's share of profit oil.

The issue is that this market price definition may be different from the price which producers actually achieve in the market when they sell the oil.

Some PSCs, which may have been signed many years before production commences, are very specific about how this market price is to be measured when production is onstream. Market price may be a government sales price or it may be a published marker price, adjusted for the specifics of each project, or it may be a fair price to be agreed at the time and place of delivery – typically with a disputes resolution procedure often involving independent expert determination. Most modern PSCs have a reference to a Brent-related oil price that is in some way related to prices obtained in the international market at arms-length between a willing buyer and seller. For example, the Saudis and Iranians set their prices by reference to 'BWAVE', the Brent Weighted Average price published by the International Petroleum Exchange (IPE).

This PSC-defined market price has a pivotal role to play in calculating cost recovery, profit share, royalty in cash and tax. Contractors have an incentive to convince the host government that the market price of oil is low, as this will boost the number of barrels that the contractor will be allowed to lift to recover its costs, lower the number of barrels to which the state oil company is entitled as profit share, and will depress the taxation/royalty bill.

In the case of domestic supply obligations, the contractor would obviously prefer to sell into the domestic market at as high a price as possible – but the net commercial driver for the contractor is for a low price. In some regimes the market price to apply for PSC purposes is the subject of a difficult regular negotiation between the host government or NOC (national oil company) and the contractor. In other regimes the market price is proscribed by the host government.

Any shortfall between the market price, as defined by the NOC, and the actual sales price achieved by the contractor in selling its oil is, arguably, a hidden project cost.

The fact that the UK's OTO is recognising the erosion of the Brent deal base in its tax reference pricing should sound a warning note to state oil companies around the world.

Saudi proven oil reserves – how realistic?

Dr Mamdouh G Salameh* *takes a sceptical view of Saudi oil reserves and production capacity, citing a wide range of sources and expressing concern about this all important supplier to the world market.***

At a time of turbulence in the global oil market, the world's attention is focusing on Saudi Arabia as the lynchpin of global oil supplies. However, questions have increasingly been raised about the actual size of Saudi proven oil reserves. The common wisdom has always been that Saudi Arabia sits on a quarter of the global proven oil reserves amounting to 262.7bn barrels.[1] This is despite a lack of significant discoveries between 1980 and 2003, and a production of more than 62bn barrels during the same period.

As global proven oil reserves are increasingly coming under close scrutiny, many experts are now questioning how Saudi proven reserves had suddenly jumped from 169.59bn barrels in 1987 to 254.99bn in 1988 – a 50% jump in one year. Doubts have also been raised about the shelf-life of Saudi Arabia's oil fields, while long-standing assumptions about Saudi oil are now being questioned.[2]

Questions are also being raised about the actual size of Saudi spare production capacity – claimed to be 3mn b/d. However, industry insiders maintain that, at current production levels, Saudi Arabia has no spare capacity.

Proven oil reserves

Saudi Arabia's proven reserves stood at 262.7bn barrels at the end of 2003, according to the 2004 *BP Statistical Review of World Energy*. Saudi reserves had remained remarkably stable for most of the 1990s, and also between 1980 and 1987, before suddenly and dramatically jumping from 169.59bn barrels in 1987 to 254.99bn in 1988 (see **Table 1**).

However, many oil analysts tend to the view expressed by Saudi Aramco's former Vice President and leading geologist, Sadad Al-Hussayni, who, in articles appearing in the *Oil & Gas Journal* this summer, insists that Saudi proven reserves amount to only 130bn barrels.[3] On the other hand, Colin Campbell, an internationally-renowned geologist, estimates Saudi reserves at less than 100bn barrels.[4]

In January 1988 the *Oil and Gas Journal* estimated Saudi oil reserves at 167bn barrels. By the end of 1988 this figure had jumped to 254.99bn – a sudden jump that could not be explained by oil discoveries as not much drilling was conducted that year.

During the period 1980–1987, net Saudi reserve additions amounted to a mere 3.19bn barrels. In more recent years, the additions to reserves have been far more modest. Between 1989 and 2003, net reserve additions amounted to only 7.46bn barrels.

In the late 1980s there were huge and abrupt increases in the announced oil reserves of several Opec nations. Earlier, each Opec member was assigned a production share based on the country's annual production capacity. Opec changed the rule in the 1980s to consider also the oil reserves of each country. Most Opec countries promptly increased their reserve estimates (see **Table 2**). The sudden additions to reserves coincided with Opec's decision in 1982 to adopt a production quota system in defence of the oil price, which was coming under heavy pressure.

Several explanations have been suggested for the sudden jump in Saudi reserves between 1987 and 1988. One explanation is that these reserve additions were clearly 'political reserves' – ie reserves that were added to support Saudi Arabia's demands for a higher production allocation within Opec's quota system. Another explanation may be that assessment of Saudi reserves was originally based on a recovery rate of 20% of oil-in-place and was later re-evaluated at a recovery rate of 60% – far above the current global rate of 29%.

One plausible explanation could be a mixture of small oil discoveries, upward revision of existing reserves, demands for higher production share under Opec's quota system and some wishful thinking. Saudi Arabia was always determined to

Year	Proven reserves (bn barrels)	Production			Net reserves additions (bn barrels)
		Daily average (mn b/d)	Annual (bn barrels)	Cumulative (bn barrels)	
1980	164.16	9.90	3.61	42.31	–2.24
1981	163.98	9.81	3.58	45.89	–0.18
1982	167.90	6.48	2.37	48.26	3.92
1983	168.85	4.54	1.66	49.92	0.95
1984	166.30	4.08	1.49	51.41	–2.55
1985	166.50	3.18	1.16	52.57	0.20
1986	169.00	4.78	1.74	54.31	2.50
1987	169.59	3.98	1.45	55.76	0.59
1988	**254.99**	**5.09**	**1.86**	**57.62**	**85.40**
1989	260.05	5.06	1.86	59.47	5.06
1990	260.34	6.43	2.35	61.82	0.29
1991	260.94	8.12	2.96	64.78	0.60
1992	261.20	8.33	3.04	67.82	0.26
1993	261.20	8.05	2.94	70.76	0.00
1994	261.37	8.05	2.94	73.70	0.17
1995	261.45	8.02	2.93	76.63	–0.08
1996	261.44	8.10	2.96	79.59	–0.10
1997	261.54	8.01	2.92	82.51	0.10
1998	261.54	8.28	3.02	85.53	0.00
1999	262.78	7.56	2.76	88.29	1.24
2000	261.70	8.32	3.04	91.33	–1.08
2001	261.80	8.02	2.93	94.26	0.10
2002	261.80	8.68	3.17	97.43	0.00
2003	262.70	9.00	3.29	100.72	0.90

Sources: BP Statistical Review of World Energy, *June 2004;* Opec Annual Statistical Bulletins, *1980–2003*

Table 1: Saudi oil reserves and production, 1980–2003

be the leader of Opec and to have a high production quota.

However, there are grounds to suggest that Saudi proven reserves could be overstated by 80bn barrels and that a more reasonable estimate should be 182.72bn instead of 262.70bn barrels. This is based on an average global recovery rate of 29%, rather than on a rate of 60%, and also on my own calculations of Saudi oil production and discovery figures between 1980 and 2003 based on data provided by Opec.

The new reserve estimate may also be arrived at by subtracting out any abrupt jump in Saudi reserves between 1987 and 1988. After 1989, it is estimated that 60% of production between 1989 and 2003 was a drawdown from the reserves and 40% was either corrections for previous underestimates or the addition of new oil reserves.[5] The 60:40 split is intended as an average performance figure for those Opec countries – Iran, Iraq, Kuwait, Saudi Arabia, UAE and Venezuela – that reported abrupt reserve increases (see **Table 3**).

Using this logic, some 80bn barrels must be deducted from Saudi Arabia's current proven reserves of 262.7bn to give a more realistic figure of 182.72bn.

Country	1982 reserves	Reserve additions	1988 reserves
Iran	56.15	36.71	92.86
Iraq	59.00	41.00	100.00
Kuwait	67.15	27.38	94.53
Saudi Arabia	165.48	89.51	254.99
UAE	32.35	65.76	98.11
Venezuela	24.90	33.61	58.51
Total	**405.03**	**293.97**	**699.00**

Sources: Opec Annual Statistical Bulletins, *1982–1989*

Table 2: Major reserve additions by Opec members, 1982–1988 (in bn barrels)

Reserves	Reserve additions	Production	Drawdown	Additions	Actual reserves
254.99	89.51	43.11	25.87	17.24	182.72

Sources: Opec Annual Statistical Bulletins, *1982–1989;* BP Statistical Review of World Energy, *June 2004*

Table 3: A revision of current reserves of Saudi Arabia (in bn barrels)

Behind the numbers

Energy analysts have recently raised questions about the amount of oil that can be easily pumped from Saudi oil fields, the world's biggest. The Saudis are downplaying those worries, arguing they could boost output to 10mn b/d and sustain that level for decades. Still, sceptics believe that Saudi reserve estimates are overstated and that Saudi oil may be more expensive to produce than forecast.

What does Saudi Arabia mean when it says it has 262.7bn barrels of proven oil reserves? Saudi Aramco uses the definition of the Society of Petroleum Engineers (SPE). The SPE defines proven reserves as quantities of oil that are 'reasonably certain' of recovery. The SPE also says there should be a 90% probability that the amounts produced will equal or exceed the estimate. Various methods are used to scope out the reserves, including drilling to delineate reservoirs and measures of flow rates from wells.[6]

The problem with Saudi Aramco's reserve data is that there is no independent auditor to vouch for them. Moreover, reserves are viewed by many analysts with suspicion because their size translates into political clout within Opec. If the Saudis don't like doubts being cast on their reserves, they could allay any such doubts by presenting transparent data to back up their claims.[7]

Since it is widely assumed that Saudi Arabia controls about a quarter of the world's proven reserves, any doubts about the actual size of their reserves go to the heart of the global economic system. If the sceptics are right, the Saudis could soon be in deep trouble. If it turns out that they have much less oil than they claim, the role of Saudi Arabia would be completely devalued strategically. With no alternative to oil in sight for decades, the US and other consuming nations would increasingly need to look to other sources, such as Iraq or Russia.

But while few in the industry doubt the Saudis have huge quantities of oil, experts warn that even the Saudis won't know their capabilities until an actual ramp-up of production. Even then, they may have surprises ranging from steep decline rates in some giant fields to water incursion problems.

In addition, if older fields elsewhere in the world run down, the Saudi fields may be called upon to compensate – they will need to produce 13.6mn b/d by 2010, rising to 19.5mn b/d by 2020, according to the International Energy Agency (IEA). The IEA reckons that global demand for oil will grow from an estimated 82mn b/d in 2004 to 120mn b/d by 2020. In this scenario, the Saudis would be supplying close to 30% of that increase.[8]

Saudi Aramco says that with more investments it can expand its capacity to 12mn b/d or more. But, according to the *New York Times*, privately Saudi oil officials are less self-assured, calculating that production beyond 12mn b/d would damage the oil fields.[9]

However, there is lingering concern among analysts about whether the Saudis are moving fast enough to develop new sources of crude. The issue is not whether there is enough oil but rather whether they have the willingness and the ability to develop it in a timely manner. With new capacity costing $3,000 to $4,000 per daily barrel, the Saudis would have to spend somewhere between $6bn and $12bn just to get to 12mn b/d – along with substantial costs to maintain production. But energy analysts worry that because Saudi Arabia and other big Middle East producers are largely closed to foreign investment, there may be financing constraints. If the reserves are closed to foreign direct investment, they may not be able to find the necessary funds.[10]

Production capacity

Until recently, Saudi Arabia was thought to have a spare production capacity of over 3mn b/d.[11] However, oil insiders maintain that Saudi Arabia has no readily available spare capacity at current oil production levels. Various estimates of Saudi sustainable capacity have been suggested (see **Table 4**).

Table 4 shows that at a current production level of 9.25mn b/d, Saudi Arabia has no readily available spare capacity. Any new addition to capacity will go to offset the production decline in its super-giant Ghawar oil field, which accounts for 59% of Saudi production.

	Sustainable capacity	Current production	Capacity utilisation	Spare capacity
EIG	9.00	9.00	100%	-
IEA	9.25	9.00	97%	0.25
Saudi Sources	10.50	9.00	86%	1.50

Sources: IEA; EIG; Arab Oil & Gas Directory 2003

Table 4: Various estimates of Saudi sustainable production capacity and capacity utilisation, 2003 (in mn b/d)

Year	Added in year	Annual production	As % of annual production
1992	7.80	23.98	33
1993	4.00	24.09	17
1994	6.95	24.42	28
1995	5.62	24.77	23
1996	5.42	25.42	21
1997	5.92	26.22	23
1998	7.60	26.75	28
1999	13.00	26.22	50
2000	12.60	27.19	46
2001	8.90	27.81	32
2002	9.00	26.99	31
2003	2.27	28.11	8
1992-2003	89.08	311.97	29
Average	**7.42**	**26.00**	**29**

*excluding the US and Canada

Sources: IHS Group's 2003 World Petroleum Trends Report *(WPT);* BP Statistical Review of World Energy, *1993–2004*

Table 5: Global crude oil reserve additions*, 1992–2003 (in bn barrels)

There are persistent reports that the country is facing major water incursion problems in the Ghawar oil field. Ghawar, the world's largest oil field, needs 7mn b/d of seawater injected to maintain the reservoir pressure.[12]

Some 90% of Saudi oil production oil comes from eight mature oil fields, including five super-giant fields discovered between 1940 and 1965. Since the 1970s there haven't been new major discoveries. In the early 1970s, four of the world's largest oil companies – Exxon, Chevron, Texaco and Mobil – estimated that the Ghawar oil field held 60bn barrels of recoverable reserves. Ghawar has already produced 55bn barrels, which means it should be at the end of its life. Moreover, Ghawar's northern regions are almost depleted.[13]

In an effort to increase capacity, Saudi Aramco is considering reviving the onshore Khurais oil field, which has a production potential of some 800,000 b/d. The Khurais field is one of five medium-sized fields containing heavy crude that were mothballed by Saudi Aramco in the early 1990s.[14]

The question is: Can Saudi Arabia expand production capacity or at least maintain it at current levels? The Kingdom is now drilling only horizontal wells in an effort to maintain production flows with around 200 additional horizontal wells drilled each year.[15] To many this sounds like a country that was working hard just to maintain production rather than one capable of increasing production by simply opening the tap.

Some experts believe that the Saudi 'miracle' of almost effortless, cheap production is nearing an end. They think the Ghawar oil field, with a production of 5mn b/d, could be running dry. The experts also suspect that most of the other big Saudi oil fields, including Abqaiq and Berri, could be past their peak. They believe that production has been sustained by water injection. They also speculate that the Saudis may soon have to develop fields once deemed marginal, just to maintain capacity. The entire world assumes Saudi Arabia can carry everyone's oil needs on its back cheaply. If this turns out not to work, there is no 'Plan B'.

R/P ratios

The current global reserve-to-production (R/P) ratio is 36 years based on global proven reserves of 1047.7bn barrels (at the beginning of 2004) and an annual production of 29bn barrels.

A downward revision of Saudi reserves by 80bn barrels will reduce the R/P ratio by three years, to 33. However, whether the figure is 36 years or 33 years, oil production will not stay flat during that period and then suddenly drop to zero. Rather it will rise to a peak after which mankind is faced with an era of declining production. Thus it is clear that 'peak production' will be an important turning point in our future reliance on oil and, therefore, consumers and governments alike should be made aware how close such a date might be.

The world is currently consuming 29bn b/y of oil on a rising trend, yet on average finding only 7.42bn b/y.[16] Over the period 1992–2003, only 29% of global oil production has been replaced by new discoveries. The cumulative shortfall over the period 1993–2003 amounted to 222bn barrels (see **Table 5**).

According to the IHS Energy Group's *2003 World Petroleum Trends Report (WPT)*, 2003 was probably the first year to have recorded no large discoveries at all, with only 2.27bn barrels of new reserves added.

Final comment

A downward revision of Saudi reserves, coupled with a lack of readily available spare capacity, could add some $10–$15/b to the price of oil.

No matter who's right about Saudi reserves, there is a growing sense that the era of cheap oil may be over. Even if the price of crude oil dips from its current $45/b, strong demand from China, India and the rest of booming Asia may keep a floor under prices. And the growing political volatility of the Middle East makes it more risky to assume that oil will flow as smoothly as it has over the past 20 years.

Dr Mamdouh G Salameh is an international oil economist, a consultant to the World Bank in Washington DC and a technical expert of the United Nations Industrial Development Organization (UNIDO) in Vienna. Dr Salameh is also Director of the Oil Market Consultancy Service in the UK and a member of both the International Institute for Strategic Studies (IISS) in London and the Royal Institute of International Affairs.

**This article is an abridged version of a paper presented at the 1st Annual CZAEE International Conference 2004 in Prague, Czech Republic, on 21 Nov 2004.*

Footnotes

1 *BP Statistical Review of World Energy*, June 2004, p4.
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3 Pepe Escobar, 'Oil's slippery slope', *Asia Times Online*, Hong Kong, 24 August 2004.
4 'Take an oil price over $40 – Then quadruple it.' *Wall Street Life Online*.
5 Kenneth S Deffeyes, *Hubbert's Peak: The Impending World Oil Shortage*, Princeton University Press, Princeton, 2001, pp147–148.
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Long-term fiscal, contractual stability proves elusive

In the first of a two-part feature, David Wood* *sets out to review the current upstream contractual frameworks, establish their objectives, explore the reasons why they sometimes fail to deliver, and consider approaches that improve flexibility and stability.*

History has shown that during sustained periods of demand outstripping supply and resulting high oil and gas prices, governments frequently attempt to extract a larger fiscal share. Conversely, during periods of widespread recession when supply outstrips demand, associated with low prices and limited flow of capital into the industry, governments are often forced to offer fiscal incentives to attract and compete for investment. Nevertheless, even the most stoical of observers have been surprised by the pernicious and innovative nature of recent attempts by several governments to challenge and erode either contractual or fiscal value of international oil and gas projects.

Some examples of recent government-induced erosion of petroleum project value include:

- ***Kazakhstan*** – increase in taxes by amending the tax code; impounding of equipment; and claiming pre-emptive rights on assignment (giant Kashagan field).[1]
- ***Russia*** – further rises in production tax (August 2004) and export tax (January 2005) add to a recent history of fiscal instability; systematic dismantling of Yukos; procurement constraints in Sakhalin projects.[2]
- ***Nigeria*** – NNPC claiming substantial back-in rights to some large deepwater discoveries (eg Agbami).[3]
- ***Bolivia*** – the introduction of a new hydrocarbon law following a referendum in 2004; government seeking to increase royalties (from 18% to 50% muted) and taxes on existing licencees.[4]
- ***Angola*** – assignment disputes with Sonangol seeking greater contractual participation; ongoing procurement constraints.
- ***Trinidad & Tobago*** – upward revision of fiscal take secured for older tax/royalty contracts (BP/RepsolYPF). Renegotiations are ongoing to impose harsher terms for existing PSAs following investment in four LNG trains.
- ***UK*** – the introduction of a 10% supplementary charge on corporation tax in 2002 illustrates that fiscal instability is not the preserve of developing nations. Historical windfall profits taxes in the US could also be cited in this regard.
- ***India*** – attempts in December 2004 by the Indian government to levy a fixed rate CESS (production tax) of some $3/b on Cairn Energy's future production from its Rajasthan production sharing contract. Cairn is disputing who should pay the CESS based upon the contract terms, which it interprets to indicate that state-owned ONGC holds that liability.[5]
- ***Venezuela*** – an increase in royalties (October 2004) on the four heavy crude upgrading projects (ChevronTexaco, ExxonMobil, ConocoPhillips, BP, Total and Statoil) in the Orinoco Belt to 16.6% from 1%.[6]

The basic principles

Figure 1 outlines a basic approach to achieving long-term contractual stability between international oil companies (IOCs) and governments (represented by their national oil companies (NOCs) and various ministries and other government agencies). It seems a matter of straightforward common sense as expressed, but all too often the reality of contract negotiations ignores these basic principles. IOCs commonly fail to integrate all the issues and risks when negotiating contracts, relying too heavily on legal, financial and economic assessments performed by groups with limited on-the-ground exposure in the country where the agreement is to operate, without taking in the bigger picture.

Governments and IOCs frequently fail to empathise with each other's objectives and look instead for ways to exploit opportunities independently and build on their individual strengths. This competitive approach works well in extracting value for the consumer in most corporate activity and is part of the rough-and-tumble of capitalism. However, it does not enhance the stability of long-term relationships in which the balance of power and value can oscillate dramatically between one party and the other.

The pendulum of power in upstream contracts swings from the government during contract negotiations towards the contractor as it invests and discovers petroleum, back towards the government as investment and technology is sunk into field and facilities development. The contractor is most exposed to contractual changes just before a field comes onstream (all investment spent, no revenue yet received) and governments have most power. During the production phase the volatility of market conditions cause value to oscillate back and forth between the parties and governments are able to use their power to claw back value, but frequently slow down investment and development as a consequence.

However, this cycle is now well established and companies and governments should be able to overcome their urges for short-term gains. A cooperative approach is usually in the interest of all parties. It involves empathy, shared vision, flexible fiscal mechanisms and agreed long-term objectives. It is unlikely to be achieved by lawyers, economists and financiers drafting and interpreting contracts remotely or dealing with issues in isolation.

Figure 1 also highlights the fact that it is not just two parties involved. Many assume that all key issues and agreements are polarised between IOCs and NOCs. This is far from reality – on the side of the state exists the NOC, ministries, agencies, local community bodies and NGOs; on the side of the IOC are joint venture partners, suppliers, engineering contractors, debt financiers, export credit agencies and, in some cases, corporate divisions with conflicting strategies. Conflicting issues amongst these parties frequently lead to minor disputes (minor, that is, in terms of the overall long-term objectives). Clearly defined and workable timeframes and principles for dispute resolution are therefore essential.

E&P agreement framework

There is a plethora of upstream fiscal and agreement structures operated worldwide, each designed to extract economic rent to suit sovereign needs. To get to the root of the instability issues it is necessary to explore and understand how these agreements work and influence the returns achieved by the parties involved. They can, in broad terms, be classified into three main groups (see **Figure 2**).

Concessions (tax-royalty) – The earliest systems originating and maintained in OECD countries where governments hold mineral rights (US excepted) and title to reserves discovered is vested in concessionaires through licences with no contract involved. Fiscal instruments include royalties, special petroleum taxes (eg the defunct petroleum revenue tax (PRT) in the UK) and corporation tax. The rates of royalties and taxes are frequently linked to other metrics that trigger specific rates and increase flexibility (see below).

Production sharing agreements (PSAs) – Since the first one was signed by US independent IIAPCO in 1966 with the government of Indonesia these have become popular with developing nations because they retain title to reserves and are able to share in the revenues from risk investments without taking the financial risks. Disputes are dealt with under contract law. The IOC receives its reward for taking E&P risks and making investments in terms of a fee made up from shares of field production. Fiscal mechanisms that determine how production is shared vary significantly from country to country, but usually involve distinctive elements relating to profit and to cost recovery (see below). Most PSAs involve exploration and production phases (EPSAs), but some (eg Qatar) are signed to cover development of already discovered reserves (DPSAs). Some PSAs attempt to achieve fiscal stability by either allocating tax and royalty payments to be made only from the government's share of production, or, including a fiscal stability clause.

Service contracts – The least favoured by the IOCs because they are engaged to perform development work on a financial fee basis (cost plus an agreed rate of return) without the opportunity to share in the upside revenues from long-term field production. There are some hybrid contracts between PSA and service types that link the IOC's fee to production performance and revenues.

These tend to place more technical and financial risk on the IOC than straight service contracts, but severely limit their long-term participation in successful ventures (eg Iran's buy-back contracts).

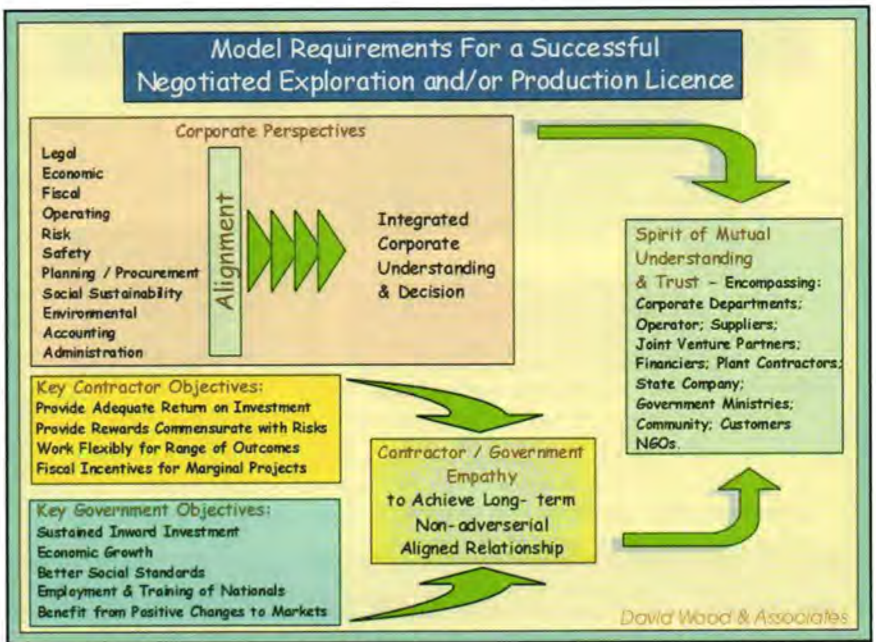

Figure 1: Basic requirements for stable long-term agreements – the word 'alignment' is the key to this approach

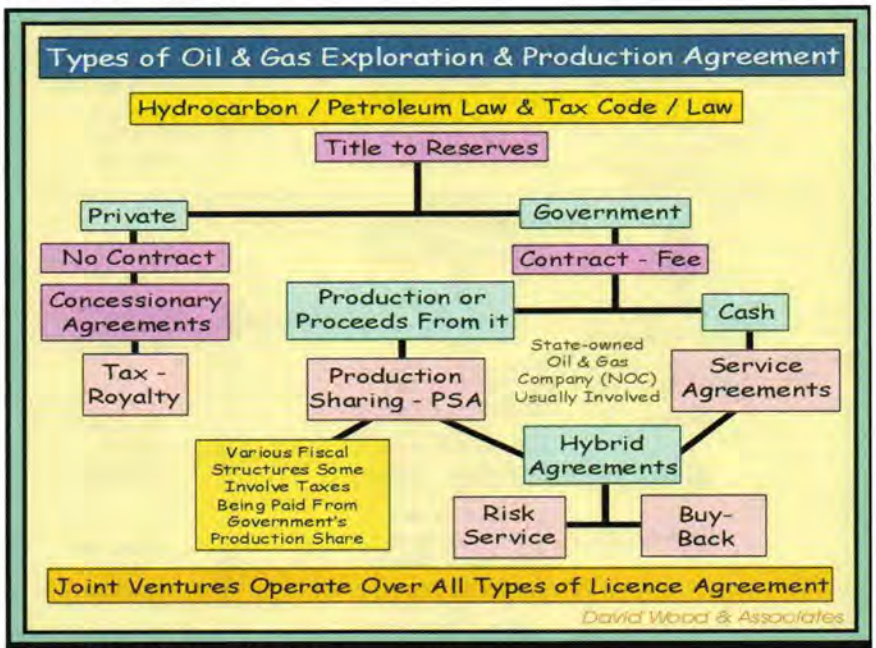

Figure 2: Classification of upstream agreement types

Not all countries operate just one or other of these types of contracts. In Nigeria, for example, projects with all three of these contract types are active. Moreover, countries may operate several contracts with different PSA mechanism for historical, geographic, variable risk or cost reasons.

Indices that attempt to rank the severity or otherwise of fiscal terms in a country should take such complexities into account, but rarely do so. This article focuses on PSAs because they are now the most common contract type employed for the exploration and development of large fields in the developing world, and are frequently associated with high political risk countries. They are not, however, embraced by all developing nations.

Several Opec countries refuse to entertain them (eg Saudi Arabia, Kuwait and Iran) and a fierce debate has ensued in Russia, which adopted a few PSAs in the 1990s (eg Sakhalin I and II) but has essentially rejected them in recent years in favour of a tax system that enables the government to more easily adjust (generally upwards) its take and control the industry in line with market conditions.

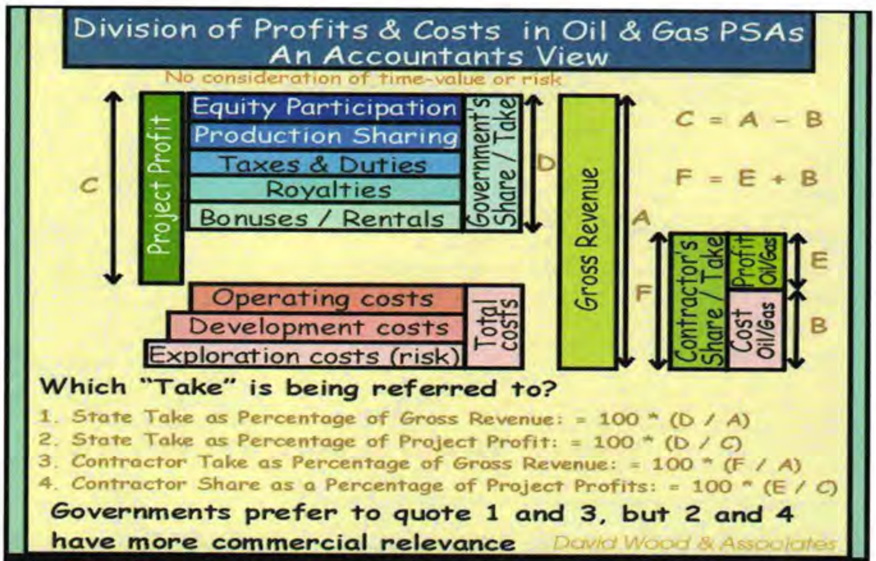

Figure 3: Make up of contractor and state takes of gross revenue and of field profits – the term 'take' requires precise qualification

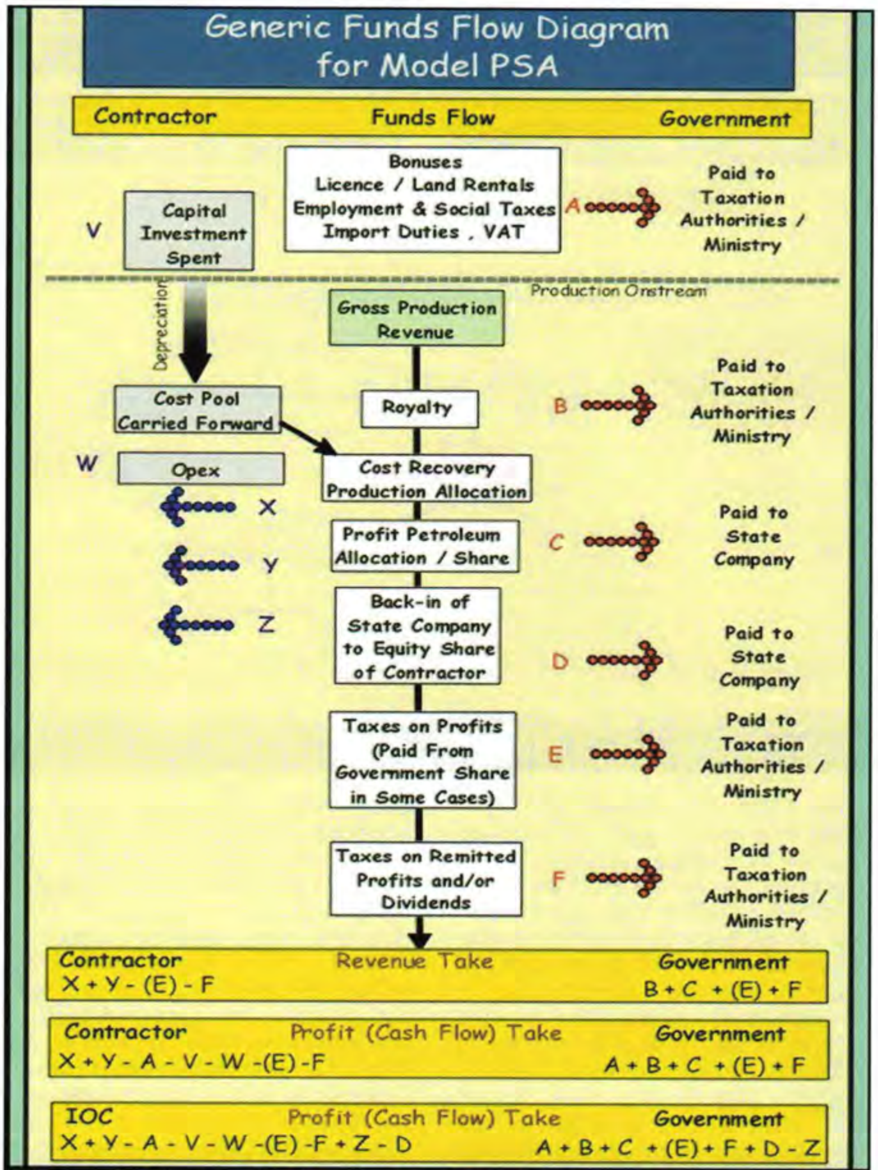

Figure 4: Flow diagram of fiscal mechanism and take components in a typical PSA[7]

PSA contractor – state takes

The fiscal mechanisms of PSAs determine which party gets which share of production. The 'contractor' usually involves a joint venture of IOCs, but frequently also involves a NOC with a carried interest through exploration and/or with a back-in right to take an equity stake in the contractor's contractual position (commonly ranging from 10% to 40%). Hence the term 'contractor' is often *not* synonymous with an IOC and it is distinguished from such in this article. It should also not be confused with the contractors that undertake to engineer, procure, install, fabricate and commission facilities under EPC contracts for the contractor (licences) parties to the PSAs. Some of the fiscal elements yield shares to the NOCs, others go directly to a government's taxation authorities. **Figure 3** illustrates the key financial and fiscal elements of PSAs from an accounting perspective.

The key components of shared production are cost oil (or gas) and profit oil (or gas), but they form only part of the fiscal mechanism that usually involves bonuses, royalties and taxes of various types extracted in sequence from the revenue stream. **Figure 4** illustrates this sequence of fiscal extraction, which is contract-specific, with certain elements sometimes negotiable and others enshrined in a hydrocarbon law. Although providing a simplified accountant's view of the process, it is useful for analytical and negotiation purposes to develop this into a simple quantified spreadsheet. Such a sheet should identify how and in what sequence the actual rates for each fiscal element and contractor's share are extracted from one unit of production based upon an appropriate oil or gas price.

The contractor take of profits is more complex than revenue take because it may vary depending upon field size and the interaction of actual prices and costs on the fiscal elements. Cross-plotting contractor profit take versus contractor revenue take (**Figure 5**) reveals a wide spectrum of IOC, contractor and (by difference) government fiscal takes that exist worldwide for tax-royalty, PSA and service contracts.

Whilst it is possible to generalise that the toughest fiscal takes (from the contractor's perspective) are associated with PSAs and applied in the most prospective areas (highest potential for large reserves) this is by no means a universal rule. There is much overlap in the fiscal take from the various types of contract and prospectivity levels. Poor cost recovery mechanisms (see below) and large government back-ins to take equity shares in the contractor position account for the lowest IOC take of profits for a given contractor take of gross revenue.

The problems with considering PSAs in such simplistic percentage 'take' terms include failure to take into account:

- Non-fiscal contract terms that influence contract value.
- Field size expectation and environment.
- Time-value issues impacting production sharing.
- Flexible scales and triggers for specific fiscal elements.
- Variable market conditions (oil and gas prices).
- Country track record in respect of honouring contracts.

Yet government and contractor takes are widely quoted in isolation when comparing upstream contract performance. A detailed economic and contractual analysis is essential to evaluate economic performance of specific contracts. This involves building a detailed fiscal cash flow model and stress testing it with a range of model field sizes, cost, prices and production profiles.

Relevant commercial issues

Key commercial issues and objectives arising under PSAs from the contractor's perspective and ranked approximately in descending order of importance are:

- Maximise production split for contractor's (IOC) benefit.
- Minimise regressive taxation elements (eg royalty and bonuses).
- Strive for tax stability guarantees – taxes paid from government share.
- Minimise participation, carry or back-in by state (NOC), either by contractual entitlement or through pre-emption of assignments.
- Maximise cost oil (or gas) allocations (>50%) and accelerate cost recovery.
- Minimise or avoid domestic market obligations at subsidised prices.
- Secure access to existing infrastructure at market tariff rates.
- Link oil and gas prices to international benchmarks not posted prices.
- Accelerate depreciation of capital costs (<=5 years).
- Eliminate or minimise price caps or other windfall profit taxes.
- Avoid exclusion of expenditure items from cost recovery pool.
- Strive to include interest payments on project debt as a cost recovery item.
- Avoid ring-fencing of costs around specific fields or licences.
- Secure exemption from customs duties, local and value added taxes.
- Minimise impact of local currency obligations and interest rates.
- Accelerate approval process for field development.

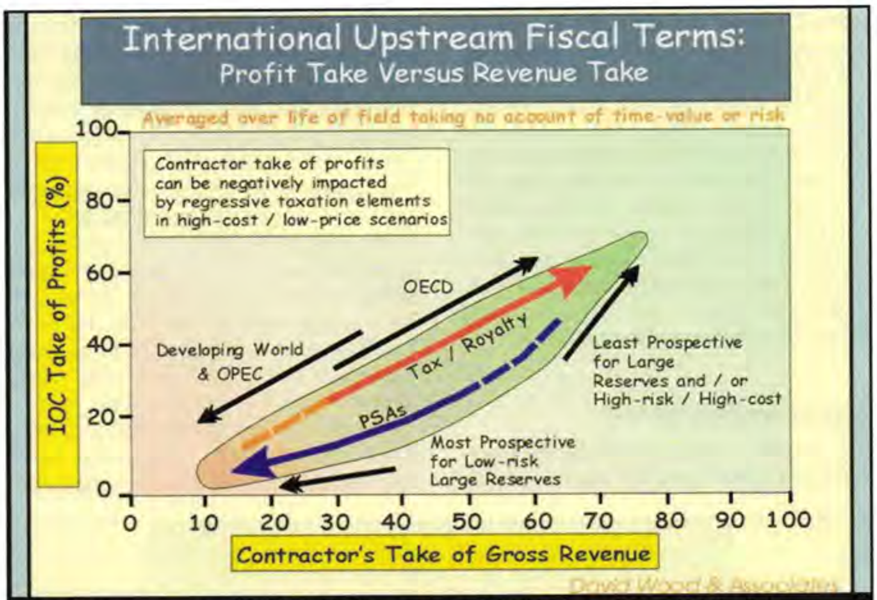

Figure 5: Take comparisons for global agreements.[8] (IOC take excludes NOC back-in portion of contractor take where applicable)

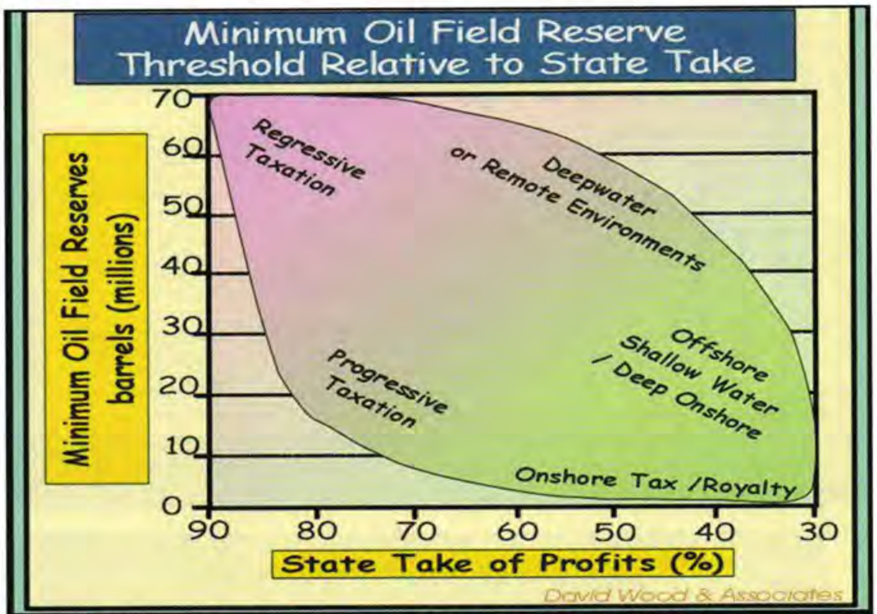

Figure 6: Minimum field size for commerciality is not simply dependent upon contractor:government take – fiscal mechanisms, technical factors and environmental issues also influence it

- Avoid procurement constraints that insist upon local contractors or substantial government interference in procurement;
- Avoid constraints on using local staff if skill levels are inadequate.
- Involve international arbitration and clear dispute and default resolution terms (eg withering clauses) focused on the principle of time being of the essence.

Of course, the exact order of importance of the above list will depend upon local circumstances, track records and specific contract structures. In many cases such terms will not be negotiable and must be either accepted or a contract rejected. Nevertheless, their impact on contract value and risk should not be overlooked in an integrated analysis.

Field size and environmental considerations

The expected size of the oil and gas field either discovered or yet-to-be found, the depth to its reservoir, its reservoir quality and its physical location (eg remote difficult terrain, deepwater etc) and a host of other technical factors associated with specific oil and gas fields will determine, together with the fiscal mechanism, the minimum reserve size required for a commercial development. This may vary greatly from area to area and contract to contract (**Figure 6**).

Very small onshore fields under tax and (low or no) royalty concessionary systems can be commercial as costs are low and fiscal take is limited to profits. On the other hand, in deepwater or remote areas where development costs are high, the minimum commercial field size is much higher, but, irrespective of fiscal mechanisms, will vary depending upon its distance and access to existence infrastructure.

Fiscal instruments

It is possible in quite high state take systems for small or medium size fields to be commercial if progressive and flexible fiscal mechanisms are involved. As fiscal systems become more regressive the threshold field size for commerciality to be achieved increases. The more distal the point from the wellhead that a tax or levy is deducted from the revenue stream the more progressive it is (**Figure 7**).

The regressive nature of royalties is a consequence of the royalty being deducted at the wellhead from each barrel regardless of whether it is profitable or not. In times of high oil price and with large oil fields few worry about regressive taxes. In the case of high cost or marginal fields or low price environments, regressive taxes can make the difference between a project being commercial or not.

Figure 8 provides an illustration of the impact of progressive and regressive fiscal mechanisms on the same field.

Progressive Versus Regressive Fiscal Elements in Petroleum Exploration and Production Agreements

Impact on E&P Companies Returns	E&P Phase	Fiscal Instrument	Revenue or Funding Component Impacted
Most Regressive	Pre-Commerciality Exploration Discovery Appraisal	Signature/ Training Bonus Land Rentals / Welfare Programs Carried Government Interest Value Added Taxes & Import Duties	Equity/ Risk Capital
	Post-Commerciality Development Commissioning Start-up	Government Back-in Discovery / Training Bonuses Capital Gains on farmout or sale Environmental Levies Production Startup Bonus	Equity & Debt Funds
	Production	Royalty Production Bonus Local Taxes based on Production	Gross Production Revenue
		VAT & Import Duties Cost Recovery & capital depreciation mechanisms Production Sharing Profit Oil	Net Taxable Revenue
Most Progressive		Special Petroleum Taxes Rate of Return or Profit Investment mechanisms to share profits Corporate Taxes Excess Profits or Windfall Taxes	Taxable Profits
		Repatriation / Withholding Taxes	Post-tax Profits
		Advance Corporate Taxes	Corporate Dividends

Figure 7: Royalty is the most regressive of post-production taxes – all pre-production levies and duties are regressive

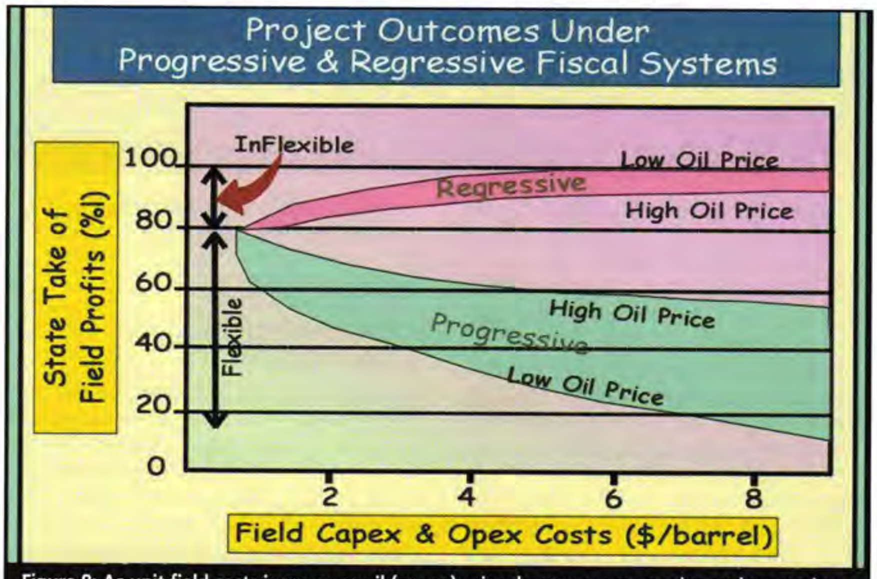

Figure 8: As unit field costs increase or oil (or gas) price decreases, progressive and regressive fiscal mechanisms operate quite differently in terms of the take of profits accruing to the state

**David Wood is an international energy consultant specialising in the integration of technical, economic, risk and strategic portfolio evaluation and management. Research and training concerning risk, fiscal and contracts terms, gas and LNG are key parts of his current work. Please visit his website at* www.dwasolutions.com *or contact him at e:* woodda@compuserve.com

Footnotes

1 Christopher Pala, 'Kazakh government discourages Caspian exploration', *Petroleum Review*, November 2004, p12–13. Martin Clark, 'Call the lawyers', *Petroleum Economist*, September 2004, p22–26.

2 On 1 January 2005, crude oil export duty rose to the record level of $9.6/b (from $5.7/b). Base mineral production tax on crude oil rose to $1.98/b of production from $1.89/b, although the effective rate will be nearly twice that as it is linked to world oil price. The tax on produced gas rose from $3.69 to $4.66/1,000 cm. The latest increases in export and mineral production taxes combined amount to some 87 US cents in every dollar of revenue above a threshold of $25/b.

3 Recent articles addressing fiscal issues and NNPC back-in in Nigeria include: David Wood, 'Evolution and economic performance of production sharing terms', *Petroleum Review*, January 2003, p36–40; David Wood, 'Marginal field initiative raises political tensions', *Petroleum Review*, March 2004, p42–47.

4 'Business Report', *Times*, 25 October 2004, which discusses the threat from a popular movement clamouring for nationalisation of hydrocarbon resources as well as the new hydrocarbon bill being debated.

5 Z Rashmee, *Times of India*, 17 December 2004.

6 Brian Ellsworth, *International Herald Tribune*, 12 October 2004.

7 In **Figure 4** the component 'E' –tax on profits – is in brackets as it may be paid from the government or contractor's profit share depending upon the contract. If 'E' is paid by the contractor the brackets should be removed from the formulae; if 'E' is paid by the government then 'E' should be removed from the formulae. In the case of a state company back-in payment 'Z' covers its percentage share of past eligible capital costs and ongoing operating costs. The absolute values of 'E' and 'F' will be different in a situation with no state company back-in than one where a back-in occurs and IOC profits are reduced by ('D'–'Z').

8 Information compiled from various sources. Useful published accounts addressing contractor take are: David Wood, 'Appraisal of economic performance of global exploration contracts', *Oil & Gas Journal*, 29 October 1990, pp48–52; D Johnston, 'Global petroleum fiscal systems compared by contractor take', *Oil & Gas Journal*, 12 December 1994, p47–50; P Van Meurs, 'Governments cut take to compete as world acreage demand falls', *Oil & Gas Journal*, 24 April 1995, p78–82.

Part 2 of this article, to be published next month, will build upon the fiscal and contractual framework outlined here, to identify how flexibility and stability can be improved and how situations of potential future instability might be identified and approached.

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Oil loss – keeping it under control

The recent strong growth in the world economies, combined with instability in many countries of the world, has driven the price of crude to high levels again (see **Figure 1***). As a result, it has become increasingly important to ensure the accurate measurement and full delivery of the oil that is being purchased, writes* Robert T Luckritz. *

The Hydrocarbon Management Committee 4 (HMC-4) of the Energy Institute (EI) has been collecting measurement data on marine movements for more than 15 years. Its data show that the earlier efforts to improve measurements and custody transfer during periods of high oil prices achieved significant reductions in the reported losses. However, with reduced emphasis on loss control in times of lower crude prices, this effort has lagged and much of the impetus in improving measurement accuracy has been lost.

In 2003, the EI's Marine Oil Transportation Database Committee (HMC-4A) reported[1] a mean net standard volume (NSV) loss of –0.20% for almost half of the crude oil transported at sea (see **Figure 2**). If similar losses apply to total reported global trade of almost 13bn barrels, the total loss is 26mn barrels. At recent crude prices of more than $40/b, the total loss is more than $1bn.

The HMC-4 data also showed a standard deviation of 0.36% in the reported NSV loss data. This reflects extensive scatter in the data and large variation in the reported losses on individual cargo movements. Improvements in measurements and custody transfer are clearly achievable and can reduce losses.

With the increase in the price of crude oil, the importance of an effective oil loss control programme has grown. The losses associated with one high loss voyage can easily exceed the annual salaries of several staff. An effective loss control programme can not only identify and initiate claims on individual voyages, but it can also lay the foundation to identify and correct chronic measurement errors responsible for ongoing losses.

Marine transportation oil loss

Marine transportation oil loss is defined as the difference between the cargo quantity measured at the loading terminal and the cargo quantity measured at the receiving terminal. It is normally calculated as a volume percentage of the net quantity loaded.

The calculation is:

$$\text{oil loss (vol \%)} = \frac{\{[(\text{net loaded quantity}) - (\text{net received quantity})] * 100\}}{(\text{net loaded quantity})}$$

The loss is normally reported as a volume percentage of the loaded measurement. Controlling the loss is important because the loaded quantity measurement is normally used as the basis for billing and payment.

Oil loss is inherent in the marine transportation of oil. In addition to any measurement and calculation errors, there will also be evaporative loss and clingage on the surfaces of the tanks for carriage. The key role of all loss control groups is to minimise and control this loss through a programme that includes loss monitoring, measurement verification and compensation for excessive losses.

Causes of marine oil loss

Marine transportation loss falls into three main categories – physical loss, paper loss and measurement loss. In each of these categories there are specific causes of loss:

- Physical loss
  - evaporative loss
  - cargo retention
  - cargo diversion
- Paper loss
  - measurement table error
  - calculation error
- Measurement loss
  - procedural error
  - calibration error
  - measurement error
  - sampling error
  - testing error

Physical loss

Physical loss is the actual loss of the hydrocarbon. These losses occur due to the evaporation of the cargo during loading, transit and discharge; the cargo retained on the vessel after discharge, and any cargo diverted due to theft or misappropriation.

Evaporative loss is the loss of the light ends from crude. The higher the concentration of light ends, the higher the vapour pressure of the crude. As the vapour pressure, temperature and surface area increase the evaporative loss from the crude increases. The surface area is affected by physical conditions in the cargo tank throughout the voyage, including free surface sloshing and dispersion of the crude into droplets during initial loading and when crude oil washing. These effects increase the rate of release of light ends from the crude.

Uhlin in his paper[2] reported on an Exxon International study of typical physical losses. He reported an average evaporative loss of 0.13%, with a range of 0.07% to 0.19%. Since then there has been an increased emphasis on reducing volatile organic carbon (VOC) emissions. Emphasis has been placed upon reducing carriage temperatures and crude oil washing. Some terminals are using vapour return lines to reduce vapour loss during loading and/or discharge, and studies are underway to control evaporative loss using onboard control systems.

Cargo retention is the cargo left onboard the vessel after discharge. This is primarily the clingage of the oil to the top, sides and bottom of the cargo tank or the cargo that is unreachable by the vessel pumping and stripping systems. The amount of clingage is dependent upon the viscosity and pour point of the oil. A viscous, high pour point cargo will exhibit greater retention than a light, low pour oil, especially as the carriage temperature decreases. Retains onboard (ROB) is a measurement of the cargo retained and measurable on the tank bottom. ROB is composed of any non-liquid and liquid cargo that collects at the dipping point. Measurements of ROB do not include clingage to the sides or top of the tanks.

Cargo diversion is the theft of the cargo or the use of the cargo as a fuel. This can be accomplished through the use of hidden tanks, hidden connections from the vessel cargo tanks to the fuel system, or direct transfers to other vessels or barges. These activities have become increasingly rare as standards have improved throughout the shipping community.

Paper loss

Paper loss occurs during the calculation of observed volumes and the conversion of observed volume to standard volume (volume at 60°F or 15°C used for trading purposes). It includes both calculation errors and errors in reference material or the transfer of values used in the calculations.

Measurement table errors are those associated with the use of outdated or incorrect mathematical functions or measurement tables that convert observed volume, temperature and pressure to standard volume. The international standards organisations have adopted a common mathematical function for the calculation of standard volume (ISO 91-1, IP 200, API MPMS 11.1). The latest and most accurate function was reaffirmed with some mathematical improvements and reissued on CD-ROM in 2004. Not all countries use the latest adopted ISO standard. Some countries continue to use the 1952 measurement tables that generally produce a larger standard volume quantity than the ISO formula. Similarly, many terminals in the Former Soviet Union use GOST tables which are used to calculate cargo quantities as weight in vacuum. Calculation errors can occur in the use of these tables and when converting to standard volume.

The large number of calculations involved while working under time pressures made such errors common. The use of a number of look-up tables, combined with interpolation of values, resulted in many transposition or calculation errors. The advent of calculators helped reduce the number of mathematical errors, but other errors continue.

Errors are now more often related to incorrect data entry or selecting wrong values from tank tables. The use of computers has further simplified the quantity calculation. However, incorrect data entry and possible program errors will continue.

Measurement loss

Measurement loss includes all the activities related to the actual custody transfer operation. It includes all the errors associated with measurement procedures, equipment and operator performance. When most people talk about oil loss, they primarily are thinking about measurement errors. An emphasis on reducing measurement loss can effectively reduce the variability in the loss and consistently report more accurate values.

Procedural error occurs when the custody transfer operations deviate from the industry measurement standards and good custody transfer practices. An example would be the failure to ensure pipeline fullness at the start of the custody transfer. Other examples would include operational upsets with potential loss of cargo.

Calibration error relates to accuracy (calibration) of the measurement equipment. Only the base international standards are exact. Every other piece of measurement equipment that is used as a measurement standard will have some error from the base international standard. This error, no matter how small, will bias all measurements and calibrations using that equipment. If the equipment is then used in the calibration of other equipment, the bias in the subsequent calibration will add to the initial bias. Also, the uncertainty will increase with each step away from the base standard.

Measurement equipment is also affected by handling and use while in service. The measurement equipment may be physically distorted, electronics may be affected by the power fluctuations or drift, and the installation may affect performance. To keep errors small, regular calibrations or verifications are necessary

Measurement error is inaccuracy with which a physical measurement is taken or recorded. Measurement errors occur in both the field and the laboratory. An example is the manual gauging of a

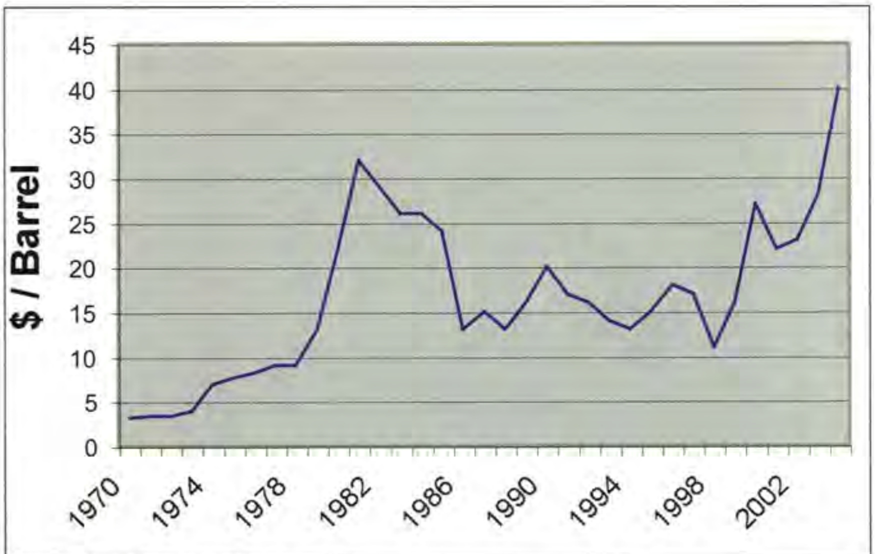

Figure 1: Historical crude oil prices

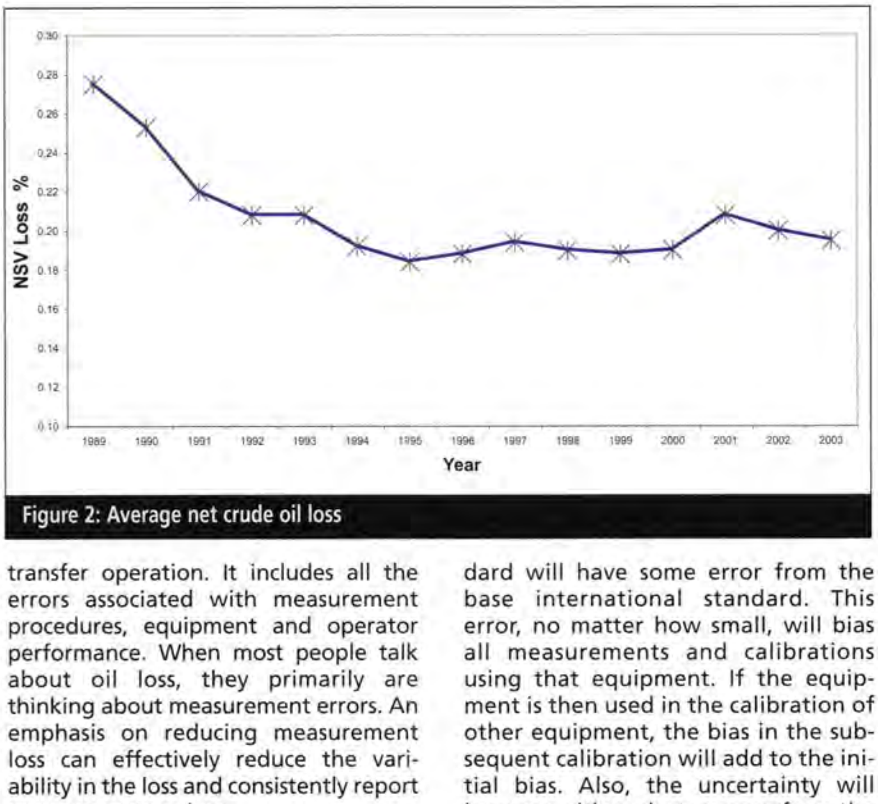

Figure 2: Average net crude oil loss

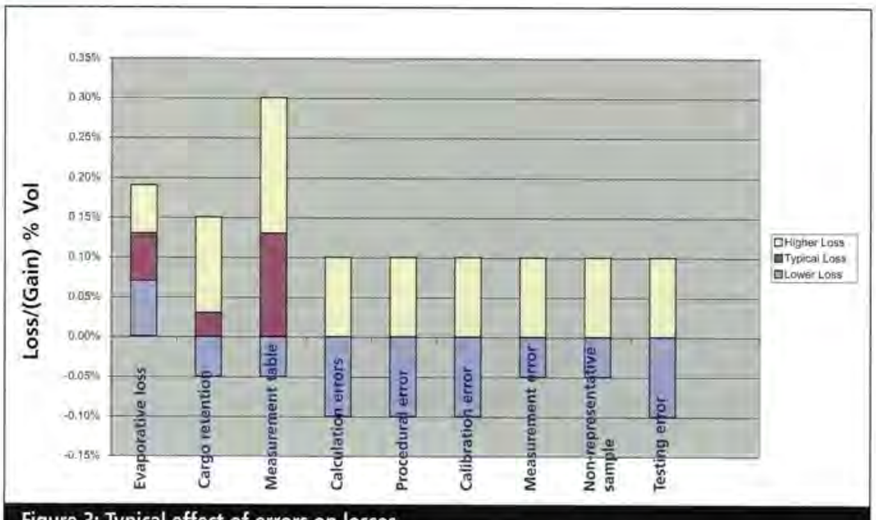

Figure 3: Typical effect of errors on losses

cargo tank. A tank gauger will make multiple dips of the tank and each will be different. The higher the proficiency of the gauger the more consistent and accurate the level determination. Any difference from the actual level or mistake in recording the value is a measurement error that will affect the volume calculation. Similarly, incorrect reporting of visual measurements in the laboratory result in errors.

The precision of the measurement is the incremental difference in the measurement that is recorded. As an example, in experimental physics temperature is measured and recorded to minute fractions of a degree. Typical cargo temperature measurements are recorded to a tenth of a degree centigrade. The more precise the measurement, the more precise the calculation using that measurement.

Sampling error is the result of non-representative samples. The non-homogeneity of crude oil can result in samples that understate or overstate the water content. An automatic flow proportional sampler is needed to collect a representative sample. Manual samples from crude tanks, especially through restricted or closed gauging systems, are generally non-representative.

Testing error results from laboratory errors or the inaccuracies of some of the test methods that continue to be used in many terminals.

Density is one of the factors used in the volume conversion to standard volume for measurement and billings. The accuracy of the density determination is affected by the performance of the laboratory technician, the calibration of the laboratory equipment, and test equipment utilised. Shortcomings in any of the three areas will result inaccurate quantity determination.

Water content is needed to adjust gross volumes to net volumes. Industry standards recognise that centrifuge water determination may significantly understate the water content but this method continues to be used. Karl Fischer titration and water by distillation are acknowledged as the more accurate water content methods.

Effects of measurement errors

Marine oil loss is a combination of all the many errors and effects noted above. Over a large number of voyages many of the errors offset one another. However, on an individual voyage, compounding errors may result in a high loss. The buyer of that cargo will be seeking compensation or an adjustment for the loss. It is thus in the interest of both buyer and seller to promote accuracy in the determination of quantity and quality, and to minimise measurement errors that can lead to costly claims activities.

An effective loss control programme will provide oversight and controls to improve measurement accuracy, improve custody transfer procedures, and minimise oil loss. In order to be effective, the programme must address the key marine loss control elements. (See **Figure 3**.)

Marine loss control elements

An effective marine loss control programme must be able to identify high loss voyages, determine the cause of the loss and initiate corrective action or compensation. It should also be able to identify terminals with measurement biases that result in smaller, but continuing measurement errors with cumulative losses. The key elements in a loss control programme include:

- Measurement verification
- Loss monitoring
- Detailed voyage loss analysis
- Effective cargo loss claims processing
- Technical and commercial follow-up
- Improved contract and charter party terms
- Accurate internal measurements
- Management commitment

Measurement verification requires an independent observation of the custody transfer to verify that measurement standards are followed and to validate the measurements and calculations used for the quantity determination. Without oversight and verification, terminal personnel make their own measurements and, over time, the procedures and measurements may become relaxed with increasing opportunities for error.

Verification is normally done by independent inspectors, but can be done by internal company personnel or other contractors. The oversight of the measurements emphasises to the terminal personnel the importance of their work and encourages them be more attentive to proper procedures. The results of the measurement verification are reported in both detail and summarised format.

The hiring of inspectors or other contractors may be inadequate by itself without oversight of contract performance. There should be a programme in place to ensure that the parties doing the verification are performing to the expected standards.

Loss monitoring of movements must be done to identify high losses and initiate corrective action. The inspector or other verification report is reviewed for accuracy and completeness. All high losses are identified for additional analysis.

Effective loss monitoring will include a database that collects the key measurement data on all custody transfers. The measurements are linked together to track and monitor the quantity and quality throughout the voyage. The overall shore-to-shore loss for the voyage is calculated and each custody transfer documented. Losses can be analysed on an individual voyage or data from multiple voyages can be analysed together to determine average losses by load port, discharge port, grade and vessel. High loss problems can be identified for additional follow-up work. The database can also provide vessel experience factors (VEF) for loading and discharge.

Detailed voyage loss analysis of high loss voyages is used to determine the cause of the excessive loss.

Measurement data from the shore at load, vessel at load, vessel at discharge, and shore at discharge is analysed to determine the primary location of the loss. The shore delivered quantity is compared to the VEF adjusted vessel received quantity, the change in vessel quantity in transit is determined, and the VEF adjusted vessel discharge is compared to the shore receipt quantity. These differences may be used to determine if there is a claimable loss on the voyage.

Effective cargo loss claims processing is a tool to receive compensation for excessive cargo loss. After the cause of the loss is determined, the data must be collected and presented to the responsible party with a clear identification of the cause of the loss. The data should be presented in a concise technical summary of the basis for the claim and corrective actions. A well-documented claim will have a clear presentation of the technical basis of the claim and should present a case that would survive both technical and legal scrutiny. After the claim is submitted, it provides an effective tool to notify and pursue chronic measurement problems within terminals or vessels. Correction of chronic measurement problems provides significant long-term benefits of loss reductions on future cargoes with the associated savings.

Technical and commercial follow-up demonstrates an ongoing commitment to custody transfer and loss control improvements. Technical follow-up involves meetings and site visits by loss control personnel. They should review measurement procedures and equipment and work with terminal personnel to improve measurement accuracy. Many terminals provide new personnel with limited training in custody transfer and measurements. Training may be primarily on the job, with the skills passed from person to person with limited knowledge or reference to the standards. A review by a knowledgeable loss control expert will identify shortcomings in the custody transfer and recommend improvements.

Commercial follow-up involves working with trading personnel to improve the contract language for measurements and custody transfer. If the trader includes measurement procedures in their negotiations, it shows a commitment to effective loss control. Reference to open claims issues during commercial discussions assists in the proper resolution of outstanding claims. Similarly, commercial reference to ongoing measurement errors or biases that cause ongoing losses will assist in generating changes and measurement improvements.

Improved contract and charter party terms provide the basis for measurement improvements. If the measurement and custody transfer terms of the contract or charter party are generic and non-specific, the terminal and vessel are not held to any minimum standard for the quantity and quality determination.

Requiring the terminal and vessel to perform measurements and custody transfer in accordance with the latest industry standards provides the contractual basis to require quality measurements and procedures. Specifying the most accurate equipment and test procedures establishes an even higher quality custody transfer.

Accurate internal measurement is the internal quality control which ensures that any losses are real, not caused by errors. Trading partners should expect that similar levels of attention are given to custody transfer. The receiving terminal has a responsibility to measure cargo receipts accurately to avoid 'false alarms' that tie up valuable resources that can be more effectively utilised to address real problems. Personnel must be trained, equipment must be accurately calibrated and effective loss control procedures implemented for cargo transfers.

Management commitment is required for any successful loss control programme. Unless management fully supports the activity and is willing to dedicate qualified resources, the loss control programme will be ineffective. Loss control requires the commitment of all personnel involved in measurements. Lax reporting or poor performance by one individual will be carried through the calculation. The personnel involved in loss control should be experienced or be provided with adequate training to properly perform their functions.

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**Robert Luckritz is President of Qanalytics, an oil loss control company based in Solomons, Maryland, US. For more than 15 years he was manager of Exxon's international crude oil loss control activities.*

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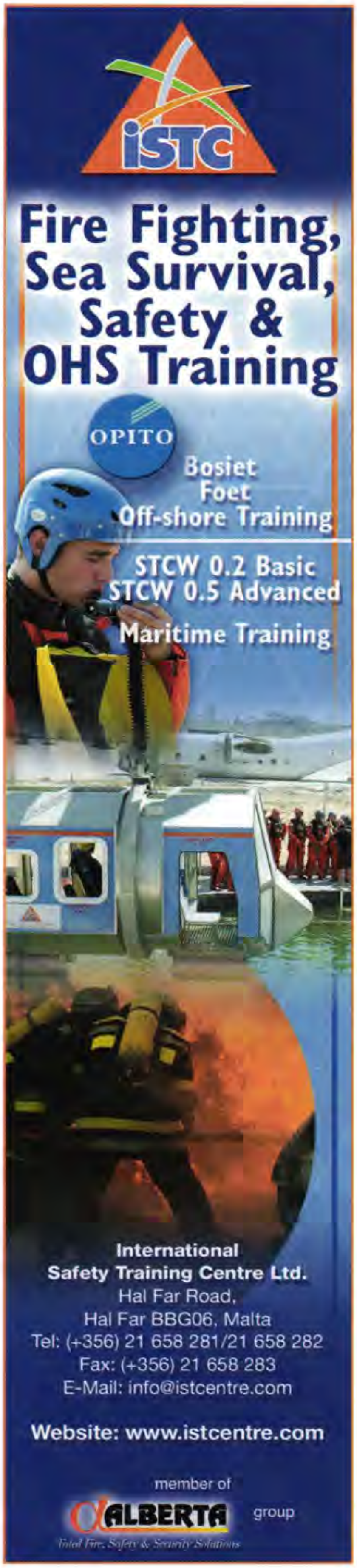

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This report questions the proposition that LNG will develop a 'global market' similar to that for crude oil. In addition, the author of the study questions whether LNG trade will be as competitive as the current trade in pipeline gas in the liberalised gas markets of North America and the UK. The book indicates that the short-term LNG market, while growing, represents a relatively small share of the market. More significantly, no new LNG supply project has been launched without at least some long-term purchase contracts. Such long-term contracts will continue to be a mainstay of international LNG trade, despite the fact that these have all but disappeared in North America.

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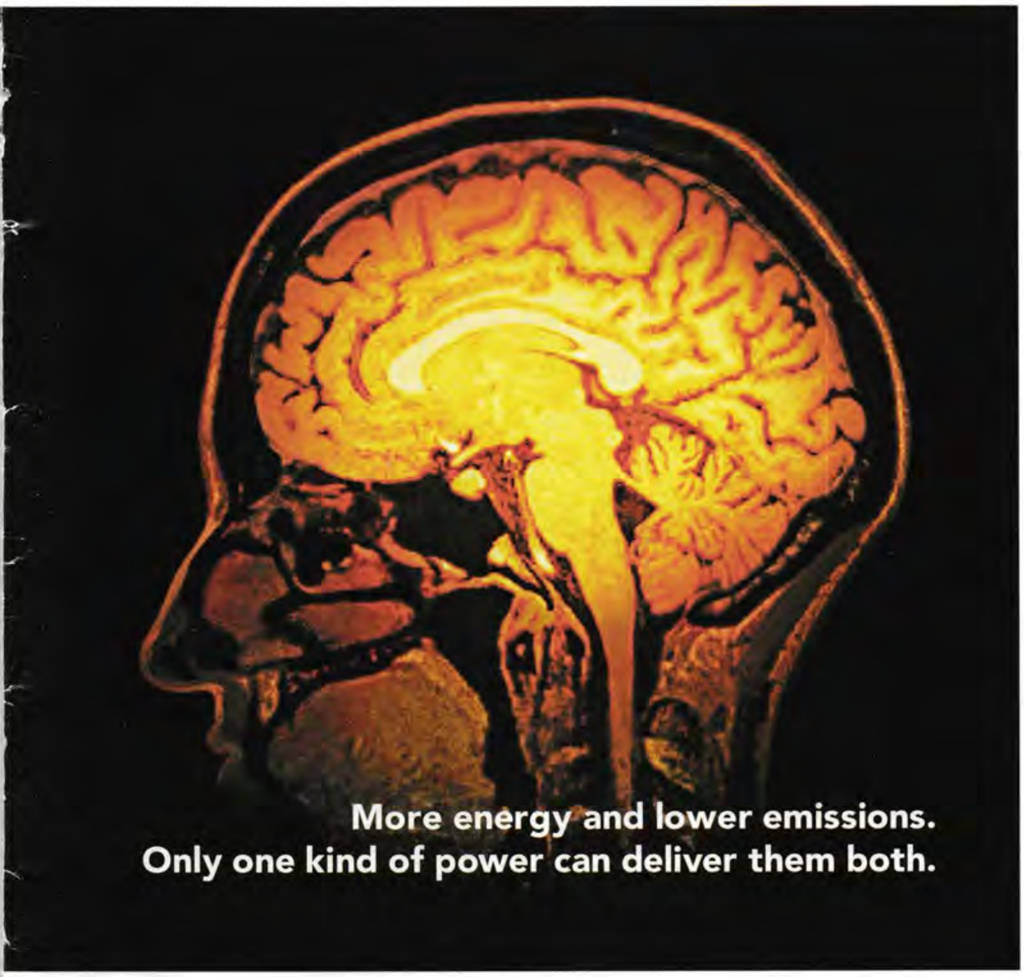

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