PETROLEUM REVIEW

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July 1995

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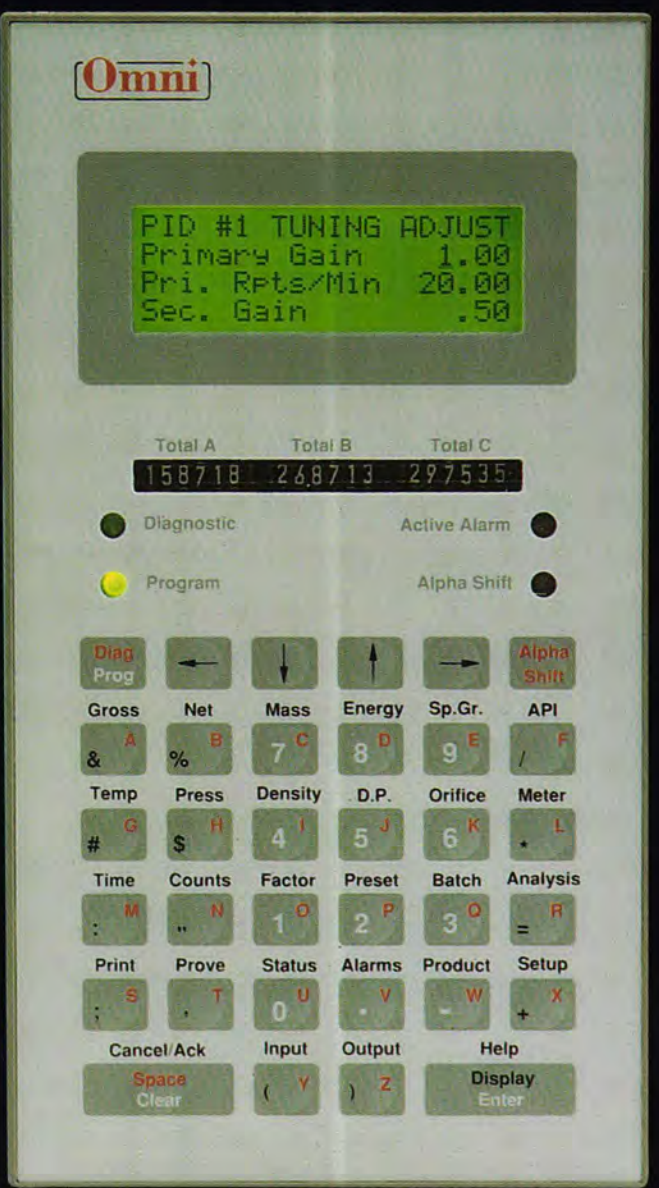

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EDITORIAL

Editor: Carol Reader
Deputy Editor: Susannah Cardy
Production Editor: Emma Parsons
61 New Cavendish Street, London W1M 8AR
Telephone: (0171) 467 7100
Fax: (0171) 255 1472

ADVERTISING

Alison James
Anne Marie Fox
Classified: Elaine Smith
Landmark Publishing Services
8 Garrick Street
London
WC2 9BH
Tel: 0171 240 4700
Fax: 0171 240 4771

PUBLISHERS

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Director General: Ian Ward

61 New Cavendish Street, London W1M 8AR
Telephone: (0171) 467 7100
Fax: (0171) 255 1472

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For details of subscriptions, please apply to Anne Poynter at the Institute of Petroleum
Tel: 0171 467 7124

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CONTENTS

COVER PHOTO
Gas processing facilities in Mexico.
Photo provided by Pemex.

NEWS IN BRIEF

1 June
Oryx Energy has sold its 15.5 percent stake in the North Sea Alba field to Union Texas Petroleum for $270m.

The EC has given the go-ahead to the £400m UK Interconnector, which will run between Bacton in Norfolk and Zeebrugge in Belgium.

2 June
The longest strike in the history of Petrobras ended after 31 days without the government conceding to any of the workers' demands. Over 20 oil unions took part in the industrial action, which began on 3 May.

Cuba has opened up 14 blocks to foreign participation.

5 June
A $100m racial and sex discrimination lawsuit has been filed by ten black employees against Shell Oil.

A *'Don't Choke Britain'* campaign, which urges drivers to leave their cars at home for one day in five during June, has been launched by Transport Minister Steven Norris. Organised by four local authorities, the campaign has the backing of the AA.

The EC has approved a joint venture between Saudi Aramco and the Greek Vardinoyannis family, under which the Saudi Arabian company acquires a 50 percent stake in Motor Oil Corinth Refineries and Avinoil Industrial and Maritime Oil.

Lasmo has announced first gas production from the Kadanwari field, in the Sindh province of Pakistan.

7 June
UK Energy Minister Tim Eggar has announced new petroleum licensing regulations, including a single onshore licence. The Petroleum Exploration and Development Licence (PEDL) will replace the current three licence system and is designed to cut out red tape.

8 June
Ofgas published a consultative document inviting views on the controls that will govern British Gas' transportation and storage prices from April 1997.

Dolphin Expro DOC and the Expro Group announced plans to establish a joint venture company which will provide integrated services to the Norwegian upstream oil and gas industry.

The sale of CAM Shipping's business and assets to Viking Supply Ships AS is now complete.

The BP-led western oil consortium operating in the Caspian Sea has delayed the decision on a final export route for another three months. Further negotiation is necessary because of intense rivalry between Russia, Iran and Georgia over which country should be the recipient of early oil from the $8bn project *(see page 324).*

The Brazilian Congress has voted to end Petrobras' 42-year monopoly by 364 to 141.

9 June
Shell Petroleum is selling its exploration and production interests in Turkey. The company has decided that the 27 producing fields it operates in the southeast of the country are no longer of 'strategic interest'.

Drilling rig company, Sedco, has been fined £1,000 for breaching the Health & Safety at Work Act. The company pleaded guilty to failing to ensure riggers were not exposed to risk from asbestos.

Britain has refused to join other North Sea countries in an agreement to completely phase out the dumping of hazardous chemicals over the next 25 years. Britain argued there was not as yet a technically feasible solution to the problem.

HSE has published an Approved Code of Practice and interpretative guidance on the protection of offshore workers from fire and explosion.

10 June
Five sub-contractors have died in a wellhead fire in Syria. The blaze took place in a semi-desert area of the El Isba field at a well operated by the Al Furat Petroleum Company, which is jointly owned by Syria Petroleum Company, Royal Dutch Shell and Deminex.

Natural gas production from Norway is set to double within the next decade, according to a new government report.

11 June
Argentinian Foreign Minister Guido di Tella has warned that his country will take its case to the International Court of Justice if Britain or the Falkland Islands issue oil exploration licenses unilaterally. The announcement was made during bilateral talks with London during which it was hoped the two countries would come to a co-operative agreement on the matter.

12 June
Wood MacKenzie has predicted a sharp rise in the market for cheap floating oil production platforms in the North Sea. Almost a quarter of the 64 new developments planned for the next few years are expected to use some sort of floating system.

The Swan Hunter Wallsend shipyard on Tyneside has been saved just one week before its industrial fittings were due to be auctioned off. THC Group has bought the yard for an undisclosed sum to build floating oil production platforms.

Scottish Power has cancelled a contract option with Statoil and Norsk Hydro for the purchase of gas from the Froy field. The failure of Norway and Britain to ratify the Frigg treaty was behind the cancellation.

Quest has opened an office in Norwich to offer offshore inspection, planning and management services, together with structural and corrosion engineering, to the southern North Sea.

13 June
Amoco has announced plans to move into the Polish retail market next year. The company hopes to open between 10 and 15 stations by the end of next year and up to 150 over the next decade.

Ofgas chief Clare Spottiswoode has received a pay rise which brings her annual salary up to £90,000 a year, Trade and Industry Secretary Michael Heseltine announced. The rise is only half the 65 percent she had sought and follows a furious outcry from MPs over her request.

The cost of fuel has risen 140 percent in Angola, following the government's decision to end subsidies.

14 June
BP has awarded a £14m contract for the design and engineering work on a floating production system for Schiehallion, west of Shetland. The work has gone to Atlantic Frontier Alliance, a consortium of Brown & Root, Single Buoy Mooring and Harland & Wolff.

Oil service company, Consolidated Supply Management, has acquired the Latin American-based Latchmoor group of companies.

Vanguard Petroleum has agreed to sell its 50 percent stake in Magma Oil Company to Petro-Hunt for around $50m.

Kvaerner and DuPont have signed a collaborative agreement aimed at developing new materials for shipbuilding and offshore applications.

Conoco and its partners are to invest £85m in offshore compression facilities for the Caister Murdoch gas gathering and transportation system.

15 June
BP has awarded pre-sanction contracts for early planning, design and engineering work on the Eastern Trough Area Project (ETAP), in the central North Sea. Brown and Root, AMEC and Trafalgar House are among the award winners.

18 June
An explosion at a Fina station in Belgium killed 13 people and seriously injured many others. The cause of the blast was thought to have been a gas leak in the kitchen restaurant.

19 June
Enagas SA is to purchase the remaining 40 percent of production from a planned LNG plant in Trinidad, according to British Gas.

20 June
Despite complaints over rising North Sea production, OPEC ministers meeting in Vienna have agreed to stick to their current output ceiling of 24.52 million b/d for the rest of the year.

Chevron moves African unit to London

Chevron will soon be masterminding its African activities from headquarters in London rather than California.

As of 1 August, the unit will be taking up residence at 2 Portman Street. It will continue to be headed by Mr Luigi Caflisch but will merge with the company's Middle Eastern unit.

'It makes sense to combine the two,' said Mr Bob Connon, Managing Director of Chevron UK, 'because they are new venture areas which are competing for the same dollar'. There is already an overlap between the two; the Middle Eastern unit currently covers an area stretching as far as Somalia. The London move also makes sense for geographical reasons.

The African unit is currently operating in the Congo and Namibia. It does not have jurisdiction over Angola, Zaire or Nigeria, which will continue to have headquarters in Africa itself.

Confidence grows over cheaper Alba option

Chevron is now fairly confident it can develop Alba South by improving existing facilities on Alba Northern, although no firm decision will be made until the end of 1996.

According to Mr Bob Connon, Managing Director of Chevron UK, technological improvements in extended reach drilling mean the company 'is almost certain it can develop the field from a single point'.

However, there are still some doubts over whether Alba Northern could handle the extra processing modules that would be required to handle fluids from Alba South.

A second, but more expensive option, would be to install a smaller, unmanned structure in the field and bridge-link it to the existing Alba Northern unit.

According to a Chevron spokesman, the final decision on development options will not be made until the end of next year, after the company has drilled several wells. Meanwhile, DTI approval will be sought for both options.

Mr Bob Connon, Chevron UK

Algeria tops discovery league

More oil was discovered in Algeria than in any other country in the world last year, according to Petroconsultants.

A total of 1.13bn barrels of oil and condensate were discovered in Algeria in 1994, twice the volume found in Norway, which came second in the league table. However, Norway will be more than pleased with its ranking: the country's strong showing of over 600 million barrels was in sharp contrast to the previous year, when only 61 million barrels were discovered.

Petroconsultant's survey also shows that the North Sea producers still lead the world in discoveries. 'Over the past five years, more oil has been discovered in the North Sea than in all of Latin America, the entire Far East and West Africa.'

Other oil exploration hotspots in 1994 included Brazil, Angola and Vietnam.

Lifting the Alaskan crude export ban: winners and losers

BP stands to benefit to the tune of $100 million a year now that the Republican-controlled US Senate has voted to lift the 23-year export ban on crude oil produced in Alaska.

The Republicans have been able to break a log jam of conflicting regional and industry interests that for many years have precluded the federal government from lifting the ban, despite long-standing and widespread bi-partisan support nationwide for such action. Although the House of Representatives will not vote on the issue until early July, the administration has not voiced strong objections to the measure and no veto is expected.

If BP, which pumps 680,000 b/d from the North Slope, is set to gain, the people of the United States and their various governments will benefit even more. However, this will be at the expense of the US shipping industry and petroleum refiners along the US Pacific coast.

For the Californian refining industry, which has successfully campaigned against a repeal of the ruling for so long, the ban guaranteed a generous supply of crude which allowed them to pay lower prices than refiners in the rest of the country.

For the US shipping industry, the ban meant an indirect subsidy of sorts. The government required the industry to use US flag carriers to transport any Alaskan crude in excess of west coast needs to and from the Panama pipeline, which would then transport the crude to domestic markets east of the US Continental divide.

Since it is difficult to win in a US presidential contest without California, presidents have never dared favour the interests of populous, powerful California over Alaska. However, now that Alaska's Republican Senator, Frank Murkowski, stands at the helm of the Senate Energy committee, his state's interests have prevailed.

A study carried out in 1992 for the Alaska Department of Revenue indicated that lifting the ban would raise Alaskan and Californian crude oil prices by $1 a barrel. At the time, such a move would have added roughly 60 million barrels of Californian production and 110 million barrels of Alaskan production. Now it would probably be somewhat less.

However, a US Department of Energy study released in June 1994 indicated that lifting the ban would raise federal tax revenues by $99 million, increase Californian state revenues by $180 million and boost Alaskan state revenues by up to $700 million over the remaining life of the Prudhoe Bay field. At the same time, it would add up to 25,000 new jobs in the United States by the year 2000 and increase domestic oil production by 100,000-110,000 b/d while augmenting Alaskan reserves by up to 400 million barrels.

The US balance of trade would also improve, according to the report, and east coast consumers would no longer have to pay $2.70 per barrel in incremental transportation fees, which resulted from the forced shipment of 200,000 b/d of Alaska's crude surplus to the west coast and to other portions of the US market.

Brent Spar: will the UK government now allow onshore disposal?

At the last minute, Shell has succumbed to international political pressure and the activities of Greenpeace and abandoned its plans for the deep water disposal of the 141 metre high, 14,500 tonne Brent Spar. As *Petroleum Review* went to press, Shell was seeking a licence for onshore disposal for the loading buoy but the UK government is in no mood to help the company out.

The Spar, which had served for 15 years, was almost at the end of its tow to the disposal site when Shell reversed its decision. The site is situated in 2,000 metres of water at North Feni Ridge, 240 km out in the Atlantic from the west coast of Scotland. Greenpeace had managed to land protesters by helicopter onto the structure.

Shell's climbdown was accompanied by a statement, which read: 'We still believe that deepwater disposal is the best practicable environmental option, and one which was supported by independent studies.

'We obtained the necessary permit for disposal from the UK authorities, which have handled every aspect of the approval process in accordance with established national and international policies and standards.

'As the disposal involved the Atlantic deep water, other governments have taken an interest and voiced strong objections. Notwithstanding the efforts to convince these governments of the validity of the approach, most of them remain strongly against deep water disposal.

'The European companies of the Royal Dutch/Shell group find themselves in an untenable position and feel that it is not possible to continue without wider support from the governments participating in the Oslo-Paris Conventions.

'Shell UK has decided to abandon deep water disposal and seek from the UK authorities a licence for onshore disposal. This application will include a further review of methods to minise the risks involved. The way forward will require the co-operation of all concerned.'

Shell's immediate concern, following its climbdown, was to find a temporary deep water safe anchorage for Brent Spar. Few sites are large enough for the buoy, which has a draught of 109 metres. This problem was solved relatively quickly by a prompt invitation from the Norwegian government, giving Shell permission to store the buoy in one of the country's fjords. The problem of disposal, however, is expected to be a far harder nut to crack.

Mr Tim Eggar, Industry and Energy Minister, said Shell would 'have to work extremely hard' to get a licence for disposal on land. 'I am not going to imperil the UK environment', he said, 'just because Shell have changed their minds. I am not going to put up with pollution onshore in the UK. They have given in to what can only be described as blackmail.'

Trade and Industry Secretary, Mr Michael Heseltine, said: 'They should have kept their nerve and done what they believed was right. They have spent three years convincing the government that deep sea disposal was the best option. I believe they should have persevered. They would have received the backing of the British government – that was made clear to them.'

Government approval was given on 17 February but from 30 April Greenpeace began a high-profile campaign against the dumping. Industry sources claim that emotions, indeed almost mass hysteria, alongside UK opposition and European politicians who were quick to jump on the bandwagon, won the day over hard facts.

They claim that Greenpeace skillfully disseminated half-truths and untruths to inflame the already-susceptible Germans. Several Shell petrol stations were attacked and, in one instance, a Hamburg station was firebombed. Stations

Industry Minister Tim Eggar has warned Shell it will 'have to work extremely hard' to get a licence for land disposal of Brent Spar

across Germany, Britain, the Netherlands and Switzerland were picketed and motorists asked to boycott Shell products. In the Netherlands, protesters dumped a seven-metre high replica of the structure made from old oil barrels next to Shell's headquarters in The Hague.

The financial effect of the boycott would not have been very great on a company of Shell's financial strength. However, it was concerned about its environmental image and there had been complaints from some of its managers in other European countries that they had not been kept informed of company decisions during the crisis.

Greenpeace has continually claimed that the sinking would release radioactive waste, heavy metals and 100 tonnes of oily sludge into the sea. Shell responded by stressing that disposal at 2,000 metres would have a 'minimal effect on the environment'. It also claimed the cost of deep water disposal would be £11.8 million, compared with £45.95 million for onshore dismantling.

Nor surprisingly perhaps, contractors such as Heerema, Smit Engineering and McDermott have argued for some time that complete removal of all platforms is feasible and should be adopted.

Greenpeace believes it has now virtually prevented any offshore disposal of platforms, but Shell argues that the Spar is a 'unique case' and totally different to a production platform. According to UKOOA, there are some 219 installations on the UK Continental Shelf, at least 75 percent of which will be totally removed. The remainder will be assessed by government on a case-by-case basis. Meanwhile, the future abandonment policies of North Sea countries have been thrown into disarray.

Further shake-ups in UK network

Last month, Frost acquired Burmah Castrol's entire UK petrol retailing and wholesaling business for £83 million, whilst Jet announced cuts of over 20 percent in its own UK network.

The Frost acquisition involves the handover of supply contracts for over 800 independently-owned and operated sites. The company also gained 182 freehold and leasehold company-owned sites.

As a result, Frost claims it is now the seventh largest owner of company-owned sites in the country, with well over 400.

Burmah cited competition from hypermarkets and the high capital requirements of new service stations as the major reasons behind pulling out of the market. Jet's decision to rationalise its network was made for much the same reasons.

A total of 200 of its dealer-owned sites and 30 of its company-owned stations will be sold or closed in the southwest of the country, bringing Jet's overall network down to under 800.

The announcement follows a decision to cease operations at the Aldermaston terminal in Reading, Hallen in Bristol and Bramhall in Cheshire by the end of the year.

'Jet aims to more than replace lost volume through focusing on core marketing areas,' said retailing manager Tom Souls.

Georgian allies

JKX Oil & Gas has joined forces in Georgia with the Shell subsidiary, Pecten Intl.

Pecten now has a 40 percent working stake in the foreign participating interest of the onshore Rioni basin and offshore Black Sea licences. JKX retains 60 percent of the foreign participating interest.

Rhone Poulenc claims solution to diesel pollution

French chemical company, Rhone Poulenc, claims to have developed a new technology to combat diesel engine pollution.

The technology uses an additive, EOLYS, which, when used in conjunction with a metal or ceramic filter fitted to exhaust systems, 'makes it possible to eliminate 80-90 percent of the carbon particles released from diesel engines'.

The technology, which the company has worked on since 1989, can be adapted to all types of vehicles, whatever the characteristics of the diesel fuel used.

When mixed with fuel, EOLYS, a cerium oxide catalytic compound, reduces the particle combustion temperature to a range varying from 200-400°C. The particles trapped in the filter are then periodically burned off at temperatures reached by the exhaust gases. The filter thus becomes self-generating.

The Paris public transport authority, RATP, and mail order firm, 3 Suisses, are testing out the additive on their fleets of vehicles with a view to adopting it on an operational base.

'By the year 2000, the aim is to have the additive incorporated in all new vehicles,', explained project manager Jean-Pierre Clamadieu, 'and it was in this context that we signed an agreement with motor manufacturer, Renault, in October last year'.

The cost of the additive, presented in the form of a one-litre cartridge and with an active life on private car engines of up to 50,000 miles, is estimated at between one and two percent of a litre of fuel.

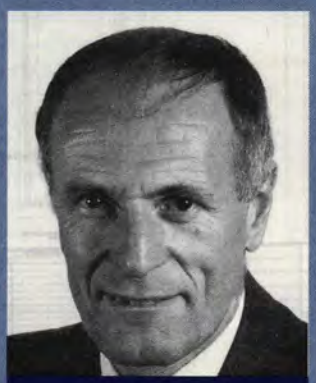
Birthday Honours

David Alec Gwyn Simon, Knight Bachelor, F Inst Pet, Group Chief Executive and Deputy Chairman, the British Petroleum Company.

David Simon, Knight Bachelor

Dr Rex William Gaisford, CBE, F Inst Pet, Director of Development, Amerada Hess.

Professor Alan Williams, CBE, F Inst Pet, Livesey Professor and Head of Fuel and Energy, University of Leeds.



Dr Rex Gaisford, CBE

Roy Arthur Jeffreys, OBE, Honorary Treasurer, the Royal Society of Chemistry.

Jolyon Edward Sloggett, OBE, Secretary, Institute of Marine Engineers.

David Stephen Wright, OBE, Chief Medical Officer, British Petroleum Company.

Frazer John Ellis, MBE, UK Commercial Director, Davy International.

Institute of Petroleum's Annual General Meeting

The 82nd IP Annual General Meeting took place on 6 June, with the President, David Varney, in the chair.

In his report, the President singled out two particular challenges now facing the Institute. The first was to continue to make a case for industry self-regulation both in Britain and across Europe and to develop the common technical standards and codes upon which this could be based.

Mr Varney, who is Managing Director of Shell UK Ltd Downstream Oil, praised the progress made so far by the Institute in this area. Amongst other achievements over the year, the IP had added a second BSI Secretariat to its portfolio, published eight new Codes and Guidelines, developed new working relations with other associations across Europe and prepared a report on the methodology of estimating VOC emissions for the House of Commons' Environment Committee.

The second challenge highlighted by the President was to continue to develop the professional standards of individual employees in order to help them meet the increasing demands of their work. To this end, the Institute had provided a wide range of conferences, publications and information services during 1994 to increase knowledge and understanding of the oil and gas industry. However, more needed to be done in the future to expand individual membership, which was the foundation for the IP.

The President thanked the IP staff and colleagues on Council and the Management Committee for their advice and support over the past year. He also paid special tribute to Mr John Orange, who retires as vice-president of the Management Committee but remains on Council, Mr Peter Johnson and Ms Elaine Priest, who retire from Council this year, and Mr Alan Green, who retires as a representative of the Branches.

Mr Varney was re-elected as President for the session 1995-6. Mr David Setchell, Managing Director of Gulf Oil, was elected as President-Elect. Mr David Simon and Mr David Sharp were re-elected as Honorary Secretary and Honorary Treasurer respectively.

Dr Graham Bell, Esso Petroleum Co Ltd, and Mr David Brown, BP Oil Europe, were elected as Ordinary Members of Council for the first time. Mr Bob Hooks, Shell Research, was elected as a Branches Member of Council for a term of three years.

The Report of Council was presented by IP Director General Ian Ward and subsequently adopted.

The accounts were presented by the Honorary Treasurer, Mr David Sharp, and adopted. Ernst & Young were re-appointed as auditors for the coming year.

The prestigious Eastlake Medal was presented to Mr Peter Ellis Jones, for his exceptionally long and meritorious service to the Institute. Mr David Varney thanked him for 'bringing knowledge and wisdom about the Institute directly to the President's door'. In his acceptance speech, Mr Ellis Jones congratulated the IP on successfully reflecting the organisational and structural changes taking place within the oil industry at large. He said the Institute now had 'a greater breadth and depth' and was 'increasingly attuned to meeting the requirements of its members'.

Awards of Council, each commemorated with a cut-glass rose bowl, were presented to Messrs David Atherton, Alan Davison, Brian Goodland OBE, Eric Whitford and Jim Williams.

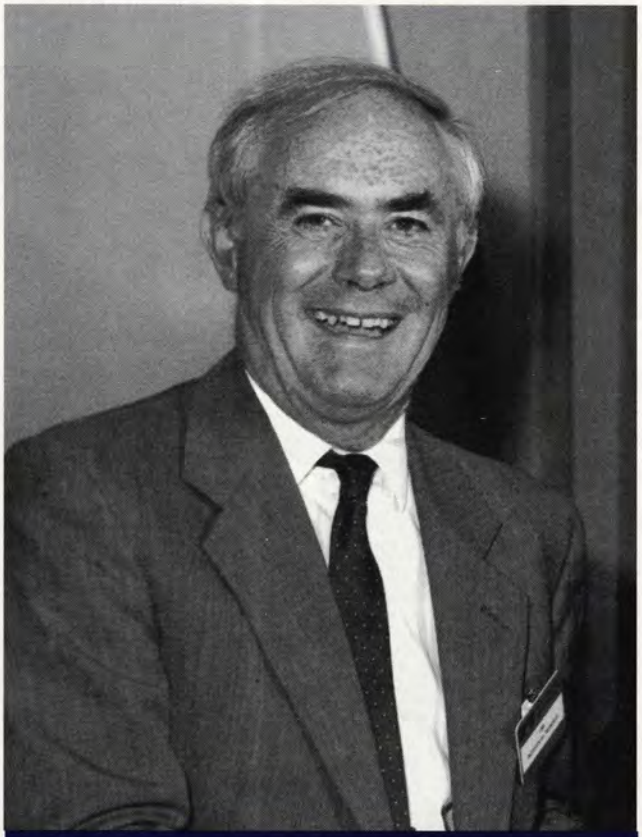
Further Awards of Council will be presented to Mr Derek Brown and Mr Alan Higgins later in the year.

Mr David Setchell, Managing Director of Gulf Oil, elected as President-Elect at the 1995 AGM.

Alan Davison joined the Essex Branch as a local member in 1973 and in 1983 was elected as Assistant Secretary. He became an individual member in 1986 and early the following year was elected as Branch Chairman, serving for six years. He has recently completed 20 years as Branch Secretary.

Eric Whitford had been a successful Chairman of Safety Sub-Committees from 1976 to 1984 prior to joining the IP. At the Institute, he was well-known and respected by the Department of Transport, Home Office (Fire Services) and at senior levels in the HSE and was also the first IP employee to become the Secretary of a CEN Working Group on road tankers.

Peter Ellis Jones (left, with David Varney) joined the Institute of Petroleum in January 1975 and was elected to Council in 1979. He became a fellow in 1981 and, in the same year, was appointed Chairman of both the Education Committee and the Energy Economics Group. In January 1985, he was appointed Honorary Editor. He has also been Chairman of the Publications & Information Services Committee since 1985 and in 1991 became an IP Vice-President. He has played a major role in arranging and chairing many IP conferences.



David Atherton joined the IP in 1968 and became a regular attender at the Northern Branch meetings. He subsequently became a committee member, a position he held throughout the 1970s and into the 1980s. He was a founder member of the Midlands Branch and subsequently became Chairman. David held the post of Technical Director of Midland Oil Refineries from 1970 until his retirement in 1989. He is still an active member of the Midlands Branch.

Brian Goodland OBE was until recently Director of Safety and Environmental Affairs at Texaco Ltd. He was a member of the Board and was responsible for the implementation of health, safety and environmental policies and their observance in the Texaco Group of Companies in the UK. He is a Master Mariner and a member of the Honourable Company of Master Mariners and the Royal Institute of Navigation. Brian was IP Vice-President from 1989 to 1992 and has been an IP member of Parliamentary & Scientific Committee since 1988.

Jim Williams (left) was elected onto the South Wales Committee in 1963, taking over as Treasurer in 1970 and serving in this capacity until 1993. His approach to his work helped the South Wales Branch through one of its most difficult periods when company reductions and closures and loss of Branch members were widespread.

Retirement from regular employment did not prevent him from continuing as an officer and he has continued to be a mainstay of the committee.

He has represented the Branch at Branches Committee on many occasions – deputising for the Chairman.

Microbial quality tests for fuels

Spasmodic outbreaks of problems with middle distillate fuels which are attributed to microbial contamination have occurred over many years. The most recent widely reported episode was in 1992 when gasoil imported into western Europe from the Russian Federation resulted in widespread contamination. The ensuing debate and calls for the introduction of standards led the Institute of Petroleum's Microbiology Committee to establish a Microbiology Fuels Group (MBFG) charged with:

1 Revising IP 385/88 'Code of practice for examining light distillate fuels for viable micro-organisms';

2 Developing guidelines for sampling, testing, and interpretation of test results.

The MBFG has completely revised IP385, retitled IP 385/95 *'Determination of the viable microbial content of fuels and fuel components boiling below 390°C - filtration and culture method'*. It has also developed and published a rapid method for examining fuels, IP PM BY *'Determination of the fungal fragment content of fuels boiling below 390°C'*, and the guidelines are expected to be completed later this year.

A workshop entitled 'Microbial quality tests for microbes' was held at the Institute on 23 May at which the new methods were presented and the various sections of the proposed guidelines discussed.

Following discussion it was agreed that, as the entry of microbes into fuels cannot be prevented, avoidance of water contamination and good housekeeping were the keys to the prevention of problems associated with microbial growth.

The ability of microbes to multiply and die rapidly means that within a storage, distribution and supply system levels of contamination can be temporal. Whilst microbial growth within the storage and distribution system can cause fouling and corrosion problems, it is problems relating to filter blocking at the end use where most of the customer complaints arise. In most systems filter blocking can also be caused by non-microbial particles that are commonly found in fuels, however this is catered for in existing fuel quality specifications which vary for different end uses.

After a lively debate, a consensus was reached that a universal quality standard for microbial content in middle distillate fuels was not appropriate and that only guideline ranges should be produced. Whenever these guidelines are applied at any point in a storage and distribution system, any interpretation needs to take into account the level of housekeeping downstream and the intended end use. It was further agreed that the views expressed at the workshop will be taken into consideration by the MBFG when they finalise the guidelines.

Is there a future for the UK's offshore oil and gas industry?

This was the question tackled by senior industry managers at a private workshop held at the Institute of Petroleum recently.

Employing the techniques of scenario planning developed by the Rand Corporation, Shell and others, the workshop's participants produced four alternative visions of how the UK offshore oil and gas industries might look in the year 2010. Their findings have now been published in a concise report, on sale from the Institute of Petroleum (telephone 0171 467 7100 for details).

The workshop's participants 'projected' themselves into the future, in order to provide a series of scenarios designed to stimulate further discussion and to act as an aid to forward planning for everyone involved in the industry. The workshop report makes challenging and interesting reading, exploring as it does the potential shape of the future, good and bad. In brief, the four scenarios explored in the report are:

- *'Triumph in Adversity'* - a low oil and gas price, unsympathetic tax and regulatory regimes, make the industry struggle hard to achieve returns. Production continues, but with a heavy emphasis on cutting costs and getting the economics right.

- *'Best of Both Worlds'* - given a high oil price and favourable government and public attitudes, the industry stays lean, effective and responsive to public demand and environmental concern. The UK's natural resources are explored and produced effectively and with minimal waste.

- *'Sunset Industry'* - faced with low oil and gas prices, and a generally unfavourable world arena, the industry fails to keep its costs competitive and fails to innovate. Alternative energy sources, or imported oil and gas, take over and the industry as we know it dies a slow death.

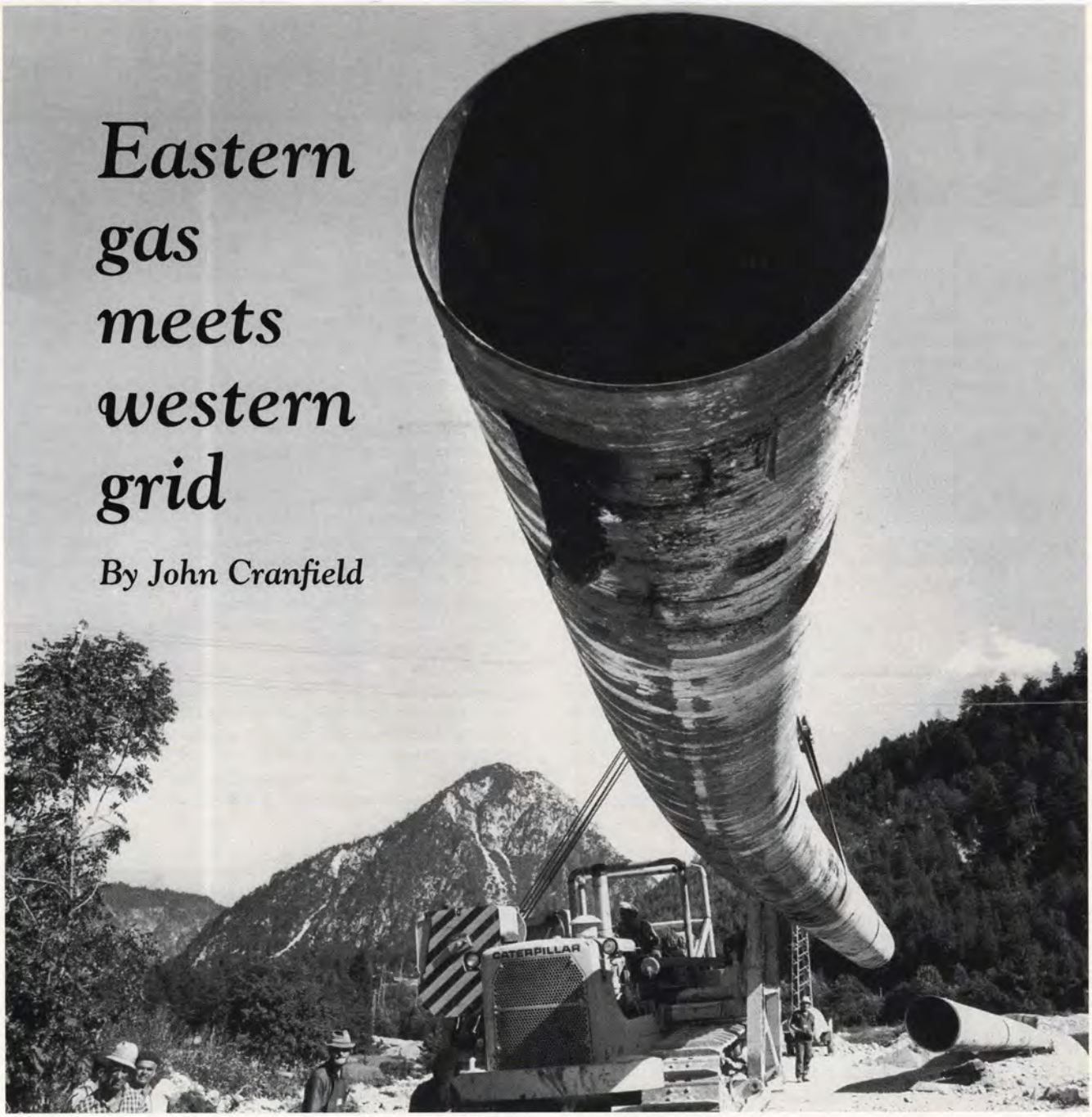
- *'Gold Plating'* - in a time of high prices, strong demand and an easy regulatory climate, the oil and gas industries rest on their laurels and become inefficient high cost producers, failing to make use of the UK's natural wealth or to generate real value for their shareholders.

There are many intriguing points explored in the report, including the value of the existing platforms and pipeline infrastructure in the North Sea: rather than being abandoned, many of these become vital to developing marginal fields; new technology drives costs down but new relationships and company structures are needed to exploit it.

The report is not an attempt to predict the future, but it is designed to provide a creative basis for discussion and development. Ian Ward, Director General of the Institute of Petroleum and a participant at the workshop, said, 'The scenario planning session was an excellent exercise in focusing on the challenges ahead, especially at this time of change for the industry. I hope, by publishing our findings in this way, we will stimulate further investigation of the issues by everyone involved in the industry. Readers must judge for themselves how controversial or fantastical our scenarios may be, but we certainly hope that by "projecting" ourselves into the future we have provided some interesting and challenging food for thought.'

Eastern gas meets western grid

By John Cranfield



Italy has become an important transit point for gas flowing both east and west

Since the collapse of Soviet Communism, links to western grids have opened up the gas markets of eastern Europe and reduced their dependence upon Soviet supplies. Yet, despite the advances, complete integration remains out of reach. The Iron Curtain may have lifted but only to be replaced by a new barrier to free trading – Bosnia. As long as hostilities rage, a sizeable chunk of eastern Europe will continue to be cut off from the west.

The removal of the Iron Curtain has once more allowed natural affinities across Central Europe to be resumed. Nowhere is this more apparent than in the reconnection of natural links in the region's infrastructure. Roads and railways no longer peter out as they approach the artificial barrier once laid down across the continent by Communism. Countries on either side of the border can once again co-operate in the development and use of waterways – both for supply and transport. And the same is now being applied to gas, a much later development as far as cross-border trade is concerned, but today just as important.

Prior to the erection of the Iron Curtain there was no such thing in Europe as an international gas trade. Each town had its own gasworks, making town gas from coal. Even in countries unaffected by the political divide, national grids were in their infancy and international links were non-existent. The introduction of natural gas from the late-1950s onwards changed all that. Throughout western Europe, national grids took supplies from a number of sources, many of them outside the nation's borders. Today there is in effect one huge transmission system that can, in theory if not always in practice, feed homes with gas from sources as diverse as North Africa and the North Sea, Russia and the Middle East.

All this totally bypassed the countries of eastern Europe. The introduction of gas from the Soviet Union added another factor. While western Europe could – and did – take sizeable volumes of Soviet gas to balance that from other sources, countries east of the Iron Curtain continued to be restricted. The choice was either Soviet gas (thus strengthening political ties) or local supplies, some natural but mostly manufactured. Satellite nations were restricted in their freedom to choose. Primitive

Soviet methods also meant that waste was endemic – the gas meter, for instance, was virtually unknown until the collapse of Communism.

The introduction of a market-orientated system, with consumers paying the market price for what they use, showed up huge deficiencies in the old system. But the parallel growth of a freedom to choose meant that supply sources could be negotiated outside the Soviet Union. The result has been a spate of projects. Some are geared to linkage with western grids, others are more concerned with internal upgrading, such as the final elimination of town gas in favour of cheaper, more environmentally-acceptable natural gas. For alongside the development of market economies is the realisation that the old Soviet-inspired industries, largely based on coal and much of that brown coal, were hugely polluting. Natural gas is thus seen as contributing not just to the economic revival of the east but to the development of a healthier lifestyle for the population.

German integration

Naturally enough, this process has gone furthest in the former German Democratic Republic. Soviet gas had been available for years but was mostly used in selected industries. Domestic grids continued to be fed with town gas manufactured from brown coal, and there was no national grid. One of the first successes of the privatisation trust, Treuhand, was the attraction of western gas utilities to revamp the old municipal systems. Regional grids have been established and the old transmission company – Verbundnetz Gas (VNG) – has been transformed from a state-owned entity to one jointly owned by western German utilities, eastern German municipalities and a number of foreign firms, such as British Gas and Statoil.

The German gas grid was completed in 1994, with the final links being brought into service last December. At the same time, connections have been made to the former west German transmission grid, allowing the new eastern länder to import gas from a variety of sources, including the North Sea. From October 1996, VNG will start taking 4 billion cubic metres per year (Bcmy) from Norway via the new link.

Prior to reunification, only 10 percent of GDR domestic consumers had access to natural gas. By the end of 1995, VNG hopes this figure will have risen to 80 percent. To some extent this depends on pricing. VNG sells to regional distributors which in turn sell to municipal concessions. Cross shareholdings have tended to ensure a quasi-monopoly but the Federal Cartel Office seems satisfied so far. And the rapid growth in consumption suggests that end-users are also generally happy.

This could change. VNG is not only the biggest transmission company but it also has a 50 percent stake in Erdgasversorgungsgesellschaft (EVG) which serves three länder. Further theoretical competition could be expected from Wingas, whose Stegal/Midal pipeline system gives alternative supply options in several areas. But Wingas is owned by Wintershall and Gazprom, both of whom have stakes in VNG. It may be that this cosy arrangement falls foul of EU competition law but challenges so far have come to nothing.

Two-way options developing

One spin-off from the reunification of Germany and the rapid extension of the gas grid has been the establishment of a first-ever link with Poland. Soviet (now Russian) gas always flowed into the GDR via what is now the Czech Republic, with Poland having separate access via Belarus. Now the German-Polish link means that, as well as Russian gas flowing west, gas from sources such as the North Sea could flow to the east. That would provide two immediate benefits: improved security of supply; and the possibility of price competition.

'The gas meter was virtually unknown in eastern Europe before the collapse of Communism'

It is these two points that have spearheaded the development of links across other parts of the former Iron Curtain divide. However, for many states, access to alternative supplies is not straightforward. For this reason, Poland and the Baltic States have begun looking at the option of LNG import and future diversification can be foreseen in, for instance, the acquisition by Ruhrgas of a stake in the Estonian utility, Eesti Gaas. Further south, the geographical constraints are less restrictive. Even so, moves are slow. The Czech Republic and Slovakia both benefit greatly from the fact that transit-line fees for Russian gas heading to western Europe provide income offsetable against the local purchase of such gas.

Nevertheless, Plynoprojekt deputy managing director Jan Ruml sees Czech demand rising from 7 Bcmy in 1993 to 14-15 Bcmy in 2010. This doubling will have to be supplied from a variety of sources so talks are underway over the possibility of Norwegian gas flowing in via Germany and LNG being regasified in Croatia and piped north. Slovakia has nailed down deals with Russia for the next few years and no other source is yet contemplated. However, a venture with Austria's OMV is seeing joint peak-shaving storage being built on the border. This could be fed with gas from various sources and also

Pipe-laying in Northern Europe

provides a link between the Austrian and Slovak grids.

Hungary is following a similar pattern to Slovakia, with further Russian gas secured. This will be partly paid for by barter, partly in cash. But plans are well advanced for the privatisation of the main transmission company and five regional distributors. When this is complete, links to the west are almost certain to follow. Already Ruhrgas has a co-operation deal with transmission company Magyar Olaj es Gazipari, looking at the option of imports via Germany. A link with Austria is also being mooted. Currently, demand of 10 Bcmy is met 50:50 by local and Russian supplies but a 10 percent demand increase is expected over the next five years.

'Natural gas is seen as contributing to a healthier lifestyle for the population of the east'

Austria is rapidly becoming a new gas hub

'Anywhere east of Croatia is unlikely ever to be linked to western gas grids'

Romania produces 82 percent of the gas it uses, the balance coming from Russia. The latter's contribution is growing as local production slides, so plans are being looked at for LNG import and for offshore development. France's Sofregaz is drawing up new plans, expected shortly. Sofregaz is also involved in Bulgaria in a joint distribution venture. Local production is small, with Russia piping in some 4.5 Bcmy. About 10 percent of that is free, a payment for transit fees for Russian gas going to Turkey. That element will likely double once lines to Greece and Macedonia are in service, while a link to Serbia is planned, pending the ending of United Nations sanctions.

Balkan integration and disintegration

The break-up of Yugoslavia has opened up a range of possibilities. In Slovenia, gas utility Adriaplin has been largely privatised, with state oil firm Petrol Zemeljski Plin (PZP) retaining 21 percent. Italy's Snam holds 64 percent and Austria's Steirische Ferngas 15 percent, with an option to take 13 percent more. A link to the latter's grid is to provide more supply security for both, while there are plans for a link from Italy so that Adriaplin can take Snam gas for use around Koper.

Since 1992, Slovenia has received Algerian gas via Italy and this is due to build up to the point where it supplies 40 percent of local demand, the rest coming from Russia. However, the Croatian LNG-import plan could change this and already Slovenia is easing back on Russian imports. There are also moves by Steirische Ferngas to enter the neighbouring Hungarian market and the result could be a sizeable regional distribution grid largely unhampered by national borders. Meanwhile, PZP is also holding talks with Italgas on joint operations in distribution.

A vital link could be provided by the Adria LNG Consortium. This plans to import LNG through the Croatian port of Krk, for distribution both within Croatia and via links to Slovenia, Hungary, Slovakia and the Czech Republic. Total and OMV are also involved. An initial study by M W Kellogg has since been followed up by feasibility and financial studies, but the project is still held back by the uncertain political situation.

As things stand at present, Croatia would take 0.4 Bcmy, Bosnia 0.3 Bcmy, the Czech Republic 1 Bcmy, Slovakia 1 Bcmy, Hungary 2 Bcmy, Austria 0.7 Bcmy and Slovenia 0.012 Bcmy. Two 125,000 cubic metre tankers would be required, shipping in LNG from either North Africa or the Middle East. These would cost $500 million, with $510 million going on the regasification plant at Krk, to handle 5.5 Bcmy. The 400 km transmission line north, laid in 36-in and 24-in pipe, would add a further $320 million.

The beginning of 1995 saw hopeful signs that this project might progress. The United Nations, following negotiations with Croats and Serbs, predicted a spring reopening for the long-closed Adria crude oil pipeline that served much the same area as the projected gas system. Alas, deteriorating relations made that impossible and the Adria LNG scheme remains firmly grounded. The continuance of active hostilities and less damaging but equally unhelpful political rhetoric mean that anywhere east of Croatia is unlikely to be linked to western gas grids in the foreseeable future.

So, Balkan and Black Sea states are likely to remain dependent on Russian supplies or, if suitable payment arrangements can be sorted out, on imports from Middle East suppliers. The collapse of the Iron Curtain may have allowed a significant push eastward by the free-trading gas utilities of western Europe, but the situation in Yugoslavia means that a sizeable chunk of eastern Europe continues to be cut off from energy freedom. That could change, but nobody should hold their breath.

More oil is coming from offshore fields as modern drilling techniques begin to make an impact

UAE finally moves downstream

By John Cranfield

After years of contemplation, the United Arab Emirates (UAE) is moving downstream. Until recently, the export of crude oil was the be-all and end-all. The odd exceptions to this rule, such as the Das Island LNG-export project, still left vast amounts of unused or under-utilised resources, gas being the most obvious. But the slump in oil prices a decade ago began to concentrate the minds of policy-makers and now a sense of urgency has crept into the country's strategic deliberations.

Instead of a short-lived blip, the price falls of the mid-1980s turned out to be long-lasting. The UAE has thus been forced by events to look to added value. Project after project has now been approved and the country is once more a hotbed of contractor activity. With 94 percent of the UAE's reserves, Abu Dhabi naturally takes centre stage. But, although crude oil production capacity is being hiked from around 1.8 million b/d to some 2.5 million b/d by the end of this year, it is the hugely under-used gas reserves that are getting most attention.

Doubling in LNG

Leading the way, and building on a successful trade kicked off 18 years ago, is Abu Dhabi Gas Liquefaction Co (Adgas), the firm responsible for the LNG-export project based on Das Island. Original capacity of 2.5 million tonnes per year (t/y) has now been expanded to 5 million t/y, with additional gas supplies coming not just from the traditional associated gas produced in the giant Umm Shaif and Zakum fields, but from the deeper Permian Khuff formation, source of much of the Gulf's non-associated gas.

The move towards more non-associated gas has resulted in a change in the relative importance of LNG and LPG. Under the original deal, Tokyo Electric took 2.05 million t/y of LNG and 550,000 t/y of LPG. Following inauguration of the $1.35 billion expansion towards the end of last year, the company is now contracted to take 4.3 million t/y of LNG and 700,000 t/y of LPG. And the volume of gas flowing to Das Island is now so high – at around 1.2 billion cubic feet per day (bcfd) – that Adgas has also managed to break into the European market. Surplus LNG is now being sold, on a more or less regular basis, to Gaz de France, Distrigaz and Enagas.

This expansion has involved a major development effort by Abu Dhabi Marine Areas – Operating Company (Adma-Opco). Horizontal completions are now being widely used on the company's two main fields – Umm Shaif and Lower Sakum, which provide much of Adgas' feedstock. The result has been a rise in crude oil production capacity from around 500,000 b/d to 600,000 b/d. This has been achieved partly by the use of additional gas injection although, as gas demand rises, water injection is clearly a preferred route. As a result, the super-complexes built back in the 1970s are being taken out of mothballs and rehabilitated. Similar work is underway by Zakum Development Co (Zadco) on Upper Zakum, where capacity is to be boosted from under 500,000 b/d to 600,000 b/d by end-1996.

Total expenditure on continual upgrading offshore amounts to around $500 million/year. Most of this goes on Zakum and Umm Shaif, but smaller fields such as Satah and Umm al-Dalkh also benefit.

Onshore hike underway

Running parallel to Adgas' expansion on Das Island is a similar boost based on onshore associated gas by Abu Dhabi Gas Industries Co (Gasco). This year, the company aims to raise capacity by 50 percent to 6 million t/y of NGLs. Dry gas is being supplied in increasing volumes to industry and to the power-and-desalination plants that are an essential foundation for all other activities. Fundamental to this expansion is the $120 million development of the Thamama C and F pays in the Bab field, being carried through by Bechtel and Consolidated Contractors. Work includes the drilling of 38 wells, a gathering system for sour gas, a distribution system

An artificial island helps to extend oil exploration into the shallow waters of the Gulf.

for sweet gas and an electrical network. But this is less than 10 percent of the total Bab project, costed overall at $1.35 billion.

Central to the whole project is the expansion of the Habshan gas processing plant, where capacity will hit 1.865 bcfd by the end of this year. It was previously just 540 MMcfd. Condensate output will also undergo a quantum leap, from 5,000 b/d to 130,000 b/d. The result will be a doubling of onshore gas production, much of it destined for re-injection, but with more and more heading to market. For instance, the Taweela B power-and-desalination plant, which is currently under construction, will take up to 42.5 MMcfd through a new $190 million, 178.5 km pipeline from Bab. The plant will cost $1.8 billion and is designed for dual gas/crude oil-firing. Taweela B will add 488 MW of capacity to the existing A plant, bringing total power capacity to 732 MW. Up to 76 million gallons per day (gpd) of water will be produced if required, but the station (which is being built by ABB, Deutsche Babcock and Six Construct) is designed for flexible operation between water and power output. Fuel needs will also thus be variable, hence the apparent oversized delivery line of 20/42-inches in diameter.

A second power-and-desalination station, at Mirfa, will cost $490 million. Fed via another new pipeline from Bab, it will produce 16.2 million gpd of water. Power-generation capacity will be 180 MW. Construction is being handled by Ansaldo, Focchi and Six Construct.

Also planned is a gas distribution grid for Abu Dhabi city. Consultancy bids were called for this back in 1992, but so far the project remains in the planning stage. The aim is for a grid to supply 250,000 domestic and commercial users. Plans also exist for a grid in Sharjah city. However, when the Habshan project is complete, Abu Dhabi remains likely to get piped gas, with delivery through pipelines which are currently under construction to serve power-and-desalination stations near the city. Oversizing of delivery lines will allow substantial extra flows without the need for more construction.

Gas boosts oil

The increased availability of gas will also benefit oil production. Bechtel is working on the Sahil field contract, a $120 million development which will double output to 25,000 b/d via gas injection. Basic engineering is complete and a construction contract is due shortly. Bu Hasa field will also get a boost in gas injection, with 150 MMcfd due to be pumped into the Thamama B formation. This project is set for end-1995 completion. As a result of these various schemes, output from the six major fields operated by Abu Dhabi Co for Onshore Oil Operations (Adco) should rise from last year's 350,000 b/d capacity to nearly 500,000 b/d of crude and condensate.

It is the boost in condensate production that will give Abu Dhabi its best route downstream. New pipelines will carry the extra output from Bab to Ruwais, where Gasco's fractionator will produce ethane, LPG and other streams to the tune of 6 million t/y. The company is also installing a sulphur-recovery plant for Bab sour gas, giving it another export line. The fractionator is being de-bottlenecked to provide the extra capacity, whilst two more 21,500 cubic metre LPG storage tanks are being built at a cost of $50-60 million. All work is scheduled for end-1995 completion, in line with upstream developments. Initially, boosted Gasco output will mostly go for export. However, pending the building of local gas grids, demand is rising internally for LPG and an increasing volume will find its way to local customers.

Downstream moves

This will be only a stop-gap. The Supreme Petroleum Council recently approved plans drawn up by the Abu Dhabi National Oil Co (Adnoc) to develop a petrochemicals complex at Ruwais. Details are still lacking, but overall cost is put at $1.85 billion and the one plant so far confirmed is a 300,000-t/y polyethylene unit. That in turn will require an ethylene cracker, almost certainly using Gasco-produced ethane as feedstock, though modern technology would make a mixed feed possible, giving LPG a further potential outlet.

Also approved is a $1.5 billion expansion to the Ruwais refinery, with capacity set to rise from 140,000 b/d to 350,000 b/d. Hydrocracking capacity will go up from 27,000 b/d to 67,000 b/d. Both this and the petrochemicals scheme are due for completion in 2000. The Ruwais marine terminal is already being expanded to take ships of over 100,000 dwt. That adds a further $50 million to the overall investment.

Cash flow and secure financial backing will be essential if all these plans are to go through.

Estimates suggest that plans due for completion this year will have cost $5-6 billion. Add to that the $3 billion investments downstream just approved and the as yet unapproved gas grids, and the result is a capital expenditure of over $1 billion/year. That should pose no problem to a country currently earning around $13 billion/year gross from oil sales alone. But much of that goes towards the total federal budget. The continuing surplus of crude and the possibility that crude oil prices could slump just as unpredictably as they rise, means that planners would be wise not to try to do too much too quickly.

Pipelaying is a familiar feature of the Abu Dhabi desert

Maverick Dubai

Abu Dhabi's position as the UAE's main paymaster has long had a restraining influence on its own investment level. Neighbouring Dubai has always argued that, since it was not an OPEC member before the UAE was formed, OPEC rulings on production apply only to Abu Dhabi. The latter has therefore had to bear the burden of cutbacks which, in theory, should have been shared. However, Dubai is now becoming far less important as an oil producer. Output has slid inexorably from around 450,000 b/d at peak to under 250,000 b/d now. At the same time, industrial development at Jebel Ali has led to a marked rise in electricity demand.

Already some 350 MMcfd of gas fuel is being imported from Sharjah, and Dubai is now looking to Qatar and Iran for more. Current plans will see electricity-generating capacity rise from the current 1,859 MW to 1,967 MW by February 1996. Further down the line, Dubai Electricity & Water Authority is looking at a total capacity of 2,300 MW. The obvious source for more gas would seem to be Abu Dhabi but, given the lack of co-operation in the past, Abu Dhabi probably reckons on using its resources more for its own direct benefit. However, as moves continue downstream, it would start to make sense if co-operation were pursued, if only to save duplication of effort and unprofitable inter-emirate competition. Dubai Natural Gas Co (Dugas) has just started up its $250 million, 500,000 t/y MTBE plant at Jebel Ali using a mixed butane feedstock from the company's neighbouring NGL fractionator.

A further logical move would be construction of a gas-fed methanol plant to provide the other necessary MTBE feed. But Dubai's own gas supply is falling as oil flows dwindle, with much of the current output being re-injected. The emirate is thus increasingly dependent upon imports. As long as Sharjah is happy with the low(ish) price now paid, Dubai might be able to negotiate the supply needed for methanol production. But local energy demand is rising by 20 percent/year and this alone will require 500 MMcfd of gas in the near future.

Currently all oil products come from Abu Dhabi, something that clearly upsets the Dubai authorities. For some four years now, plans have been tossed around for a local refinery. These now seem to have stalled as, one after another, potential investors have shied away from the $2 billion cost of the planned 250,000-b/d unit. A refinery on this scale would have to depend mainly on export markets. But these have mostly been snapped up already by established refiners, while other expansion plans in the area, such as Abu Dhabi's Ruwais scheme, would make life very hard indeed for a newcomer.

Sharjah's rising star

Third oil and gas producer among UAE members is Sharjah. Although only turning out 10,000 b/d of crude oil, it also produces 40,000 b/d of condensate as a co-product of its burgeoning gas industry. The latter is now producing around 800 MMcfd, following Amoco's expansion of the Khaif field and Sharjah LPG Co's boosting of processing capacity to 800 MMcfd. Field potential is thought to be even higher, but further processing expansion will be needed first. Apart from the 350 MMcfd going to Dubai, Sharjah uses substantial gas itself, with more destined this year to feed the Layyah power-and-desalination plant. Dodsal has a construction contract for the $30 million pipeline required to move gas from Sajaa process plant. Layyah itself has just undergone a $28 million expansion, to 728 MW. Industry uses most other gas, with liquids mostly being exported.

British Gas explores the world

By Neil Potter

For almost a decade now, British Gas has been engaged in a compelling drive to become a major world player in oil and gas exploration and production. Today it is active in over 20 countries across five continents.

By the end of last year there was significant production from eight fields around the world, two of which started up during the year. Two more were under development, including Miskar in Tunisia, which came onstream in May this year. BG is either operator or joint operator of seven of these eight fields. 21 exploration and appraisal wells were drilled overseas, of which 15 tested hydrocarbons.

It all began in 1986 when the UK government sold its 100 percent interest in British Gas (BG) and the company was privatised. This enabled BG to break out from controls which had previously restricted it to activity within the United Kingdom (where it now holds the second largest reserve portfolio on the UKCS) and specifically excluded it from oil operations.

Through a series of acquisitions and awards of licences, BG then rapidly built up a portfolio. The object was, in the company's own words, 'to make use of its skills to secure long-term growth in its profits and cash generation'.

In total, British Gas Exploration & Production had interests in 43 international licences at the end of 1994. Since 1989, its drilling activity has more than trebled. In 1994, it participated in 10 exploration wells, 11 appraisal wells and 31 development wells in Argentina, Bulgaria, Cambodia, Egypt, Pakistan, Russia, Thailand, Tunisia, Vietnam and Yemen.

In 1987, worldwide production was less than 23 million barrels of oil equivalent (boe), by 1994 this had risen to 82 million boe. International reserves stand at 2,983 Billion cubic feet (Bcf) of gas and 138.3 million boe.

Strategy review

Faced with growing competition in the UK gas market, a thorough review of strategy was undertaken last year. According to Chairman Richard Giordano, 'This review confirmed our belief that to ensure long-term success we must look outside the United Kingdom to grow our core businesses'.

So a new strategy was developed, focusing on international markets where BG saw the greatest growth potential. This led to the sale of some assets, including, for £348 million, a 53 percent interest in Bow Valley Energy, the international E&P company based in Calgary and, for an undisclosed figure, its operating interests in Gabon to Kelt Gabon, where production was 11,000 b/d.

'To make the most of our opportunities worldwide, we are strengthening our management structure to reflect a new focus on strategic areas of the globe,' says Cedric Brown. 'We have decided to emphasise the natural synergy between our upstream and downstream activities.'

In effect, the aim is for BG to fulfil each stage in the gas chain, from exploration and field development, pipelines, internal gas supplies, to power generation. The company has also divided the world into four areas: the Middle East, North Africa and the CIS; Asia-Pacific; the Americas; and Europe, each with an executive director, who would also have responsibilities for developing downstream opportunities. The major developments this year have been in Trinidad, Tunisia and Kazakhstan.

Trinidad

The Dolphin gas field, where BG is operator with Texaco as partner, is at a depth of 122 metres, 90 km offshore from the southeastern tip of the island. Proved and probable reserves are 1.2 Trillion cubic feet (Tcf) and the gas is 99 percent methane with no contaminants, no associated water and limited condensates.

The $300 million development includes one drilling and production platform in 400 feet of water, designed by Aker Omega in Houston, with accommodation for 10-12 crew. There will be some separation and metering of 325 MMcfd of gas and space for future compression facilities.

The initial programme is for six wells to be drilled, utilising a platform-supported rig. The gas will be exported via a 24 inch pipeline for tie-in to the existing National Gas Company of Trinidad's pipeline network. Platform installation will take place in October 1995, with first production planned for February 1996.

Tunisia

In May, the Miskar gas field, situated 120 kms offshore in the Amilcar Permit, came onstream three months ahead of schedule and £36 million under the £497 million budget. This has been one of the largest international projects undertaken by British Gas E&P and will enable Tunisia to become self-sufficient in gas supply.

There are two large reservoirs, each divided into a number of productive layers, at an average depth of 3,200 metres. Recoverable reserves are put at 22.7 Bcm. The field development was designed for a plateau rate of 6.8 million cubic metres per day (Mcmd).

There is a three bridge-linked platform complex, a production platform with 24 well slots, a quarters and utility platform and a flare boom platform. The jackets and topsides were fabricated in Louisiana and towed across the Atlantic to the Mediterranean.

The use of deviated wells and hydraulic fracture technology contributed greatly to the development. Eight of the 10 initial development wells have been drilled, and the remaining two will be drilled this summer.

The gas goes via a pipeline to the purpose-built onshore Hannibal gas plant, which removes carbon dioxide, nitrogen and hydrogen sulphide, to deliver pipeline quality gas.

Key E & P activities worldwide

Societé Tunisienne de l'Electricité et du Gaz (STEG) has a contract to purchase up to 4.5 Mcmd of gas for the first five years of production and 5.7 Mcmd after that.

BG has four exploration permits. Two of them, Kerkennah West and Amilcar, are held with Enterprise Tunisienne d'Activites Petroleum (ETAP). Amoco is operator of Kerkennah South, in which BG has a 30 percent interest. BG has 100 percent and operatorship in the Roumedia permit, for which it signed an exploration agreement in 1992 and in 1993 BG obtained the Abassia permit which is held on a seismic option basis.

BG holds a 49 percent working interest in two small onshore producing concessions in the Kerkennah West permit – Gremda/El Ain and El Hajeb/Guebiba.

In May 1994, the Cercina oil field, which is offshore Kerkennah Island and within the Kerkennah West permit, came onstream at 4,000 b/d. Further oil discoveries in this permit are being developed as the Rhemoura field.

Kazakhstan

In 1992, BG and Agip won exclusive rights to negotiate with the government over the enhanced development of the giant, partly-developed Karachaganak oil and gas field. Estimated recoverable reserves are put at 16 Tcf of gas and 2.4 billion barrels of condensate. Ultimate recoverable reserves could be in excess of 20 Tcf and 3 billion barrels. Investment by BG and Agip could eventually reach more than $6 billion, mainly on drilling and development facilities, plus the building of a refinery and gas stabilisation plant near the field. There will also be substantial investment in the local social infrastructure.

Production began in 1984 and reached 4 million tons and 4.5 Bcm/yr of gas. But due to lack of investment by the state-owned gas concern, Kazakhgas, which took over in 1990 from a Gazprom subsidiary, this fell to 1 million tons and 1 Bcm/ yr.

After initial separation and stabilisation, the gas and liquids are transported 150 km to Orenburg in Russia. The gas goes into the Russian transmission system and the stabilised liquids to two Russian refineries at Ufa and Salavat.

In 1990 BG was invited to consider involvement in the future development of the field. Eventually BG and Agip, which had also submitted a pre-feasibility study, decided to develop a joint tender approach.

In March this year, BG, Agip, Gazprom and the government of Kazakhstan signed a production-sharing principles agreement and the three companies formed a contractor group in which BG has 42.5 percent, Agip 42.5 percent and Gazprom 15 percent. This will use western technology to upgrade and improve existing production facilities. Long-term transportation and export arrangements will have to be finalised to justify entry into the next development phase.

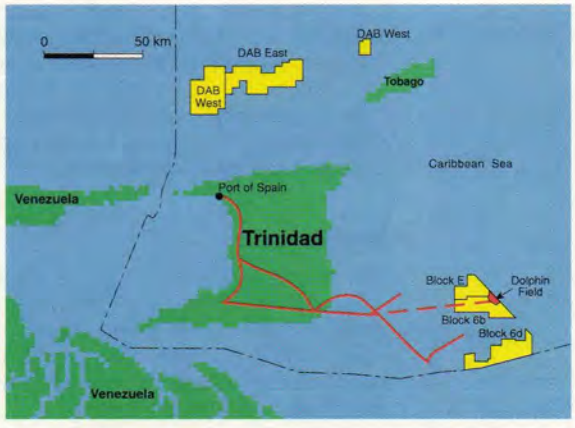
Separately, BG is participating in a six-company major exploration project in the Kazakh section of the Caspian Sea, close to the onshore Tengiz field. Last year, a 100,000 sq km seismic survey was started. At the end of the programme the companies will be allowed to choose a number of blocks in what they regard as the most prospective area.

Russia

In Russia, BG has a 50 percent interest

E & P activities in Trinidad

- Gas field
- Oil field
- Gas pipeline
- Gas pipeline (under construction)
- City/Town
- Licence interest – British Gas operated



in the Russian company KomiArcticOIL. There are two projects, 1,500 km north-east of Moscow on the Arctic Circle.

The first is the appraisal and development of the Upper Vozey field, with recoverable reserves of 400-500 million barrels of oil. Phase 1 is designed to recover 100 million barrels. Drilling was completed early this year and new production facilities installed. Production has risen from 4,000 b/d to 16,000 b/d.

Three rigs will shortly begin drilling wells in Phase 2, designed to recover an additional 100 million barrels. New facilities will be installed in 1995/96.

Thailand

Asia-Pacific, which is viewed as an area of rapid growth in gas markets, is one of BG's core areas. In the Gulf of Thailand it has a 20 percent interest in Total's Bongkot gas field. This has estimated recoverable reserves of up to 5 Tcf of gas and 50 million barrels of condensate.

Production began in July 1993 and by January this year had reached 250 Mcf/d. This will rise to 350 Mcf/d in January 1996. The gas is delivered by a 177 km pipeline to Unocal's Erawan complex and then goes to the mainland.

To maintain and ultimately increase production to a possible peak output of 650 Mcf/d by 2000, additional platforms and further wells will be needed.

BG operates block B5/27, which contains an oil discovery. In 1993 it acquired Blocks 7, 8 and 9, which lie in disputed waters between Thailand and Cambodia.

Cambodia

In Cambodia, it has 20 percent, non-operated interests in Blocks 1 and 2. The first well, Angkor-1, drilled by the joint venture in 1994, discovered gas and condensate. A 3-D seismic grid has been acquired and a well is planned for the end of this year.

Indonesia

In Indonesia, BG has a 95 percent interest and is operator of the Muturi concession in western Irian Jaya, where shallow oil has been produced. Exploration is now to be focused on deeper horizons, 15 km to the south. Drilling is scheduled to begin late 1995 or early 1996.

Pakistan

BG has a 50 percent stake and is operator of Block 34 which extends along the eastern flank of the Sulaiman Ranges of central Pakistan. The block contains the Savi Ragha gas condensate discovery and further exploration and appraisal is underway.

In November last year, BG became operator in three new exploration licences – Sulman in Baluchistan (57 percent), Guddu and Gambat in the Central Indus Basin (95 percent).

Vietnam

The first well offshore Vietnam was drilled last year in block 04-1 (BG has a 50 percent stake and is operator) in the Con Sun Basin, to the north of Lasmo's Flying Horse discovery in block 04-2. But the well, Song Tien 1X, was reported to have only gas shows and was not tested.

Yemen

Exploration with an oil bias is being carried out in Yemen, where BG is the third largest net acreage holder. Onshore, it farmed-into the Al Hajar licence covering Block 9 in 1991 and became operator in 1993, with a 66.6 percent stake. Two exploration wells have tested hydrocarbons.

After the withdrawal of Lasmo, BG took over operatorship of the Hood block and has a 49 percent interest. A three-well exploration programme has been completed.

In March 1993, BG acquired the offshore Socotra concession and has a 100 percent interest. This is 580 km south of the Yemen coastline. The initial work programme included the acquisition of 3,000 km of seismic and two wells will be drilled in 1995/96.

Egypt

Egypt is another key area where BG has oil production. It is operator of the Zaafarana field in 61 m water depth in the northern part of the Gulf of Suez. This came onstream in late 1994. The development involves one offshore platform, a subsea flowline, a mooring buoy and a dedicated FPSO. Development costs are $100 million.

Oil production is up to 25,000 b/d with no associated gas. Development drilling continues and a water injection facility may be installed late this year.

Other operated interests include: North Zaafarana (100 percent), North Sinai (100 percent) offshore the eastern Mediterranean; Rosetta (40 percent) and West Delta Deep (50 percent), offshore the Nile Delta Basin. The company also has a 30 percent interest in the Agip-operated West Abu Gharadig concession onshore the Western Desert.

Bulgaria

In Europe, Bulgaria has attracted interest and BG, with 100 percent, is operator of the offshore block IV, Kamchia. A drilling programme began in 1993 and by April 1994 two dry holes had been completed. A third, 95-day well was begun in April 1995 with a total depth of 4,600 metres. This fulfils BG's commitment under the existing licence agreements with the Committee of Geology.

Onshore, it has a 100 percent interest in Block 10 Burgas. BG has acquired 600 km of vibroseis data and is currently evaluating the results.

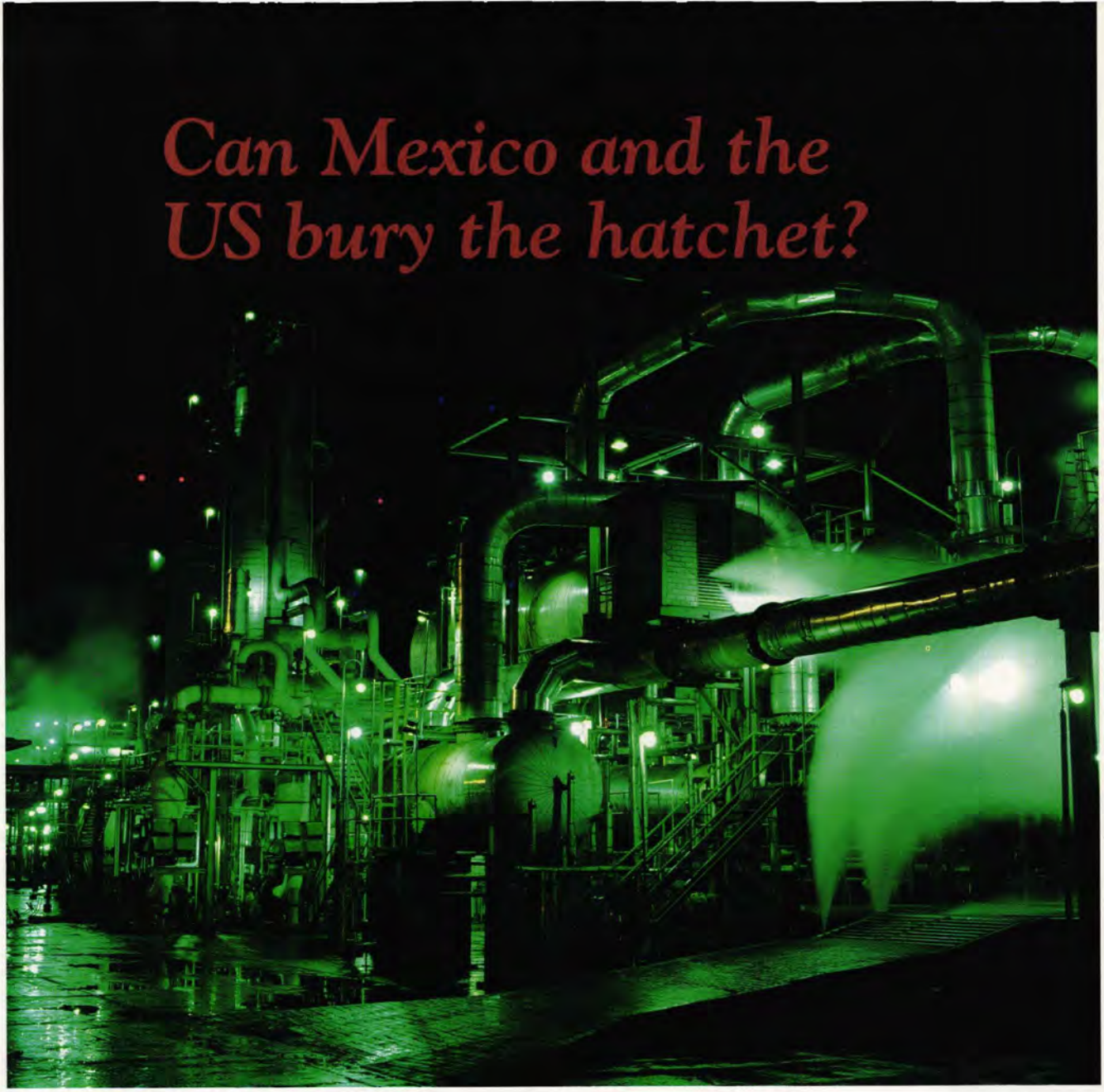
Others areas

As if this wide sweep of international E&P operations were not sufficient to place BG among the major world players, it is involved in an oil field development programme in Argentina and has an interest in five onshore blocks, in two of which it is operator. In Qatar, it has acquired a 25 percent interest in an exploration and production-sharing agreement which includes part of the giant North field, with estimated reserves of 300 Tcf of gas. This will give BG access to around 8 Tcf of gas.

In Italy there are interests in eight licences and BG is operator of one. In the Netherlands, there are interests in blocks B/17a (55 percent and operator); F/12d; G/17c and Q/10d,d,f.

In Poland, BG has a 100 percent stake in the Kutmo licence which it operates; in Somalia there are interests in four blocks and in Algeria, two blocks.

Can Mexico and the US bury the hatchet?



Pemex's gas processing facilities

By Peter Adam

If Mexico, the United States and Canada can create a unified hydrocarbons market all the way from Hudson Bay to the Yucatan, there could be benefits all round. But the transition will involve major changes in attitude on both sides of the Rio Grande River.

After two years of deregulation, the pace of consolidation amongst natural gas companies in the United States has at last begun to abate. Yet, just as firms have begun to relax again, a new concern has appeared on the horizon – Mexico. Those companies currently in the North American gas patch are now asking how the possible inclusion of Mexico in a unified North American hydrocarbon market (via modifications to the terms of the North American Free Trade Agreement - NAFTA) would affect the rest of the industry.

They have reason for concern. Creation of a unified oil and gas market stretching from the reaches of Hudson Bay to the Yucatan may boost the prospects for gas in all three countries. However, it could also disturb the cosy atmosphere that the more prosperous US and Canadian oil and gas 'club' members were looking forward to now that the wrenching changes wrought by deregulation and continental economic integration had supposedly been put behind them.

On the other hand, failure to develop a cohesive, integrated North American oil and gas sector could well hinder prospects for economic development and political reform in Mexico. This, in turn, would adversely affect both Canada and the United States and jeopardise international trade liberalisation in the western hemisphere and elsewhere in the world.

The natural gas industries of Canada and the United States have become, to all intents and purposes, one entity, with several sub-divisions: producers; marketers; providers of transportation and storage services; brokers; and financial intermediaries. The US-Canadian Free Trade Agreement (FTA), now supplanted by NAFTA, together with deregulation on both sides of the border, have made free trade in energy between the two countries a reality. Together, US and Canadian gas companies have emerged from a decade of capacity surplus and declining prices during which the industry has undergone a dramatic, policy-driven, market-based re-orientation.

Major changes

Although it will take a while, the North American gas industry fully expects that Mexico will eventually extend provisions governing the opening up of its economy to oil and gas. It seems rather less

likely, however, that inclusion of Mexico's hydrocarbon sector in the free trade area will proceed as smoothly as US-Canadian integration. Instead, developing Mexico's hydrocarbons and integrating them into a continental trade zone will be a complex undertaking, involving major political and economic changes south of the Rio Grande River.

Accommodating Mexico is not likely to alter the basic gas balance of North America. Because of the size of its gas resource base and the magnitude of its market, the United States will remain dominant. In his report, '*NAFTA and Energy*', G.C. Watkins, currently with Charles River Associates, the Cambridge Massachusetts-based resource consultancy, points out that while Mexico's petroleum reserves exceed those of the United States and Canada combined, US natural gas reserves are roughly equivalent to Mexico's and Canada's put together.

In terms of fossil energy consumption, the United States places greater reliance on oil and coal than Canada, which relies more heavily on natural gas and electricity. Mexico relies most heavily on oil.

While both Mexico and Canada ship substantial amounts of petroleum to the United States, their combined US exports still represent only about 10 percent of the US supply. Canada exports 40 percent of its gas, all of it to the United States, but still only satisfies about 10 percent of US gas demand. Mexico hasn't exported gas in appreciable volumes to the United States in years and, since the late 1980s, has been importing growing quantities from its northern neighbour.

The dominance of the Institutional Revolutionary Party (PRI) over Mexico's political life has enabled Pemex, Petroleos Mexicanos, the state-owned oil and gas company, to monopolise the indigenous oil and gas sector and has precluded development of Mexico's hydrocarbons. Significant domestic capital constraints have only added to the industry's difficulties. While US and Canadian companies could bankroll Mexico fairly easily, protecting the oil and gas patrimony of the motherland from exploitation by 'Yanquis' has been a policy priority south of the border for most of the 20th century. However, that may soon change.

Four possible paths

According to a soon-to-be-released study by the Canadian Energy Research Institute (CERI), there are four different paths Mexico could take vis-a-vis developing its gas in the context of continental integration.

Because of dramatic changes occurring in the Mexican economy in general, and the energy sector in particular, the authors reject a status quo or 'business as usual' scenario and opt instead for a base case entitled 'Pemex evolves - imports solve' as the most likely course for Mexico. Under this scenario, Pemex does not develop its gas resources adequately because of a dearth of domestic capital and preclusion of foreign investment. Mexico imports what it needs from the United States fostering economic growth and environmental improvement south of the border.

Another scenario – 'Mexican Gas for Mexicans' – assumes that political constraints preclude high levels of gas imports from the United States and Pemex is forced to secure sufficient funds to develop Mexico's extensive low-cost, non-associated gas reserves.

In the third scenario of the CERI report, entitled 'North American Tiger', everything comes together for Mexico. The government removes impediments to foreign participation and destroys Pemex's monopoly. Unfettered markets allocate hydrocarbon and other resources efficiently. Mexico becomes a net supplier of natural gas from its low cost fields to the North American grid.

In CERI's fourth and worst case scenario, 'Times are Tough', the Mexican government makes major policy mistakes, a cyclical downturn reverses liberal economic reforms, foreign investors withdraw and Mexicans start sending money abroad. While Pemex can easily supply the country's lowered energy needs, economic, social and political upheavals ensue and impede development

LPG storage spheres

and integration. CERI holds that events are not about to unfold this way, and the study concludes that Mexico is likely to become an important, though not a dominant, factor in the continental natural gas scheme of things.

The authors admit, however, to an optimistic bias throughout the report, explicitly stating, 'A major assumption made in this study is that the Mexican economy will continue to be opened up to international market forces. The commitment of PRI to growth and the increasing number of stakeholders in the new economy support this view, in which Pemex adopts competitive pricing concepts'.

'Protecting its hydrocarbons from exploitation by 'Yanquis' has been a policy of Mexico's for most of the 20th century'

What if such assumptions prove wide of the mark? For some, the situation does not appear to be so rosy.

A recent study from Mr Matthew Simmons, Chief Executive of the Houston-based oil and gas investment firm, Simmons and Co. International, paints a sombre picture of the US gas industry, which is very much at odds with the consensus. In his report, *'Has the Natural Gas Goose Killed the Golden Egg?'*, Simmons holds that, far from being a financially-strong and operationally-sound industry reaping the benefits of deregulation and boldly venturing abroad to conquer new markets, the US gas industry is headed for trouble. This, he implies, has serious ramifications for the entire North American gas sector.

The Fuel Use Act

Tracing the tortuous, intertwined paths of US gas market and policy development over the last two decades, Simmons points out the grave mistakes energy planners, politicians and policy-makers have made. In the early 1970s, natural gas provided 32 percent of total US energy requirements. Over the next 15 years, while overall US energy demand rose slowly, natural gas experienced a remarkable loss in market share. The Fuel Use Act of the late 1970s assumed resource scarcity. Swept away by a policy crusade in which energy self-sufficiency was held to be 'the moral equivalent of war', the US federal government did declare a war of sorts – on natural gas use. The Act made it illegal for many logical customers to use the stuff. In a number of applications, coal and nuclear energy supplanted natural gas which saw its piece of the energy pie decrease 40 percent by the mid-1980s. At its low point, gas accounted for less than a quarter of US energy needs.

As perceptions and policies based on resource scarcity gave way to presumptions of plentitude, a different political dynamic came to the fore. In the mid-1980s, the US government started deregulating the natural gas sector in order to allow it to elbow aside petroleum, a resource seen as scarce and diminishing, and become the primary source of US energy.

Gas storage casino

As a result, US gas use has been on the upswing. Mr Simmons contends, however, that post-deregulation gas pricing mechanisms in the United States are seriously flawed. He argues that the market is driven by a 'gas storage casino' mentality, in which speculators' hunches concerning the weather in winter, rather than long-term agreements reflecting economic fundamentals, govern the prices at which gas changes hands. Thus, the market does not provide a systematic way of ensuring that gas availability in the United States keeps pace with demand growth. According to Mr Simmons, the only constant in the industry over the past six years has been the steady decline in worldwide and US drilling activity. He also notes that spare delivery capacity is rapidly diminishing.

It is quite likely, his report says, that gas demand from non-utility generators will remain robust. If current, just-in-time gas well completion trends persist, it warns that supply capacity will, in the not-too-distant future, fall short of meeting burgeoning US demand.

Canada

Many analysts argue that this degree of concern over US availability is overdone and point to the plenitude of gas lying just over the northern border in Canada to prove their point. Simmons, however, believes that these supplies would be constrained by inadequate transport capabilities.

Canada supplied about 11 percent of US gas needs last year, triple what it exported to the US a decade ago. While some expect Canadian imports to grow exponentially, Mr Simmons points out that Canada supplies two separate US gas markets, one west and one east of the Rocky Mountains. The four pipelines that carry gas to the weather-sensitive areas to the east of the Rockies represent almost half Canada's total export capability. These lines were 97 percent full in 1994 and their spare capacity is a mere fraction of total US gas demand. 'Thus, counting on Canadian imports to always keep the United States in balance is a dangerous and risky bet,' writes Mr Simmons. 'Obviously, new pipeline capacity can be built, but construction takes years, not months, and little or none is on the drawing-boards today.'

The long-term implications which follow from such an assessment are troubling, and not just for the United States. Extrapolating US Department of Energy figures, the Simmons report projects that, if growth in natural gas demand continues at the rate it has over the last eight years, the United States will be consuming 25.8 Tcf of gas per annum by 2000. This is an increase of 4.8 Tcf or over 70 Bcf per day, a big jump from the 57 Bcf per day which the States consumed in 1994.

Mr Simmons' analysis casts doubt over whether the United States will be able to supply Mexico if it needed to. If the rosy scenario that CERI puts forth does not pan out for Mexico and it must import gas from the United States who will get the stuff if the States needs it too? Will it be shipped north or south of the Rio Grande? And how will this effect the prospects of economic integration?

'For an industry so important to the United States, one would think we could do a lot better,' the Simmons report concludes. 'This is a crazy way to run the natural gas railroad.'

Other viewpoints

The situation may not be as dire as Mr Simmons has it. Unseasoned markets and market-based pricing

mechanisms, in which accurate information is easily accessible and futures play their proper role of 'price discovery', may yet evolve and come to reflect 'all in' gas prices accurately. This might enable 'just in time' production capacity additions to preclude the need for a significant inventory of surplus in the United States. Canadian supplies could be augmented by using compressors to enhance pipeline deliverability. And gas demand growth in North America may not be as robust as the Simmons report projects. But all this remains to be seen.

Regulation

At a recent energy conference in Washington DC, representatives of international gas industry majors outlined some of their ambitious development plans. Yet their 'go for gas' enthusiasm contrasted sharply with a presentation given by a major international consultancy on the type of regulation required at different stages of economic development and market maturity.

The consultant concerned categorised markets as embryonic, emerging, competitive or efficient and explained that regulatory regimes must adopt approaches appropriate to each one in order to promote growth and development. In embryonic markets, regulators must protect fledgling industries; in emerging markets, they must ensure stability; in competitive markets, they should preclude industry concentration; and in efficient markets, where a variety of well-established participants exist, regulators must avoid over-regulation and interference. If the regulatory approach is inappropriate, it can inhibit growth and destroy an industry, he warned. This has been evident in various capital-intensive industries of the United States at different times: natural gas in the late 1970s and early 1980s; savings and loan companies over roughly the same interval; and domestic gas carriers in the last few years, many of whom have had to file for bankruptcy. US gas companies may once again have such troubles.

Over-capacity

Throughout the late 1970s and 1980s, technological changes transformed the relative proportions and costs of the raw materials used to manufacture goods across the spectrum. There was over-capacity all over the world, relative to actual demand, in basic raw materials, as well as for many basic industrial goods, such as automobiles, main-frame computers and airplanes. Prices crashed in industrial commodities. Companies' market shares plummeted. Policy-makers and regulators in developed countries facilitated adjustment to new dynamics of production by deregulating. This allowed markets to force inefficient producers out of business and thus freed up resources for use elsewhere. Companies in various industries downsized, re-engineered themselves, reduced costs, etc., in order to survive.

But this dynamic may soon have run its course. As billions of new consumers enter a free enterprise international economic system in the wake of the collapse of socialism and communism in the former Soviet Union, government policy-makers may have to adopt regulatory approaches geared to expanding markets and encouraging capacity additions rather than orderly liquidation.

In this regard it was interesting to note that at the recent Washington conference referred to above, the success of the mega-projects of the integrated major gas companies presented often depended upon long-term contracts. These included pricing arrangements to ensure coverage of investment costs in the billions of dollars and guarantees provided by governments and quasi-government entities. This implies a much more highly-regulated environment than those establishing a free trade zone in North America are presumably striving for.

The emergence of a truly integrated North American gas and oil sector will depend on adoption of an appropriate regulatory framework. Time alone will tell whether the US gas industry will facilitate or impede development and continental integration of Mexico's hydrocarbons.

Political factors

In the final analysis, though, integration of Mexico's oil and gas sector into the North American Free Trade Zone may turn on US and Mexican political developments as much as anything else – a disquieting thought as recent news from both countries is far from good.

While the peso has stabilised and foreign investors are once again buying shares in Mexican companies, the austerity programme, upon which the US and IMF-sponsored financial bail-out of Mexico earlier this year was contingent, is costing one million Mexicans their jobs and casting a pall over the entire economy. Social unrest could prompt Mexico to reconsider its commitment to economic liberalisation, hemispheric integration and domestic democratic reform.

'Poor Mexico, so far from God, so close to the United States'

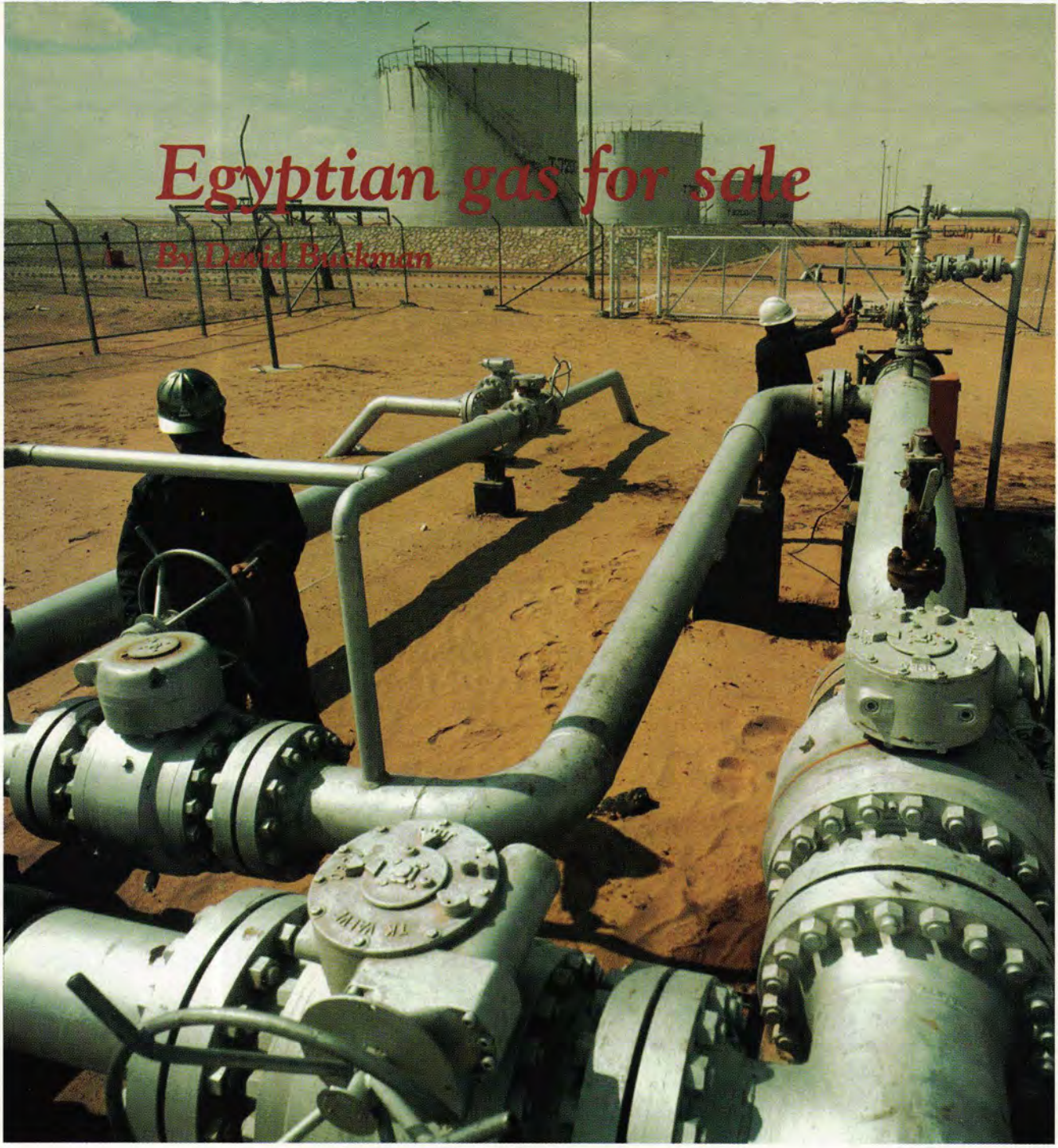
And in the United States, where the government is divided, the Mexican bail-out package may yet become a contentious political issue. If events take a turn for the worse in Mexico, Congress could act upon its threat to hold hearings to investigate why the peso's collapse earlier this year caught officials of the Clinton administration, as well as most financial authorities and participants and observers of international capital markets, by surprise.

If politics on both sides of the Rio Grande jeopardise the development of NAFTA, it would not be the first time that these countries have failed each other. The legacy of the history of Mexican-US relations is, after all, a tragic one and nowhere is this more evident than in oil and gas.

The pre-revolutionary President of Mexico, Portfirio Diaz, once said, 'Poor Mexico, so far from God, so close to the United States'. Memories of the heavy-handedness of US oil companies early in the 20th century has always been the major factor prompting Mexicans to adopt highly-nationalistic, Europe-orientated and independent approaches to economic development, aimed at keeping the United States out. This has hurt both Mexicans and Americans. Mexico has remained poor and starved for capital. And the United States has had to turn to the oil fields of the Middle East for petroleum, with all that implies.

Egyptian gas for sale

By David Buckman



Israel, Jordan, Palestine, the Lebanon, Turkey and Italy all have at least one factor in common: they're potential customers for Egyptian gas. Once under-used, this major resource is now set to become a valuable export commodity by the turn of the century.

It is a move which seemed highly improbable a few years ago. As recently as the mid-1970s little use was made of gas in Egypt. Yet now a national grid is spreading, based on greatly enhanced reserves, with industry, commerce and domestic users all consuming more gas.

Following an agreement in principle in April, Egypt hopes to sign a Memorandum of Understanding with Israel by the end of this year to export gas by pipeline. Israel's Energy Minister Gonen Segev hopes that first gas will flow within two years and that it will be equal to the volume of crude which Israel has received from Egypt since the political situation between the two eased (Israel pressed for more oil, but Egypt resisted). Mr Segev anticipates the supply of gas quadrupling within a decade and hopes that by 2005 almost half the country's electric power will be generated by gas. Israel Electric Corporation will receive most of the initial Egyptian supplies, at a price yet to be determined.

Production facilities in Egypt's Western Desert

The Israeli deal could be the beginning of a much more grandiose piped gas scenario for the region. Jordan and the Palestinians have shown interest in Egyptian gas, whilst the Lebanese and Turkey are also possible customers. Turkey is keen to widen its supply base witness the opening of LNG supplies from Algeria through a new terminal on the Marmara Sea last year. Agip Chairman Guglielmo Moscato reckons that with proven and probable gas reserves of over 35 trillion cubic feet (Tcf), Egypt's gas export potential equals Libya's and is not far behind Algeria's.

Political problems

On a visit to Cairo just over three years ago, ENI Chairman Gabriele Cagliari discussed an ambitious project for a gas line from Egypt to Italy via Libya. Libya has huge offshore gas potential, has considered

A compression jacket is installed next to an existing platform in the Abu Qir gas field

a cross-Mediterranean line to Italy and wants to enhance its gas export potential. The most formidable obstacle to a three-country scheme would probably be political agreement. More ambitious still, governments in Africa and the Middle East have been mulling a UN plan for regional gas and electricity development to achieve a common energy market by early next century. Again, political problems loom.

Agip is in a strong position to comment on Egypt's gas potential. Source of the gas for export to Israel would be the Baltim and Temsah fields in the Mediterranean, off the Nile Delta, where Amoco and Agip – through International Egyptian Oil Company (IEOC) – share reserves. There has been a long series of finds in this area, and IEOC has been a persistent driller, despite some awkward setbacks. In 1986, for example, the Italians had a blowout with the Abu Daqn 1 well, 50 km north of Port Said, which found 25 million cubic feet a day (MMcfd) of gas but called for a specially equipped semi-submersible rig to cope with the problem.

The latest find in the series was Baltim 2, with Amoco operating. In April, the Egyptian Petroleum Ministry announced a flow of 58.5 MMcfd of gas and 860 b/d of condensate from a well 28 km off the Nile Delta in 60 m of water. It was 5 km from the Baltim 1 find made in July 1993. In November that year the same firms, this time with IEOC operating, made a find in the Temsah concession, close to Baltim, which flowed 34.5 MMcfd of gas and 2,300 b/d of condensate.

Shortly before the Temsah find, IEOC found a new gas field in the Port Said concession, 52 km off the port city in 46 m of water. First drilling yielded 31 MMcfd plus condensate. This find was 18 km northeast of IEOC's Port Fuad discovery and Egyptian General Petroleum Corporation (EGPC) reckoned that the two finds would be able to use the same development facilities, with additional finds Abu Daqn, Al Qirsh and Wakar being tied in.

Port Fuad is due onstream in April 1996. Egyptian state company, Engineering for the Petroleum and Processing

'The Israeli deal could be the beginning of a much more grandiose piped gas scenario'

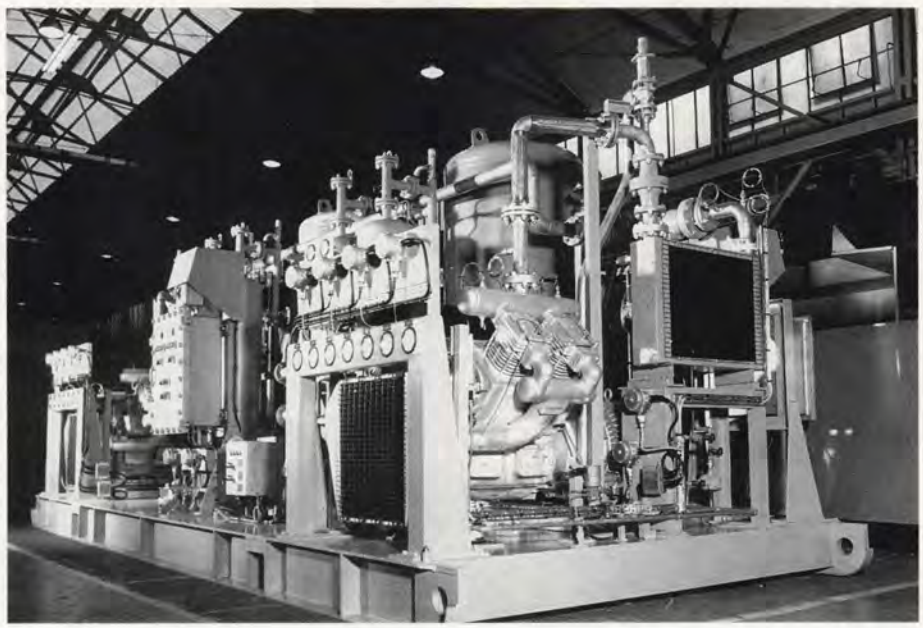
Gupco rig drilling in the Western Desert

Industries (ENPPI), is involved in a scheme to pipe 70 MMcfd to shore, initially using an offshore platform and a pipeline link.

'Egypt's gas export potential equals Libya's and is not far behind Algeria's'

Egypt piloted its Mediterranean Sea production with the Abu Qir gas field, which it put onstream off Alexandria early in 1979. A pipeline to shore provided gas for industrial use. It was developed by Western Desert Operating Petroleum Company (Wepco) – a combine of Phillips Petroleum, EGPC and Hispanoil – acting for EGPC. The state firm had chosen to exploit the field without partners. Although initial output of gas and liquids was modest, Wepco gradually tied in more production from an Elf discovery at North Abu Qir and further hardware was added.

Thus a couple of years ago the system was contributing about a quarter of Egypt's total gas output. More gas might yet be tied in, and it should be flowing for another decade or so. Two booster platforms have been worked on, and hook-up and commissioning of one is due in mid-1995, according to Lloyd's Register of Shipping which has been overseeing activity.



A purpose-built compressed air supply package for Egypt's Mediterranean North Abu Qir field

Towards the end of the 1980s it became apparent that Egypt had established a national gas reserve of 12 Tcf, which it had long desired in order to provide a sound base to develop a national grid. Until this was achieved the country's rulers rejected all ideas of exporting gas. Energy planners have striven, in particular, to divert gas to power generation, releasing more oil for export to earn much-needed dollars.

'The country aims to have natural gas available to all power stations, industries and households'

Gas for all Egyptians

Currently, 80 percent of electricity is provided by gas generation, and within two years this should rise another 10 percent. The country's eventual goal is for natural gas to be available to all power stations, industries and households. The replacement of costly liquefied petroleum gas (LPG) for household use has been a key part of the natural gas expansion programme.

Egypt's Oil Minister, Dr Hanbi el-Banbi, anticipates the country's gas production capacity rising from 1.4 billion cubic feet a day (Bcfd) now to 3 Bcfd in 10 years' time. The gas industry began to gain pace in the mid-1970s, based on three areas: these were Abu Qir; Petrobel's Aub Maadi field in the northern Nile Delta onshore region to which El Qarta's flow has been added; and Gulf of Suez Petroleum Company's (Gupco's) Abu al-Gharadiq reservoir in the Western Desert, spearheaded by Amoco.

In 1986, Egypt unified oil and gas terms in one model agreement, making gas exploration and production a more attractive option for private companies. Two years ago, Shell renegotiated the formula for pricing gas which it had found in the El Obaiyed concession, bringing the price more in line with internationally accepted rewards.

The Western Desert is now a key area for potential gas developments. Bapetco, jointly owned by Shell and EGPC, has established production from the Badr el-Din/Sitra area, with oil and gas flowing by pipeline towards the Mediterranean coast. Output in 1994 was about 280 MMcfd of gas and 34,000 b/d of liquids. State firm General Petroleum Company's (GPC) Abu Sinan oil and gas production ties into this system.

In addition, the northern part of the Western Desert is now exciting interest, where an oil production and pipeline infrastructure is well established. A number of companies, including Shell at El Obaiyed and Norsk Hydro at Ras Kanayes, have been considering a common gas trunkline to exploit reserves, although separate systems may develop.

Another gas development area to be watched is the Gulf of Suez, which Israel earlier eyed as a possible imports source. A big scheme based on the exploitation of associated gas from such established fields as El Morgan, July, October and Zeit Bay continues to expand.

IP

THE INSTITUTE OF PETROLEUM

London Branch Programme 1995-1996

'Back to Basics'

The programme for the forthcoming season comprises a series of talks about the industry, step-by-step, from exploration for crude oil, right through to product used by customer. Each presentation will describe a fundamental operational activity within the industry, covering its objectives, operations and economics, and will conclude with an account of the problems and challenges that are being faced today.

There will be something of interest for everyone!

Date	Subject
24 October 1995	Exploration
TBA November 1995	Production (at Imperial College)
23/24 January 1996	Refining
20 February 1996	IP Week, Special Event
19/20 March 1996	Supply & Distribution
23/24 April 1996	Marketing/Retailing
21/22 May 1996	Special Products
5 June 1996	Visit to Ford Motor Company

The dates of some of the meetings and the names of speakers will be finalised nearer the event. Please check in *Petroleum Review* for updates.

Speakers: if you would like to be considered as one of the speakers for this programme, please contact Michael Wood at the Institute on 0171 467 7128 as soon as possible.

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THE INSTITUTE OF PETROLEUM

EEG Discussion Group

Planning Future Refinery Hydrogen Requirements

Professor Keith Guy, European Marketing Director, Air Products plc

Wednesday 5 July 1995, 17.00 for 17.30 - 19.00 at the Institute of Petroleum, 61 New Cavendish Street, London W1

Details from Jenny Sandrock at the IP

Tel: 0171 467 7104 (direct line) Fax: 0171 255 1472

Odfjell Drilling Asia's rig, Deepsea Ice, working off Myanmar for Texaco

New lease of life for Myanmar

By David Buckman

Whilst the countries surrounding it have set pace-making growth rates, Myanmar has remained a sluggish backwater. For the past seven years, it has not even been able to meet its own energy needs. But natural gas is now set to transform the country's fortunes and turn it into a burgeoning energy exporter within the next three years.

Myanmar (formerly known as Burma) has considerable hydrocarbon reserves and a long history of development. Many hand-dug wells were active 200 years ago, Burmah Oil Company launched the modern oil industry in the late 1880s and by 1939, before war destroyed the infrastructure, output had hit a peak of almost 18,000 b/d.

In 1975, Myanmar declared it could meet its own oil needs.Yet, by the early 1990s, an oil output of around 15,000 b/d, together with just a small amount of gas, was providing only half Myanmar's very modest requirements. Now the situation is changing again. Impending offshore gas production is likely to foster interest in Myanmar's marine potential and there are also signs that its little-developed onshore industry is exciting explorer interest once again.

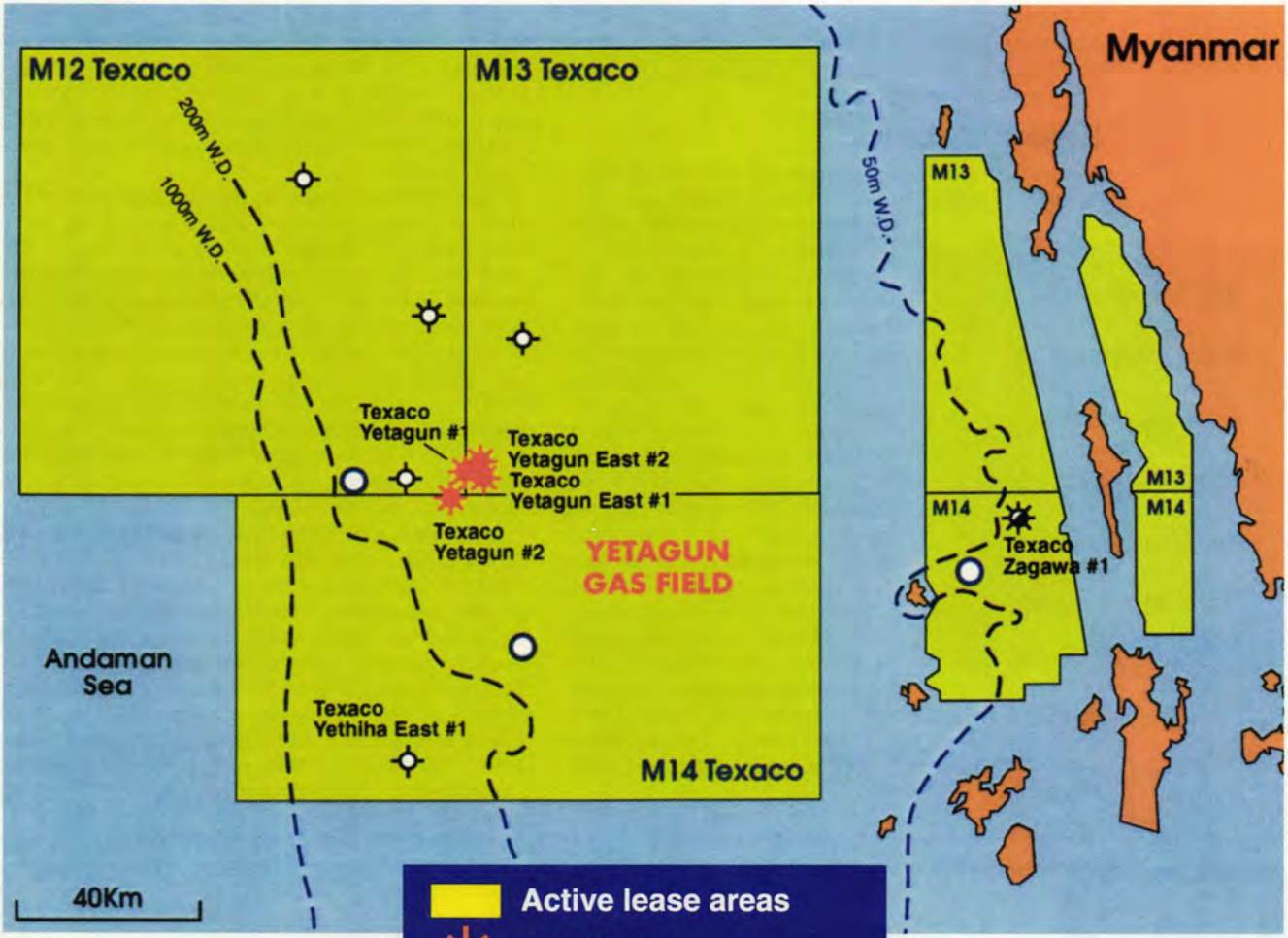
Total leads the way

Spearheading the turnaround is Total, which has the huge Yadana gas field in the Gulf of Martaban to develop. Myanmar's first offshore commercial reservoir, with recoverable reserves estimated at 5.8 trillion cubic feet (Tcf), will cost around $1 billion to exploit. The deal behind the development was signed in February this year between the state-owned Myanma Oil & Gas Enterprise (MOGE), Total and its partner Unocal Myanmar Offshore, and Petroleum Authority of Thailand Exploration and Production (PTTEP). PTTEP's parent, PTT, will take gas over 30 years, with deliveries starting by 1 July 1998 at 65 million cubic feet a day (MMcfd). They will rise to 130 MMcfd before levelling at 525 MMcfd 14 months later.

Gas output could eventually hit 650 MMcfd, including 125 MMcfd for Myanmar's own use, for which a separate sales agreement has been signed in Yangon (formerly Rangoon). Total, Unocal and PTTEP will, under another agreement, create a firm to lay and operate a trunkline to move gas from Yadana to the Thai border – in September last yeat Thailand made an agreement with Myanmar's military government to pay about $500m/yr for gas. Gas will move through a 354 km submarine line to the coast of southwest Myanmar, before continuing another 65 km to the border. PTT will lay and operate a 300 km line from there to a 2.8 MM-kilowatt combined-cycle power station which Electricity Generating Authority of Thailand (EGAT) plans for Pilok, Ratchaburi, in southern Thailand. PTT is already a supplier of gas from prolific fields in the Thailand Gulf.

Since gas was discovered at Yadana, the shareholdings in the venture have been reshaped and are still open for re-alignment. Total acquired its right to blocks M5 and M6, 250 km southwest of Yangon, in July 1992. It said that its main objective was to appraise gas finds made by the Myanmar state firm in the 1980s, with sales to the domestic market and Thailand in view. Previous to the deal with Total, MOGE had already been in talks with Thailand about reserves known to be large, and it said that an alternative plan to liquefy the gas for export had been discussed with 'some parties'. Total, Unocal and Royal Dutch/Shell were then said to be interested in the Martaban Gulf's production potential.

Before it drilled its 26,140 sq km area, Total began talking with a number of 'major international oil companies' about offloading part of its



Myanmar's offshore blocks

stake. Early in 1993, Unocal acquired 47 percent, PTTEP later taking 30 percent after a gas sale was agreed. That leaves Total with 36.75 percent and Unocal with 33.25 percent. In addition, MOGE holds an option to acquire 15 percent that could cut the other partners' holdings proportionately. Drilling of the first two appraisal wells about two years ago proved encouraging, with Yadana 1 and 2 each testing a good volume. Total went on to drill further, using Maersk's Vanguard jackup.

One black cloud over the Yadana development horizon is the threat to overland pipelaying in afforested areas of Myanmar. The anti-Yangon Mon and Karen minority groups have threatened to sabotage work and early this year several nationals were killed and others wounded during route surveying. The military junta has affirmed that it will meet force with force to ensure pipelaying can go ahead this year.

Gulf of Martaban

The Gulf of Martaban has long been an attraction for searchers but work has been sporadic and hindered by a lack of cash. It resumed in 1982 after a six-year lull when Japanese private interests and the Japan National Oil Corporation – as Burma Petroleum Development Company Ltd – teamed with Myanmar to sink an initial two wells, backed by around $17m of Japanese funds. The Japanese-Myanmar MOC-13A well flowed 39 MMcfd of gas from three middle Miocene limestone reservoirs at 6,300-6,700 ft on the 3DA structure. In the course of sinking another 10 wells, five of which flowed over 5 MMcfd each, a second structure, 3CA, was delineated and condensate reserves confirmed.

This effort followed an earlier unsuccessful go-it-alone policy after which one spearheaded by foreign explorers met with modified success. In January 1972 Myanmar, through Reading and Bates, began the first of a series of wells in the Gulf funded by Japanese loans. Some gas was found during the dozen-well effort, although a rig was lost because of a blowout.

'The military junta will meet force with force to ensure pipelaying can go ahead this year'

Modifying its hard-line socialist policy, in 1974 Myanmar awarded 13 blocks to four foreign groups on a service contract basis. A total of 17 wells were drilled, with more gas being found in the Gulf, but by 1977 the last of the groups had exited and two attempts in the late 1970s to tempt foreign firms back failed, as the terms were too onerous. Prior

to Total's entry, PTT was already eyeing Gulf of Martaban potential, but it took the French company to bring development to reality.

Political shake-up

After the political shake-up of mid-1988, Myanmar's new rulers decided they would opt for foreign private investment in a move to revitalise an economy crippled by 26 years of rigid state control. Before Total signed its production-sharing agreement in 1990, another prospective offshore gas developer, Premier Consolidated Oilfields, had agreed to look at blocks M13 and M14, covering 32,000 sq kms off the west coast of southern Myanmar, close to the Mergui Archipelago. Late in 1991, following a farm-out deal with Texaco Exploration Myanmar and Nippon Oil Exploration, Premier assigned operatorship of the project, which by then included block M12, to Texaco. Texaco now holds 50 percent, Premier 30 percent and Nippon 20 percent.

'In 1988, new rulers moved to revitalise an economy crippled by 26 years of rigid state control'

In the first drilling campaign, started in 1992, four wells were drilled. Two on the Yetagun structure were successful and tested gas and condensate at 75 MMcfd and 1,800 b/d and 63 MMcfd and 1,922 b/d respectively. The other two wells, which tested separate geological pays, were unsuccessful.

Thailand soon began to eye the potential of the Texaco group's gas, and preliminary talks were held with PTT. MOGE managing director Pe Kyi said that an initial estimate had put Yetagun reserves at 1.5 Tcf. Thai officials reported that talks with Myanmar and Texaco had focused on delivery of about 200 MMcfd of gas by around end-century, with PTTEP again seeking a stake as part of a sales deal. Gas would be delivered through a line to be laid from the field to Thailand's southern peninsula at landfall near Ranong or Krabi. A cross-land line would then move gas to the Khanom/Nakhon Si Thammarat industrial area.

Last year, a further drilling programme was conducted, using the Neddrill Workship I. In March Premier was able to announce the results of two successful appraisal wells at Yetagun. Yetagun 2 was sufficiently similar to the first well that it was not considered necessary to test. Yetagun East 2, drilled on the eastern fault block, flowed at an impressive 75 MMcfd of gas and 1,900 b/d of 55° API condensate from three zones. Studies were then under way 'to establish a commercial development'.

Indonesia plans widespread expansion

Surging home demand and the need to remain a dominant exporter of liquefied natural gas (LNG) will keep Indonesian explorers busy onshore and offshore and will foster big developments during the coming years.

Like a number of other oil producers, Indonesia is concerned that within a few years it could become a net importer. This makes the encouragement of gas production to replace oil, releasing more oil for valuable exports, of vital importance.

The emerging dominance of gas became apparent in a survey carried out last year by Wood Mackenzie Consultants. This showed that of Indonesia's remaining recoverable reserves totalling 12.7 billion barrels of oil equivalent (bboe), gas comprised 53 percent and liquids 47 percent. Seven of the top 10 companies operating in Indonesia by value were found to be suppliers of gas to LNG facilities at Arun in north Sumatra or Bontang, East Kalimantan. 'Of the top 10 companies, seven have more than 60 percent of their remaining reserves in the form of gas,' according to the report.

Indonesian Mines and Energy Minister Ida Bagus Sudjana says that oil's share of the domestic energy mix declined from 88 percent in 1970 to 65 percent in 1993, even though the volume has continuously increased. 'By contrast, the role of natural gas has been rising signficantly — from only five percent in 1972 to 20.3 percent in 1993.'

Gas grid planned

New fields have been developed, mainly in east and west Java and south Sumatra, and an integrated gas grid is planned. The main section will be completed by about 1997 in central Sumatra and will be followed by an extension to Java. Big gas reserves off east Java will make development of the grid there possible.

Home demand for gas is expected to rise fourfold by the year 2000 to about 4 billion cubic metres (Bcm), according to national gas company Perum Gas Negara (PGN). Based on a proven reserve figure of 3 trillion cubic metres (Tcm), with as much yet to be found, output should soar from a current 200 million cubic metres a year (MMcm/yr) to over 90 billion cubic metres a year (Bcm/yr) by end-century.

Indonesia has steadily pushed to raise LNG exports based on the Arun and Bontang plants and has given consideration to piped gas exports, maybe as part of a regional network. In 1973, the country signed a 20-year contract with Japan to supply 14.7 million tons a year (m t/yr) of LNG linked to the crude oil price. A similar deal was signed with South Korea in 1983 for 2m t/yr, and in 1987 an additional contract with Taiwan followed for 1.5m t/yr. Additional contracts have been made with Japanese and Korean utilities and state oil company Pertamina continues to scout for overseas customers. Mr Sudjana says that Indonesia plans 'to export about 26 million tons of LNG in 1994-5 and this will increase to 28 million tons in the 1998-9 fiscal year'.

Undoubtedly the most important gas development looming is exploitation of reserves in the Natuna Sea. These were found by Agip in 1973 and now lie in Esso Natuna's D-Alpha production-sharing block, awarded by Pertamina in 1980. Based on a handful of wells by Esso, a long series of production tests and collection of 1,000 km of seismic, a reserve of over 200 trillion cubic feet (Tcf), or almost 5,700 Bcm, is estimated, just under a quarter recoverable. As over 70 percent of the reserves are C02, special techniques will be called for to treat the gas.

Production facilities off East Kalimantan

Private funds required

Development of Natuna gas will call for private funds, says Mr Ryutaro Hashimoto, Japan's Minister of International Trade and Industry, as the project will absorb an estimated $35 billion. Esso is understood to be obligated to provide funds of about $19.5 billion.

Pertamina has already been putting out feelers to Japan as a possible customer, while South Korea, Taiwan, China and India may also be interested. If customers respond as hoped, Natuna should be on stream by about 2002. Gas would flow from the field, which lies in some 145 metres of water, through a 225 km trunkline to Natuna Island, where Indonesia's third liquefaction plant would be created. This could be the world's biggest single offshore development, with output eventually rising to 68 million cubic metres a day (MMcmd) of gas and 14m t/yr of LNG, sus-

A seventh train is being added to Bontang liquefaction plant

tainable over 30 years. Ultimately, 18 fixed steel-jacketed platforms could be needed: six for processing, six for drilling with 36 well slots each, four injection and two quarters platforms.

Development of the Natuna LNG plant will be similar to the Arun and Bontang complexes. The LNG will need to be moved out in a fleet of 11 dedicated carriers, the cost of which could be $3 billion. Pertamina will order the ships with advice from Exxon. The state company said late last year that it will trim its 50 percent stake in the Natuna project to at least 10 percent, as it cannot fund its share. Mobil and some Japanese companies are known to be interested.

Prospects look good for Sanga Sanga gas production

Mobil is a major producer of gas in north Sumatra, supplying the local LNG plant. Around mid-1994 it took a 50 percent interest from Indonesia Petroleum (Inpex) in a production sharing contract covering the North Aceh block off Sumatra, adjacent to Arun acreage. Inpex has found gas and condensate there. In 1993 Mobil said that it was 'pulling out all stops' in the area. By mid-1993 Mobil had achieved four gas finds on its North Sumatra offshore block, where its contract is now extended to 2018, with a reserve of over 50 Bcm proved. The Arun LNG complex's six trains can produce 12.3m t/yr, but will run down to four by 2000 and two by 2007-8, completely closing by 2014, unless new reserves can be tapped.

As a contrast, expansion is under way at Bontang, Indonesia's second operating LNG plant, in East Kalimantan. Pertamina recently let a contract to Japanese firms Chiyoda Corporation and Mitsubishi Corporation to build a seventh train. Scheduled for completion in late 1997 it will add 2.6m t/yr of capacity to the 14.5m t/yr achievable with six trains. Exports from the seventh train are due to begin moving to Japan, South Korea and Taiwan in 1998.

Buoyant mood

Suppliers to Bontang are in buoyant mood too. About the time the sixth train went on stream, at end-1993, Total announced that it had initiated development of phase two at the huge Tunu offshore field, where first production began in February 1990. Total has been a successful finder of gas in the Mahakam Delta area and expects by 2000 to be producing around 6.9 Bcm/yr of gas from Mahakam, tripling its production within a decade. The main supplier will be Tunu, but other finds await development.

Additional suppliers of gas to Bontang are VICO and Unocal. Lasmo, which has a stake in VICO, is bullish about prospects for the Sanga Sanga production sharing contract, which has six fields supplying Bontang. Unocal last year announced plans to develop the Santan field's gas and liquids off East Kalimantan, with first output due in about two years.

Gas mixes with politics in Latin America

By Maria Kielmas

The private sector is at last beginning to make inroads into the gas industry in Latin America, but the transition is expected to be anything but smooth. Whilst many of the initial problems are of an economic nature, it is politics that will create the biggest stumbling-block.

The gas industry in Latin America has moved over recent years from being a Cinderella by-product of oil production to a putative engine of energy supply. Throughout the region, governments are encouraging the use of gas as both an environmentally-friendly fuel in domestic and industrial use and as a major new source for electricity generation.

This diversification has become an imperative to combat both urban pollution and the risk of power shortages in a region heavily dependent on hydro-electricity but subject (in Central America and Andean countries) to climatic aberrations which have caused severe droughts over the past few years.

'Bureaucrats are loathe to relinquish control over the gas industry'

Moves towards greater regional economic integration have given an impulse to long-gestating plans to build international gas transportation pipelines, notably between Argentina and Chile in one project and Brazil and Bolivia in another. Perceived problems over future gas supply to Europe, due to economic/political crises in Russia and Algeria, have boosted the market prospects for proposed LNG developments in Venezuela and Trinidad.

Political hurdles

Economic liberalisation measures, adopted in varying degrees by all governments in the region, have succeeded in attracting considerable private sector interest in gas development. But the transition from state-owned, centrally-planned energy industries to a semblance of privately-run utilities is punctuated with hurdles, initially economic, but largely of a political nature. Gas markets in Latin America are still waiting to be created. A fierce debate is underway, notably in Chile and Colombia, over whether these should be created via an immediate open access and free market system, or through a diluted form of monopoly concessions. Latin American economies are still coming to terms with the effects of the Mexican devaluation crisis, and Mexico and Argentina are facing severe recessions, despite bullish government pronouncements that they have overcome their immediate problems.

Recession

Gas consumption is directly proportional to economic growth and the next few years are unlikely to witness the kind of optimistic growth which had been predicted prior to the devaluation crisis. Mexico, Venezuela and Argentina are mired in recession. But assuming governments continue to implement measures attracting private sector investments into infrastructure and to reform labour laws and education, growth could top six percent per annum into the next century, according to a recent report from the World Bank. However, this will require a strengthening of state institutions, such as legal systems and regulatory agencies. For oil and gas investors who seek opportunities in the gas and electricity sectors, this means that relations with governments are entering unchartered territory. Bureaucrats brought up in a legalistic, centralised system are loathe to relinquish control over an industry. Meanwhile local industrialists are reluctant to lose the protected status they have enjoyed in a corporatist state and compete in a free market with better-financed foreign companies.

To date, the Latin American experience of a free market in public utilities has meant that prices to consumers have moved in one direction only – up. As recession threatens a region where over half the population is poor, these tariffs have become a political football to governments seeking re-election or even survival. Whereas for most of this century oil exploration contracts have been one of the most sensitive of political matters, as the next century approaches, gas and utility prices will be the battleground for the future.

Gas reserves in Latin America and the Caribbean have grown at 5.5 percent annually over the period 1973-93 and now total some 47.8 billion barrels of oil equivalent, or about 270 Trillion cubic feet (Tcf), according to figures from the Latin American Energy Organisation (OLADE). Though consumption has tripled over the past two decades, it remains just 19 percent of primary energy, and nine percent of final energy demand. Since 70 percent of the region's proven gas reserves are in the form of associated gas, the easiest solution has been to utilise them as cheap feedstock for the petrochemical industry or marginally distribute them to domestic users. Only Argentina in the 1960s developed a countrywide gas transportation and distribution network after a political decision on the part of government.

New project development and gas export plans in this region are handicapped by the relatively small size of fields, mostly less than 10 Tcf, compared with the 60 Tcf of better fields

which supply European users. No country has anything like the 27,000 gas suppliers that the United States boasted when the open access process began there.

Another problem is that non-associated gas is preferred for gas trade. Worldwide, 80 percent of gas reserves are non-associated but this figure falls to just 30 percent in the case of Latin America. Speaking at a recent conference, 'Natural Gas in the Americas', organised by the Des Plains-based Institute of Gas Technology, Mr James Jensen, President of Boston-based consultants Jensen Associates, said, 'the fact that you have gas is not a starter for projects'.

Mexico

Most industry experts agree that the region's greatest gas investment opportunities are in Mexico. Although the development of Mexican gas is far less mature than either the United States or Canada, conventional wisdom suggests that in the long term it will form part of the nascent North American Free Trade Agreement (NAFTA) gas commodity market. At present, 86 percent of Mexican gas reserves are associated and occur mainly in two basins, the offshore Campeche Shelf and the onshore Salina Basin. Further reserves occur in two smaller basins, the onshore and offshore Tampico - Mislanta basins. Most of the country's remaining or potential gas resources, which are thought to be largely unassociated, lie in northeastern basins, according to a study by the Calgary-based Canadian Energy Research Institute (CERI). The most promising of these are the Burgos basin with an estimated 6 Tcf gas potential, and the Sabinas and Parras basins with a joint potential of 54 Tcf.

'Tariffs have become a political football to governments seeking re-election, or even survival'

The Mexican government published a new gas law on 11 May this year which will permit private sector investment in gas transportation, distribution and storage. Since the major industrial markets are in the north, investors will have to build new infrastructure to pipe gas from south to north. State oil company Pemex has had long-standing plans to explore and develop northern gas potential, and gas drilling forms part of the company's latest plan, but it has scant funds to do so. Pemex's financial situation will deteriorate as the economy slumps. Although official economic figures indicate that the country is stabilising from the devaluation shock, the real economy, i.e. industrial production and employment, is entering its worst crisis for decades. Companies, banks and government agencies are insolvent; the country is expected to run out of money by August, and some analysts suggest that higher inflation and a debt moratorium will be the inevitable outcome. Should this doomsday scenario materialise, the entrance of private capital into the upstream oil and gas sectors – the country's only real assets – will be the only solution for economic salvation.

Argentina

A looming recession provides both opportunities and risks in the continent's only open gas market in Argentina. The Argentine government has responded to the 'Tequila effect' by monetary tightening and so has avoided a devaluation, for now. But the price has been a recession, and one which has been played out in the gas market.

Last Austral winter (mid-1994) Buenos Aires ran out of gas for one day, because of tight supplies and heavy demand. One year later, gas sales to power plants are down 45 percent because of an increased use of cheaper hydro power, while domestic sales are falling as the population tightens its belt. Some 60 percent of the Argentine gas production is controlled by the former state oil company, YPF. But over two-thirds of YPF's earnings originate from domestic oil, gas and refined product sales. These earnings have begun to fall, together with the economy. As the recession bites, bank illiquidity, falling sales and lower tax revenues have meant the government has missed International Monetary Fund (IMF) budget targets. Without an economic upturn, this will hinder the government's, YPF's and other Argentine companies' plans to raise funds on the international markets later this year. Industry observers have long predicted that, come the real recession, a huge chunk of oil and gas properties held by YPF and other Argentine companies will come onto the market in a fire sale to be mopped up by foreign investors.

With only half of its proven gas reserves developed, Argentina is well-placed to export gas to markets such as Chile and Brazil, and to improve its overall trade performance. Feasibility studies for three projects to Chile are concluding but this market is small and concentrated on the capital, Santiago, where peak demand is not expected to be higher than 5 million cubic metres/day. Current low wellhead prices in Argentina, long distances and pipeline economics mitigate against sales to Brazil. Furthermore, while there is a clear government policy in Chile to integrate its energy network with Argentina, the Brazilian market is shielded by government subsidies and monopolies. The constitutional amendments currently ploughing through the Brazilian Congress will open the oil and gas sectors to private investment, but their ability to dilute the strength of Petrobras within Brazil is debateable. Argentine Energy Secretary, Carlos Bastos, has argued that the four countries of the Southern Cone Common Market (Mercosur) – Argentina, Brazil, Uruguay and Paraguay – must harmonise the rules of the energy game, otherwise these grand export projects will remain merely on paper.

Brazil

Petrobras's monopoly in Brazil and, once the constitutional amendments are passed, its inevitable dominance of the Brazilian energy market, has been a major stalling factor on the financing of the proposed Bolivia-Brazil gas pipeline. The US$2 billion project has received qualified support from the World Bank and the Inter-American Development Bank (IDB) now that the Bolivian state oil company, Yacimientos Petroliferos Fiscales Bolivianos (YPFB), and Petrobras have diluted their interests in the project and associated themselves with private sector partners. These

are Enron on the Bolivian side and a consortium of British Gas, Tenneco and BHP Power on the Brazilian side. But progress, if any, is still likely to be slow, according to one Brazilian industry executive who said cynically, 'put together two governments, two state oil companies, and two multilateral institutions and you have the perfect recipe for doing nothing'.

Other than red tape, this project is fraught with risks at both ends. Bolivia officially has proven gas reserves of 4.5 Tcf, barely sufficient to fill up the proposed 8-16 million cubic metres/day line for 20 years. The Bolivian government has been hoping that the existence of this project will promote exploration at home, though progress has been slow. The lack of a realistic gas market in Brazil is a more pertinent problem. The line is supposed to provide gas to meet incremental energy demand triggered by economic growth. But Petrobras has a good business in selling fuel oil to utilities and industry which, in turn, have been given little incentive to switch to gas, environmental concerns notwithstanding. Equally, it may prove far more lucrative for Petrobras to associate with foreign companies to develop gas reserves in Brazil and in the Atlantic offshore, allowing gas supply and a gas industry to grow organically throughout the Rio de Janeiro-Sao Paulo industrial region.

Colombia

Colombia is now in the throes of creating a domestic gas market. Under a gas development plan formulated by the previous adminstration of President Cesar Gaviria (1990-94), the government has awarded Build-Operate-Transfer (BOT) contracts to private companies to construct various legs of a new transportation network. The network will be managed by the newly-created company, Ecogas, shares in which will be sold to industry buyers. Gas will be piped to major urban centres, firstly from the Texaco-operated fields in the onshore/offshore Caribbean. Just into the next century this supply will be augmented by deliveries from the BP-operated Cusiana/Cupiagua fields, once Cusiana oil production begins to decline, as well as by gas from other operators.

The energy regulator, Comision de Regulación de Energía y Gas (CREG), is drafting a regulatory framework based on the proposed British model. Under the framework, joint venture partners in one gas development would be obliged to sell their gas separately in order to create the semblance of a spot gas supply market in a country with only three real suppliers: state company Ecopetrol, with 40 percent of the market, Texaco and BP. CREG wants to provide open access to pipelines, introduce competition into transportation and distribution, and curb the overwhelming power of Ecopetrol. As in Chile, municipal gas distributors call these proposals 'Utopian', saying long-term contracts and monopoly concessions are necessary to build up a gas market, just as the gas infrastructure in Europe and the United States was built up. They are seeking associations with foreign gas companies to boost their technical and financial prowess in order to defend and then to expand their market shares.

CREG is aiming to learn from the experience of Argentine and British gas de-regulation. The Colombian regulator will be an eight-member commission, where decisions are taken by a majority vote rather than an individual. The new Mexican regulator, Comisión Reguladora de Energia (CRE), is a five-member panel based on the Federal Energy Regulatory Commission (FERC) in the United States. In both the Colombian and Mexican cases, the regulators will try to define and control the role of the giant state-owned energy companies, while the state companies are preparing to reinforce their new roles. Both Ecopetrol and Pemex plan to develop major interests in transportation, the most lucrative part of the gas chain. Relations between the regulator, Enargas, and industry in Argentina have ranged between cool and acrimonious. Enargas claims that the companies are flouting regulations while industry says that the regulator wants to run the gas industry in parallel with the companies. The local gas distributors' grouping, Asociación de Distribudores de Gas en Argentina (Adigas), has applied for membership of the American Gas Association (AGA) in the hope that this link will help in its battle with the regulator.

'The Brazilian market is shielded by government subsidies and monopolies'

But in Colombia CREG is facing the same real battle as its counterparts elsewhere, in tariffs. The regulator wants to introduce a differential transportation tariff but this is opposed by local industry in regions such as the Valle de Cauca in the south, who would pay the most. The local industrialists have significant political clout and, as of mid-year, the transportation tariff issue remained unresolved.

Venezuela

This battle is expected to erupt in Venezuela over the coming half year. The government and state oil company PDVSA are drafting a new, integrated energy tariff structure as part of an overhaul of investment regulations in the oil and gas industry. The aim is to encourage investment into gas, especially for power generation. But Venezuela's associated gas (90 percent of total reserves) is virtually given away to clients such as the steel and petrochemical industries. Industry in Venezuela pays only half of the cost for gas that is paid by Mexican counterparts. Petrochemical producers in Venezuela pay only 50 US cents per MMBtu for feedstock, compared with between US$1.80 and US$2.50 for a US Gulf Coast-based company. Venezuelan industry is only competitive on the back of cheap gas prices and will lose its markets should the gas industry be placed on a realistic financial basis.

Of all the major Latin American economies, Venezuela is the basket case. The banking crisis, exchange controls and runaway deficits have prompted a contraction of foreign investment. The only solution to the impasse is to attract meaningful direct investment into oil and gas, even at the price of higher energy tariffs, though the government is reluctant to admit this publicly. But the entry of the private sector into the gas industry throughout Latin America has to be balanced with a new political awareness, and the implications of a popular resistance to increasing tariffs.

The author is Editor of Latoil.

Coastal oilfields south of Baku

Ramco comes ashore in Azerbaijan

By Jeremy Cresswell

Azerbaijan is taking off in a big way. With the huge Azeri, Chirag and Guneshli project now bagged by the largely western consortium – Azerbaijan International Operating Company (AIOC) – oil companies are keenly hunting out other major opportunities. Among the hunters is Mr Steve Remp, Chairman of the Aberdeen-based oil company Ramco. Jeremy Cresswell tracked him down in Baku to learn that he was hatching another big deal – this time onshore.

Jeremy Cresswell: You have in the past said that Ramco Energy would pursue other projects after Azeri/Chirag/Guneshli. Are you in a position to talk about these now?

Steven Remp: We are well advanced in discussions with SOCAR about a joint venture with the state oil company over a large onshore area in the south-west part of Azerbaijan called Murad Hanli. This is an area of some 3,000 sq km and, in our view, has extremely sizeable oil reserves in place...several billion barrels.

This is a surprising move because the onshore sector of the Azeri oil and gas industry has been winding down in terms of exploitation – the most obvious targets having long been investigated. How soon can Ramco expect production from Murad Hanli?

What we don't yet know is whether that field is commercial or not. We have every confidence that the oil is there but the question is can we get it out economically. Question-marks include the geology and the kind of wells that will be needed to produce the field. The reservoir was discovered in 1970. SOCAR drilled about 100 wells on it, which is not many for an area of that size but the state operator has not had much luck with the field. It has proved very difficult and, when Guneshli was discovered in 1979, it overshadowed everything else and the emphasis of the Azeri oil industry moved from onshore to offshore.

Murad Hanli has essentially been left producing small amounts of oil. If the field is commercial then I believe RAMCO will probably emerge as the only other producer in Azerbaijan besides AIOC with the prospect of early oil by 1996/97.

Does this mean you are taking an even closer interest in discussions on the export route for production from the offshore project as you could presumably tie into it?

This whole question of early oil exports is not only important for us as a shareholder in AIOC, it is also crucial for us as a prospective producer in our own right. Clearly, we would hope to be able to gain access for our own production into the early oil route.

If things go to plan, we hope to drill several wells next year to prove up the field and to get some production going. And, besides continuing negotiations with SOCAR over the field, we are quite well advanced in identifying and agreeing a relationship with a major western partner who would joint venture with us in this field. This would be a similar relationship to the one we have with Pennzoil on the Azeri, Chirag and Guneshli fields. I hope the benefits generated will be as great for the new partner as they have been for Pennzoil and ourselves in the previous deal.

Baku seems to be buzzing with activity. What is it that makes the Caspian '95 oil show so different and important?

It really is quite unlike any other show in the world. It's dominated by big oil companies, which is very unusual. Normally shows are focused on oil service companies but, in Baku, we have some of the largest oil companies in the world setting out their stalls in order to show the Azeri government exactly what it is they can do.

The service companies are gathered around the periphery though I suppose that in due course, once the majors are well situated here, that may change.

I think the atmosphere in Azerbaijan is very positive and President Aliyev has shown great leadership qualities and given a tremendous sense of confidence. What I also think is so amazing is the strength of support from other governments – five or six different countries. It shows how important and popular the Caspian Sea has become.

But one thing I'm curious about is why this hasn't yet sunk in with more British service companies. I'm bewildered by that. They have been slow off the mark.

What is the problem?

So many British service companies have focused on western Siberia – in my opinion erroneously – when it was very, very clear that Russia was going nowhere. I think the opportunity is here. It is a place that needs a lot of time and a lot of effort, without immediate return. But I think what we're seeing now is enormous opportunity – one of the great oil provinces of the next century.

Who, in your opinion, is beginning to make it in Azerbaijan?
There are a few shining examples of British companies that have come in here, have earned their stripes and are now starting to reap rewards. One of these is Morrison Construction, a Scottish company that came in here a couple of years ago, put people on the ground, spent time doing very modest jobs and has just been awarded the first major construction contract for AIOC, building its first work camp. There are other examples, but not many.

I hope that, as a result of UK Energy Minister Tim Eggar's emphasis on the area, we'll see more British companies. With the complex make-up of the AIOC consortium, where there are so many different nationalities represented, British companies really need to pull their socks up and get going fast, otherwise it may soon be difficult to get entry into this market.

You acknowledge that many companies have probably held back pending the signing of the $7.4 billion offshore Azeri, Chirag and Guneshli project. But several months have passed since that milestone occasion and yet the debate on pipeline routes continues. Some seem to doubt it will work. Could you clarify?
There were many detractors. There were few people that ever thought this deal would get done. But there were those who held on to optimism and the deal did get done.

Of course the most important topic at this moment is early oil. Will the consortium elect for early oil or not?
That decision is expected very soon, based on two things. One, will the Chirag platform perform technically? And two, can we find an early oil route out?

At the moment it is a two-horse race between a northern route through Russia using existing pipeline infrastructure to Novorossisk. Equally, there is infrastructure west through Georgia and the Georgians are equally desperate to get the oil. These are two viable options in the short term, but I think the longer term option needs a lot more work. It's not an urgent question at the moment though. Early oil is the topic.

Rumours are circulating that an agreement has been reached but is being kept under wraps for some time. Can you comment?
There is no doubt that achieving early oil would deliver the 'correct' signals to the outside world. But there remain a number of commercial, technical and political issues that have to be weighed up before a decision could be made.

We hear much about the huge resources of the Caspian region. What other opportunities are bubbling away?
There are several other very large deals being negotiated here at the moment. For example, hopes are high that BP and a number of partners will shortly conclude a deal on Shaqdeniz. I don't think anybody yet knows what Shaqdeniz is but it is certainly a giant structure. I believe Lukoil and Agip are to be involved in the Kapaz field, which is a very large structure on a parallel trend to the Azeri trend. I believe negotiations are going on at the moment.

But Azerbaijan is in the midst of a region known for political turmoil. What are the prospects?
Political stability has increased greatly in the area and things are much better now than at any time since I first came here in 1989. It is a complex area which has been very unstable because of breaking apart from the Soviet Union. I think the advent of big oil and western government interest in the area brings new stability that didn't exist before.

The region is a strategic area of firm interest for the United States and that was not the case 18 months ago. It has been of interest to the United Kingdom for slightly longer. But then the Russians also have an interest. They hate to lose influence and will do everything they can to prevent this. This is why they ensured that Lukoil gained financial participation and why the Russian Foreign Ministry is trying to keep a finger on the Azeri pulse....And then there is Turkey.

'British service companies have been slow off the mark'

I think the best thing to say is that risk certainly exists in the political arena. But the oil and gas fields are there and they're giant - some of the world's largest. The geology is excellent. I believe they will be developed and the sooner they are, the quicker the area will gain wealth and stabilise. However, we're going to see ups and downs for some time to come. In large part, it depends on the leadership of the region. If you look at the leaders of some of these Caspian/Caucasian republics, there are very strong people. Azerbaijan's President Heydar Aliyev is one of the strongest, most visionary leaders I've ever seen. President Nazerbayev in Kazakhstan is equally so.

But there have been attempts to dislodge Mr Aliyev – the most recent in March. What is your view?
I don't think they were coup attempts. I think they were factions who were trying to exert pressure. They were described by the Azeris as coup attempts, the last time being when the secret police were shut down and destroyed by Aliyev. As I go around Baku, I don't see any sign of a lack of safety. It looks like a fairly stable place.

Equally, I've just come back from Georgia having had meetings with President Shevardnadze. I was extremely impressed by the Georgian leadership and that area is much more stable than it was a year ago. They've done a lot to crack down on crime and they're desperate to see the export pipeline go through their country. While there are tensions here and will be for some time to come, there are world class leaders who are being actively supported by western governments.

Are western oil companies fully alive to the issues and to the need to treat the area with greater respect than perhaps they did elsewhere in the past?
That was a different era of western arrogance that I see little sign of now. But you may see small pockets of it with certain companies that are exceedingly arrogant.

Here in Azerbaijan, western companies have, I believe, behaved impeccably and made a point of understanding local culture. The ones who do it worst chop and change people and they don't get a chance to build contacts.

What we have now is a country that has become the stomping ground for the world's biggest oil companies. There are hardly any little guys here, except for us. There are four or five big companies currently trying to get in on Azerbaijan in some way – Elf, Mobil, Shell, Agip – but it's become too late for other small companies.

As for Ramco, we will continue to do an intensive amount of work here to investigate other prospects.

The hypermarket challenge

By Mathieu Zajdela, Enerfinance

How can Britain's motor fuel retailers best meet the growing threat to their trade from hypermarkets? Mathieu Zajdela of Enerfinance suggests they could learn a lot from survivors of the altogether more devastating hypermarket onslaught that has already taken place in France.

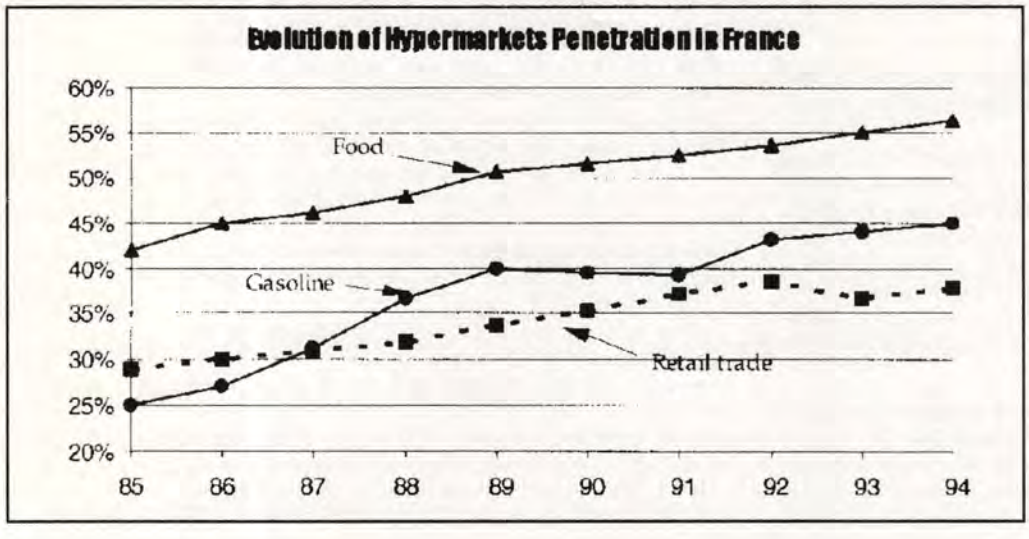
Since the early 1960s, hypermarkets have developed rapidly in the French retail sector, reflecting changes in consumer purchasing habits and lifestyles. Their expansion in the gasoline market is principally a direct consequence of this evolution **(see Graph 1)**.

The growing presence of hypermarkets in the motor fuel retailing sector has also been favoured by changes in car technology: today, the average frequency with which a customer goes to this type of store (once every fortnight, for the majority) corresponds exactly to the average time lapse between tank-filling requirements.

In analysing the evolution of the hypermarket market share in motor fuel retailing and in forecasting their presence, the predominant question is not so much why hypermarkets are so strong – and growing – in certain markets, but why they have such a low penetration in others.

Their market share has exceeded five percent in only five countries – Belgium, France, Germany, Switzerland and the United Kingdom. Hypermarkets have only a marginal presence in other markets, such as Italy, Spain, Sweden, the Netherlands etc.

Graph 1



Anglo/French similarities

Within the group of countries in which hypermarkets have a significant level of penetration, only two have a market share of over 15 percent – France and the United Kingdom. For both countries, 1994 was a year of strong growth: hypermarkets reached a 48.1 percent share of the gasoline retail market in France (against 46.4 percent in 1993), and 18 percent in the United Kingdom (against 14 percent in 1993).

These two countries are also similar in that hypermarket networks are largely independent from oil companies, whilst in other countries over 60 percent of hypermarket service stations are supplied via long-term contracts with traditional oil companies or are even owned by them.

Hypermarket penetration has grown quickly in both countries over the past five years. In contrast, growth has tended to be more stable in other countries.

Anglo/French differences

Despite these common features, there are also large differences between the two countries. In Britain, hypermarkets selling gasoline are mainly large sites (more than 2,500 sq m. of sales area and large parking facilities), and established in the suburbs of large cities. The situation is very different in France, where 4,000 small hypermarkets (usually referred to as supermarkets) represent half of total hypermarket sales. Supermarkets which sell gasoline (about half the total) are more often located in semi-rural areas, where their service station networks have simply replaced those of traditional oil companies.

UK forecast

So how might the situation evolve in the United Kingdom? To analyse the development of hypermarkets in a given market, two questions must be answered:

- What is the hypermarket position in total trade, and how might it evolve?
- Given this position, can the hypermarket hope to equal its level of penetration in the specific area of motor fuel retailing, and how might this position evolve?

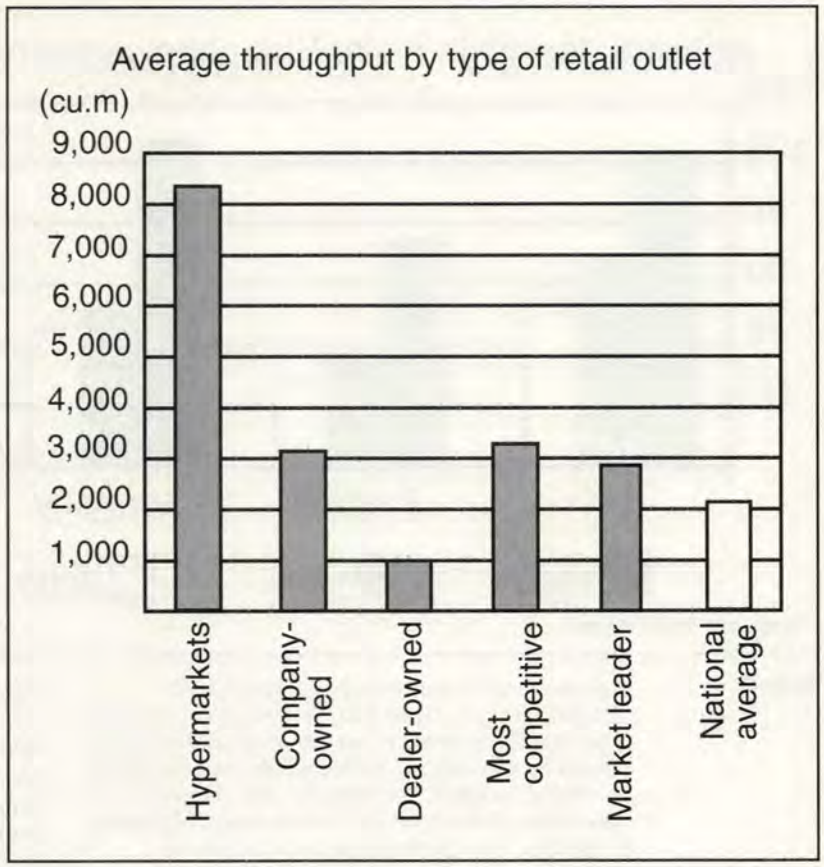
There are three main factors which explain why the level of hypermarket penetration in general retail trade may be very different from one country to the next. These are: the country's level of economic development; the legislative context; and the demographic situation.

Britain is in an intermediate position. The environment for hypermarket development is more favourable than in Germany, the Netherlands or in Italy, but less so than in France. Hypermarkets in the United Kingdom held 27 percent of the retail market in 1994 (eight percent in 1983), compared to 37 percent in France (27 percent in 1983).

Recent announcements made by the British government imply that a more interventionist policy is to be adopted, making it harder to build new hypermarkets. If this is the case, the current rate of hypermarket growth in total retail sales will fall drastically.

Nevertheless, although there may be a strong deceleration of hypermarket growth in the overall retail sector, there will not necessarily be a halt in hypermarket development in the retail gasoline market. In fact, further gains could well take place, as hypermarkets choose to build service stations at existing sites. For instance, between 1988 and 1994, the number of Tesco sites with gasoline retailing facilities rose from 15 percent to over 50 percent.

Therefore, the share of hypermarkets should continue to grow between now and 2000, rising to between 23 percent and 27 percent. This growth will be linked to growth in the number of sites, which Enerfinance predicts will reach 1,000 by the turn of the century, compared to under 700 now. Half of these new stations will be constructed at existing hypermarket sites. The consultancy also foresees a slight decrease in throughput per site, due to increased competition from traditional service stations.



Graph 2

Site closures

The results of this gain in hypermarket market share will be of considerable consequence for the market. Restructuring of the UK network has been slowed by the existence of relatively high margins. Therefore, throughput at traditional sites has been low and the density of the network the highest in Europe, with the exception of Italy.

The average throughput of hypermarket service stations in Britain is over 8,000 cu m per year, compared to around 1,800 cu m/y on other sites **(see graph 2)**. This partly explains a differential in distribution costs: on a full-cost basis, the distribution cost for hypermarkets is £28 per cubic metre, exactly half that of a 3,000 cubic metre company-owned site.

With the necessity for increased restructuring apparent, Enerfinance estimates that around 4,000 sites could disappear by the end of the century in Britain. This would leave approximately 13,000 service stations, of which 1,000 would be hypermarket sites, 4,000-5,000 company-owned sites with high levels of throughput, and 7,000-8,000 dealer-owned sites with an average throughput of close to 1,500 cu m/y.

It should be noted that even with the closure of 4,000 stations by 2000, the density of the UK network would still be 20 percent higher than that forecast for Germany, and nearly double that predicted for France and Spain **(see graph 3).**

Oil company responses

There are two possible ways in which oil companies could respond to the hypermarket challenge. France offers an interesting case study because the reaction had to be very rapid. Total and BP represent the best examples of the two strategic approaches that can be adopted. Total has focused its response to the challenge on qualitative issues, whilst at the same time carrying out a restructuring programme. BP, on the other hand, has based its response upon restructuring and a dynamic pricing policy, although it too has a 'qualitative strategy'.

Within a very competitive market, these two companies have had good success compared to other oil companies. Several conclusions can be drawn from their achievements.

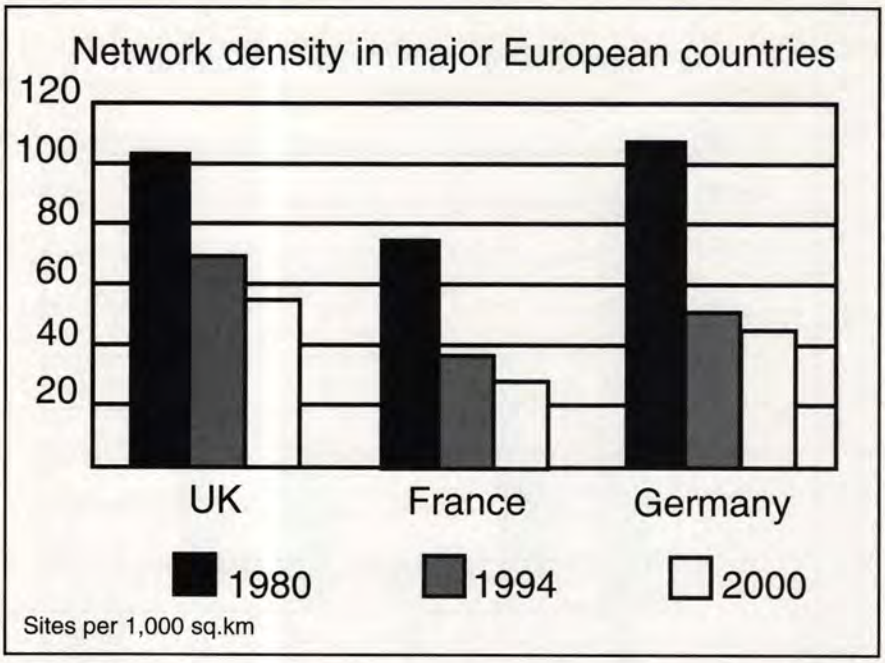
The first is that the optimal strategy is a combination of two strategies, based on either quality orrestructuring/ pricing. Operators with a high market share – over 10-12 percent – should focus on the qualitative aspect. Operators below this size must concentrate their strategy on zones where they have appreciable logistical advantage.

The 'price weapon'

A second conclusion is that a dynamic pricing policy is indispensable, whatever the size of the oil company. This observation is valid for all markets, but especially those in which hypermarkets can develop rapidly. Oil companies need to ensure that a marked price differential between their stations and hypermarkets does not become entrenched, keeping in mind that the maximum differential acceptable to the consumer is about $2/cubic metre. The major risk is that the customer will definitively perceive the hypermarket price as substantially less expensive, leading him or her to stop fueling at traditional service stations and even to cease checking the price difference.

Investment policy is key

The fact that hypermarkets are progressing is not an indication that there is no market for traditional service stations, because the retail market is segmented. If there is a market, there is a strategy which allows for profitability. The challenge is to find the appropriate strategy for each market, both



Graph 3

organisationally and in terms of investment.

In addition, it should be remembered that the most important factor is not the level of the margin offered by the market, but rather the level of return on capital invested. For example, the margin by service station is much weaker in Italy than in Germany or Britain, but profitability was higher in 1994 because the capital invested is low.

The decline in the profitability of motor fuel retailing in the United Kingdom is a result of the decline in margins, but is also linked to the very high level of investment made by the oil companies. Some oil companies over-estimated the level of investment per station that customers would be prepared to pay for.

From this point of view, the strategy developed by BP in France is very interesting: in most cases, the company has reduced its investment in the country's network to the strict minimum, even for stations in prime locations, such as those in Paris. This permits it to achieve a higher optimisation on its capital invested than many other companies.

Dated design

Another problem arises from the design definition of the service station itself. Certain concepts age poorly and necessitate re-imaging every seven years. On the other hand, some concepts can be maintained at minimal cost and updated only every 10 years or so. Operators in the second category have a distinct strategic advantage, with direct impact on the structure of their costs, and even more impact on their return on capital invested.

In general, Enerfinance's data confirms that:

- Cost spreads between oil companies for construction and re-design of their service stations are very wide.
- Cost spreads between oil companies and hypermarkets for construction and re-design of their service stations are also very wide.

Period of adjustment

The UK market has entered a period of adjustment, linked to the strong growth recently exhibited by hypermarkets, to the presence of a surfeit of operators on the market, and to an over-sized network.

The strong decline in margins seen in early 1995 will result in an increase in concentration of the market and in network performance. However, the evolution of retail sales could amplify the downward trend in margins over the short and medium term. (Enerfinance's forecast of a reduction of 4,000 sites is based on an estimated annual growth of 1.5 percent per year in retail sales.)

In the longer term, other positive factors could come into play, such as legislation that allows traditional service stations to sell a wide range of non-oil products, demographic factors, as well as a likely slowing of the further penetration of hypermarkets.

With hypermarkets' share stabilising at 25 percent of the market, the United Kingdom appears to have definitely lost its status as a highly profitable market for motor fuel retailing but companies with appropriate organisation and investment policy will probably be able to recover a reasonable rate of return on capital.

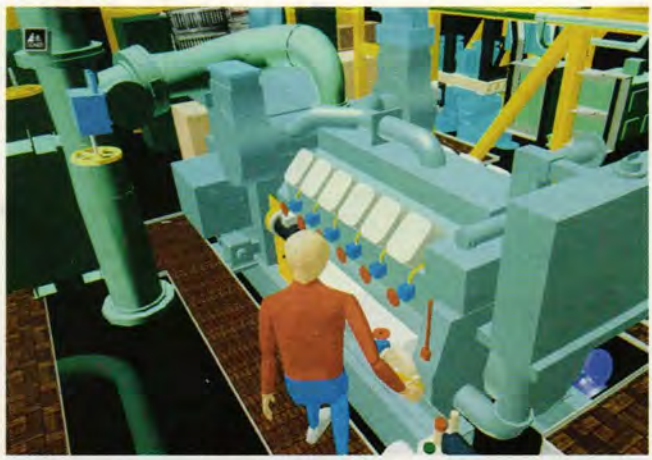
The author is Head of Studies at Enerfinance Consulting Services, Paris.

Engineering simulation is here

Immersive virtual reality (VR) software systems for engineering simulation and physics-based, interactive, 3D graphic simulation and ergonomic tools for task analysis have been launched as 'world firsts' by Deneb Solutions Ltd.

Telegrip can provide a 3D visualistion environment where all the images are based on physical geometry and properties. The kinematics are built-in, so jointed mechanisms, robots and machines can be easily modelled. When coupled with the Deneb/ERGO option, human workers can be modelled with a high degree of accuracy and dynamics exactly mimic real life so objects obey the laws of weight, friction, inertia and gravity. This makes it possible to model, via virtual prototyping, subsea roots and ROVs specifying all the variants, so they are shown with the correct velocity, joint limits and acceleration.

Deneb-ERGO showing NIOSH lifting analysis



Telegrip engine room simulation

They can also be controlled in an offshore or teleoperation environment and can be used for land and surface-based oil platforms and chemical installations. The software runs as desktop VR on anything from an ordinary workstation to a multi-pipeline computer platform.

New machinery troubleshooting software

Bruel & Kjaer has introduced new field analysis and balancing software for its 2526 Series Data Collector System. The two new software packages enable off-line maintenance personnel to extend their capability for trouble-shooting and balancing.

The software is loaded directly into the Data Collector to provide comprehensive in-the-field static and dynamic balancing capabilities for rotors with up to four planes. Data for up to 25 machines can be stored and recalled.

A number of key balancing features include recommended trial masses, correction mass position displayed in degrees or arc length, correction masses calculated for rotors with fixed correction angles and a trim function for balancing previously balanced rotors without the need for trial masses. In addition, the system also offers field analysis capabilities and answers the need for a simple, alarm-based monitoring system which is independent of any computer-based software.

New software from Bruel & Kjaer

New offshore cable armour termination grip

Hawke Connection System has designed and manufactured a new type of cable termination grip for above sea, offshore use.

The Armour Termination Grip was designed to secure 40 loops of armoured, 104mm OD Amercable power cable; 100 metres in length per loop and to hold a total weight of 10,000 lbs, at each end of a cable loop. This includes both the actual weight of cable, and a considerable wind loading factor, to withstand any extreme climatic conditions encountered.

Addition to aggressive media sealant

The Permanite Sigma range of biaxially-orientated PTFE sheet sealing materials, manufactured by TBA Sealing Materials Ltd, gives a secure seal against aggressive industrial chemicals. A new member to the range, the Permanite Sigma 522, has a reinforcing core of Sigma 533 onto which highly conformable expanded PTFE surface layers have been sintered. The company claims it is chemical resistant and is suitable for use in a wide range of media including concentrated acids, alkalis, oxidising agents, steam and general chemicals.

Easy-to-use steel cavity fixing system

Lindapter International has launched a new cavity fixing system which combines ease of installation with high tolerance to common site practices.

The Hollo-Bolt has been designed for fixing to hollow section steel and is suitable for use with thick or thin wall rectangular or circular hollow section.

It can be used for cavity steel structures which are accessible from one side only, and eliminates the need for unsightly welding or strapping.

It also produces an aesthetically pleasing finish since, once installed, only the Hollo-Bolt head and collar are visible.

The Lindapter Hollo-Bolt range

New automated viscometer

Stanhope-Seta's Setavis Double 6 KAV is a new automated addition to the range of Kinematic Viscometers meeting the requirements of ASTM D445.

The unit is suited for testing viscosity index, and features two independent oil baths digitally set and controlled over the range ambient to 150°C. Each bath has a capacity for up to six viscometer tubes.

Preparation, test and operator time are minimised by in place sample loading, tube cleaning and auto timing.

The tubes are of a duplex design and feature two measuring bulbs in series, providing two tests per sample. Tests may be carried out using filtered micro samples of less than 0.3mL of clear or opaque liquids over the range of 3 to 2000mm²/s.

Each one is fitted with optical start and end point detectors, and calibrated at 40 and 100°C. The detectors are coupled to an integral 24 channel auto timer, and results fed into a PC loaded with Microsoft Windows software. To verify performance, a set of Setavis Viscosity Standards is available accompanied by a NAMAS certificate providing an official assurance of traceability to primary standards.

Viscometer linked up to a PC

Real-time speed of sound for seismic ships

A new system for real-time measurement of speed of sound in water from seismic vessels has been introduced by Valeport Ltd. The battery-powered Model 600-S Seismic Streamer CTD System assembly fits directly onto the standard streamer fitting for compass or depth birds and is protected by the transponder guard.

Operation is automatic, with on-line, real-time calculations of speed of sound available on demand: the system stays in sleep mode until addressed by the streamer communications system. It then makes its measurements and holds the data in memory until requested to communicate it. Salinity, speed of sound and density are derived from the CTD data to give a speed of sound accuracy of 0.02 metres per second. The unit has an aluminium bronze housing, a diameter of 76mm, overall length of 1080mm, weight in air 12kg and is depth-rated to 1,500 metres.

New gas additive to minimise emissions

Chevron has introduced a new gasoline with Techron – a new patented additive – specially formulated to help prevent engine deposit build-up and minimise vehicle emissions. The gasoline was launched by a national advertising campaign throughout the company's 30-state US marketing area.

The additive is included in all grades of the company's gasolines: Regular, Plus and Supreme, with a higher dose in the Supreme for faster clean-up of deposits left by lower quality gasolines. The company claims that it does an unbeatable job in the engine's intake system without contributing to harmful combustion chamber deposits, which can cause knocking or loss of power during acceleration and higher emissions.

High-sensitivity leak detection

Locating leaks in natural gas pipelines is now easier, cheaper and more accurate following the introduction of a new detection system which injects a safe, non-flammable tracer-gas mixture of hydrogen and nitrogen in pipes, even those buried a metre or more beneath concrete or asphalt, claims Sensistor AB, the Swedish company who developed it.

The Sensistor Hydrogen Leak Detector 8012

The Sensistor Hydrogen Leak Detector 8012 is a microelectronics instrument employing a range of probes developed for specific applications. The five percent hydrogen/95 percent nitrogen gas is the same low-cost, widely available standard mixture used as a protective atmosphere in welding and sintering processes.

Environmental energy oil spill kits

Increasingly stringent health and safety legislation allied to environmental protection requires a rapid response to accidental oil spillage. The Pirtek Energy Oil Spill Kit is designed to deal with hydraulic hose or component failure and consists of four 75mm diameter socks some 1200mm long, 20 melt blown polypropylene pads, a disposal bag and instructions for use. The socks are used to surround the spillage to prevent it entering waterways and spreading outside a clear area of containment. The pads are placed on top of the spill to rapidly soak up the waste oil.

They are capable of absorbing up to 25 times their own weight in oil and because they are hydrophobic the company claims they will not soak up water and are only effective on oil and similar hydrocarbons.

Airport fuel leak detection system

A new system to detect possible leaks in its fuel hydrant system has been unveiled at London Stansted Airport. The LeakLoc system, proposed by JP Kenny Technology Ltd, is the first of its kind to be installed at a British airport. It works by monitoring pressure waves during normal operations, including aircraft fuelling, and provides continuous leak detection and location on all sections of the hydrant system.

Economical eyewashes

Steripak, manufacturers of emergency eyewash solutions, has launched a small-volume eyewash designed to deal with minor incidents such as a speck of dust in the eye.

Steri-Wash 20ml plastic pods contain sterile 0.9 percent saline eyewash which allows accurate and controllable irrigation of the eyes. The flow of eyewash, from single drops to gentle flushing, is governed by simply squeezing the pod.

The company believes the wash will be useful in a wide range of industrial and other work environments, even in low-hazard situations where eyewashes might not be provided. It will also be of benefit in vehicle first aid kits.

Steri-wash 20ml eyewash from Steri-pak

Static shoe safety test

In a variety of industries, many companies now provide anti-static footwear for their operatives, to prevent the build-up of static charge which could provide the ignition source for an explosion within flammable atmospheres. However, product build-up (ie: paint, adhesives and plastics) can act as an insulating layer rendering the footwear useless.

The Sole-mate from Cenelectrex enables personnel to prove that their anti-static footwear is properly conductive before entering safety critical hazardous atmospheres. The simple-to-use test gives a 'pass' display if the footwear resistance is lower than the maximum suggested by BS5958, and a 'fail' display and alarm if above the pre-set level. The unit uses its own independent power source and is supplied 'ready for use', complete with a safety hazard warning sign and fitting kit.

Sole-mate and friend in action

On-the-spot burn relief

A comprehensive first-aid kit specially designed for the emergency treatment of burns is now available from Virusolve Ltd. The 'Water-Jel' kit consists of several burn dressings and one large burn wrap all of which are soaked in a specially formulated sterile cooling gel. The gel relieves pain instantly and forms a protective barrier against possible contamination of the burn area. The kit provides paramedics, ambulance crew and firemen with all the equipment necessary for administering rapid first-aid assistance to burn victims at the scene of an accident.

How many points for a petrol pump?

Careless drivers on service station forecourts are the biggest cause of petrol pump damage, according to Wayne Autocourt. On average, drivers damage two pumps a day – mostly due to collisions with pump bodyshells or damaged nozzles and damaged hoses which have either been run over by the motorists, or left in the car's petrol tank when the driver pulls away.

To reduce the occurrence of these problems the company has introduced a number of improvements. The Series 8000 and 9000 pumps have been fitted with specially-designed hose break couplings which disconnect the hose from the pump unit if the car pulls away. This prevents the pump being pulled from its mountings and the newer models feature retractable hoses to avoid damage.

Safety spectacles which perform with style

Cabot Safety has introduced a new range of safety spectacles which combine all the benefits of performance with comfort and style.

The Nassau® Plus which use an anti-fog, anti-scratch, anti-UV, anti-static and anti-chemicals DX™ coating, are manufactured in a shiny, tough polymer which makes them extremely comfortable to wear yet highly durable. Fully extendable arms have been incorporated into the design for a secure fit, whilst the integral brow guard design offers added protection to the wearer, and to the lens when not in use. The spectacles conform to the European standard EN166 for safety eyewear.

CONTACTS

Deneb Solutions Ltd	0161 745 7384
Hawke Connection Systems Division	01229 587366
Bruel & Kjaer (UK) Ltd	0181 954 2366
TBA Sealing Materials Ltd	01706 715000
Lindapter International	01274 521444
Stanhope-Seta	01932 564391
Valeport Ltd	01803 834031
Chevron Corporation	00 1 415 894 4440
Sensistor Ltd	Fax: 01908 670013
Pirtek (UK) Ltd	0181 749 8444
BAA London Stansted	01279 662709
Steripak Ltd	01928 579110
Cenelectrux Ltd	0115 981 9666
Virusolve Ltd	01924 422599
Wayne Autocourt	01875 400025
Cabot Safety Ltd	01625 878320

Improve the efficiency of your purchasing process

NVQ/SVQs in purchasing are now available through 112 centres nationwide. They combine the professional knowledge of The Chartered Institute of Purchasing & Supply (CIPS) and the specialist training organisation, Link Training and are backed up by flexible learning materials and in-company programmes.

Developed by the Purchasing and Supply Lead Body (PSLB), the NVQ/SVQs in purchasing are at Levels 2, 3 and 4. There are nine units at Level 2, 12 at Level 3 and 15 at Level 4.

Candidates achieving NVQ/SVQs Levels 3 and 4 in purchasing will, on presentation of a project and case study, be received as Members of The Chartered Institute of Purchasing & Supply.

Single post-school qualification under consideration

A single qualifications framework for post-school education and training, with a new points system for entry into higher education, could emerge from a government-backed review.

Sir Ron Dearing, who heads the review of 16-19 year olds' qualifications, says he wants to explore an overarching system in which points could be accumulated on either academic or vocational courses. This could build on existing qualifications and take on board achievement in a wider range of areas, including new routes such as the Modern Apprenticeship.

Sir Ron wants to create a framework which recognises that there may well be a major change in the balance between A-levels, National Vocational Qualifications (NVQs), General NVQs and the Modern Apprenticeship as a gateway into higher education. It will also have to recognise that universities may not in the future be just concerned with degrees, but may place greater emphasis on two-year diplomas.

One of the concerns has been the waste involved in high drop-out and failure rates on courses. Sir Ron is interested in providing new routes between different types of qualifications, whereby students gain some credit for uncompleted courses. Common elements could also be developed between the emerging modular A-level and GNVQ courses, to give students more time to decide which kind of study is best for them.

Understanding Energy on CD-ROM

Understanding Energy is an interactive multimedia CD-ROM which introduces the topic of energy to young people. Targeted primarily at the 11-14 age group, it will have uses through to a senior level.

The programme is produced by Anglia Multimedia.

The media used to explain and demonstrate the concepts includes text, vector-based graphics, bit-mapped scanned images, digital video clips and animations.

Useful NVQs

A review of the 100 most used National Vocational Qualifications, and their Scottish equivalents, has been launched. The review will be carried out by the National Council for Vocational Qualifications and SCOTVEC.

Australian prize-winners

(Left to right) Mr Ted Wziontek, Chairman, AIP Queensland Branch, Mr Graham Sutherland, IP prize winner, Mr Jim Starkey, Executive Director, AIP

The Institute of Petroleum's student prize-winners are now working throughout the world and the most distant presentation this year was in Melbourne, where Mr Graham Sutherland, who attained his M.Eng in Petroleum Engineering at Heriot-Watt University last year, was presented with his certificate by the Executive Director of the Australian Institute of Petroleum at a Queensland Branch meeting. Graham is now working for Santos in Brisbane. Last year's winner of the Heriot-Watt prize is also an Australian and is now working in Scotland.

Standards for managing energy

The Energy Efficiency Office is supporting a training initiative under its Best Practice programme to develop a set of generic standards for managing energy, suitable for the entire spectrum of energy management. The standards may form the basis of National Vocational Qualifications (NVQs) and Scottish Vocational Qualifications (SVQs) for Managing Energy.

The project is run by the Management Charter Initiative (MCI), and is being jointly sponsored by the Energy Efficiency Office, British Gas and the Electricity Association, with guidance from academia, professional associations and employers.

The standards will raise the professional status of energy management in the United Kingdom and help industry, commerce and the public sector to gain full value from its energy investments.

Engineering students apply for Top Flight bursaries

More than 2,000 engineering students have applied for bursaries in the Top Flight scheme being run by The Engineering Council and The Department for Education.

The scheme provides suitably qualified students with £500 per year in addition to their maintenance grants for the duration of their undergraduate courses.

Altogether £10 million of funds over the three years has been provided by the Department for Education for the scheme, which is being administered by The Engineering Council.

FORTHCOMING EVENTS

July

3rd-7th
Edinburgh: 'PVT and Phase Behaviour of Reservoir Fluids'. Details: Tom Inglis, Director of Continuing Education, Heriot-Watt University, Riccarton, Edinburgh EH14 4AS.
Tel: 0131 451 3014/5
Fax: 0131 451 3005
Telex: 727918

3rd-6th
Birmingham: 'LNG 11'. Details: Nelton Exhibitions Ltd, Nelton House, 46a High Street, Gravesend, Kent DA11 0AY.
Tel: 01474 536535
Fax: 01474 536552

3rd-6th
Cranfield: 'Fluid Engineering and Instrumentation'. Details: Short Course Administrator, Department of Fluid Engineering & Instrumentation, School of Mechanical Engineering, Cranfield University, Cranfield, Bedford MK43 0AL
Tel: 01234 754766
Fax: 01234 750728

4th-6th
Cannes: 'Undersea Defence Technology'. Details: Gillian Shinar, UDT 95 Conference, Nexus Events, Warwick House, Azalea Drive, Swanley, Kent BR8 8HY.
Tel: 01322 660070
Fax: 01322 661257

6th-7th
Budapest: 'Restructuring & Privatisation of the Electricity Industries in Central and Eastern Europe'. Details: IBC Financial Focus Ltd, Gilmoora House, 57-61 Mortimer Street, London. W1N 8JX.
Tel: 0171 637 4383
Fax: 0171 323 4298

10th-11th
Manchester: 'Freight Transport and the Environment'. Details: Chris Kaighin, Department of Continuing Education, Lancaster University, Storey Institute, Meeting House Lane, Lancaster LA1 1TH.
Tel: 01524 849494
Fax: 01524 849499

10th-14th
Brighton: 'Continuous Flow Gas Lift and Electrical Submersible Pumping'. Details: Carolyn Ogans, The University of Tulsa Division of Continuing Education, 600 South College Avenue, Tulsa, Oklahoma 74104-3189.
Tel: 918 631 2347
Fax: 918 631 2154

10th-12th
London: 'Using Derivatives to Manage Energy Risk'. Details: Bookings Department, BRi Financial Training, 57-61 Mortimer Street, London W1N 8JX.
Tel: 0171 637 4383
Fax: 0171 636 2330

12th-13th
London: 'The Financing and Economics of Gas and Electricity Projects'. Details: IBC Financial Focus Ltd, 57-61 Mortimer Street, London, W1N 8JX.
Tel: 0171 637 4383
Fax: 0171 323 4298

14th-19th
Cambridge: 'Ion Exchange Developments and Applications'. Details: Society of Chemical Industry, 14/15 Belgrave Square, London SW1X 8PS.
Tel: 0171 235 3681
Fax: 0171 823 1698

18th-20th
London: 'Energy Models for Policy and Planning'. Details: Ms Esther Welsh, London Business School, Regent's Park, London NW1 4SA.
Tel: 0171 262 5050 ext 3525
Fax: 0171 724 7875

24th-28th
Cambridge: 'Applied Groundwater Modelling'. Details: Dr Angela McMahon, Suite A, Conqueror House, Vision Park, Histon, Cambridge, CB4 4ZR.
Tel: 01223 236950
Fax: 01223 236242

September

5th-8th
Aberdeen: 'Offshore Europe '95'. Details: Offshore Europe Partnership, Rowe House, 55/59 Fife Road, Kingston-upon-Thames, Surrey KT1 1TA.
Tel: 0181 549 5831
Fax: 0181 541 5057/5016/547 2807
Telex: 8954102

6th-8th
Mexico: 'Coastal '95; Computer Modelling of Seas and Coastal Regions'. Details: Liz Johnstone, Wessex Institute of Technology, Ashurst Lodge, Ashurst, Southampton, SO40 7AA UK.
Tel: 44 0 1703 293223
Fax: 44 0 1703 292853
EMail: CMI@uk.ac.rl.ib
Intl EMail: CMI@ib.rl.ac.uk.

10th-13th
Nice: '1995 AAPG International Meeting'. Details: AAPG International Conference, PO Box 979, Tulsa OK 74101-0979 USA.
Tel: 1 918 584 2555
Fax: 1 918 584 2274

11th-13th
Cambridge: 'Oil and Gas Transportation Workshop'. Details: Langham Oil Conferences Ltd, 37 Main Street, Queniborough, Leicester LE7 3DB.
Tel: 01509 881022
Fax: 01509 881576

11th-13th
Aberdeen: 'Loss Prevention in the Oil and Gas Industry'. Details: Ms Catherine Cox, BHR Group Ltd. Cranfield. Bedford MK43 0AJ.
Tel: 01234 750422
Fax: 01234 750074

11th-15th
Dundee: 'UK Oil & Gas Law'. Details: Ms Moira McKinlay, Summer Programme Registrations, Centre for Petroleum and Mineral Law and Policy, University of Dundee, Dundee DD1 4HN, Scotland.
Tel:01382 344303/344300
Fax: 01382 322578

INSTITUTE NEWS

NEW MEMBERS

Mr A Abela, Valletta Survey Company Ltd, 11/22 Vincenti Buildings, Strait Str, Valletta VLT08, Malta.
Mr R S H Anderson, Rakers, 24A West Street, Abbotsbury, Dorset, DT3 4JT.
Mr M Arnell, W T Hills Limited, 160 Brompton Road, London, SW3 lHW.
Mr W Barnes, Lower Maisonette, 68 Holland Park Avenue, London, W11 3QZ.
Dr R Bottom, Mettler Toledo, 64 Boston Road,, Beaumont Leys, Leicester LE4 lAW .
Mr Brown, 61 Langdale Way, The Pastures, East Boldon, Tyne & Wear, NE36 OUF.
Mr A Carradice, Angus Chemie GmbH, Unit 7 Rotunda Business Park, Thorncliffe Park Estate, Chapeltown, Sheffield S30 4PH.
Mr E Clark, Clark Marketing Partnerships Ltd, Vigilant House, 120 Wilton Road, London, SW1V IJZ.
Mr M P Combes, Stevens & Bolton, Solicitors, 1 The Billings, Walnut Tree Close, Guildford Surrey, GU1 4YD.
Mr J G Evans, Institute of Petroleum, 61 New Cavendish Street, London, W1M 8AR.
Mr T R Goss, 252 Kiln Road, Thundersley, Benfleet, Essex, SS7 1RR.
Mr J E Harris, Gibwen House, Bix, Henley on Thames, Oxon, RG9 6BY.
Mr T Hendron, Summerhill Commercials, Summerhill, Dublin 1, Ireland.
Mr C Holloway, SGS Redwood UAE, P O Box 4836, Fujairah, UAE.
Mr P M Hunt, 2 Croft Court, Westhill, Aberdeen, AB32 6TU.
Mr M Lui, 36B Block 7 Phase 2, Belvedere Garden, Tsuen Wan, NT, Hong Kong.
Mr J A Mahmoodi, c/o Capt Kausar, Marine Surveyor, Oil Lab & Marine Surveyors Co, PO Box 6400, Sharjah UAE.
Mr K W McNulty, 36c Moray Road, Finsbury Park, London, N4 3LG.
Mr S P Moran, Moran Process Design Svos Ltd, 21 Farmers Heath, Great Sutton, South Wirrall, L66 2GX.
Mr J F Mosedale, 17 Essex Road, Llawion Park, Pembroke Dock, Dyfed, SA72 6ED.
Mr J Moulin, Association Francaise des Techniciens et Professionnels du Petrole 92038 Paris, La Defense, Cedex, France.
Mr S S Nawaz, Marketline International, 16 Connaught Street, London, W2 2AF.
Mr A R Pope, National Power plc, Pembroke Power Station, West Pennar, Pembroke, Dyfed, SA71 5SS.
Mr C T Selwa, 69 Weaverham Road, Sandiway, Northwich, Cheshire, CW8 2NF.
Mr B Smith, Hawk Lodge, New Holland Road, Barrow-upon-Humber, South Humberside, DN19 7EF.
Mr H T Studd, Gransmore, Causeway End, Felstead, Essex, CM6 3EY.
Mrs M L Sykes, Muse, Stancil & Co, 3 Berkeley Square London WIX SHG.
Mr J C Theo, Theo International Oils, P O Box 371, Brakpan 1540, South Africa.
Prof V Tseguelski, NPT Corporation Limited, Kestrel House, 19-20 Grove Orchard, Highworth, Wilts, SN6 7LB.
Dr P R A Wells, East West Business Consultants Ltd, 121 Felstead Road, Orpington, Kent, BR6 9AD.
Mr J White, Heath Engineering Tank Maintenance, Unit E Teesbay Business Park, Brenda Road, Hartlepool, Cleveland, TS25 2BU.
Mr M Wills, Control Risk Group Ltd, 83 Victoria Street, London SW1H 0HW.
Dr A Willson, Brown & Root Environmental, Thorncroft Manor, Dorking Road, Leatherhead KT22 8JB.

STUDENTS

Mr H Zackrisson, Saybolt Estonia Ltd, Lume 3, EE0004, Tallinn, Estonia.
Mr A Alpamgbo, Centre for Petroleum and Mineral Resource Policy, University of Dundee, Dundee DD1 4HN.
Mrs C E Doggart, 23 Ovington Gardens, Lonodn SW3 1LE.
Mr R S Kanwar, 153 Boston Manor Road, Brentford, Middx TW8 9LE.

NEW FELLOW

Mr P Shammas

Mr Shammas graduated from the University of Munich with a degree in Petroleum Economics. In 1972 he launched the APS Group. This was based on the concept of multi-disciplinary study and analysis which he had developed for oil exporting states. For over 20 years he has been Editor of the weekly oil and gas review of the Middle East industry, the APS Newsletter. As an active member of the IP, he has addressed some of its conferences and meetings.

NEW COLLECTIVE

ISO – Peritagens Cargas e Seguros, Limitada
Av. 24 de Julho, 128 A
1350 Lisboa
Portugal

IP nominated representative: **Mr C A A Rovisco**

ISO – Pertagens Cargas e Seguros LDA are independent approved surveyors of petroleum products including LPG and chemicals, bulk grain, coal and general cargo marine surveyors equipped with laboratory facilities, servicing Portugese and Spanish ports.

Its staff consist of experienced Master Mariners specialised in vetting surveys and cargo loss control, operating out of offices at the ports of Sines and Leixoes, covering Faro, Setubal, Aveiro, Figueira da Foz and Viana do Castelo, Huelva, Algeciras and Sevilla, amongst others in the Iberia Peninsula.

PCS-Robinson Intl Portugal are fully accepted by the major petroleum concerns, Portugese Power Supply Commission, major importers and exporters and leading insurance companies.

UK Deliveries into Consumption (tonnes)

Products	*†Apr 1994*	**Apr 1995*	*†Jan-Apr 1994*	**Jan-Apr 1995*	*% Change*
Naphtha/LDF	245,302	223,680	1,030,743	1,118,255	8
ATF – Kerosene	553,616	572,635	2,101,474	2,141,199	2
Petrol	1,890,937	1,787,867	7,354,069	7,002,517	-5
of which unleaded	1,070,108	1,099,668	4,114,893	4,280,422	4
of which Super unleaded	119,389	83,792	455,572	328,972	-28
Premium unleaded	950,719	1,015,876	3,659,321	3,951,450	8
Burning Oil	145,259	214,871	1,264,347	1,165,320	-8
Derv Fuel	1,013,371	1,059,645	4,052,302	4,303,377	6
Gas/Diesel Oil	609,310	564,116	2,779,420	2,664,971	-4
Fuel Oil	802,953	640,545	3,392,700	3,084,499	-9
Lubricating Oil	63,999	70,099	256,530	289,859	13
Other Products	677,020	711,476	2,672,080	2,884,440	8
Total above	**6,001,767**	**5,844,934**	**24,903,665**	**24,654,437**	**-1**
Refinery Consumption	523,195	494,421	2,084,996	2,096,565	1
Total all products	**6,524,962**	**6,339,355**	**26,988,661**	**26,751,002**	**-1**

*† Revised with adjustments *preliminary*

INSTITUTE NEWS

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THE INSTITUTE OF PETROLEUM

Petroleum Review Index 1994

Copies are now available from

The Library
The Institute of Petroleum,
61 New Cavendish Street,
London W1M 8AR
Tel: 0171 467 7100
Fax: 0171 255 1472

Strathclyde University celebrates its Bicentenary year in 1996

Professor George Maxwell is delighted to invite alumni from Mineral Resources Engineering and the University of Strathclyde Mining & Petroleum Engineering Society to attend a reunion celebration in April 1996.

If you would like further information, or are in touch with someone who you think would be interested in attending the event please, contact the **Alumni Affairs & Development Office, University of Strathclyde, McCance Building, 16 Richmond Street, Glasgow G1 1XQ. Tel: 0141 552 4400 ext. 2773/2911 Fax: 0141 552 6558.**

RECRUITMENT

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An excellent remuneration package is available – reflecting the seniority of the position.

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Corporate Treasury Management for the Oil and Gas Industries

Price Waterhouse

A series of seminars focusing on the major corporate treasury issues of interest within the petroleum industries.

- **11 September 1995 – The role of corporate treasury.**
- **9 October 1995 – Identification and reduction of financial risk.**
- **13 November 1995 – Management information systems in the treasury environment.**
- **11 December 1995 – Trading and the misuse of derivatives.**

Speakers will be from Price Waterhouse and other experts in the industry.

All seminars will be from 17.00-19.00

Details from Jenny Sandrock at the IP Tel: 0171 467 7104 (direct line) Fax: 0171 255 1472 or Iain Fidler of Price Waterhouse Tel: 0171 939 3000 Fax: 0171 378 0647

PEOPLE

The International Association of Independent Tank Owners (Intertanko) has confirmed the appointment of New York-based banker **Dagfinn Lunde** as managing director. He will take up his position in November when the present managing director **Tormod Rafgard** retires after 25 years service.

Amerada Hess has announced that **John Hess**, son of **Mr Leon Hess**, has been appointed Chairman and Chief Executive Officer of the corporation. **Sam Laidlaw** has been appointed president and chief operating officer based in New York and chairman of Amerada Hess Ltd in the United Kingdom. Mr Leon Hess has a new role as chairman of the executive committee. In the UK, **Francis Gugen**, formerly Finance Director, succeeds **Sam Laidlaw** as Managing Director, **Rex Gaisford Knight Bachelor** has been appointed Director of Worldwide Developments and **Ian Gray** has joined the company as Vice President of International Exploration and Production.

Robert McCrackin has been appointed managing director of Ranger Oil (UK) Ltd. He replaces **Phil Irwin** who has been promoted to chief operating officer for the company.

Ian Carroll has been appointed to the board of Brisco Engineering Ltd as Aberdeen operations director.

Richard Tett has joined Sulzer (UK) Pumps at Leeds as sales & marketing director for Sulzer Pumps Europe. Previously he was sales director (Power Generation) at European Gas Turbine at Lincoln.

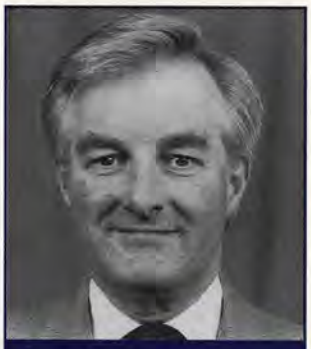
Thomas G Finck, has been elected chairman of the board of Triton Energy Corporation, succeeding **William I Lee,** who retired as Chairman at the company's annual shareholders's meeting. Mr Finck will continue as Triton's President and Chief Executive Officer.

Mr Harry W Rowson has been named as director fuels marketing for Mobil. He will be responsible for marketing all Mobil fuel products in the United Kingdom . He will be based in the new head office in Milton Keynes. He joined the company in 1971 and most recently has been working for Mobil Europe Ltd.

Mr Mike Pink, currently chief operating officer responsible for exploration, production and technical activities at Enterprise Oil will be taking on further management responsibilites as Group Managing Director.

Recent appointments to A&B Geoscience, UK include: **Helen Constanti**, systems support geophysicist; **Brian Hughes,** processing geophysicist; **Andy King**, manager, Abu Dhabi core laboratory; and **Jon Willington,** processing geophysicist.

Central Area Transmission System (CATS), operated by Amoco (UK) Exploration Company has appointed **Terry Hughes** to take over as Manager CATS from **Rob Johnston**, who is promoted to Manager, Northern and Central North Sea Assets for Amoco. Hughes was previously resource development manager of Amoco Norway Oil Company. They will both report to Amoco (UK) Exploration company Managing Director **R J Criswell**.



David McKenzie has been appointed chief executive of the Marine Technology Directorate. He spent 20 years with BP where he held key posts in some of the major oil provinces. He has also been a director of the Offshore Petroleum Industry Training Organisation.

Liebherr Great Britain Ltd annouces the appointment of **David Milne** as the new Divisional Director – Cranes and Concrete Products. He has been involved in crane and access platform sales for 20 years and will be based at Liebherr's Hatfield headquarters.

Paul Carvell has joined United Transport (UK) Ltd as chief executive based at the company's head office in Thame, Oxfordshire. He was previously at TGD subsidairy Beck and Pollitzer where he spent five years as a Managing Director.

Mobil Corporation has announced that **Axel Commichau**, Marketing Manager for Mobil Erdgas-Erdoel GmbH, its exploration and producing unit in Germany, has been named General Manager of Mobil Europe Gas Inc (MEGAS).

Thierry Desmarest has been named as the new Chairman of French oil company Total following the resignation of **Serge Tchuruk**. He is presently head of the group's exploration and production division. Mr Tchuruk has accepted a position as Chairman of telecommunications and engineering giant Alcatel Alsthom.

Pogo Producing company has promoted **Ronald B Manning** to Vice-President and General Counsel and **John W Elsenhams** to Vice President and Treasurer. Mr Manning has been with Pogo for eight years and was previously Associate General Counsel and Corporate Secretary. Mr Elsenhams has been with Pogo for four years and was previously Director of Corporate Finance.

Chris Tutt has been named Director of Industry Relations for Western Geophysical. He joined Western after leaving university in 1978 and in 1992, he was named senior account representative for both land and marine data sales. He will continue to be based in Western's Houston headquarters.

Chevron Corp. announced that **Lydia Beebe** has been elected secretary of the corporation. She will replace **Malcolm J McAuley,** who has been appointed Chief Financial Officer of Caltex Petroleum Corp, of which Chevron is a 50 percent shareholder. Ms Beebe joined Chevron in 1977 and was previously a Senior Manager in Chevron's tax department. She is also chair-person of the California Fair Employment and Housing Commission.

Western Geophysical has appointed *Mike McCormic* as general manager, new ventures – worldwide. He joined Western in 1964 and has held management positions in crew field support, marine operations and spec/marketing. He recently served as general manager,new ventures – EAME.

New 1994-95 edition

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CONSULTANT HANDBOOK

Members of the Institute of Petroleum offer consultancy services in a wide range of petroleum industry subjects. Currently over 600 members offer 66 different categories of expertise.

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- ▲ *Energy Efficiency*
- ▲ *Environment - General*
- ▲ *Environment - Marine Pollution*
- ▲ *Expert Witness Services*
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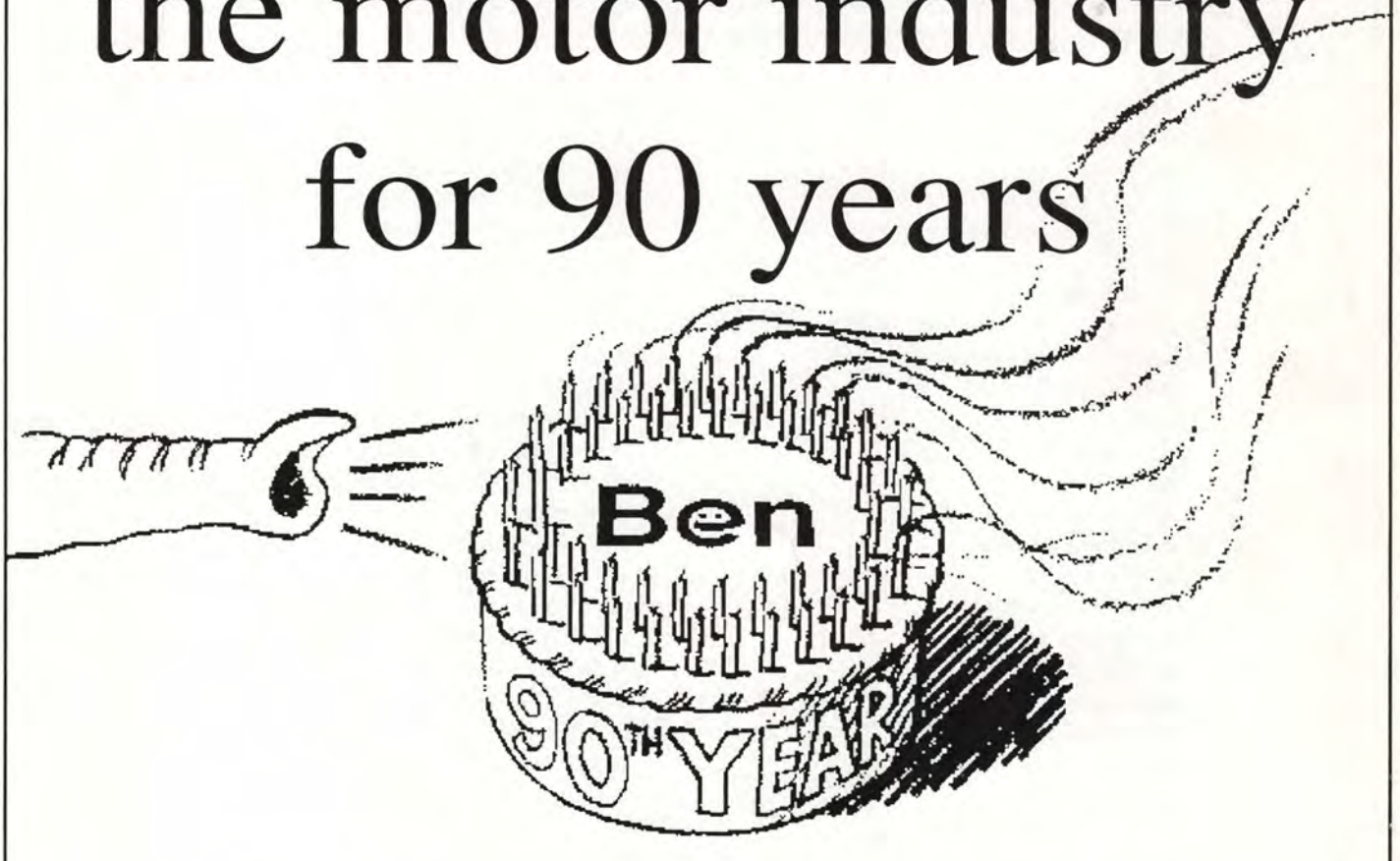

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