DECEMBER 1992

The Institute of Petroleum

PETROLEUM REVIEW

United States

Will the new president be friend or foe of the oil industry?

Gas

Gas strategies in Europe by Mr Loïk Le Floch-Prigent

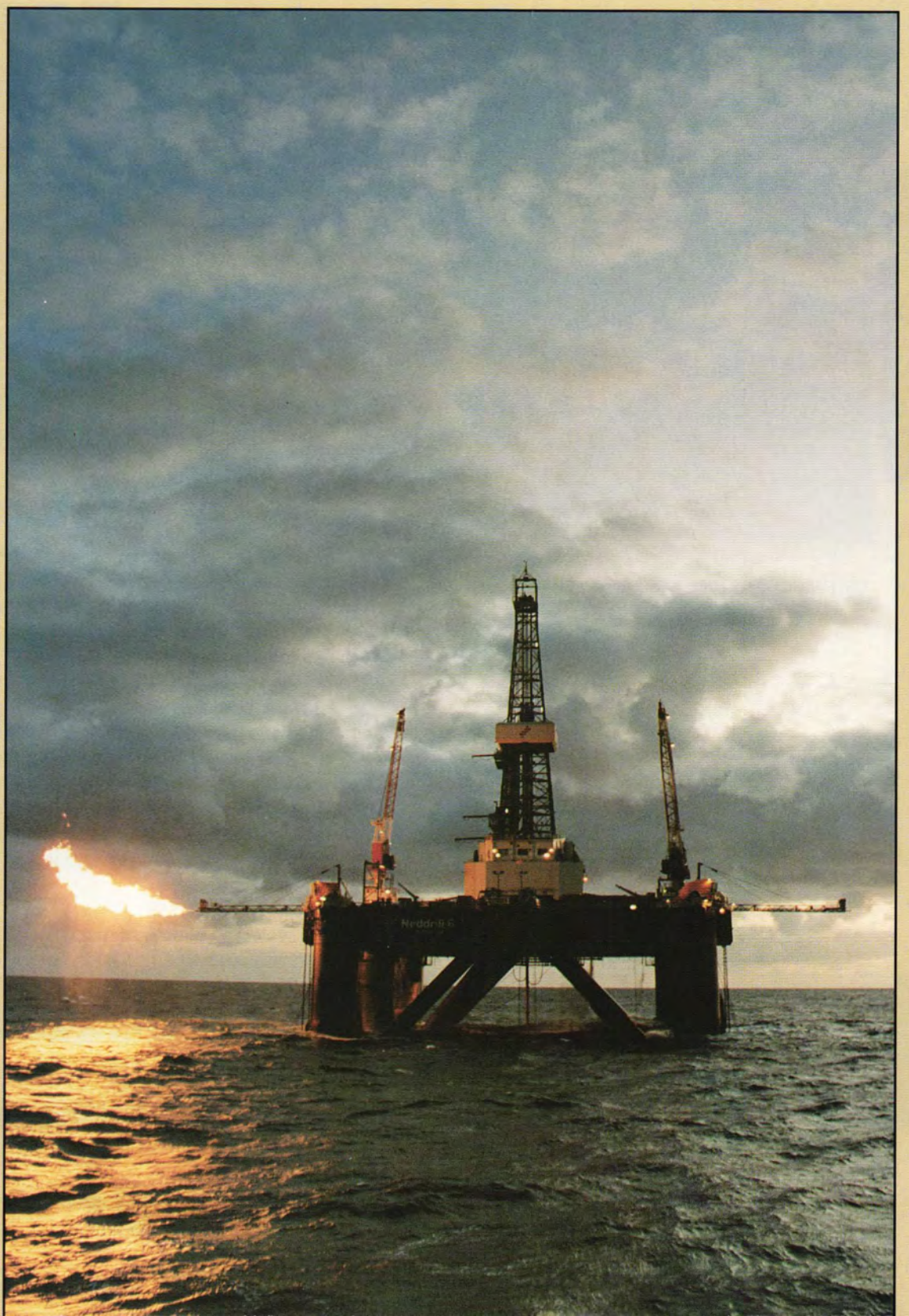
Malaysia enters the gas era

Environment

Post-war marine life in the Gulf

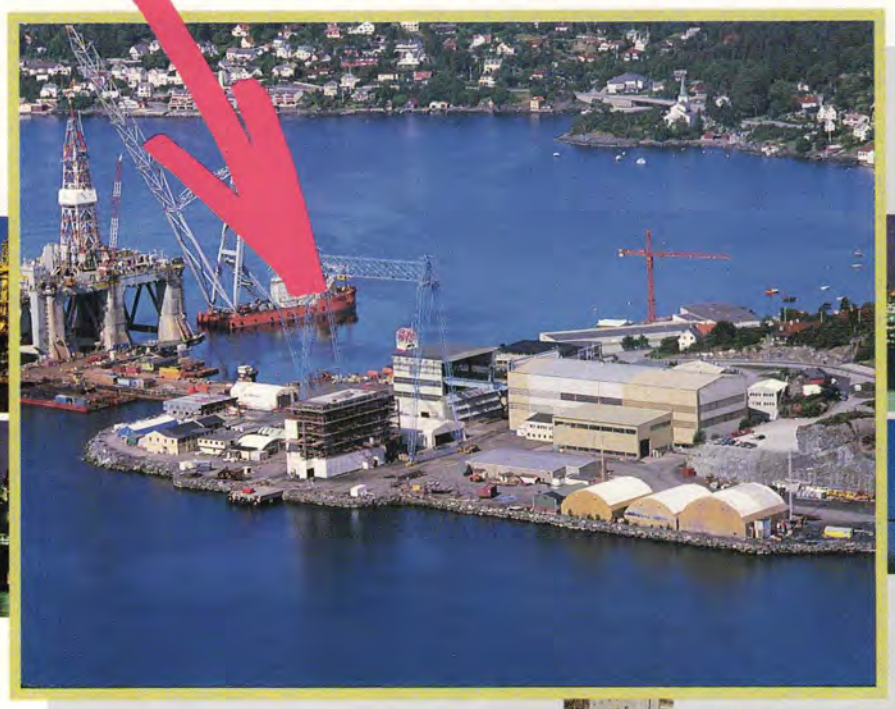
Philately

Stamps from round the world



This is where the Nelson Accommodation Module for Shell U.K. Exploration and Production is being built.

Again and again Leirvik Sveis has been chosen as main contractor of modules in aluminium or steel.



The Nelson field is being developed by Shell on behalf of Shell, Esso, Enterprise Oil and other co-venturers.

Leirvik Sveis is a leading supplier of accommodation modules for the North Sea. We also carry out refurbishing and reconstruction of existing or outdated structures, including engineering, fabrication and assembly/hook-up.

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Contents

Cover photo: The Neddril 6 rig on Conoco's Britannia appraisal well.

. . . news in brief

19 October

Survivors of the *Ocean Odyssey* blowout have received compensation settlements totalling more than £55 million.

Russia's oil plants will soon be reorganised into joint stock societies, according to a draft decree submitted to President Boris Yeltsin.

20 October

Amoco (UK) Exploration has made what it describes as a 'significant' new oil discovery in the Central North Sea, 120 miles northeast of Aberdeen.

Oil production has ceased from Hamilton's Argyll and Duncan fields in the UK North Sea, as output rates have declined to a level where the fields are no longer economic.

21 October

Three French oil refiners — Shell France, Elf Aquitaine and Esso SAF — have been fined a total of FFr60m by the country's competition regulator for limiting the sale of unleaded petrol by discount retailers which compete with brand name petrol stations.

22 October

The state-owned Trinidad and Tobago Oil Company has received a US$18m loan from the Caribbean Development Bank to help finance a programme for onshore and offshore secondary oil recovery and to improve the volume of refinery throughput.

Kuwait expects to complete repairs to all its oil wells which were damaged during the Gulf war within 18 months.

23 October

Brabant Resources have completed the £2.5 million deal — announced in August — to buy a package of UK interests from Monument Oil and Gas.

Premier Consolidated Oilfields announced a potentially significant oil discovery in North Sea block 39/26a. The discovery has been named Fife.

UK Energy Minister, Tim Eggar, announced the first out-of-round award of petroleum licences for North Sea blocks 39/1 and 39/2 to co-applicants Amerada Hess and Premier Consolidated Oilfields.

26 October

The Nigerian government has sacked its representatives on the board of the country's $4.5bn liquefied natural gas project, raising concerns about the venture's completion timetable.

27 October

Vietnam plans to increase its oil production output this year with the start-up of the Rong (Dragon) field.

28 October

Enron has moved a step closer to becoming a pure natural gas player through the decision to spin off its crude oil trading and transportation subsidiary to shareholders.

29 October

Babcock International has cut its interim dividend by 0.25p to 1.00p in the face of falling profits.

US oil group, Atlantic Richfield, has applied for a listing on the London stock market.

3 November

Shareholders in Cairn Energy have taken up 36.5 percent of the shares in its open offer aimed at raising £5.1 million to help finance the purchase of additional UK onshore oil interests and cut borrowings.

Kazakhstan's oil production should rise by 7.7m barrels to 198m barrels this year and continue to rise, according to a senior ministry official in Alma-Ata

4 November

Dutch minister of economic affairs, Koos Andriessen, described the latest round of Dutch licensing as very successful.

5 November

British Petroleum has agreed to sell its interest in an Australian mine producing uranium and copper to Minorco for $456 million.

6 November

British Petroleum returned a £172 million profit in the third quarter of 1992, large redundancy costs kept the company in the red for the first nine months of the year.

7 November

A United Nations body recommended the retention, for the time being, of a non-mandatory oil embargo against South Africa.

Total announced that its Peciko discovery offshore Indonesia may be a giant new field with reserves of around 3.5 tcf of gas.

9 November

Kuwait has salvaged and exported 1.3m barrels of crude oil from vast lakes spilled in the desert since the end of the war.

Mobil has made its first natural gas delivery under contract to British Gas from the Scottish Area Gas Evacuation plant at St Fergus.

12 November

A consortium led by Shell is to develop the Galleon gas field in the North Sea.

Britain has only 21 years of proven gas reserves left if the gas-fired power generation plants now planned go ahead, according to British Gas.

Obituary

Stan Holding

It is with deep regret that we report the death of Stan Holding on 5 October. He worked for Shell Research at Thornton from 1949 until he took early retirement in 1985. He then took up a position with Spectro Oil Analytical. His work with the IP's Test Method Standardization Committee covered a long period. He joined the Inorganic Analysis panel ST G-3 in 1970 and was appointed chairman in 1983, a post he held until 1986. From 1983 to 1986 he served on the Analysis Sub-committee ST G.

After relinquishing the chairmanship he maintained his membership of ST G-3 until he retired through ill health early this year. In addition to his IP work he was involved with both BSI and CEN in the production of test methods.

Stan will be greatly missed by all who knew him and we extend our sympathy to his wife Brenda and his family.

The Institute of Petroleum

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Mr A C DeCrane Jr

Chairman, Texaco Inc

who will speak on the subject

'BACK TO THE FUTURE'

Petroleum's Contributions to Progress in the 20th Century Are Prologues to Its Prospects in the Century Ahead

The availability of affordable, reliable energy was a major contributor to the growth, the spread of progress and the broadened prosperity that marked this century. The petroleum industry was the key provider of that energy. In doing so, the industry met, matched and exceeded the challenges of increasing consumption, demanding and often hostile operating conditions and a startling array of product specifications. It demonstrated technical ingenuity, operational flexibility and commercial competence in meeting customer requirements.

Continued growth and the further spread of enhanced prosperity in the century ahead will require energy policies bottomed on good science, solid economics and an ordered prioritisation of social objectives. Under such conditions the petroleum industry will broaden the availability of products appropriately formulated to help fuel that progress.

Only an era of intelligent cooperation and open communication between governments, scientists, suppliers and consumers will ensure continuation in the years ahead of the positive aspects of the record of progress we look back upon as we close this 20th century.

For a copy of the ticket application form, please contact Caroline Little, The Institute of Petroleum, 61 New Cavendish Street, London W1M 8AR. *Telephone:* 071 636 1004. *Telex:* 264380. *Fax:* 071 255 1472.

EXPLORATION AND PRODUCTION DISCUSSION GROUP

A meeting of the Exploration and Production Discussion Group will be held at the Institute on **Thursday, 3 December 1992** starting at 5.30 pm. (Tea and biscuits will be available from 5.00 pm).

AN ENGINEERING VIEW OF FUTURE DEVELOPMENTS IN THE NORTH SEA

Speaker — Mr R Abma
of Shell UK Exploration and Production.

If you would like to attend this meeting please contact Mr J Hayes, Institute of Petroleum, 61 New Cavendish Street, London W1M 8AR. Tel: 071-636 1004.

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First gas from Markham

Gas production has commenced from the Markham field, straddling the Dutch and UK sectors of the North Sea, signalling the first gas exports from the United Kingdom.

The field, operated by LASMO, the company's first major operated field in the North Sea, will produce gas at a peak rate of 6.6 million cubic metres a day. Reserves are estimated at 20 billion cubic metres and the estimated field life is 20 years.

Gas from the platform is transported through a 24-inch diameter pipeline laid between the Markham platform and an existing platform K13A 70 kilometres to the south, where it is mixed with gas from other fields and transported to shore via a 36-inch pipeline to a distribution terminal at Den Helder.

Most of the gas will be sold to Gasunie, the Dutch national gas utility, with the balance contracted to Wintershall.

European refining upgrade levels

The United Kingdom and Norway have the most sophisticated refining industries in Europe with a ratio of upgrading to distillation capacity of 37 percent.

This compares to the European average of 28 percent, according to a report by Datamonitor. Of the five largest refining countries only Germany approaches the UK's level with an upgrading capacity of 36.1 percent.

Among the companies operating in Europe, Exxon is the market leader with a share of 12.5 percent of total capacity followed by Shell (11.6 percent).

However, the report highlights the differences between the strategies of the two companies with Exxon having more than 91 percent of its installations with a capacity greater than 100,000 barrels a day (b/d) contrasted with the more geographic diversification of Shell with only 67 percent of its plants exceeding that capacity.

● An explosion and fire at the Total oil refinery in La Mede, France, which left six people dead, has knocked out the catalytic cracker at the centre of the complex.

The refinery supplies Total's customers in Provence, the Alps, Cote d'Azur and eastern France. A spokesman for the company said it would be 'several months' before the unit would be fully operational.

Accelerating market for fuel additives

The increasing number of cars on European roads will not be reflected by a corresponding rise in petrol consumption as cars become more efficient and diesel-powered vehicles take a larger sector of the market.

A report by market research publishers, Frost and Sullivan, says that the switch to fuel efficient cars and diesel powered vehicles combined with higher grade and unleaded fuels containing higher levels of sophisticated detergents will boost the additive market throughout Europe.

The size of the European transport fuel additives market is currently 135,714 tonnes with an estimated value of $401.3 million. By 1996 this is forecast to reach 166,603 tonnes.

There are five key additive products — anti-knock compounds, gasoline deposit control agents, diesel detergents, diesel cetane number improvers and diesel cold flow improvers — which account for over two-thirds of the total volume of the market and represent more than 87 percent of the market value.

A spokesperson for the company said: 'Engine designers and fuel suppliers are continually responding to the restraints imposed by environmental legislation.

'Restrictions on volatile organic and particulate emissions will require near-complete combustion and this is expected to increase the need for fuel detergents to keep the fuel injection systems in good condition.'

The biggest national market for transport fuel additives is Germany, worth $82.6 million in 1992, followed by the United Kingdom, France and Italy.

Cusiana reserves appraisal

BP has announced that the appraisal of its Cusiana field in Colombia is proceeding faster than expected and reserves estimated from drilling results to date were already up to 1.5 billion barrels of oil.

The full extent of the reserves will not be evident until wells are completed and tested next year and the limit's of the field's boundaries are firmly established by subsequent drilling.

The company said that it also discovered a further field at Cupiagua, some 15 kilometres to the north in the same licence block, believed to be about one third of the size of Cusiana.

Both fields are on a geological trend which is believed to extend northwards into a separate licence area where BP has a 100 percent interest and is carrying out exploratory drilling.

BP said it expected to apply for the Cusiana field to be declared commercial by around mid-1993, at which point Ecopetrol would acquire a 50 percent stake under the terms of the association contracts between BP, its partners — Total and Triton — and the Colombian government.

Production is expected to reach 150,000 barrels of oil a day by the end of 1995.

Central North Sea oil find

Amoco has announced a significant new oil and gas discovery in the UK sector of the Central North Sea.

The discovery well, 15/22-11, flowed at about 6,500 barrels of 41 degree API oil a day with 1,620 standard cubic feet of gas per barrel gas/oil ratio through a 56/64 inch choke, at a wellhead pressure of 1,500 psi.

An early appraisal of the discovery is planned.

Other co-venturers are Amerada Hess, Enterprise Oil and Mobil North Sea.

Supermarkets lose law suit against refinery groups

French supermarkets have lost their law suit against refinery groups over the sale of unleaded, high-octane petrol.

The French Fair Trading commission, le Conseil de la Concurrence, has rejected the supermarkets claim, dating back 18 months, that producers had an illicit agreement on the sale of unleaded supplies. The supermarkets were said to be seeking damages of FFr600m.

A spokesman for the government's energy department said that the Commission's ruling 'would enable producers to pursue a real policy on brands and also put an end to the uncertainty which was blocking attempts at developing a strategy on quality.'

However, Jacques Marie, an analyst at the Bulletin de l'Industrie Pétrolière, BIP, doubted whether the ruling would have any lasting impact on the distribution sector. 'This affair has become "anecdotal" and even the supermarkets would admit this,' he claimed. 'It dates back to April 1991, when supermarkets were very worried about supplies of unleaded petrol. Today it's no longer the same scenario. Unleaded is available to them from a number of other sources, including importers and traders.'

Despite the Commission's verdict in their favour, three producers, Shell France, Esso France and Elf Aquitaine have received fines of FFr20 million, FFr10 million and FFR30 million respectively, for having demanded conditions of sale which were too restrictive, namely tying supermarkets to 'exclusive' contracts.

Shell and Esso have appealed against the ruling. Shell says that the contracts offered to the supermarkets were the same as those it has employed over many years for its own network. 'The commission judged that we demanded the sale of our unleaded brand at the exclusion of all others and that this amounted to unfair competition,' a source at Shell commented. 'However, one can question this interpretation of events by pointing out that these contracts with supermarkets were very short-term in nature, between three to six months. Moreover, supermarket service stations do not, in general, have the necessary storage capacity to accommodate the sale of several brands of unleaded petrol.'

Elf has until 15 December to decide whether it is to appeal. It received a bigger fine because the Commission ruled that it had linked supplies of unleaded to supermarkets agreeing to sell its range of 'Optane' fuel products.

Two other producers, BP France and Mobil, escaped fines as the Commission judged that they did not have sufficient stocks of unleaded to distribute outside their own networks while Total's contracts with the supermarkets were not viewed as being restrictive.

Motorway oil pollution

A new report claims that UK motorists release 126 kilogrammes of motor oil along every mile of motorway every year, adding up to half a million litres a year.

The finding appeared in a report by Save Waste and Prosper Ltd (SWAP), a Leeds-based independent research and consultancy agency.

The report takes a critical look at the collection of used motor oil in the United Kingdom and examines the sources and effects of pollution and the range of solutions currently available on the market.

Amongst the report's findings are:

- Up to 20 million litres of motor oil are sold annually through DIY outlets, representing half the total amount of used oil which escapes into the environment annually;
- 30 percent of waste disposal authorities in the United Kingdom provide no facilities for the collection of used motor oil from the public; and,
- The National Rivers Authority (NRA) prosecuted less than two-thirds of the companies responsible for major oil pollution incidents in inland waterways. Major incidents, as defined by the NRA, are those that cause the most severe damage to the environment.

SWAP aims to initiate trial operations on recycling by bringing together relevant organisations, businesses and local authorities. Its report stresses the need to develop and coordinate a national approach towards pollution prevention by educating the public and extending recycling facilities.

Dr Paul Martins (left) and Dr Tim Harper of BP, have won the 1992 Royal Academy of Engineering MacRobert Award for advances made in hydraulic fracturing technology for enhanced hydrocarbon recovery.

The award was presented by HRH The Duke of Edinburgh at Buckingham Palace.

Production ceases from two fields

Production from the Argyll and Duncan fields located on Block 30/24 has ceased.

The UK's first North Sea oil was produced from Argyll which came on stream through the floating production facility. Transworld 58, in June 1975. The neighbouring Duncan field was brought on stream in 1983 initially using the same facility before it was replaced with another converted drilling rig, Deepsea Pioneer.

The two fields have produced a total of 97 million barrels of oil.

Stamping out oil

Ever since Great Britain invented postage stamps in 1840, postal authorities around the world have commemorated individuals, industries, historical events and works of art that shaped their countries and cultures.

The oil industry has been honoured on stamps by over 130 countries who have recognised that the industrial age began when the earth's oil was discovered and utilised.

More than 2,000 postage stamps have been issued to celebrate the oil industry and its vital services, a portfolio which comprises a postal history of the industry from the first discovery at Titusville, Pennsylvania, to its present giant complex. And this could include many of the chemical by-products and inventors who pioneered new developments and uses for oil.

A page of carefully selected oil stamps would just about cover the entire process of bringing oil from the ground to its myriad of uses around the world: a map of the Sahara dotted with oil derricks, the pipelines of Iraq, an early oil lamp of the 1890's, a cracking unit in the Netherlands Antilles, a tanker from Poland, the industrial uses of oil which run cars, trucks, buses, railroads and planes; the flourishing cities in the wastelands which spring up and are sustained from the nearby oil fields, the related chemical industry and its dependence upon oil, the boon to the shipping lines from Brazil to India and Turkey and the tremendous wealth created by this world's biggest industry.

Places

The first oil stamp was issued in 1919 when the Soviet province of Azerbaijan issued a stamp showing oil derricks as a background to ancient temples of the primitive Fire Worshippers.

Romania with its huge Ploesti oil fields contributing so greatly to its economy, is the leader today in oil stamp issues printing over 100 varieties, while Venezuela runs a close second.

Canada with its vast wealth of oil reserves has issued three oil stamps. In 1959 a five-cent stamp was released showing a kerosene lamp and refinery outlined in two oil drops to commemorate the centennial of Canada's oil industry. In 1955 a stamp was issued to commemorate the 50th anniversary of the founding of the province of Alberta, showing oil derricks in the background of a farm scene. Canada's most spectacular oil stamp was issued in a 50 cent denomination in 1950 printed to publicise the development of oil in Canada. The stamp shows oil derricks and tanks in Alberta.

England in 1978 issued a set of four stamps to honour its wealth of energy resources. Besides stamps of a coal pithead, electricity-produced nuclear power plant and uranium atom diagram, it issued two additional stamps showing an oil production platform, North Sea and another portraying a natural gas flame.

The United States, which uses most of the world's oil, issued a stamp on the 100th anniversary of the discovery of oil in 1959 which showed the Drake oil strike, the first in the United States.

There is hardly any new development in oil technology that is not depicted somewhere on stamps. In 1969 Dubai issued five stamps honouring its construction of the world's first underwater oil storage tank holding 21 million gallons. The stamps show the construction, the completed tank and the launching.

Poland issued in 1961 a stamp commemorating the 15th session of the Council of Mutual Economic Assistance of the communist states which shows part of the map of central and

eastern Europe with lines in red detailing the route of the great petroleum pipeline from Western Siberia to Germany and Czechoslovakia across Poland, Romania and Hungary. This system originating in the Ural-Volga area is about 2,700 miles long with more than 20 pumping stations, one of the largest crude oil pipeline systems in the world.

In 1962 Libya issued an unusual stamp showing an oil drop above an oil field. Within the drop is a visionary city acknowledging the part oil plays in the country's development.

People

Scientists who have pioneered oil technology have also been shown on stamps. In 1956 Paul Sabatier, Nobel prize winner for catalytic chemistry, was pictured on a stamp issued by France. An important Russian chemist who developed refining techniques, ND Zelenski, was commemorated by his native country in 1961. Ignacy Lukasiewicz, who distilled kerosene from oil and used it for lighting was portrayed by Poland in 1960.

The world has acknowledged the great executives and financiers of oil too. John D Rockefeller was selected by Belgium for a 1955 stamp and Andrew Mellon, an oil company president is pictured on a 'Famous American' series stamp. The legendary Gulbenkian who became fabulously wealthy from developing the oil fields in Iraq and Turkey, was shown on the 1965 stamps of Portugal.

The history of oil as portrayed on stamps is a marvellous graphology of how our industrial system operates and its wonderful and varied adaptation to meet and develop new, vitally needed and beneficial commercial products. As author Ida Tarbell said: 'The true value of an industry is not measured in dollars. It is measured by the services to the masses of men.'

Starting a collection

Outstanding collections of oil stamps have already been made by philatelists, many of them oil executives and field workers who have been intrigued by the hobby.

In France, an oil man, Jean Barbedette formed a 'Friends of Petroleum'* organisation of 300 worldwide oil stamp collectors who exchange stamps and help new hobbyists get started in oil stamps. They have held exhibits of oil stamps in Brussels and Paris and have appeared on television to discuss the hobby.

A member of the Friends of Petroleum, George Yurkas, an oil geologist of Bakersfield, California, put together a 50 page checklist of oil stamps and a German oil executive has published a book on the subject. The American Topical Association (Box 630, Johnstown, PA 15907, USA) also has checklists and publishes a magazine *Topical Time* dealing specifically with topical collecting.

There are no great rarities or misprints among oil stamps that could erupt into a gusher, such as the 'upside down' 1918 Jenny aeroplane of the United States, which recently fetched $148,000 at auction.

Not yet, any way. ■

Raymond Schuessler

***Friends of Petroleum, 5 Rue Nicolet, Paris.**

The Clinton administration: friend or foe?

It is unrealistic to assume that what was said in the heat of the US election campaign accurately forecasts the Democrats' policies in the year to come. President-elect Bill Clinton's energy programme, when it emerges, will be subordinate to his economic policy, shaped from an environmental perspective. The same would have been true of the energy programme of President George Bush, had he won a second term, with less emphasis, however, on the environment. For, without a doubt, the economy is going to be the main issue for the US administration and lawmakers.

Campaign promises

At best, the Democrats' campaign pronouncements indicate directions that will be favoured. Energy did not play a significant role in their pre-election speeches and press releases. In the party platform, issued at their July convention, the Democrats declared that they 'reject the Republican myth that energy efficiency and environmental protection are enemies of economic growth.' They argued that it is possible to 'make our economy more efficient by using less energy, reducing our dependence on foreign oil and producing less solid and toxic waste.' To accomplish this, they advocated the use of mass transit and alternative-fuelled vehicles, increased reliance on natural gas, the promotion of clean-coal technology and investment in R&D in renewable energy sources. They also called for 'the support of incentives for domestic oil and gas operations.'

In various speeches during the campaign, Mr Clinton presented his views on energy issues. Since he supports a more activist government than President Bush, the Clinton administration will be more inclined to use government powers to accomplish declared aims than its predecessor. The president-elect's campaign energy positions included:

Greater reliance on natural gas On several occasions during his campaign, he made it clear that he aggressively supports the increased use of natural gas over oil, coal and, where practicable, electricity. He backs incentives to encourage gas use in homes, businesses, industries, power-generating facilities and transportation. He has pledged to convert the entire fleet of federal vehicles to natural gas power and to speed the construction of gas pipelines.

Reduction of foreign imports of oil US dependence on imported oil has hit higher levels than those reached before the oil price shocks of the 1970s. Net oil imports in 1991 were almost 40 percent of total oil use, up sharply from 28 percent in 1982. Despite his statements of intent, it is difficult to see how Mr Clinton plans to increase domestic oil production and thus cut imports. He has said, for instance, that he will generally oppose drilling in new offshore areas. In addition, he has stated that he is opposed to opening the Arctic National Wildlife Refuge to exploration and wants to convert this into a wilderness area where production would be forever forbidden. He may find such a permanent ban unacceptable to many in Congress, however, given ARCO's recent major oil discovery in the Beaufort Sea, 16 miles off the coast of the Arctic National Wildlife Refuge and 60 miles from Prudhoe Bay.

What he may advocate is specialised tax treatment for domestic oil development and production initiatives. In addition, he has suggested taxing the income US companies earn and reinvest overseas, on the grounds that this will prompt them to invest in the United States instead.

Support for energy efficiency Declaring that his 'goal is to improve America's overall energy efficiency by 20 percent by 2000,' Mr Clinton has endorsed raising the current 27.5 miles per gallon (mpg) corporate average fuel efficiency (CAFE) standard for automobiles to 40 mpg by the year 2000. He has also suggested raising it later to 45 mpg, pledging to look for solutions that would ease the burden on automobile manufacturers. He has also called for new, stricter building codes to increase energy efficiency.

Opposition to increased reliance on nuclear power Mr Clinton has not advocated shutting down existing nuclear power plants but he has argued that the nation should pursue other options because of the problems of nuclear waste and the escalating costs of nuclear plants.

Protection of the environment Mr Clinton has pledged to cap the emissions of those gases that result from the combustion of oil and other fossil fuels which are blamed for global warming. He has talked about limiting carbon dioxide emissions to 1990 levels by the year 2000 and has said that he would give 'serious consideration' to even deeper cutbacks. It is possible that he may favour higher fossil fuel prices in order to create incentives for switching to alternative fuels but he did not endorse either a carbon tax or an increase in federal excise on gasoline in the course of his campaign. He seems to favour the use of market forces in environmental protection and tax incentives to encourage use of alternative fuels and renewable energy resources. He has promised to direct Energy Department research to renewable and alternative energy projects and has proposed the creation of an advisory research agency for renewable technologies. He has called for 'revenue neutral' tax incentives to encourage the use of recycled materials.

His own views aside, Mr Clinton has inherited an extensive energy programme from his predecessor which the new administration must implement. A number of changes will occur in the energy scene in forthcoming months as a result of the recent enactment of the Bush administration's energy bill.

The National Energy Strategy Bill

The long-debated US energy bill was passed by Congress on 8 October, less than four weeks before the election, and signed by President Bush on 24 October at a ceremony by an oil well in Maurice, Louisiana. The first major overhaul

of energy legislation in the United States since the oil crisis of the late 1970s is a formidable 900-page document. It was first presented to Congress, after two years of framing in the executive branch, in February 1991. Its final form reflected another two-plus years of disputes, often heated, and compromises, often begrudged, in 17 Congressional committees. As a result of these deliberations, lawmakers stripped out the controversial provisions that would have opened up the Arctic National Wildlife Refuge in Alaska to oil and gas exploration. They decided against including CAFE requirements to increase fuel-economy standards for cars and scuttled a proposed amendment that would have required the United States to stabilise its emissions of carbon dioxide by the year 2000 at their 1990 level. Along the way, they beefed up the bill's original language on energy efficiency and conservation.

The major shortcoming of the final energy bill is that it does not substantially address US dependence on foreign oil. In the opinion of the American petroleum industry, it will do 'little to encourage the production of more domestic energy.' An outspoken *Oil & Gas Journal* editorial described the bill as a 'fiasco born of compromise with a hostile legislature, a quaking shadow of what the Bush team had proposed as a national energy strategy.'

The main thrust of what emerged at the end is the promotion of energy conservation and the use of renewable fuels. The legislation's greatest effect, in the long term, will be in the generation and use of electricity, and in the development of alternative-fuelled vehicles. The Bush administration confidently predicted that these changes would reduce US energy demand from currently predicted levels by 6 percent by the year 2010 and boost the use of alternative fuels in the year 2010 by 50 percent. Provisions of the bill include:

Major changes in the electric utility industry The bill substantially revises the existing 1935 Public Utility Holding Company Act. These changes will lead to greater competition in the generation of power and better access by independent, non-utility power producers to transmission lines. They will allow utilities and non-utility companies to build, own and operate power plants in more than one state, and in foreign countries, without being subject to the regulations — including oversight by the SEC — that currently apply to utilities under the holding company act. Independent, non-utility power producers stand to gain access to vast new markets as a result, particularly as, after considerable wrangling, Congressmen agreed to accept provisions designed to ensure that small generators get better access to utility transmission lines. The bill also offers incentives to facilities that generate power from solar or renewable energy by providing them with a per-kilowatt hour tax credit.

Encouragement of efficiency in energy use The bill sets, or increases, efficiency standards for electric motors, commercial heating and air conditioning, fluorescent lamps, windows, light fixtures, showerheads, and office equipment. It requires states to establish and update mandatory energy standards for commercial buildings and encourages them to set similar standards for residential buildings. Utility rebates to residential energy-savers are declared tax-free. The bill offers incentives to promote energy efficiency in federal buildings. It also effectively subsidises mortgage rates for energy-efficient homes by declaring that houses which don't meet state efficiency standards can't qualify for federal government mortgage assistance programmes.

Encouragement of the use of alternative fuels in motor vehicles The bill expands the requirements for alternative-fuel vehicles which were stipulated by the 1990 Clean Air Act. It requires the federal government and companies that make alternative transportation fuels — such as electric utilities and natural gas companies — to buy more cars, trucks and buses which are not dependent on gasoline as a fuel. Earlier provisions in the bill that aimed at converting more private vehicle fleets, such as taxi cabs and delivery vehicles, to alternative fuels, were diluted. Buyers of cars that run on natural gas or other alternative fuels will receive a $2,000 tax deduction. Government aid will be given for research into technologies to refine or liquefy coal into transportation fuels.

Tax relief for independent oil and gas producers The bill grants an estimated $1 billion in Alternative Minimum (AMT) tax relief to independent oil and gas producers. AMT is a tax that automatically comes into effect if deductions reduce regular income tax below a minimum percentage of income. It thus often denies oil and gas producers the benefit of deducting some of their intangible drilling and development costs. The petroleum industry, however, is critical of the bill's AMT relief provisions. Spokesmen point out that the bill stipulates that AMT relief lasts only for five years, only applies to independent oil and gas producers and does not fully restore capital and cost recovery to drilling and production investments. The government, on the other hand, predicts that AMT relief will result in oil and gas production increases equivalent to 75,000–100,000 barrels a day by the year 2010.

Stimulus to energy industries The bill endorses competition in natural gas production and stipulates that the Federal Energy Regulatory Commission (FERC) shall not discriminate against Canadian natural gas. The mild language of the final version of the bill regarding freer competition reflects a hard-fought compromise between some producing states — Oklahoma, Texas, Louisiana — that have sought to limit output of their gas wells through so-called pro-rationing regulations, and Northeast consumer states that oppose these efforts. The provision that banned states from using pro-rationing to limit natural gas production for the purpose of raising prices was dropped.

The bill expedites the approval process for oil and gas

Energy Bill taxes

The cost of the energy bill, arising from tax cuts for the energy industry and consumers, will be met in unusual ways. Some $5 billion in revenue increases will be largely covered by eight tax provisions that were shifted from the tax bill to the energy bill by Congress in the last minutes before its passage. One revenue-raising feature tacked on to the bill is an excise tax on ozone-depleting chemicals but most of the others have no connection with the oil and gas industry. The energy bill mandates, for instance, an increase in withholding rates for gambling and lottery winnings. It addition, it requires banks to withhold a larger percentage of the dividends and interest from individuals who fail to provide proper taxpayer identification numbers. It also includes a measure to prevent 'disguised asset sales' by partnerships, eliminates travel expense deductions for individuals who are away from home on a job for more than a year and limits the amount of employer-subsidised parking that employees can receive without having the subsidy count as taxable income.

pipelines. It gives oil pipelines a simplified ratemaking methodology at the FERC with less opportunity for tariff changes. It also authorises government assistance to the coalbed methane industry.

Assistance to the nuclear fuel industry The bill makes it easier to build nuclear plants by streamlining the approval process for nuclear plant licensing. It authorises the Nuclear Regulatory Commission to issue a single operation and construction licence, rather than the two licences now required, thus cutting the licensing process to an estimated six years from the current average of 14 years. The bill also removes the federal government from the business of uranium enrichment.

Effect on Strategic Petroleum Reserve The bill expands the size of the Strategic Petroleum Reserve (SPR) but a provision was dropped in the final version that would have required oil refiners and importers to provide 1 percent of the stocks each year, or the cash equivalent, to fill the SPR at a rate of 150,000 barrels a day until the 1 billion-barrel reserve was filled.

Ethanol subsidies Current tax breaks for corn-derived ethanol are expanded by the bill, although an amendment that would have required greater use of ethanol in gasoline was defeated in the final debates. The bill lowers the purity thresholds of ethanol blends that can qualify for partial exemption from the gasoline excise tax.

What to expect in 1993

The oil industry should benefit from any measures crafted by the Clinton administration for the purpose of stimulating economic growth. On the other hand, the industry should not hope for energy initiatives to emerge soon. It is unlikely that there will be many new energy directions in 1993, given the time it takes to change key administration posts and to decide and act on priorities. Moreover, policy decisions taken by the Bush administration may cause difficulties for the oil and gas industry. There is, for instance, the question of enforcing the environmental goals of the Clean Air Act which the Clinton administration is apt to pursue more enthusiastically than its predecessor. In addition, there is some unfinished legislative business that the new Congress will have to act on promptly, which could cause the industry difficulties. One of the environmental bills left over from the previous Congressional session, for instance, which the Clinton administration will presumably support, is the reauthorisation of the Resource Conservation & Recovery Act. The revised act will force the oil industry to comply with tougher regulation of drilling muds and produced fluids.

French retail outlet trends

An annual report published by the French government's petroleum products directorate, La Direction des Hydrocarbures, on retailing trends reveals that the national network of retail outlets decreased by 7.8 percent in 1991. Some 2,350 service stations closed and 350 opened last year. 'The trimming-down of the network is likely to continue at the same rate for the next three or four years,' the report forecasts.

France now has 23,700 stations nationally, compared with 42,500 in 1975 and 31,100 in 1987. The rate of growth in the network of hypermarkets and supermarkets outlets appears to be slowing down. The network increased by 110 stations last year to total 3,860, while average annual growth since 1986 has been close to 340 new stations.

In 1991, the oil companies owned or controlled through franchise agreements, 14,500 outlets, 61 percent of the global retail network. Of this figure, Total operated 3,540 stations, followed by Elf (1,910) and Shell (1,670).

While all categories of service station have been affected by the reduction of the network, the oil companies franchise outlets were hardest-hit in 1991 (a drop of 14.8 percent), partly because a number of stations were transferred to networks operated by subsidiaries.

The oil companies official/ownership network decreased by 4.6 percent while the number of supermarket outlets increased by 3 percent. The number of independent stations totalled 5,630 (a drop of 6.6 percent) while the figure for motorway stations rose slightly to 322.

The report attributes the decline in the network's size to a number of factors; a change in consumer preferences linked to the greater fuel economy of vehicles, price de-regulation, which has increased supermarkets share of the market and the low level of stocks held at outlets, leading to dearer prices at the pumps. Moreover, in the mid-term, meeting new environmental and security constraints will necessitate significant investment which certain operators will find difficult to undertake thus generating more closures. 'The return on the large investments required to re-structure the network depends on increasing outlets throughput and also on developing supplementary income from accessory services, the latter ushering in a new concept of service station in keeping with consumer expectations.'

Surge in productivity

One of the major effects of rationalisation has been a meteoric rise in the productivity of service stations. Average monthly throughput per outlet totalled 139 cubic metres, up 12.1 percent on 1991. According to the Direction des Hydrocarbures, this compares to an average of 200 cubic metres for Germany's network, 150 cubic metres in the United Kingdom and 85 cubic metres in Italy. Productivity at French outlets has leapt by 80 percent since 1985. Last year, the best performance was recorded by motorway service stations with an average of 664 cubic metres followed by the supermarkets, 326 cubic metres and the oil companies official network, 246 cubic metres.

In addition to important productivity gains, the French network has undergone an important modernisation programme. In 1991, 10,500 pumps were equipped for self-service, 400 more than in 1990. Fully-automatic pumps totalled 1,500, compared to 1,270 the previous year.

One consequence of the reduction in the number of service stations has been to break links in the national network chain, particularly in rural and mountainous areas. In March 1991, in response to such difficulties and to facilitate the rationalisation of the network in general, the government created a special body, the Comité Professionel de la Distribution de Carburants, CPDC. It has the dual task of offering appropriate support to operators and studying ways of adapting the network to the conditions imposed by the Single Market.

Funded by a para-fiscal tax, levied at 10 centimes/hl, the CPDC provided FFr29 million in financial aid to the retail sector in 1991 in addressing 582 applications for assistance. Over half of this figure went on redundancy payments, while FFr11.2 million targeted new investment.

Among other retailing highlights in 1991 was a strong increase in sales of gas oil, +13.2 percent. This is attributed to France's growing number of diesel-powered engines which last year represented almost a quarter of the total fleet of vehicles. In contrast, the volume of petrol sales realised by the network was down by 2.2 percent. The report concludes that this trend will probably continue given that the French vehicles fleet decreased by 1.7 percent between 1990 and 1991.

This year for the first time and as part of its annual international service station exhibition, the Direction des Hydrocarbures organised a symposium on the theme of 'Environmental Protection and Safety,' the first step towards drawing up a charter on safety at service stations. ■

Stuart Todd

Contamination of the Gulf marine environment following the war

By JW Readman, SW Fowler, J-P Villeneuve, C Cattini, B Oregioni and LD Mee
IAEA Marine Environment Laboratory

Following the Gulf war, controversy and speculation have surrounded the extent to which the massive spillage of petroleum and the burning of oil wells in Kuwait have damaged marine ecosystems in the region.[1–5] We report here the results of a rapid assessment survey of hydrocarbon contamination undertaken in the coastal marine environment from Kuwait to Oman during mid-1991.

Our results show that severe oil pollution was restricted primarily to the Saudi Arabian coastline within ~400km from the spillages, and that during the four months following the conflict and preceding our survey, the spilled oil had extensively degraded. Surprisingly, concentrations of petroleum hydrocarbons in sediments and bivalve molluscs from Bahrain in June 1991 were lower than those recorded from our pre-war (1983–86) surveys at the same site, probably as a result of decreased tanker traffic and associated deballasting during and after the conflict. As for carcinogenic polycyclic aromatic hydrocarbons produced during burning of the oil wells, we found that concentrations in sediments from even the most heavily contaminated sites were relatively low, and comparable to levels reported for the Baltic Sea,[6] coastal locations of the northeastern United States[7] and United Kingdom estuaries.[8]

Estimates of the quantities of oil directly released into the Gulf during the war from, or near, the Sea Island terminal in Kuwait have ranged from 0.5 to 8 million barrels.[3,4] Furthermore, from the best available data[2,4] it can be estimated that over the ~250 days during which the wells were burning, some 500 million barrels (67 million tonnes) of oil were emitted or ignited, releasing oil aerosols, soot, toxic combustion products and gases for atmospheric transport and subsequent deposition. Even if only a few percent of those emissions fell out in the coastal marine environment, they would far surpass the amounts of crude oil that were spilled. To our knowledge, no scientific reports have appeared that quantitatively describe the extent of hydrocarbon contamination in Gulf waters, although some address potential environmental and climate effects from the pollution.[1,2,4,9–11] Following the war we collected coastal samples from throughout the Arabian coastline of the Gulf. Aerial and satellite observations[4] supported physical oceanographic data on prevailing currents[12] and identified this area to be initially affected and at most risk from the spilled oil.

During three visits to the Gulf from June to October 1991 we collected 14 samples of nearshore sediments, nine composite samples each comprising 20–30 specimens of a single species of bivalve mollusc (*Meretrix meretrix, Tapes sulcarius* and *Trachycardium lacunosum* from Saudi Arabia; *Pinctada margaritifera* from Bahrain and United Arab Emirates; *Spondilus* sp. from Bahrain; *Saccostrea cucullata* from Oman) and 17 samples of fish (*Arius thalassinus* from Kuwait; *Lethrinus nebulosus* from Saudi Arabia; *Epinephelus tauvina* from Bahrain and Oman; *Epinephelus jayakari* from Bahrain; *Acanthopagrus bifasciatus* from Bahrain; and *Epinephelus suillus* from United Arab Emirates). In Kuwait, access to the entire coastline and nearshore waters was forbidden owing to mines and unexploded ordnance. We were, however, able to travel by helicopter to Qaruh Island (station 1, **fig 1**) to collect sediment samples and, in addition, to obtain freshly caught fish from near Kuwait City within ~20km of the spills. For the other countries visited, sample locations that had been visited in previous surveys[13,14] were preferentially selected. Sampling and sample preparation procedures were done according to internationally recognised guidelines.[15,16]

Figure 1

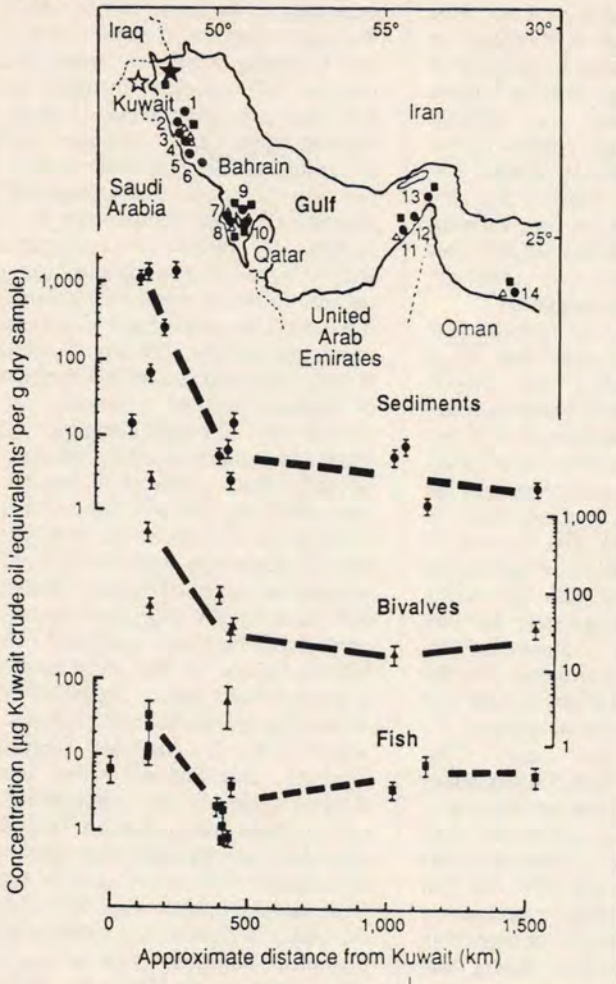


Figure 1: Concentrations of petroleum hydrocarbons (as estimated by fluorescence comparison with Kuwait crude oil) in individual samples of subtidal surface (0–2 cm) sediments, bivalve molluscs (soft parts) and fish (muscle). The approximate locations of the oilspills and burning wells are depicted by a filled and an open star respectively (see text for further details). Locations for individual sampling stations are indicated by circles, triangles and squares for sediments, bivalve molluscs and fish respectively. The notation for samples in the map is repeated for the graphs. Sample numbers refer to the sediment sampling stations shown in Fig. 3. Samples from the Bahrain area (near stations 8 to 10) and Kuwait (station 1) were collected in mid- to late June 1991, those from Saudi Arabia (stations 2 to 7) in mid-August 1991 and those from the United Arab Emirates and Oman (stations 11 to 14) in late September or early October 1991. Bivalve mollusc samples are composites (comprising 20–30 individuals) of single species available at the various locations. Fish concentrations represent analyses of the muscle from individual specimens obtained. For each individual point an error bar is included to reflect analytical variability (as determined by triplicate analyses of a single homogenised sample). Bold broken lines indicate trends in 'oil' contamination. The 'distance from Kuwait' scale, which is used to delineate the sample locations, gives the approximate relative distances from the pollution sources using a coastal (rather than a direct) trajectory.

Figure 3: Concentrations of hydrocarbon compounds together with relevant ratios (see text for explanation) obtained from gas chromatographic analyses of the sediments. Locations of the sample stations are shown in Fig. 1. Analytical precisions for the individual parameters (as determined by triplicate analyses of a single homogenised sample) were: total hydrocarbons, ±13%; resolved aliphatic hydrocarbons, ±5%; unresolved aliphatic hydrocarbons, ±13%; the sum of n-C_{14} to n-C_{34} alkanes, ±6%; resolved aromatic hydrocarbons, ±12%; and pyrene, ±10%.

Figure 2

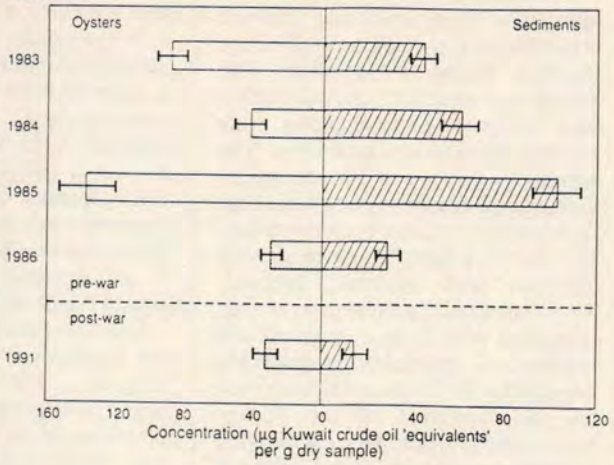
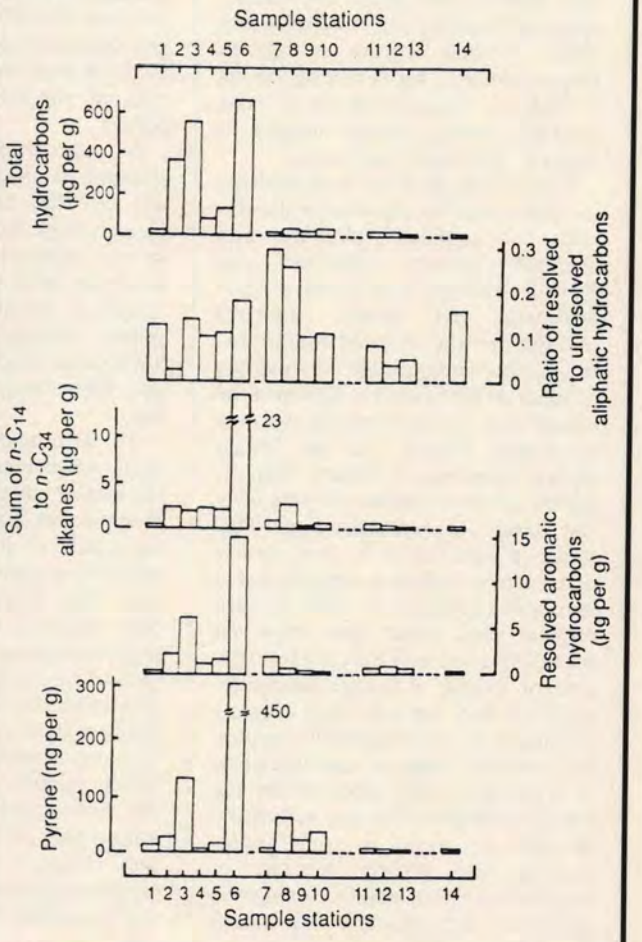


Figure 2: Concentrations of petroleum hydrocarbons in a composite (n=20 to 30) sample of pearl oysters (*Pinctada margaritifera*) and sub-tidal surface (0–2 cm) sediments sampled from a single site at Askar on the eastern coast of Bahrain (station 10, Fig. 1) in consecutive years from 1983 to 1986 (ref. 13; S. Fowler, unpublished results) together with post-war results. Concentrations are expressed as micrograms Kuwait crude oil equivalents per gram dry weight and were determined by fluorescence analyses. Error bars indicate the analytical variability as determined from triplicate analyses of a single homogenised sample.

Figure 3



Frozen samples were returned to the laboratory, freeze-dried and analysed according to the methods used in our previous studies.[13,16] Sediments were solvent-extracted and residual sulphur was removed. Biota samples were solvent-extracted and saponified. The sediment extracts and the non-saponifiable lipids from the biota were then fractionated by column chromatography on silica gel/alumina to provide 'aliphatic' and 'aromatic' fractions. The fluorescence intensities were then compared with Kuwait crude oil (the reference oil selected as an analytical standard by the Regional Organization for the Protection of the Marine Environment (ROPME)). Additional synchronous excitation and emission spectra were also obtained to characterise the residues.[16] Fractions were then analysed by capillary gas chromatography with flame ionisation detection (GC–FID).[16] Gas chromatography-mass spectrometry (GC–MS) was used for confirmatory analyses.[16]

During a helicopter flight along the southern Kuwait coast (June 1991), several small slicks were observed, especially in areas of the terminals that had suffered war damage. Nevertheless, except for some localised oil patches which came ashore, the beaches appeared from the air to be relatively clean. Tar-ball surveys on Qaruh Island (station 1, **fig 1**) revealed levels ($\sim$380g m^{-1} of beach) similar to those recorded during pre-war surveys in Kuwait[17] and other Gulf States.[13]

Concentrations of oil hydrocarbons (as determined by the relative fluorescence of combined aliphatic and aromatic fractions compared with Kuwait Crude oil[16]) are shown in **fig 1**. Sediment and bivalve analyses indicate that the main oil contamination has been restricted to the shoreline of Saudi Arabia within $\sim$400km of the release sites. Stations outside this area (including Muscat on the Indian Ocean shoreline of Oman; **Fig. 1**, station 14) have similar comparatively low levels of contamination. This trend of distribution is most clearly delineated in sediment samples but is strongly supported by the bivalve mollusc data which also show an overall decrease with distance from the area of impact. Although concentrations in fish species seem slightly elevated in the most northerly samples, their relative degree of contamination is lower than that observed for the bivalve molluscs. This may be because the fish can avoid oil spills and/or because they rapidly depurate or metabolise oil. Although sampling was conducted throughout a four-month period, satellite observations[4] showed that extensive dispersion of the slick occurred rapidly (and well before our sampling commenced). In addition, it is apparent from **Fig 1** that the highest concentrations were in samples obtained from Saudi Arabia in the middle of the collection period. For these reasons we believe that the gradients described are not substantially influenced by temporal differences in our sampling and truly reflect the spatial trends in contamination.

If the area outside the directly affected locations of Kuwait and Saudi Arabia is considered, the relative degree of oil pollution from the war can be evaluated by comparison with our data obtained in previous years (**Fig. 2**). For example, a sampling location off Askar on the eastern coast of Bahrain (station 10, **Fig. 1**) was revisited to obtain sediment and oyster samples. Compared with our earlier samples, there is an apparent decrease in hydrocarbon contamination. 'Normal' oil pollution inputs into the northern Gulf from oil production and transport activities are on average $\sim$2 million barrels per year[4]. This represents roughly half of the quantity spilled, essentially from a point source, during the conflict. Given the considerable reduction in these activities between late 1990 and 1991, the low petroleum hydrocarbon levels that we recorded have probably resulted from reduced chronic inputs during that period.

A more detailed appraisal of the situation is available from results of our GC-FID analyses of sediment extracts (**Fig. 3**). The same pattern of severe contamination at locations along the northwestern coast of Saudi Arabia is revealed, although greater spatial variability is indicated, probably because of localised topographical and depositional coastal characteristics.

To investigate the changes that occur when petroleum is spilled into the marine environment, it is essential to appreciate that oil is a composite of thousands of individual compounds with differing physico-chemical properties. These weather at differing rates once released into the sea. In its original (undegraded) state the main individual components of the oil (as determined by GC) are the *n*-alkanes. Some of these compounds (n-C_{14} to n-C_{34}) are frequently used to identify 'fresh' inputs of petroleum[8]. During the first stages of weathering (and within days of the spillage) volatilisation depletes the lower-molecular-weight *n*-alkanes (roughly, those below n-C_{14}) together with volatile aromatic compounds. Dissolution and biodegradation also act to reduce rapidly the concentrations of these components[18]. During subsequent weeks and months, heterotrophic microbes further (and selectively) reduce *n*-alkane concentrations and, together with photoxidation, aromatic hydrocarbons are also degraded. Coinciding with removal of these components is an increase in unresolved components within the gas chromatograms[18] (often referred to as the unresolved complex mixture). The composition of this mixture is only poorly understood[19], but it is frequently used as a relative measure of chronic/degraded petroleum contamination.[8] Although sampling took place within a few months of the main oil spill (which occurred in late January 1991), the very low ratios (<0.2) of resolved to unresolved hydrocarbons indicate that within this period most of the spilled oil in the sediments had substantially degraded into an unresolved complex mixture.[8] The highest values of this ratio (which indicates 'most recent' inputs of oil) were recorded off Bahrain (stations 7 and 8; **Fig. 1**). Analyses revealed, however, that fuel oil rather than Kuwait crude oil was responsible for this localised contamination. In addition, the relatively small contributions of *n*-alkanes (n-C_{14} to n-C_{34}) to the total hydrocarbons confirm that most of the oil spilled in Kuwait had substantially degraded. The high value at Ras Al Ghar (station 6, **Fig. 1**) might, however, have resulted from deposition of a 'protected' and remobilised oil pocket originating from the Kuwait spills.

Pollution from polycyclic aromatic hydrocarbons (PAH) will have arisen from both the oil spills and burning of the wells. The low-molecular-weight ($\leqslant$3 aromatic ring) compounds together with their numerous alkylated homologues are typical constituents of crude oils.[8,18] GC analyses confirmed that these were the main resolved aromatic components. It is apparent from **Fig. 3** that when summed, the resolved aromatic compounds generally co-vary with the oil contamination (as indicated by the total hydrocarbons). PAH formed during high-temperature combustion (as might be expected in the burning of oil wells) are generally larger molecular weight ($\geqslant$4 aromatic ring) parental (non-alkylated) compounds, many of which are carcinogenic. Pyrene is a principal constituent of the generally uniform assemblage of PAH associated with combustion.[7,8] The distribution of this compound (as an indicator of combustion-derived PAH) is shown in **Fig. 3.**

Concentrations in the Gulf sediments (3–450 ng per g dry sediment; Fig. 3) are well within the range of those reported for other coastlines, such as Buzzards Bay and New York Bight, USA (7–1,300 ng per g dry weight)[7] and estuaries within the United Kingdom (60–1,510 ng per g dry weight).[8] Indeed the median value for the Gulf sediments (12.5 ng per g dry weight) is lower than that for a survey of similar scope and sediment type (mostly sandy) in the Southern Baltic sea[6] (72.5 ng per g dry weight; range 1.7–150 ng per g dry weight). PAH emanating from the burning oil wells do not seem to have broadly contamined the coastal areas investigated. ■

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Malaysian industry enters the gas era

By David Buckman

Malaysia's petroleum industry is looking forward to an expansionary period until the end of the century, with the role of gas being greatly enhanced. State oil firm Petronas sees increasing oil and gas reserves, making fuller use of abundant gas reserves, an exploration thrust into deepwater areas and the intensification of environmental protection as some of the points of emphasis in its current programme. State firm president Tan Sri Datuk Azizan Zainul Abidin says that in the past few years a national economic growth rate of 8 percent has resulted in rising energy demand. Economic growth is projected to continue, so that an increase in power demand can be expected for the next few years. 'Fortunately, we are experiencing the same bullish trend in oil exploration and development,' he says.

According to the president, exploration is now being carried out in 29 blocks: 25 offshore and four onshore. A total of 127 exploration wells and 296 development wells were drilled between 1988–91. The programme for the next five years calls for the drilling of 475 wells. Tan Sri Azizan says that exploration has resulted in several finds in the past year, with some 400 million barrels of oil and 1.7 trillion cubic feet of gas added to Malaysia's reserves. At the end of last year these stood at 3.6 billion barrels of oil and 59 trillion cubic feet of gas. Since the start of this year there have been several more finds. Malaysia's oil reserves should be good for up to 15 years, its gas for about 40 years. The country plans to maintain output of some 600,000 b/d for the coming five years. Last year's oil production was a record 649,000 b/d including condensates, according to the Central Bank. Gas production was some 2.2 billion cubic feet a day. Oil exports were 470,000 b/d, says Central Bank.

The last few years have seen explorers rush to take up Malaysian acreage. In 1985 the government had moved to encourage the search when it relaxed the rules of production-sharing contracts. By the end of 1990 about two dozen new deals had been signed under the revised terms, in addition to four pre-1986 contracts. Early in 1991 Petronas' president indicated that the country would start exploration in deepwater areas as most shallow areas had been taken up. It was hoped that the first deepwater contracts, in depths over 200 metres, would be granted in the second half of last year, but in the closing days of 1991 Tan Sri Azizan said that Petronas had plans to 'sweeten' terms for foreign firms interested in deepwater regions. It was recognised that better terms were needed for the more challenging plays.

First, Petronas would lengthen the allowable exploration and development time and improve the profit split. Modifications would create a two-tier system of production-sharing contracts, the existing standard for current water depths, another for over 200 metres. Under the deepsea terms the allowable time for exploration of a defined area would extend to seven years from five, and the development period would extend from the current four to six years. The production period, however, would remain at 15

Esso Production Malaysia's Jerneh. A gas production platform.

years. Despite this blueprint, timing on deepwater exploration remains vague.

Most successes under current exploration terms have been made in peninsular Malaysian waters. During the past two years or so the major producer Esso has had a series of finds, with Hamilton and Texaco also recording successes. With 335,000 b/d of production already in hand, in September 1990 Esso Production Malaysia Inc (EPMI) made the Larut find, about 250km off Kuala Trengganu, with a flow rate of 3,000 b/d of oil. Early last year, about 175km off the coast, North Lukut 1 was successful with over 6,650 b/d plus some gas. Two more successes last year were EPMI's Abu 1, which flowed oil at a cumulative rate of 12,406 b/d, with Abu 2 a good follow-up hole, and Lawang 1, which flowed over 4,000 b/d from three zones. Esso in 1992 has had further successes, with Serudon 1 yielding a combined 13,000 b/d; Babu 1 flowing interesting crude, although mechanical problems prevented acquisition of reliable data; and Penara 1, completed in August — yet another find in PM 8 area — with three production tests giving a combined 7,400 b/d of crude, gravity ranging from 29°–47° API.

Hamilton's successes have been in PM 3, stemming from drilling begun in March 1991. Bunga Orkid 1 was abandoned after six of the zones tested flowed at a combined 4,971 b/d of oil and condensate with 47.1 MMcfd of gas. This was followed with Bunga Pakma 1, where five of the tested zones flowed at a combined 1,120 b/d of condensate and 62.9 MMcfd of gas. Bunga Rayal, where four of the zones tested flowed at combined rates of 5,719 b/d of oil and condensate with 41.6 MMcfd of gas, indicated that more drilling was needed to assess what appeared to be very interesting commercial potential. In October Hamilton granted a contract to Clearways Drilling to use the semi-submersible *Eagle* for another drilling programme on PM 3. The initial well is the Bunga Orkid 2, downdip from the discovery. Texaco's find was made earlier in 1992 on PM 14, about 160km off Kuantan. Wildcat Rhu 1/A flowed a combined 6,050 b/d of 34° API oil from three zones through a half-inch choke. This was the fourth well in PM 14 and the first find in the Penyu Basin, previously unproven as a petroleum source.

The Malaysian search is set to spread now with a series of agreements offshore on joint exploration, following disagreements about a median line. In 1990 Malaysia and Thailand set in motion plans to establish a fund to finance development of a 7,300-sq km tract off the Kelantan coast, northeast of Kuala Lumpur. The Joint Development Area stemmed from a disagreement lasting over a decade, settled with a pact signed in May 1990. One estimate of reserves is about 230 million barrels of oil and 3.6 trillion cubic feet of gas. Another pact is that between Malaysia and Vietnam, signed in the first half of 1992, where action by Petronas and Petrovietnam could begin in 1993. The Vietnamese foreign minister N M Cam stressed, however, that the deal applied only to areas claimed by the two states and not island groups also disputed by China, Taiwan and the Philippines.

LNG plant at Sarawak.

A more immediately effective pact is that signed for peninsular Malaysian waters between Petronas and EPMI regarding PM 9 and 12 producing oilfields. New contracts revise terms made in 1976, give a greater role to Petronas Carigali and split the original deal into two similar contracts from April 1 1995. EPMI will turn over majority ownership and operation of the Pulai, Bekok, Kepong, Tinggi and Tiong fields to Carigali. However, it will be majority owner of the other seven fields: Seligi, Palas, Guntong, Tabu, Irong Barat, Semangkok and Tapis, and will remain operator. In compensation, EPMI's participation in the fields' exploitation will be extended. From 1993 EPMI will begin a new search push in the 1976 contract area.

An important event for Malaysian oil production was the inauguration about 18 months ago of the Dulang field, about 130km offshore. The field is partly unitised, 79 million barrels lying in Carigali acreage, 46 million in EPMI acreage. Later on, a western area, held by Carigali with a further 43 million barrels of reserves, and an eastern area, held by EPMI, with a further 13 million, will be exploited. Production capacity at Dulang will be 72,000 b/d and peak output should be attained in 1996.

A notable recent development has been EPMI's bringing on stream of the Jerneh gas field, a key segment of output in the company's ambition to be the country's top gas producer. This is the company's first gas-only reservoir to be tapped off Malaysia and it is the largest such reservoir it has found there, holding 3 trillion cubic feet of gas.

A sales deal with Petronas prepared the way for development and for EPMI to become the major supplier to Malaysia's giant Peninsular Gas Utilisation (PGU) project. The company

estimated that total gas demand to be handled by PGU would rise to 1 billion cubic feet a day by end-century. By the time of the Jerneh pact, in 1990, first-phase PGU development, based on associated gas from offshore oilfields, had been proceeding for five years at a flow rate of some 100 million cubic feet a day.

The initial development of Jerneh is costing M$1.4 billion (£365 million). Its capacity in the early stages will be 450 million cubic feet a day, which will rise with the installation of more hardware to 750 MMcfd 'as demand grows in the 1990s'. EPMI plans to tap more fields to match anticipated need, so that investment during 20 years is 'expected to total more than M$10 billion.'

Gas in the economy

The increasing role of gas in the Malaysian economy was spelled out recently by Tan Sri Azizan. He told a conference in Singapore that the PGU project had made available a new and indigenous and therefore more reliable and secure source of primary energy. It would help in meeting the country's growing energy demand and would help to cut air pollution and dependence on oil. All power plants that could be reached by the gas trunkline so far had been converted to gas. Power plants in the north would be similarly converted and would tap gas from the third stage of PGU (PGU III), which would be in place in 1995. Electricity generated from oil-fired power plants currently accounts for 63 percent of total supply, but this will be cut to 5 percent over the next 10 years. Natural gas's share will rise from 20 percent to 70 percent. Hydro-electric schemes and other forms of energy will make up the balance.

The PGU trunkline scheme was planned in three stages. Its beginnings were in the early 1970s, when large volumes of oil and gas were found off Terengganu. In May 1981 PGU1, costing M$527 million, was launched and completed in 1984. This saw gas come ashore to a processing plant at Kertih, with a limited network supplying the TEN power plant at Paka and Perwaja steel mill in Kemaman, with a pilot gas reticulation system supplying Kertih township. PGU II was inaugurated about a year ago, a M$2.3-billion, 730-km transpeninsular line reaching west to Port Kelang power station and south to Johor Bahru via Segamat. Now a third stage is under way, to extend the line up the west coast to Bukit Keteri in Perlis, and on the east coast a study is proceeding to direct the artery north from Kertih.

The propane, butane and ethane extracted from the gas stream by gas processing plants will provide feedstock for four petrochemical projects being set up by Petronas and partners. Petronas says that more than 300 km of feeder lines and 7,000 km of distribution and service lines are to be laid under a Natural Gas Distribution Project, another effect of PGU. 'Project implementation has begun and the first gas delivery is targetted for early 1994. The planned network is expected to be implemented over a 10-year period.' Further, Petronas wants to see vehicles converted to gas to help overcome pollution. In May 1992 vehicles in the Klang Valley were able to begin using six natural gas vehicle stations, with one in Miri. Three workshops were set up to convert about 1,100–1,750 vehicles. The M$16 million programme was the launch pad for a wider scheme, to be implemented in stages elsewhere in the country following the start of the Gas Distribution Project in 1994.

PGU is the springboard for exports, too. These were begun when Singapore through PGU II early in 1992 began piping gas to Singapore under a 15-year contract covering 150 million cubic feet a day. A line across the Straits of Johor supplies Senoko power station. This launched the international piped gas trade in the region, which could expand enormously in coming years with Malaysia as a key component. As one of the ASEAN states it is a party to the multi-national gas network now under study. Separately, Malaysia has talked with Thailand about supplying gas through an extension of PGU III, and the contract could be bigger than that with Singapore.

In addition to all this peninsular Malaysian activity, more than M$12 billion will be invested into the offshore sector in the states of Sabah and Sarawak over the five years 1991–1996, with gas prominent. Although Petronas Carigali has been expanding its role in recent years Shell is the major player, and it expects its share of the five-year investment to be just over M$8 billion. Malaysia's oil industry began in 1910 when Shell found the onshore Miri oilfield in Sarawak. Sabah Shell Petroleum Company and Sarawak Shell Berhad now produce over 150,000 b/d of oil and 1.1 billion cubic feet a day of gas from a dozen offshore fields. Shell also provides technical assistance and services to Carigali which, since 1988, has been operating a further nine offshore oilfields on behalf of its joint venture with Shell in Sarawak. The Baram Delta fields when handed over were tapping just over 100,000 b/d.

The thinly populated states of Sabah and Sarawak offer a small local gas market, but they are the springboard for big export earnings. Over 200 million cubic feet a day of associated gas from Sabah Shell's offshore oilfields is fed to Sabah Gas Industries (SGI) on Labuan Island. SGI uses gas for a methanol plant, a hot briquetted iron plant and a power generating complex, but it has accumulated big debts. The federal government has now found it prudent to take over SGI and the Sabah Energy Corporation gas grid and will sell these assets to 'parties which are interested in opening in

Gas production platform offshore Sarawak.

these fields.'

Shell has a new oilfield off Sabah for which it says 'development plans are in preparation.' This is Kinabalu, confirmed in 1990 with a second well that flowed 5,740–6,640 b/d of light, sweet crude. Recoverable reserves have been conjectured at 200–250 million barrels.

Bintulu is the focus of Sarawak's burgeoning gas industry, based on widespread offshore supplies. Several big projects are under way. Shell tells *Petroleum Review* that it expects the Shell Middle Distillate Synthesis complex to come on stream 'February 1992'. (See *Petroleum Review*, April 1990) Gas will flow from the Central Luconia fields to a novel plant that will take 100 million cubic feet a day to make 12,000 barrels a day of synthetic products. Shareholders are Shell 60 percent, Petronas 10 percent, the Sarawak state government 10 percent and Mitsubishi 20 percent.

That complex is a neighbour of the Malaysia LNG complex (MLNG 1), which takes around 1.1 billion cubic feet a day of gas down two 125-km, 36-inch trunklines rated at around 1.25 billion cubic feet a day. Now a MLNG 2 plant is being added, which will see gas uptake double, drawing on more Central Luconia gas through a third — 1.25-billion cubic feet a day — trunkline, a line from Baronia field worth 100 million cubic feet a day and a 60-million cubic feet a day line from the D-35 region. That region will be a special focus of interest in 1993. Thus MLNG will boost capacity from 8.1 million tons/year to over 15 million tons/year, with three new trains, a fifth storage tank and a second berth for LNG tankers. The cost is put at M$8 billion and the first new train will be ready in 1995.

Malaysia expects more revenue from gas exports than from oil by 1995. Revenue from gas exports should rise to M$7.3 billion in 1995 against M$6.9 billion for oil, gas earnings having soared almost 75 percent to M$3.8 billion in 1991 from M$2.2 billion in 1990. The customer base for LNG is expanding from Tokyo Gas and Tokyo Electric Power to include Seibu Gas, a fourth Japanese firm, Korea and Taiwan. Moreover, there is already talk of another LNG export complex. Not long ago Petronas was reported talking with unnamed foreign partners, following the discovery of around 2.7 trillion cubic feet of reserves by a group led by Occidental with Jintan 1, in the SK 8 block, early in 1992. The MLNG group has also been quoted as saying further expansion of Bintulu is impracticable, so that a new complex will eventually be needed.

Further onshore use of gas is planned, too. ASEAN Bintulu Fertiliser Company is lifting gas uptake from 45 million cubic feet a day to 55 million, with plans to double that volume. Another Bintulu customer, the Sarawak electricity utility, has been raising uptake substantially to 30 million cubic feet a day as it converts from oil burning. This will also be doubled as the grid expands.

Another important gas development of Sarawak is the Baram Delta Gas Gathering System (Bardegg), being advanced by Petronas Carigali. In 1988 Petronas and Shell agreed a contract by which the state firm would take over as operator of the Delta oilfields under a new 50:50 deal, by which Shell would invest heavily in nine fields, raising oil output from 100,000 barrels a day to 130,000. Since the 1960s associated gas from three fields has been piped to shore. Bardegg will make up to 40 million cubic feet a day available in the Miri-Lutong area, as well as supplying Bintulu. ■

Reaching the converted in Germany's burgeoning gas market

Consumption of natural gas in eastern Germany is expected to triple by the end of the century as the country seeks to switch its energy requirements from coal to natural gas. The gas market itself is undergoing a radical change as the former state transmission company begins its transition to private enterprise.

As part of the restructuring of the country, a decision has been reached on environmental and commercial grounds to increase the market share of natural gas, to link east Germany to the North Sea and European gas network and to reduce the reliance on energy supplies from the former Soviet Union.

The new merchant company, Verbundnetz Gas Aktiengesellschaft (VNG), was previously a pipeline operator supplying natural gas and town gas to industrial users and distributors. It is now carving out a share of the new market, developing and expanding its existing infrastructure to compete in the gas supply business.

The competition for gas markets has been intense. Wintershall and Ruhrgas have both signed contracts for gas supply to industrial users and regional distributors, although in some cases access to the buyer has been thwarted by lack of either available pipeline capacity or VNG's refusal to grant access to its system.

Several companies have gained some access to the market in the form of shareholdings in VNG. Ruhrgas holds 35 percent of the stock; Wintershall, 15 percent (plus one share); BEB Erdgas and Erdol GmbH, 10 percent; British Gas, Statoil, Elf Aquitaine, Gazprom and Erdol-Erdgas Gommern five percent each; and an east German towns holding company, 15 percent (minus one share).

In 1989 natural gas accounted for only 9.3 percent of East Germany's energy requirements. By 2000 this figure is expected to reach 22.3 percent — cutting the level of reliance on lignite from 69.2 percent to 38 percent of needs and bringing the country more into line with world energy consumption patterns.

With unemployment in eastern Germany rising rapidly, resistance is expected from mining communities. The majority of coal reserves comprise, however, high-sulphur lignite and although hard coal's share of the energy market is set to increase from 3.8 percent to 9.4–12 percent of

Converting eastern Germany's heavily-polluting industries to gas is complicated by not knowing which industries will survive.

demand, this will do little to reverse the decline in importance of the indigenous coal industry, as these supplies are all imported (from the former West Germany).

Dr Walter Altmann of VNG stressed that the conversion to natural gas is essential to the future energy requirements of the former East German state.

Current consumption of natural gas stands at around 5.2 billion cubic metres (bcm) a year, most of which is imported from the former Soviet Union.

In 1989, around eight bcm a year of town gas was supplied through an existing transmission system to all areas in the five eastern states as well as a further eight bcm of low calory domestic natural gas for selected industrial customers and power stations. In the same year, 7.6 bcm of high calory gas was imported from the Soviet Union.

By 1996/97, the government hopes to complete the conversion from coal and town gas to natural gas for domestic users. More than 200,000 town gas users were converted in 1991 alone.

One reason for the pace at which the German authorities believe they can achieve the changeover is the existence of pipelines, both high and low pressure, which are being connected to the natural gas grid. Some 3,300 kilometres of newly constructed or converted lines were added to the existing trunk system in a single year. Connections to the west German grid have also been made at nine points along the former border.

In order to obtain access to new gas sources, the company is negotiating contracts with western European suppliers including the Norwegian gas giant, Statoil.

The situation, however, is complicated by difficulties in analysing future demand.

'We simply do not know which industries and companies will survive,' said Dr Altmann. 'This makes negotiations difficult and we are seeking flexibility in our contracts.'

East German industries are expected to switch from coal to oil and gas in order to meet stringent environmental standards. Targets have been set to reduce sulphur dioxide emissions from five million tonnes per annum in 1989 to 2.3 million tonnes in 2000 and carbon dioxide emissions from 347 million tonnes to 240 million tonnes.

The company estimates that demand for natural gas will exceed 16 bcm by the end of the century. Half of this is expected to be supplied by Russia.

'I expect the price of gas supplied by Russia compared with the West to converge over the next few years,' added Dr Altmann.

'As far as security of supply goes, supplies have been delivered from the former Soviet Union since 1973 and we have never had a major problem. The Russians, as principal producers, are very aware of the necessity of fulfilling contractual obligations and we do not expect to face any breakdown in supplies.'

A number of countries do experience some difficulties during winter months with Russian supplies. VNG believes that its extensive working storage capacity will protect the company from short-term market disruptions.

Nevertheless, VNG is expanding its supplier base and is principally looking to Norway and The Netherlands as well as the intended hook-up to the Western European Gas Grid which can source supplies from Algeria.

Robert McLeod

A place for gas in the UK energy policy

By Robert McLeod

The UK government's decision to carry out a review of the country's energy policy, such as it exists, following the debacle of the pit closures announcement could have long-term effects on the oil and gas industry. If development projects are stalled, job and revenue losses and a deterioration of the infrastructure are feared but an ever-expanding power generation market for gas now seems unlikely in the short or medium term and producers must examine their options.

The President of the Board of Trade, Michael Heseltine, has announced that the review of the coal closures and the future of that industry would encompass a study far more wide ranging than originally expected.

In an answer to a parliamentary question from Broxtowe MP Jim Lester, Mr Heseltine said the review will consider — in addition to the future of the pits — the 'consequences of the switch to gas in power generation'.

The review will cover:

- The relative costs of gas and coal-fired generation;
- the latest estimates of likely reserves;
- the present scale of gas-generated power stations in production, being built or planned;
- the use of the president's consent powers under the Electricity Act 1989; and,
- the implications of the statutory duty on electricity suppliers to purchase non-fossil power, including from nuclear sources.

It is also understood that the relationships between the different companies generating power and the regional electric companies will be examined.

During the Commons debate on the closures, it was suggested by the opposition Trade and Industry spokesman, Robin Cook, that these issues should have been examined before the decision was taken.

Relative costs

Many varying estimates have been given for the relative costs of coal and gas-fired generation.

According to a report by County NatWest WoodMac, the cost of producing electricity from the gas-fired plants varies between 2.1 and 2.4 pence per kilowatt hour (kWh), broadly in line with the cost of coal-fired generation.

To achieve this cost the operators of gas-fired plant have negotiated for the units to operate on a continuous basis and supply the base load requirement for electricity (along with nuclear and imported electricity), a role previously taken by coal.

The cost of coal-fired generation from existing plant is achieved through having all capital costs written off. Additional capital costs such as the fitting of flue gas desulphurisation equipment to meet emission targets would be reflected through higher marginal costs.

A statement released by PowerGen, however, insisted that its portfolio of coal-fired plant 'is able to generate more cheaply than most of the independent gas-fired plant which is now threatening to displace it. Such independent plant is typically backed by 10–15 year contracts with the regional electricity companies which are also in almost all cases equity holders in the project'. The statement added that the market was further foreclosed to the coal-fired plant by increased output from heavily subsidised nuclear stations, including plant operating beyond its design life.

For industrial customers, new gas marketing companies, such as that set up by British Fuels Limited, have begun to market gas by entering into supply arrangements with producers. This extra competition in the market has seen gas prices fall where, according to British Gas, in real terms industrial contract prices have fallen by around 30 percent, firm contract prices by 32 percent and interruptible contract prices by 25 percent since the privatisation of the company in 1986.

The relative costs of coal and gas appear difficult to predict in the long term because of the fast-changing nature of the gas supply/demand balance. Some industry estimates have put the projected increase in gas prices in real terms from the current $2.50–$3.00 per million British Thermal Units (mBTU) to as high as $6.00 per mBTU over the next few years but much depends on the liberalisation of the European market.

In an address to the American Society of Petroleum Engineers in Washington, Mr John Jennings, a Royal Dutch/Shell Group managing director, said that the 'rapidly expanding demand levels in Western Europe and the Far East are unlikely to be met unless the higher costs of developing new production are reflected in higher prices'. He added that he believes there is sufficient 'headroom' over the price of coal to maintain gas's cost advantage.

The arguments over foreign coal's price advantage is also complicated by the recent plunge in the value of sterling and the intention of Australia — the world's largest exporter — to seek higher prices for its product.

Reserves

The increase in reserves in the 1980s has largely dispelled the image of gas as a scarce fuel, although estimates of how many years' supply remain, being

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bandied around during the debate in the House of Commons, vary between 10 and 45. Proven reserves — those that have been discovered and can be extracted at current prices using current technology — of 19.2 trillion cubic feet do in fact run out in 10 years (at the current rate of consumption). The additional probable reserves — requiring higher gas prices or better technology — and possible reserves with a reasonable expectation of being found, will extend the life of the UK gas province to an upper end estimate of 45 years.

The increase in consumption through new gas-fired plant will mean that other reserves could become more profitable to exploit as demand for gas increases. This would enable some of the more remote or technologically challenging fields to be developed.

Gas-fired generation

Although combined cycle gas turbine (CCGT) plant has been commercially available since the late 1970s, the fuel was regarded as 'far too valuable' to use for power generation, particularly in the United Kingdom.

From 1991 to 1995 the generating capacity from gas-fired plant is estimated to increase from 0.1 percent to 21 percent of overall needs. A total of 16 stations with 9,800 MW of capacity have received consent under Section 36 of the Electricity Act 1989 and have secured gas supplies. Another three stations with 4,360 MW capacity have secured gas supplies but have not received Section 36 consent. The present review could affect their future and for one of the projects (PowerGen's 1,360 MW Connah's Quay plant) gas supplies may have to be resold.

A further 4,000 MW of plant have received consent but have not secured supplies and are unlikely to proceed in the near term.

In order to maintain their economic position as a cheap supplier of electricity, the gas-fired stations will need to supply base load electricity, a role previously held by coal. Although some coal-fired plant will need to contribute to base-load, utilisation is expected to drop below 65 per cent reducing the annual coal requirement from 82 million tonnes to 60 million tonnes.

Supply and demand

To examine the supply of gas in the United Kingdom, it is imperative to look at the situation of Western Europe as a whole because of the existence of the European gas grid pipeline network, the liberalisation of the EC gas and electricity markets and the concentration of reserves in The Netherlands, Norway and the United Kingdom.

This is of particular importance given the recent decision to allow the first exports of UK gas from the Markham field, the intention to build a gas pipeline to both the Republic of Ireland and Northern Ireland (see page 593) and the proposed connection of the United Kingdom to the European gas grid.

Estimates of the supply/demand balance of UK gas reserves cautiously predicts a supply shortfall by 2002, although rolled forward production is expected to push this date to 2007. This figure corresponds to the supply shortfall predicted for Western Europe by a number of influential industry figures.

At a conference in Stavanger in August, the President and Chairman of Elf Aquitaine and board member of Gaz de France, Mr Loik Le Floch-Prigent, predicted a shortfall of supply and higher prices for marginal field development by the end of the century (see page 589).

This echoed the view put forward by the Prime Minister of The Netherlands, Mr Ruud Lubbers, in London earlier this year when he discussed his proposals for an Energy Charter — the prime purpose of which is to develop the oil and gas reserves of the Commonwealth of Independent States, particularly Russia.

Demand for gas in Europe has been growing at around 1·7–2·0 percent annually over the past decade and this figure is estimated to rise to over three percent within the next few years. For OECD Europe consumption surged by between 4.5–25 percent in individual states from 1990 to 1991. Shell estimates a total market for gas in Europe of 16 trillion cubic feet by 2010 — an increase of six tcf over present levels.

In the United Kingdom, demand will increase with the construction of the pipeline by Bord Gais Eireann (BGE) — which will open the market there for exports — as it is intended to include a spur pipeline to Northern Ireland.

British Gas has plans to convert the 1400 MW Ballylumford oil-fired power station, which it purchased in April, to gas by 1996. Although there has been a surge in gas-fired plant in the United Kingdom, the company has been playing a minor role. A public enquiry is to be undertaken with regard to the company's plans to build a 1200 MW station in Avonmouth but a spokesman for the company said that the gas for this unit would 'possibly not' be supplied by British Gas.

An ancillary benefit of the Irish pipeline will be the opening up of the Northern Ireland domestic and industrial gas markets, particularly in Belfast where an existing — although ageing and unused — pipeline system exists from the town-gas days. Although age and demographic changes could mean that much of the infrastructure is redundant, the company is examining the possibility of using at least some of the existing network.

The British government is particularly keen to see the opening up of the gas market throughout Europe but concedes that this must be phased in gradually. 'The UK experience has taught us that a phased approach is the best way,' said the Minister for Energy, Tim Eggar.

Market mechanisms

'Market mechanisms are already beginning to develop. In the United States, for instance, where the industry has been liberalised for some time, trade is done in spots, swaps, and futures — just like oil.' Mr Eggar, speaking at a gas conference in Berlin, criticised some of the EC member states for their 'entrenched positions'.

Mr Jennings of Royal Dutch/Shell, however, stated [in his address at Washington] that he was 'unable to share the view I sometimes hear from governments that the United States represents a suitable model for the development of gas markets in Europe . . . .' He pointed out that demand for gas in the United States is still 15 percent less than it was 20 years ago.

British Gas itself is keen to see the European market open up and sees a substantial role for the company in Eastern Europe. It sees the potential from its deals in Kazahkstan, for example, to enter the market 'from both sides' and liberating other supplies for markets elsewhere.

Whatever the outcome of the British government's review of the energy sector, gas has established itself as a major electricity generating fuel both here and on the continent.

Pressure from the environmentalist lobbies, its attractive price and relative abundance until (at least) the early part of the next century should be enough to guarantee the fuel's future in expanding European markets. A transparent energy policy will enable the industry to respond to the challenges. ■

FORTHCOMING EVENTS

December

3rd
Brussels: Conference on 'The Future of Biofuels in Europe'. Details: Gerard Rousselot-Pailley, 10 rue du College St Michel, B-1150 Brussels. Tel: (322) 771 98 90. Fax: (322) 770 66 71.

7th–8th
London: Conference on 'World Energy Demand: Is Growth Inevitable?' Details: The Energy Conference, The Conference Department, Chatham House, 10 St James's Square, London SW1Y 4LE. Tel: (071) 957 5700. Fax: (071) 957 5710.

7th–8th
Jakarta: Conference on 'Combined Cycle and Co-generation System Options'. Details: IBC Technical Services Ltd, 545 Orchard Road, 12-01, Singapore 0923. Tel: 65-732 1970. Fax: 65-733 5087.

8th–9th
London: Conference on 'The Petrochemical Industry: Strategies for Survival'. Details: Financial Times Conferences, 102–108 Clerkenwell Road, London EC1M 5SA. Tel: (071) 251 9321. Fax: (071) 251 4686.

8th–9th
London: Conference 'Subsea 92'. Details: Themedia Ltd, PO Box 2, Chipping Norton, Oxfordshire OX7 5QX. Tel: (0608) 84888. Fax: (0608) 84796.

8th–10th
Stratford-upon-Avon: Conference on 'Profitable Condition Monitoring'. Details: Miss T Peters, Conference Organiser, BHR Group Ltd, Cranfield, Bedford MK43 0AJ. Tel: (0234) 750422. Fax: (0234) 750074.

10th
London: Seminar on 'Demanning Offshore Facilities'. Details: The Institution of Mechanical Engineers, 1 Birdcage Walk, Westminster, London SW1H 9JJ. Tel: (071) 973 1243. Fax: (071) 222 4557.

10th–11th
London: Conference on 'Floating Production Systems'. Details: Sarah Peace, IBC Technical Services Ltd, Gilmoora House, 57–61 Mortimer Street, London W1N 7TD. Tel: (071) 637 4383. Fax: (071) 631 3214.

10th–11th
London: Conference on 'Oil and Gas Economics in the North Sea'. Details: IIR Industrial Ltd, 28th Floor, Centre Point, 103 New Oxford Street, London WC1A 1DD. Tel: (071) 412 0141. Fax: (071) 412 0145.

15th
London: Discussion meeting on 'Preparation of an Offshore Safety Case'. Details: Society for Underwater Technology, PSTI House, Exploration Drive, Offshore Technology Park, Bridge of Don, Aberdeen AB23 8GX. Tel: (0224) 823637. Fax: (0224) 820236.

16th–18th
London: Course on 'Safety analysis and techniques required for formal safety assessments in the shipping and offshore industries'. Details: Ms Rhian Bufton, The Institute of Marine Engineers, 76 Mark Lane, London EC3R 7JN. Tel: (071) 481 8493. Fax: (071) 488 1854.

1993
January

11th–13th
Dubai: 'The First Annual Middle East Petroleum and Gas Conference'. Details: IBC Technical Services Ltd, 545 Orchard Road, #12-01, Singapore 0923. Tel: (65) 732 1970. Fax: (65) 733 5087.

21st
Melton Mowbray: '3rd Annual Seminar of the Society of Industrial Emergency Services Officers — Industry and the Environment'. Details: SIESO (EM), 22 Mourne Terrace, Lincoln LN5 9AY. Tel and Fax: (0522) 721432.

18th–19th
London: Conference on 'Understanding and implementing business process restructuring'. Details: IIR Industrial Ltd, 28th Floor, Centre Point, 103 New Oxford Street, London WC1A 1DD. Tel: (071) 412 0141. Fax: (071) 412 0145.

19th–20th
London: Conference on 'Not Normally Manned Facilities' Details: IIR Industrial Ltd, 28th Floor, Centre Point, 103 New Oxford Street, London WC1A 1DD. Tel: (071) 412 0141. Fax: (071) 412 0145.

20th–21st
London: Conference on 'Assessing your Opportunities in the Developing UK Gas Market'. Details: IIR Industrial Ltd, 28th Floor, Centre Point, 103 New Oxford Street, London WC1A 1DD. Tel: (071) 412 0141. Fax: (071) 412 0145.

London: Course on 'Exploration, Appraisal and Marginal Field Economics'. Details: DCA Consultants Ltd, Haughend Farm, Bridge of Earn Road, By Dunning, Perthshire PH2 9BX. Tel: (0764) 84664. Fax: (0764) 84665.

28th
London: Conference on 'Methane Emissions'. Details: The Conference Administrator, Watt Committee on Energy, 40 Grosvenor Place, London SW1X 7AE. Tel: (071) 235 2565. Fax: (071) 235 1960.

February

10th–11th
Aberdeen: Conference on 'Emergency Planning and Response — Offshore Operations'. Details: Langham Oil Conferences, 37 Main Street, Queniborough, Leicester LE7 8DB. Tel: (0664) 424 776. Fax: (0664) 424 832.

15th
London: Conference on 'Oil Industry Taxation — An International Comparison'. Details: Miss Caroline Little, The Institute of Petroleum, 61 New Cavendish Street, London W1M 8AR. Tel: (071) 636 1004. Fax: (071) 255 1472.

16th
London: 'Oil Price Information Seminar'. Details: Miss Caroline Little, The Institute of Petroleum.

16th–18th
Monterrey, Mexico: Symposium on 'Air Pollution'. Details: Pamela Spalding, Wessex Institute of Technology, Ashurst Lodge, Ashurst, Southampton SO4 2AA. Tel: (0703) 293223. Fax: (0703) 292853.

March

16th–18th
Manchester: Course on

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FORTHCOMING EVENTS

'Safety of Electrical Equipment in Potentially Explosive Atmospheres'. Details: Sira Communications Ltd, South Hill, Chislehurst, Kent BR7 5EH. Tel: (081) 467 2636. Fax: (081) 467 7258.

17th–18th
London: Conference on 'Certification Standards for Non-Destructive Testing'. Details: PCN, 1 Spencer Parade, Northampton NN1 5AA. Tel: (0604) 30124. Fax: (0604) 231489.

18th–20th
Wiesbaden: '3rd International Petrol Station Fair, Tankstelle '93'. Details: MMS Expoconsult GmbH, Postfach 4266, Abeggstr. 2, DW-6200 Wiesbaden, Germany. Tel: (06 11) 527017. Fax: (06 11) 52 70 10.

22nd–26th
Zurich: Course on 'Multiphase Flow and Heat Transfer: Bases, Modelling and Applications in the Process Industries'. Details: Professor G Yadigaroglu, ETH-Zentrum, CH-8092 Zurich, Switzerland. Tel: 41 1 256 4615. Fax: 41 1 262 2158.

23rd–25th
Birmingham: 'Environmental Technology '93'. Details: Showcase Communications, 36 Earls Court Square, London SW5 9DQ. Tel: (071) 373 8711. Fax: (071) 835 2081.

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3rd–6th
Bahrain: '8th Middle East Oil Show and Conference'. Details: Stephen Key, Arabian Exhibition Management, PO Box 20200, Manama, Bahrain. Tel: 973 550033. Fax: 973 553288.

24th–26th
Abu Dhabi: 'The Fourth European and Middle Eastern Pipeline Rehabilitation Seminar'. Details: Susan Carradice, Pipeline Integrity Management, The Pipeline Centre, Farrington Road, Rossendale Road Industrial Estate, Burnley, Lancashire BB11 5SW. Tel: (0282) 415323. Fax: (0282) 415326.

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Gas strategies in Europe

By Loïk Le Floch-Prigent, President and Chairman of the Board, Elf Aquitaine Group

In a paper delivered to the Offshore Northern Seas Conference in Stavanger, Mr Le Floch-Prigent examines the different aspects affecting gas supply and demand in Europe and outlines the strategies he considers necessary to ensure a successful European gas market in the 21st century.

Natural gas appears today, all over the world, as the most promising form of fossil energy:

- it has a good competitive position,
- it is favoured from an atmospheric pollution standpoint,
- there are abundant reserves, existing and still to be developed, in various countries. This means that the risk of political dependence on one region of the world could be limited.

It is therefore not a big surprise to see that the consumption of natural gas is constantly growing. In 1991, even if we dismiss the rougher winter conditions for comparison purposes, we still register a growth of around four per cent in Western Europe.

This growth covers most sectors of activity, with different figures for each. This situation will certainly also be true for the coming years.

Consumption of natural gas in the industrial sector is strongly dependent on the ups and downs of the economy. This is the sector where the toughest competition exists as industrialists are known to look closely at prices. They balance carefully the advantages of available energies and do not hesitate to shift to another form of energy if the conditions of the competition seem to warrant it.

The residential and commercial sector is more stable as consumers change energy form much less readily and have less access to information to do so anyway. The increase in gas consumption will depend on the installation of gas equipment in new buildings; these efforts take time but have a positive influence on gas consumption in the medium to long term.

Use of natural gas for electricity generation has the best perspectives; in particular in combined cycle plants, a technique which is the fashion of today.

But all these positive factors have their other side of the coin.

The competitive position of gas must be appreciated over the long term. The costs of infrastructures for production and transportation are very high and require stable consumption conditions. This is not the case for all other competitive forms of energy and one cannot rule out prices that will not yield a reasonable rate of return over the life span of the investment.

The environmental discussion is today ruled more and more by irrationality. It sometimes looks like the enemy is not pollution alone but economic growth in general and energy in particular. Therefore, a predominant position can easily be overturned for reasons unknown and not understandable to the observer.

Diversification will be limited by the cost of infrastructures, by the share that one type of energy can take in the energy balance of any one country and by the fact that adding new sources of supply will mean additional costs.

Gas sales are still today individual operations between producers and gas companies. In that respect, a fluid market for natural gas does not exist as it does for other energies. Additional thinking is needed on:

- supply conditions; and,
- gas pricing and its evolution;

to ascertain how fluidity can be reached.

Coexistence of positive and negative factors is *not* new nor specific to natural gas and we should not put too much weight on one side. It only means that we must carefully look at the predictable evolutions of the energy situation and of the regulations. In this last domain a lot is being prepared, in particular at European Community level. Due to the possible impacts on all of us of most of the measures that are in preparation it is of the uttermost importance that we try to learn from those that started before us.

Even if the situations are very different between Europe and the United States, looking at what happened there can be very enlightening.

The North-American gas bubble has taught us several lessons:

- first: that the conditions of transportation and of pricing are extremely important. The intervention of governments represents high risks, even if it appears necessary for energy in general and for gas in particular.
- second lesson from this gas bubble: the uncertainty of the forecasts. The disappearance of the gas bubble has been announced as soon as it appeared and afterwards every year with a season-like regularity.

The US lesson has also taught us that a gas spot market can develop only if there exist overcapacities of production and transportation. If we want to create such a spot market we should accept to depart from usual terms of reference on economies and security of supply from far away sources.

If we want to increase gas consumption we have to accept that additional gas will be more costly because it will come from further away or from technically more complicated fields.

One last lesson from the United States is that the share of natural gas in the overall energy balance of a country can be drastically reduced, from 33 per cent of all energy consumed in 1972 to only 23 per cent today. This, in spite of great market fluidity and depressed prices. For Europe, the share of natural gas in energy consumption appears still bound to increase. But let us remember, from US experience, that this is not a necessity and that movements can go both ways. Again I want to stress that careful assessment of the possible impacts must be made prior to taking any extreme measures.

With this in mind, let's now take a closer look at what has already changed on the European gas scene and what are the forces that will lead to further changes.

Upstream

Domestic production today covers about 50 percent of Western Europe's gas needs and this percentage will be reduced to around 30 percent in the year 2010.

The complement to domestic production comes from four sources: the former soviet republics (currently named the CIS), Norway, Algeria and the volumes exported from The Netherlands.

Let's examine first the countries bordering the North Sea.

Not long ago everything was relatively simple: the producer discovered a field; he sold the reservoir on a depletion contract to a buyer with a guaranteed market on a take-or-pay arrangement. This way they spread the responsibilities more or less evenly among themselves.

This organisation is still chosen for certain fields in the UK and the Dutch sectors, but today almost all large contracts are supply arrangements, as the Troll agreements, which means that the producer now faces additional commitments upstream. Furthermore, regulatory bodies, like Ofgas in the United Kingdom and the EC Commission have brought about, or intend to bring about, changes in the structure of the gas industry that will have a direct effect on the producer. The Statoil-headed gas sales negotiating committee (GFU) in Norway, even though not the same type of organisation as the two previously mentioned, still exercises an overall influence on the country's gas policies that all producers will have to take into account.

Finally, exploration in the North Sea is becoming more and more complex because the size of the average discovery is gradually being reduced while the cost per unit of hydrocarbons produced shows a strong tendency to increase.

On the reserve side, the existence of very large fields represents a major asset to Norway. But the Norwegian Continental Shelf also contains numerous smaller fields which in general are more costly per standard cubic metre to develop. However, when these small fields are added together they represent a significant volume of gas reserves which should find its timely development.

This could be done either by giving these fields, within a reasonable period of time, a share in the already concluded sales agreements or by allowing them a real opportunity to sell their gas directly on the European market. The latter case would naturally be an exception to the existing GFU mechanism. This issue is of crucial importance in order for both Norway and the oil companies to maintain an acceptable level of income which in turn is used to finance further exploration. To encourage the development of these fields is an economically sensible policy, because the smaller fields will for the most part use existing infrastructure and thus prolong their life and economic return to the benefit of all parties.

The Dutch have shown us that this is a very sound and positive policy in the long term.

The Netherlands adopted a long time ago a policy designed to conserve for the long term their natural resources by encouraging exploration efforts through the commercial mechanisms offered to the producers. Due to the large flexibility inherent to the export contracts for the Groningen gas, they have chosen to play the role of swing producer if the demand fluctuates strongly over short periods of time.

Dutch reserves will continue to play an important role in the European market because, as mentioned, The Netherlands decided to develop a system that allows producers to quickly put a new field into production. In addition to its role as supplier, The Netherlands offers its neighbours the possibility to use its transportation network to transit gas for other destinations.

The United Kingdom requires a specific remark, since at this time it does not physically export any gas. Great Britain has the largest production of the non-exporting countries (currently about 55 billion cubic metres per year) and is today self-sufficient save for the imports from Norway. Regardless of these imports, it is clear that if all the fields currently considered economically viable in the United Kingdom were put into production this would result in an over supply of gas on the UK market.

This situation will hurt the producers on the UK Continental Shelf and, after a while, also the level of exploration unless the following factors are present:

- That the on-going liberalisation of the UK gas market gives all the producers real opportunities to sell their gas directly to the end consumers; and,
- that commercial freedom is absolute, including the right to freely export gas to other markets.

One should note that this situation may alter the current flow routes of gas on the European market.

The CIS countries, and Russia in particular, have huge reserves but they are the most distant from the main market. Current problems, mainly bottle-necks in transportation capacity and a lack of financial resources, will inhibit any short-term increase in their exports. I nevertheless consider that these problems will be solved within a reasonable period of time.

Algeria plays a crucial role as the supplier for Southern Europe and the recent decisions on new infrastructures (the doubling of the Transmed pipeline, the construction of the Maghreb Europe pipeline to Spain, as well as the revamping of the LNG facilities) will allow Algeria to, at least, double its current export capacity. But in order for its exports to exceed these already ambitious volumes new reserves will have to be proven. Sonatrach is currently inviting foreign investment for exploration and field developments in order to reach this goal, which I hope will be successful, despite recent political unrest.

In addition to these suppliers, there are other candidates already present in the market, such as Nigeria and Libya or those who are only potential suppliers, such as Qatar and Iran. They will in total most likely not represent more than 5 percent of the West European market by 2010. This limitation is mainly due to their lack of competitive advantage. But the role they play from a diversification point of view will be more important than their share of the overall market.

Transportation

The transportation infrastructure plays a crucial role in our industry. The market can develop only if the infrastructure follows suit. Development of the European market was thus matched by the ever expanding European gas network. In the beginning these pipelines were built to connect one source with one market. Now the new connections tend to connect directly either markets or sources. We now also have to take into consideration that one day the flow might be reversed.

Transportation costs play a pivotal role in the economics of gas projects and this will be more and more true in the future since the sources will be located further and further away from the market.

One of the main obstacles for new projects will be the financing, since these projects require heavy front-end investments which are to be depreciated over very long periods of time through long-term agreements between owners and shippers. Another factor that today plays an important role is the environmental opposition to

the construction of new pipelines. When taking these two parameters into account, it seems to us that the number of major new international infrastructures that will be constructed within the next 15 years will be limited; the Maghreb/Europe pipeline, which is already decided, a new pipeline for the gas from the former soviet republics, recently planned through Poland, a fourth trunk-line in the North Sea, and finally a major pipeline between the United Kingdom and the Continent, presently under study.

These projects will be costly and therefore all the concerned parties along the gas chain will have to work together to finance them. The projects will nevertheless have to yield an acceptable rate of return without compromising the financing of the project. This aspect is one of the most important in the current debate on third party access (TPA). I will develop this point later on.

As a final remark on transportation; when it comes to natural gas, geographic position remains crucial in that proximity to a market is an absolute advantage. In this respect, the Algerian gas has a definite geographic advantage in Southern Europe, where the only competitor is situated far away. The competitive situation between the North Sea producers and the CIS in Northern Europe is much more pronounced.

Downstream Market fundamentals

As a first remark, we note that the different countries in Western Europe, even within the EC, have different energy and economic policies as well as different structures for their natural gas industries. France generates 75 percent of its electricity from nuclear power and is satisfied with that. Italy, on the other hand, has renounced this energy form and Spain has passed a moratorium forbidding the construction of any additional nuclear capacity. The United Kingdom has for several years pursued a vigorous policy of privatisation and liberalisation, the energy sector included, while in this area France continues to promote its proper model of public service, which is mainly carried out by monopolies.

The changes introduced in the United Kingdom have encouraged the emergence of new actors in the market which now compete with British Gas. However, at the same time the young Spanish gas industry is contracting into fewer and larger entities. In Germany the gas industry has introduced in the Eastern part of the country the structure of regional oligopolies as is the case in the rest of the country. This structure remains legally open and did not, however, hinder BASF and Gasprom to construct the Stegal pipeline.

Loïk Le Floch-Prigent

The liberalisation of the gas markets is advancing at an unequal pace: some markets are open, while others are still closed for competition.

Eastern Europe will continue to be the most important outlet to the West for the Russian gas. These countries have all embarked on serious programmes for economic reform aimed at installing market responsive economic systems that in the future should produce realistic levels of gas prices. Despite these efforts, diversified supplies will result in increased costs which the economies of these countries will find difficult to support in the near future.

However, in the long run, the continued integration of the European gas network will gradually make it possible for them to secure supplies from Northwestern or Southern Europe thereby further assuring their security of supply.

In looking at the changing gas scene, I will distinguish between the new actors, the producers, the traditional gas companies and the consumers.

New actors

As I have mentioned already, it is clear that one of the most significant developments is the active role that the regulatory bodies have taken.

The main issue currently subject to close scrutiny are the principles for gas transportation. The two main issues in this debate have been the Transit Directive, which was recently adopted, and the question of Third Party Access (TPA), which is currently under discussion. In terms of gas policy, I do not think that the Transit Directive currently in force poses any fundamental problems, since it has translated smoothly into written law the practices for gas transit developed over time by the industry itself.

As for TPA, this is not a question of principle but rather a question of which rules will apply and which tariff will be paid. Ideal market conditions with perfect competition makes the existence of any regulatory body obsolete; I agree that such conditions do not exist for the time being and that we still need for some time some sort of regulatory body. But, for the EC countries I doubt that we can afford to have two types of regulators; one National and one European.

The goal of the regulators must also be clear; are they encouraging free competition as a resource allocation system or as a means to reduce gas prices? My feeling is that the EC regulator has both ideas in mind.

The positions taken by the different actors depend essentially on one crucial point; do they participate in an infrastructure that gives them access to a market or not?

The owners of the systems would naturally like to retain their particular rights, while the non-owners see in the TPA a low-cost way to transport gas as

well as an access to the market.

Are the arguments from the two sides really that different?

In the present phase of the discussion it is normal that both sides express their opinion and it seems to me that the political decision still to be made will have to take into consideration the following factors:

- the consumers value more and more the quality of service and the ability to freely choose their supplier; instead of a commodity, they look for a packaged product which includes more advanced and sophisticated services; and this multiplication of the supply services is geared towards the needs of the market.
- the investments to be made must show acceptable rates of return at tolerable levels of risk in order for the projects to be financed and realised; the existing system has shown that it fulfils these conditions;
- a TPA system must find a balance between the costs and the risks to be borne by the shipper and the owner that achieves these same conditions; this is not an impossible goal but up until today this goal has not been achieved;
- the producers must benefit from a stable and durable outlet for their gas which permits the financing of costly projects and risky exploration efforts over a sustained period of time; the practice of long-term contracts, both depletion and supply, has shown that they fulfil these conditions;
- at the same time, a market ruled by the forces of supply and demand, such as the oil market, has shown that it can fulfil the above objectives; oil developments are not that different from gas developments and the instruments in the crude oil and refined products markets have proven efficient;
- the passage from the existing market structure for gas to an efficient market driven system is undoubtedly what represents the highest level of challenge for all the parties involved and this will also be the most difficult to administer.

With these remarks in mind, what must be avoided at all costs in the current study phase of the TPA is the making of tactical decisions that later prove to be faulty and non-economic.

As for the national regulators, we have seen that they also carry an important voice when it comes to natural gas;

- in changing the competition on the UK gas market the role of the Department of Energy and Ofgas can only be described as fundamental;
- in Italy, a new law has approved ENEL's new role as a direct gas purchaser, by giving ENEL access to the transportation grid for its own gas;
- in Germany, the gas industry requests the decisions of the regulators on such important questions as gas price and transportation rights.

Producers

Throughout Europe, the producers have developed their reserves. In the beginning the gas was either sold on the domestic market or at the border to foreign distribution companies. However, as mentioned new factors are changing the existing system and in order to know directly the end markets and thereby be in a better position to forecast their direction, producers are forced to take a stronger presence downstream.

This can be seen by the alliance between Statoil and BP for the British market and their creation of a gas purchasing company together with Norsk Hydro. With this example in mind, the current organisation of Norwegian gas sales where only the GFU has the right to market Norwegian gas seems sometimes to be in conflict with active involvement in the gas market by all holders of gas reserves.

Gas distribution companies

The distribution companies have played a crucial role in developing the transportation and distribution grids, a role which each gained through its geographic monopoly.

At the time, the monopolies were certainly economically justifiable since these systems are all subject to economies of scale meaning that after the system is constructed, the higher the utilisation rate, the higher the rate of return and the lower the cost per unit transported or distributed. But, as already mentioned, consumers today are requesting the freedom of choice as well as more complete and durable services which are much more extensive than the mere supply of a commodity.

As for infrastructure, these are in place and to a large extent depreciated. Thus some think that the monopolies do not have the same justification as they had in the past. If existing monopolies endure they will have to prove that they are the best placed to deliver the increased level of services requested by the consumers.

The consumers

Finally, the consumers themselves are changing their behaviour. For example, the special needs of the electricity sector justifies that the electric producer himself negotiates his gas contract with the supplier in order to get exactly the terms he needs. This is illustrated clearly by the recent contract between ENEL of Italy and the Nigerian LNG project. In addition, other large consumers such as the chemical companies are also seeking to contract their gas directly from the producer.

Final reflections

Before concluding I would like to underline the following main remarks:

- Even though we forecast a significant rise in the total demand for gas in Europe, there are enough sources to cover this demand;
- However, to think that this gas will be available at cheap conditions is an illusion. As we have seen, these sources are located further and further away which means that their costs will increase;
- Given the risks inherent in exploring, producing, transporting and marketing these reserves, all the concerned parties must be allowed an acceptable rate of return on their investment;
- The environmental positive assets inherent in natural gas will guarantee our industry a bright future if they can be fully exploited;
- New regulations must not hinder the development of new markets or the construction of new infrastructures;
- The transit directive already permits the softening of the rules regarding transportation; but in order for it to come into real effect there must be gas available on the market.

Conclusion

The gas industry strives to establish long term relationships between entities that usually find themselves very far apart, both in terms of culture and geographic location. The gas flow is continuous, and so are the relationships that it knits together. That's why I think that the gas industry will have an important role to play in a future expanded Europe. ■

Gas link Ireland/Scotland — a national view

By Tom Reeves, Department of Energy, Ireland

Gas is now a worldwide tradeable commodity. The average therm of gas in Europe now travels over 2000 km and crosses two country boundaries. Gas comes from Russia to France. Russian gas is on the way to Greece. Norwegian gas is contracted to go to Spain and to Italy. LNG comes from Algeria and Libya to Italy, Spain, France and Britain. Nigerian LNG will be on stream in the next few years. A feasibility study is underway in the United Kingdom on the question of a gas interconnector with France. The whole gas system is fast becoming interlinked. For example, France buys natural gas from Norway, Holland, Russia and Algeria as well as having its own production. There is even talk about gas from Iran and Qatar. Huge investment is planned and required to bring this vital resource to market. The demand is expected to be there. Gas is forecast to significantly increase its share of TPE throughout Europe. The main growth sector will be power generation. Ireland will be part of this new scene.

The gas interconnector linking Ireland to the United Kingdom is an enormous undertaking. It is strategically very important. It will cost a lot of money and requires very capable project management. However, there is one thing not to be lost sight of — while the cost of the interconnector at IR£287,000,000 is huge it pales into insignificance when one considers that within ten years it is quite possible that the annual cost of gas through the pipeline could be fast approaching that figure.

In this paper I will set out the background against which the decision to build the interconnector was taken. I will discuss the place of gas in Irish energy policy and the place of the interconnector in the future of the gas business. I will also try to deal with some of the issues raised by various commentators in relation to the interconnector.

Energy policy

At the outset I would like to set out the Minister's approach to energy policy. It is his policy that Ireland have secure supplies of energy at reasonable cost. In order to do that we must make sure that the country uses as wide a variety of fuels as possible, that it does not have over-reliance on any one fuel or on any one geographic area. We would also like to produce as much of our own energy as possible and that is why we continue to press ahead very strongly on the promotion of oil and gas exploration.

Most countries have about five primary energy sources — oil, coal, gas, hydro and nuclear. We of course don't have nuclear but we do have peat. We import about two thirds of our energy supplies and in turn about two thirds of the imports are oil, either as crude or product. Oil still supplies about half our energy needs. And naturally we wish to use these fuels as efficiently as possible — hence the Government's drive on energy efficiency, and also of course on renewables. The indigenous fuels we produce are gas and peat, in about equal amounts. The bulk of both of these fuels is used for electricity generation. We have taken great care over the last number of years to have as wide a range of fuels as possible for electricity generation. At present oil is used only as the marginal fuel. Diversification of fuels and sources is vitally important.

Irish gas industry

The natural gas industry in Ireland is quite new. The Kinsale Head Gas Field was initially developed on the basis of using the gas in the Cork area for the generation of electricity by ESB and the manufacture of ammonia and urea by NET. In due course the Government decided that natural gas should have other uses. So the gas was brought to Cork and then Dublin. The Cork-Dublin Pipeline was built in 1982. Gas flowed in 1983 for electricity generation and for supply to the then Dublin Gas Co. A major programme to convert appliances to use natural gas was undertaken. There was also an ambitious marketing programme with high targets. The programme was carried through successfully on the engineering side but the Dublin Gas commercial targets were badly missed. Financial problems ensued. The result was the appointment of a receiver to Dublin Gas in April 1986. Throughout 1986 and 1987 gas had a very difficult time in Dublin.

The Government decided that the gas safety standards in Dublin had to be dramatically improved, with the need also for improved procedures and training. This programme was put in place by the Receiver and continued and expanded by BGE who had acquired the assets of Dublin Gas in November, 1987. This was an enormously expensive undertaking but it

has paid dividends. However, in order to make Dublin viable it is absolutely essential to increase the market share for gas, particularly in the residential sector where the highest margins are ultimately to be had. An aggressive marketing programme was undertaken. This programme continues to be very successful. And I have to say the Government's decision on banning smoky fuels in Dublin helped in no small way.

Gas is now seen as the fuel for heating and cooking. Bord Gals have now over 180,000 customers using natural gas, throughout all sectors of the economy. The market continues to grow. Having and holding such a market brings its own cares and concerns.

As I mentioned at the outset it is Government policy to have as wide a spread of fuels as possible. Energy security and continuity of supply is vital. Remember the Gulf War and the oil stocks question? It is Government policy that gas continue to play a major role in the Irish energy scene maybe ultimately supplying as much as 30 percent of our primary energy. All the investment and effort outlined above was undertaken on that basis. Gas throughout Europe is seen as the fossil fuel of the future. It is clean; it is available and it can be burned with high efficiency.

Ireland should produce as much of its own energy as possible. To that end the Minister and Government are strongly committed to the promotion of offshore oil and gas exploration. This is clearly witnessed in the initiatives which have been taken by the Minister over the past year. First he has settled the uncertainty with regard to taxation through the inclusion of a chapter in this year's Finance Act. New terms for licences and leases are currently with the printers. Last last year he signed a deal for seven wells and 4,000 km of seismic with Marathon. Naturally, we would dearly love to have abundant supplies of gas. But we also recognise that companies are not going to expend time and money searching for gas if there is no market for the gas, or if the price is not right.

Security of energy supply is fundamental. All other European countries have multiple sources of supply, landing points, gas storage systems and the United Kingdom even has fields retained especially for peak day problems should they arise. We have in effect a single source of supply of gas from Kinsale and Ballycotton. We have 180,000 customers at the end of a single line. The risk of anything happening is slight but if anything went wrong with the field or the line we would be in serious trouble. For example, an onshore break in the Cork-Dublin line could take up to two days to fix. But an offshore break would take far longer than that to repair. No gas for a long period, especially in the heating season would be a serious situation. But not only that — gas is not like electricity. Electricity can be restored with the flick of a switch, not so gas. I am informed that it could also take a considerable time to purge the gas lines and restore gas to all customers. But by then the gas industry would be in serious trouble. So far nothing untoward has happened. BGE have excellent surveillance systems in place — but without being in any way alarmist, you'd never know.

There are many ways of contributing to security of supply. There are different levels of security. A second field and a separate pipe to shore would help. A second loop line to Dublin would also help as would a storage arrangement. An interconnector to the north of Dublin or an LNG terminal would do. Any combination of the above would do. All cost money. And someone has to decide which is the way to go and when is the right time to move. Other issues have also to be considered — is the market going to grow, will the investment be economic and can we afford it? Are there alternatives?

In December, 1989, having considered all the issues the Government decided in principle that the way to go was with either a gas interconnector or an LNG terminal. A Task Force comprising Department of Energy and Bord Gals was established to examine the issues and to advance the project.

Many issues had to be considered. Was the project economically and technically feasible? Could BGE afford it? An extensive feasibility study was undertaken. We had outside consultants help us on the economic feasibility issues and technical consultants on the engineering. We visited other gas companies in Europe for advice and help. The EC provided funds to help on the feasibility study. The study was in two phases — a preliminary study and a final study.

We concluded that there was:

(i) Plenty of European gas available from the United Kingdom, Norway and Russia as well as gas from North and West Africa
(ii) that an LNG terminal was not economic
(iii) that a pipeline to the United Kingdom was economic
(iv) that there was considerable growth potential in the Irish market particularly in the electricity sector
(v) that a pipeline could be used for exports as well as imports
(vi) that if we got EC financing BGE could afford it
(vii) that now was the optimum time to build the pipe taking account of the age of the Kinsale Gas Field and the critical stage of market growth.

Having settled on the pipeline to the United Kingdom option we had to decide on a route from the economic, environmental and technical points of view. Sea surveys were conducted in the summer of 1990 on three routes. And interestingly and unexpectedly a route to Scotland rather than one to Morecambe or North Wales emerged as best.

Detailed cost estimates and economic evaluations continued to be carried out. Finally in December, 1991 the Government gave the final go ahead to build the interconnector.

Issues

There are many issues which were addressed during the two years from the first Government decision. One major issue was the purchase of gas. We embarked on a programme of gas purchase. We talked to anybody and everybody who had gas from the North Sea. And there was and is plenty of gas in the North Sea. In the UK North Sea 28tcf have been produced to date; producing fields contain another 28tcf; another 35tcf has been discovered and there is potential for a further 32tcf. And on top of that there are the enormous Norwegian reserves.

A number of things happened throughout 1990 and 1991 in the UK gas market which made life difficult for us. Firstly, in December, 1990 British Gas bought gas from the Marathon Brae Fields which moved the price of gas up by a huge amount in one fell swoop. British Gas thought they would be short of gas in 1995–6. At the same time the effect of the privatisation of the British electricity business began to be felt in the 'dash for gas'. Gas sellers were choosy; it had suddenly become a sellers' market.

If you want to buy oil you can just go out and buy a tanker of oil on the spot market. You can buy crude or product and you buy it in US dollars.

But gas is different. It does not have the ready marketability of oil. Up to now there has been no spot market in

gas except in the United States where circumstances are quite different. Gas is difficult and costly to store. Long term gas contracts (eg for the life of the field or for 20 years) have been the norm and such contracts include all types of provisions — contract period, annual volumes, average daily volumes, daily swing, annual take-or-pay quantities, firm or interruptible supplies, make-up, payment for under of over-take, the delivery point, the delivery pressure, quality of the gas etc. All of this is reflected in the price and the price may be a mixture of currencies. The price clause will have some form of an escalation provision and it will specify how often the price changes. It is an extremely complex business.

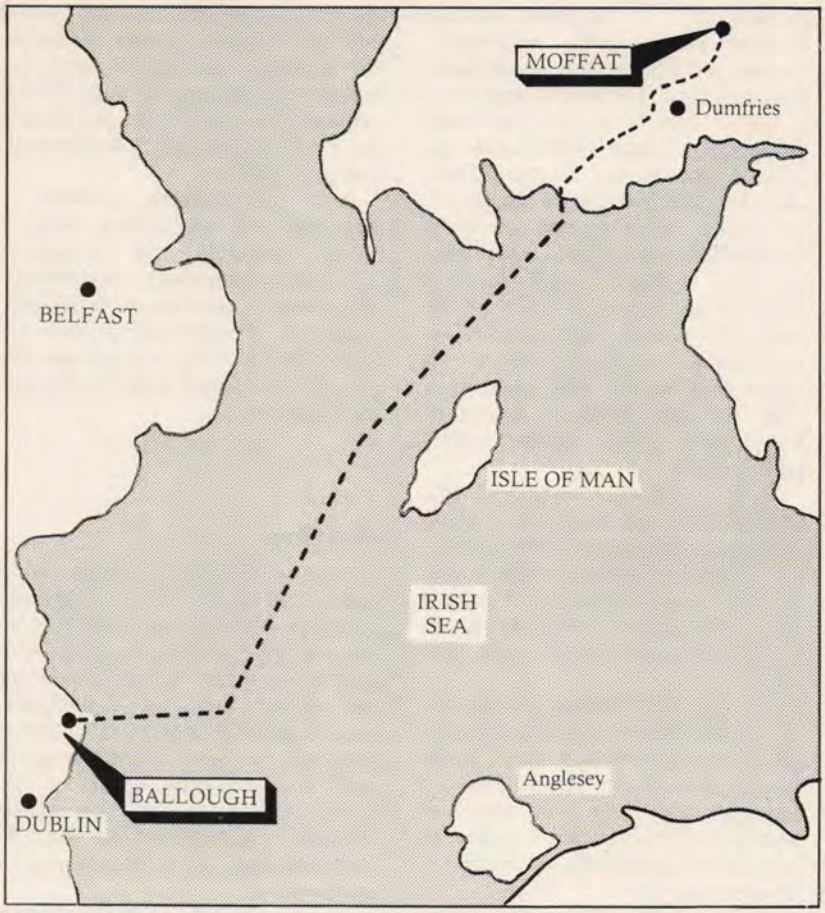
The more gas you buy, the closer the delivery point is to the producing field and the simpler the supply terms the cheaper the gas will be. Only a few suppliers could meet our requirements. In supplying the residential market load factor or daily swing are major concerns.

And at the end of all this the price has to be such that the gas can be sold at a profit. People tend to focus only on the price but as you see there is far more to gas contracts than price.

Because of the long term nature of the gas business what one has to decide is — is now the right time to buy, or should one wait (provided one can wait).

This time last year the view of certain respected consultants in the business was that the price of gas for delivery in 1995–6 rather than 1993–4 was going to soften when the UK electricity business had sorted itself out. Time will tell.

Having concluded that the current gas market would soften (and having started negotiations with Marathon on extra gas) the Board of BGE had then to decide whether or not to continue with the project or postpone it. The economics were reassessed in the new light. The Board decided that it was better to continue with the project, that security of gas supply was paramount and that the negotiators should return to the market in an attempt to purchase 'Security Gas'. The Minister agreed with this assessment. Security Gas is gas which would be available at very short notice to BGE in the event of any unforeseen event. As is now known such a deal was negotiated and successfully concluded with National Power, the largest UK electricity generator. This is a very interesting deal and is the first of its kind. So Irish gas consumers can now rest easy in the knowledge that for the next few years prior to the coming on stream of an ongoing gas supply that there will be gas available at all times — that their supply is secure.



Outline of selected route.

I should mention also that BGE, in parallel negotiations with the Minister's negotiations with Marathon late last year, concluded an agreement for extra gas from Kinsale to be made available by Marathon for five years through the provision of extra compression on the Kinsale Field. This deal will mean more gas for ESB in the short term and will allow BGE to meet its peak day requirements for the next few years.

Europe

There are a number of other issues which I would like to mention.

The EC are progressing towards the Single Market. Firstly, they are very keen on interconnecting networks — roads, railways, electricity and gas grids — and on liberalising the gas and electricity markets.

Ireland of course is on the periphery of Europe, not interconnected in any way on the energy front. Following discussions with the EC they decided to include the Irish gas interconnector project in their REGEN initiative. As part of the overall regional funding the Commission have about 10 percent of the total funding for their own initiatives. And in this energy network initiative they have four interconnection projects, one of which is ours.

Following the feasibility study we made a formal application for grant aid. After extensive discussion and examination of all the issues the Commission decided last December to grant aid the project to the tune of 108mecu, about IR£85m. We are very pleased and grateful for this. A formal monitoring committee is now in place and monthly reports on progress go to the Commission.

Also on the Single Market front the EC are trying to open up the electricity and gas markets to competition. Needless to remark this is not all plain sailing. Everyone is in favour of com-

petition, but . . . . A proper balance between public utility obligations, security of supply and competition must be struck. The level of regulation is also an issue. The Commission are proposing, amongst other things, the unbundling of the gas commodity part of the business from the pipes business, to initially allow consumers above 25,000,000 cu.m. (approx. 8m therms) per year access to high pressure pipelines and to put in place framework rules for this. They are keen on subsidiarity — each country should make its own rules and regulations. They are very much in favour of transparency and against cross-subsidisation.

There is strong objection to this proposal from many quarters — and they are not all just attempts to protect vested interests. Certainly there is concern about the protection of captive customers and the need to safeguard existing long term take or pay contracts.

However, the Minister is certainly prepared to allow gas users to transport gas through the interconnector. Details on this are not yet settled. But, for example, any large user who had bought gas in the United Kingdom or elsewhere could certainly transport it here for own use.

The Minister has stated his wish to have an equity partner with BGE in this undertaking. It is financially an onerous undertaking. However, in the absence of such a partner BGE are quite capable of going it alone. Much has been made of the negotiations with ESB. Let me state clearly that the breakdown of these negotiations had nothing to do with the principle of the interconnector or the level of the ESB minority partnership. Agreement could not be reached on some critical issues in the negotiations. In passing I should say that the failure of the negotiations had nothing to do with the price of gas. However, that is not to say that agreement is not on. It is always open to the parties to reopen negotiations at any time. The Minister would be happy to facilitate possible minority equity participation by ESB or other potential investors. Meanwhile BGE are in discussion with a number of other parties with a view to participation. They are also now finalising the financing package.

There are two other items which I would like to mention.

This interconnector will pass at some point under the Irish Sea from Irish to British jurisdiction. It also passes through the territorial sea of the Isle of Man. An agreement was reached in 1988 on a delimitation of the continental shelf between Ireland and the United Kingdom. However, the northerly most agreed point was still south of the pipeline route. So it is necessary to delimit the sea so that there is a clear boundary between the two jurisdictions.

It is also necessary to have an agreement on the pipeline itself — safety standards and inspection, ownership and operators, environmental protection, connections to the interconnector, security, liaison and dispute settlement arrangements. We hope to have these negotiations concluded soon.

Critics

A number of issues in relation to the interconnector have been raised in the media from time to time, mostly to the effect that the interconnector was being built too soon and that we should stop the project, that the Government should spend the money on something else, that it should cut off the gas to NET and from time to time we hear that we should not be using gas for electricity generation and that the interconnector is a disincentive to exploration.

I have dealt earlier with the question of timing. We have always known that there would be low but increasing volumes through this interconnector in the initial years. But you cannot build a variable size line; a decision has to be taken at the outset on the size of the line. Extensive optimisation studies on the system were done on the appropriate size of the line — even to the extent of looking at two smaller lines rather than one larger line. We looked at building one small pipe now and another in 10 years time. We looked at the best operating pressure and incremental arrangements for the compressor station. We looked at the best mix between onshore and offshore facilities. We looked at the best design life and the best design flow. This pipe will last for 50 years. It will meet Irish peak demand in 20 years time. Part of the system may supply gas to Northern Ireland. It will also be possible to supply gas to the Isle of Man. This is a long term infrastructural investment — we were never looking for a 1–2 year payback.

This time last year we examined the pipe manufacturing market and the lay-barge market. We hired specialist consultants in these areas. We concluded, on this advice that in 1992 there was plenty of spare capacity in the steel mills and that 1993 was a very good year to lay the pipe. There was plenty of activity expected in the North Sea in 1994 and 1995. There are only two lay barges large enough to lay a 24" pipe. So we decided to carry on. The advice we received was sound. Excellent deals have been struck all round. In fact we have now taken advantage of an ideal window of opportunity on many fronts. Postponing the project would be riskier on the security of supply question and the project would be more expensive.

Naturally, there are alternative means of proceeding with the interconnector. The Exchequer could have financed the project itself and continued in the normal way to receive dividends from BGE. Or the Government could have advertised for someone to build an interconnector for us and deliver gas to Ireland. The Government decided that BGE was the appropriate vehicle for this project. To meet Government policy on energy such a project would be required sooner or later. If we waited too long, BGE, as well as taking risks on continuity of supply and market growth, might not be able to afford it. The Government have decided that strategically now is the best time to build the pipeline.

It has also been suggested that the building of the interconnector could be put off by reallocating some of the Kinsale gas. In particular it has been suggested that the supply of gas at 'less than economic prices' to the fertiliser industry should be stopped and the gas reallocated if a more commercial price is not paid. There are a number of complex issues here and certain practicalities such as existing interacting contractual obligations which cannot be ignored. In order to have a reallocation of this gas BGE would have to buy out the contract. If BGE bought the gas and couldn't find a home for it at a price higher than they paid for it they would have to leave it in the reservoir. However, they have a contractual obligation to Marathon on annual take-or-pay quantities. BGE would be stuck with a huge expenditure up front and no matching income.

If the gas was kept in the ground to be used after the year 2000 its production would require a further agreement with Marathon. Also it should be pointed out that gas fields have technical optimum production profiles and there would be no guarantee that we would get out all the gas we had paid for if we deviated too far from that profile. Such an approach would not mean that there

would be no investment required for a very long time because certainly at some stage over the next few years BGE would have to provide for peak day supplies. Not everything could be postponed and postponing the interconnector in this way is not free.

It has also been suggested from time to time that using gas for electricity generation is a waste of this valuable resource. It is clear that the new technology of CCGT units are highly efficient. Conversion efficiencies of over 55 percent are common nowadays. This means that such users can afford high price for gas supply. It is recognised throughout Europe that power generation is the new developing market for natural gas. The Minister has announced on the electricity front that he is considering the question of independent power production. Maybe someone will be along in a few years time with such a station using gas supplied through the interconnector.

It has been alleged that the interconnector is a disincentive to exploration. On the contrary the existence of the interconnector allows gas from the Irish offshore access a new market in the United Kingdom and ultimately on the continent. All kinds of swap arrangements are possible in this area.

The Government are fully committed to the development of the Irish gas industry, and see this project and the furthering of offshore exploration as essential components of this policy objective. ■

Full proceedings of the conference, 'Gas Link Ireland/Scotland — Why and How' organised by the IP Irish Branch in October, are available from: Eugene McCarthy, Marathon Petroleum Ireland Ltd, Mahon Industrial Estate, Blackrock, Cork, Ireland, at a cost of IR£25.

A Shell photograph

Emphasis on Omani gas resources

By John Roberts

The first age of the Omani oil industry is now over and a new era is starting. The aim is no longer to increase production but to maximise earnings by developing downstream facilities and expanding overseas. The principal domestic emphasis in the energy sector will be on harnessing the country's gas resources, although the discovery of new oilfields in 1991 makes it likely that Oman will play safe by pursuing at least a modest increase in production capacity, if not in actual output.

So far, there have been three distinct ages in Omani oil development — if one discounts the missing years between 1951, when the Oman Oil Development Company was founded, and the actual start of serious drilling in the mid-1960s. The first age saw production move from zero in 1966 to 330,000 barrels per day (b/d) in 1969; the second saw it remain at much the same level until 1982 when, with oil prices at their highest and prospects for expansion seemingly looking good, a 10-year phase of steady growth ensued which took production up from 325,000 b/d in 1982 to around 700,000 b/d last year.

However, 1992 seems set to be the last year of this era. Various expansion projects have ensured a continuing rise in production, so that output by May was put at around 720,000 b/d, with a number of projects still in hand to ensure a further increase in capacity. At the end of May, Petroleum and Minerals Minister Said Ahmed al-Shanfari declared that 'The government of Oman has decided to raise oil production to 750,000 b/d by the end of this year.' But, he then added, this level 'would be maintained for 10 years.'

Similar statements have been made before but this time there are some compelling reasons to believe that this is the policy to which Oman will, in fact, adhere for the rest of the century — unless, of course, there is a major international supply crisis in the interim. The first reason is that so long as oil prices remain in real terms at around their current level, Oman's oil income meets its budget requirements neatly, with a little bit over to put into a newly-created fund to be touched only in the event of a major deterioration of government finances.

The second is that the government is switching the emphasis from development of oil resources to gas. Oman's financial and technical resources are limited and the aim is now to build up the gas industry to complement oil.

New oil discoveries

Oman's willingness to produce at its targeted level reflects its comparatively low reserves/production ratio. At a production rate of 750,000 b/d, the current level of reserves, 4,550 million barrels, would be exhausted in 16 years. Last year, however, a cluster of new oil discoveries meant that, while production totalled 255.5 million barrels, around 405 million barrels of oil was found, thus swelling the reserves by around 150 million barrels.

To maintain production at 750,000 b/d will, of course, require some continued development work. Bidding closed in September for construction work on the offshore Bukha field, which an affiliate of Canada's International Petroleum Corporation is developing. At the same time, the second phase of the Yibal oilfield is under way, with design studies being undertaken by Switzerland's Electrowatt and the United Kingdom's Granherne for four

gathering stations which are being expanded. The project should be completed by the end of next year.

At Lekhwair, the completion early next year of a £300 million water injection programme should raise production capacity from a mid-1992 level of 25,000 b/d to 120,000 b/d. Whether actual output will rise that high will depend very much on whether the government is serious about keeping output at 750,000 b/d.

One sign that the government is adhering to its new policy is that last year Petroleum Development Oman (PDO) spent well under its development budget. It had been allocated 163 million Omani rials (£233 million) but in the event only spent 142.3 million rials. Last year, the company's actual output grew by just two percent to around 665,000 b/d, although this did mean that it contributed no less than 1,240.7 million rials of the government's total income of 1,570.4 million rials.

In general, the government believes that this year will see an increase in oil revenues and also a substantial increase in gas revenues that will enable it both to raise spending and to reduce the size of its deficit. In 1992, according to current projections, net oil revenues look set to rise by 34.7 million rials to 1,271.4 million rials. Much depends, however, on the price of oil. The government is basing its plans on an oil price averaging around $20 a barrel for the period of the current 1991–95 Five Year Plan. One concern, the result of the 1986 crisis when an earlier plan was briefly suspended amidst the collapse of international oil prices, is to insure against any sudden cash shortage for development work. The Central Bank Governor, Hamoud ibn Singour bin Hashin, therefore announced a year ago that Oman would in future earmark 7.5 percent of its oil earnings each year to a new emergency fund. Should prices exceed $20 a barrel for any length of time, then the amount would be increased to 10 percent.

Gas potential

But if a new oil fund is one insurance policy, a still bigger one is the development of the country's gas potential. Last year, following the discovery of an estimated 7 trillion cubic feet of new gas at Saih Roh, Saih Nihayada and Barek Mohaseb in Muscat, it was announced that reserves had virtually doubled to 16.92 trillion cubic feet (tcf). That is not much less than the United Kingdom and, though considerably lower than those of its neighbours in the Gulf, it is more than is known to exist in either Egypt or Australia. Moreover, Mr Al-Shanfari has said that some studies indicate the true size of Omani gas reserves could be 33–34 tcf.

In May, the Omani government signed a memorandum of understanding with its three foreign partners in PDO (Shell, CFP and Partex) and with three Japanese companies for a $9 billion liquefied natural gas project. The proposed plant would liquefy gas for export to Japan and the Far East from around 1999 onwards. PDO would undertake exploration and development of the gas fields, with the government owning all upstream facilities, whilst the proposed joint venture would undertake construction of downstream facilities, shipping and marketing operations. The government would have 51 percent stake, while other shares would include 42 percent for PDO's three foreign partners, 3 percent for Mitsubishi, 3 percent for Mitsui and 1 percent for C Itoh. For the moment, however, gas revenues are still low. They totalled 48.8 million rials in 1991 but should reach 68.9 million rials this year.

Caspian moves

Perhaps the most intriguing aspect of Omani oil development is its move into the international pipeline sector. A new venture called the Oman Oil Company (OOC) has been set up and this is described in official publications as being owned directly by the Omani Ministry of Petroleum and Minerals.

OOC, founded four or five years ago with responsibility for all Oman's overseas oil activities, has in recent months secured two considerable coups. It has helped establish the new Caspian Pipeline Consortium to build an oil pipeline network to carry the output of Kazakhstan's giant Tengiz field and production from elsewhere in the new Central Asian republic to an international entrepot and export terminal (see *Petroleum Review* August 1992). It has also signed an agreement under which the Oman Oil Company will explore, develop and produce oil and gas in a 16,000 square kilometre region of Kazakhstan called Atyrau. As part of the second accord, OOC also has rights to exploit previously discovered reserves in the nearby Dunga field.

But it is the pipeline that grabs the imagination. Although Kazakhstan will be its prime *raison d'être*, the consortium being set up to run the scheme is open to other nations and the idea is that it will provide the former Central Asian Republics of the Soviet Union as well as the states of the Caucasus with new outlets to international markets that are not primarily dependent on routes through Russia. So far, Azerbaijan and Russia have joined the consortium and it seems likely that efforts will be made to persuade the gas producing republic of Turkmenistan to join in as well.

Chevron, which is developing the Tengiz field, has signed a Memorandum of Understanding to join the pipeline consortium. The US company has declared its 'desire to obtain priority access' to the pipeline for crude to be produced from the Tengiz and Korolev fields.

Oman will be responsible both for providing start-up costs and arranging finance for the project. The Oman Oil Company will be in charge of implementing the agreement. It is understood that Oman will undertake to raise funds on the international money markets which will be paid off through petroleum sales by Kazakhstan once the pipeline is operational.

Pipeline route

The key unanswered question concerns the pipeline's international terminal. Possible outlets on the Gulf, on the Black Sea and on the Mediterranean are all being considered. Turkey is pushing hard for the line to pass under the Caspian, through the Caucasus, across eastern Turkey and thence to the existing oil terminal of Dortyol, the outlet of the currently disused Iraqi pipeline. Russia naturally favours a Black Sea terminal with a possible approach around the northern end of the Caspian and this appears to be the route favoured by the Omanis themselves. Mr al-Shanfari, a director of the consortium, has said it is the route through Russia which is 'the most economically attractive and politically stable option.' This may be a somewhat optimistic gloss, since the route in question passes through Groznyy, capital of one of the most unstable parts of the Russian Federation.

Should a route to Iran be chosen, then Oman's diplomatic skills will be taxed to the utmost, given Arab-Iranian mistrust stemming from Iran's tightening of its grip on the disputed Gulf island of Abu Musa.

There are no less than eight major variations on these three principal routes, with the result that the cost of the project, and thus the amount that Oman will have to raise, could be anything between $700–1,600 million. For Oman, the pipeline plan, together with the LNG project and a possible 20 percent stake in a new Caltex refinery to be built in southern Thailand, are signs that the country's energy industry has come of age — and can now leave home. ■

Denmark's achievement of energy security: the role of oil and natural gas

By Geoffrey Mayhew

The use of innovative and unconventional technology in the exploration and production of oil and natural gas has enabled Denmark to fulfil its own needs for oil and gas in less than a generation. Twenty years ago, just before the time of an oil supply crisis, Denmark had only negligible oil and natural gas resources in production.

Last year Denmark became self-sufficient when domestic production of oil and gas combined provided 103 percent of demand for hydrocarbons. This year production of both is expected to be even higher.

As a result, Denmark has become a net exporter of natural gas, selling 1.3 billion cubic metres to Germany and Sweden in 1991 after meeting its own requirements from the 3.51 billion cubic metres produced for consumption. A contract for annual supplies to Sweden is expected to deliver a level which will reach 1.1 billion cubic metres of natural gas in the mid-1990s. Further market openings are being sought.

At the same time, in order to ensure the security of supply which is an essential part of its energy policy, Denmark is considering the introduction of an open-door licensing system.

New technology

Two production technologies which are playing a vital and increasing role in Denmark's success in finding oil and gas and its extraction from difficult subsea strata are horizontal drilling and the large-scale use of water injection.

In 1987 the first horizontal well was drilled as an experiment in the Dan field by Mærsk Olie og Gas AS, the operator for the Dansk Undergrunds Consortium (DUC).

At the end of September the number of drilled and completed horizontal wells in Denmark was 31.

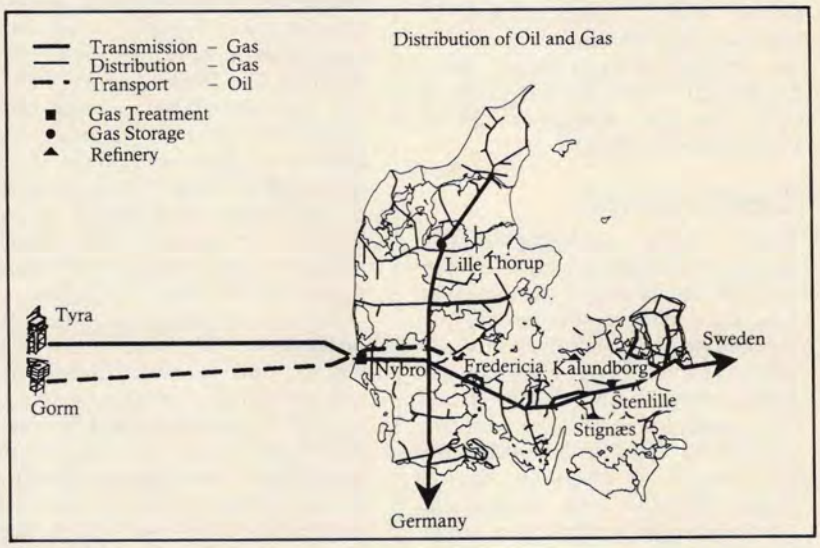
State-of-the-art technology, which makes it possible to drill long wells producing from different zones, has gained increasing importance in Danish oil production. In a number of fields such wells have been completed with extensive hydraulic fracturing of the reservoir, the fractures being subsequently filled with sand.

Most recently, hydrocarbons have been extracted from a number of open-hole sections which fan out from the last section of casing in the wells in question.

'A development of this technique is called "fingering",' said Peter Helmer Steen, Deputy Managing Director, Danish Energy Agency (DEA). 'At the end of a horizontal drilling as many as three spurs have been made. They have a spread like fingers of a hand.

'The individual lengths of these fingers will depend upon what each is trying to find, but they will not be of a great length — not more than a kilometre — but they are proving to be a useful method of enhancing recovery and DUC intends to develop them,' he added.

To an increasing extent recovery from Danish low permeability chalk fields is taking place through horizontal wells. Up to 50 wells are planned during the next three years — an



Denmark

estimated 80 percent of all new wells planned.

In 1991 the operator, Mærsk, set new records — the MFA-18 well in the Dan field is the longest well drilled to date using the technology to produce from several fractured and sandfilled zones. The total length of MFA-18 is approximately 4,300 metres measured from the platform.

It produces from 13 zones which are separated from each other with production packers, and the completion has the capability of closing/opening each zone separately. Up to 15 zones can be completed in one well. Normally the horizontal section of a well is drilled in eight and half inches and cased with a seven inch liner. Some do have five inch liners, and some have open hole sections below the seven inch linershoe.

The TWB-11 well in the Tyra field has one of the world's longest horizontal sections, extending for more than 2,500 metres through a thin oil zone. The oil zones vary between seven and 20 metres in thickness.

STAR innovation

A new, low-cost, platform type which the Danes have designed to produce from small discoveries is STAR (Slim Tripod Adapted for Rig).

The lightweight construction of STAR, which is approximately 600 tonnes excluding foundation piles, allows installation from a jack-up drilling rig. The platform is fixed at the sea bottom by driving steel pillars through steering devices mounted on the supporting legs. The lift and installation of deck and topsides can then be carried out from the rig, although some STARs have been installed with a crane vessel.

The first of these production platforms, which the DEA says provide considerable cost savings compared with conventional steel jackets, were placed on the Kraka and Dagmar fields.

The present STAR platforms are being used in fields with an average water depth of 40 metres. A larger type is being designed for deeper waters. The use of STARs, connected to a traditional platform, features in further development plans in the Dan and Skjold fields.

The use of horizontal drilling, water injection and STARs enabled the DEA to upgrade its assessment of reserves in January. This showed an increase in oil reserves of 22 percent and in gas of 17 percent, in relation to the volumes which can be recovered by known technology under prevailing economic conditions.

Miss Anne Birgitte Lundholt

The DEA stated that oil production can be sustained at 1991 levels — 8.3 million cubic metres — for 27 years, compared with the 21 years of the previous assessment made a year earlier.

Oil's share of Denmark's energy requirements was over 90 percent, almost all of it from overseas, when Denmark was hit by the Middle East supply crisis in the early 1970s. In response to energy security plans, which included the promotion of indigenous oil and natural gas production, fuel substitution in electrical generation, conservation and support for renewables, oil's share then fell rapidly.

The power stations were switched back to coal from oil, a move facilitated by their retention of coal firing equipment. By 1989 oil's share in total energy was less than 50 percent but Denmark's own oil was providing 65 percent of the oil consumed. Today Denmark imports no more than 15 percent of its oil needs.

Exploration — past and present

The quest for oil in Denmark began as early as 1935. A concession for the whole of Denmark was awarded in 1962 and DUC was founded the same year. The first discovery was the Kraka field, in 1966.

After two offshore fields had been brought into production the agreement was changed, in 1981, and an accelerated relinquishment was agreed upon. DUC's concession now covers less than two percent of the original area. The oil is brought ashore through a state-owned pipeline, paid for by DUC, and a 5 percent profit element is paid on the oil it transports. The state has a right to buy 40 percent of the oil.

DUC comprises AP Moller, 39 percent; Shell, 46 percent; and Texaco, 15 percent; AP Moller being the Chairman. The seven offshore producing fields they operate, through Mærsk, are: Dan, Gorm, Skjold, Tyra, Rolf, Kraka and Dagmar. Under development are: Valdemar, Regnar, Svend, Roar, Adda, Igor and Harald. Some finds have a very short lifetime. For instance, the Regnar field, to be produced in 1994, is expected to last only 34 months.

Discoveries have also been made in recent years by Amoco at Ravn and by Statoil at Amalie. Both are now being evaluated. The Statoil find encountered oil and gas in deep sand layers, which was encouraging as few discoveries of this kind have been made in Danish territory. However, additional investigations are taking place to assess it fully.

Open-door licensing?

Despite an encouraging picture, however, the Ministry of Energy fears that Denmark's possibilities in adapting its concession policy to the ever-changing needs of the increasingly competitive exploration situation may be overshadowed, or inhibited, by a proposed new EC directive.

The Danish government has declared its opposition to this directive because it would, among other matters, hinder an open-door licensing system.

The Ministry of Energy has not yet issued any licence under an open-door system but it sees that the adoption of such a system in certain areas would be an effective method for increasing discoveries and production in the long term.

'We have noted that is a practice which has been used in Germany, Ireland and other parts of the world and can be a possibility for areas outside the Central Graben,' said Carsten I Pedersen, Head of Licensing and Production Department, Ministry of Energy.

'The data on the Danish underground is considerable, and we are actively considering inviting companies to come and look at it and use their own resources through an open-door licence system. We regret that the EC has produced a directive which would prevent this,' he said.

'In opposing it we have also said that we do not believe a licensing directive is necessary. Member countries engaged in exploration and production

are clearly doing a good job in relation to their particular conditions. A licensing directive would not, we believe, stimulate any extra production. There is also the concern here that the directive would have a bad effect by being retroactive. This fact would require countries to change their present contracts with companies. It is not in the best interests of the community to introduce general rules to that effect,' he added.

When the directive was first discussed by the EC Council last May, the Minister of Energy for Denmark, Miss Anne Birgitte Lundholt, stressed the need for transparency and non-discrimination and stated that the general provisions of the Treaty of Rome were sufficient.

'I am also opposed to the provisions that involve significant restrictions in respect of certain regulations which member states use to achieve their energy policy objectives,' said Miss Lundholt.

'These regulations concern *inter alia* provisions on state participation, sale and purchase obligations and compulsory connection to pipelines,' she added.

The Ministry of Energy would like to have a fourth offshore licensing round but world conditions are not appropriate. But they are encouraged with the results of an onshore licensing round earlier this year.

Oil companies were invited to apply for individual percentages for the exploration of the Logumkloster, in south Jutland. The Ministry preferred that type of composition rather than applications from already constituted groups.

'The results have been very good,' said Mr Pedersen. 'A group composed of Dansk Olie og Gasproduktion AS (DOPAS), 50 percent; RWE-DEA Denmark Oil GmbH — the former German Texaco company, 35 percent; Ruhrgas Aktiengesellscaft, 10 percent; and DENERCO K/S, 5 percent, has been formed. This demonstrates the exploration possibilities in Danish areas outside the Central Graben, where the existing fields are. The group intends to start with a conventional appraisal well in 1993, as a follow-up to a previous discovery well.'

This Logumkloster discovery was not commercial but in recent years DOPAS has given it a more optimistic evaluation.

Producing fields in Denmark

The Dan field started in 1972. When 12 horizontal wells were introduced in the 1987–90 period there was a vast expansion of primary recovery. In July the average daily production of oil from Dan was 48,329 barrels, compared with 29,711 a year earlier.

Water injection systems will be implemented in large parts of Dan using four horizontal and eight conventional injection wells. In time, nine existing production wells will become injectors.

Kraka, 7 km from Dan, was initiated with two horizontal wells and a STAR platform in 1991. Recovery conditions, which have included problems in preventing gas and water from penetrating the oil wells, have led to a stage by stage development. However, Kraks's daily rate in July was above that for 1991.

A plan for Gorm's further development, which was decided in 1991 — 10 years after it came on stream — is based on secondary recovery by water injection and the drilling of further horizontal wells. Gorm's production increased by 4 percent in 1991 over 1990 to 1.5 million cubic metres.

In 1986 water injection was initiated for Skjold, four years after production began. In 1991 Skjold produced 2.73 million cubic metres of oil.

Rolf, a small satellite in the Gorm group, began to produce water increasingly after one year. Nevertheless, in 1991, four years later, 0.29 cubic metres of oil was extracted — 8 percent more than in 1990.

The Dagmar field has been developed as another Gorm satellite, and with a STAR. There is a high content of hydrogen sulphide in the associated gas but as the oil production is low the cost of cleaning is not justified. Nearly 90 percent of the gas is flared. In 1991 it produced 0.48 million cubic metres of oil.

The Dan area, it has been decided recently, is to have the first subsea system in the Danish area. This will produce Regnar, from a single well, and be hooked to a Dan platform 12.8 km distant through an 8-inch diameter pipeline. It is expected to be operated for only 34 months but the Danes will be pleased with the 0.53 million cubic metres of oil and the 38 million cubic metres of natural gas.

The Tyra field has a large free gas cap overlaying a thin black oil zone. It is the main gas source for Denmark and produced 3.67 billion cubic metres of natural gas in 1991.

Originally, Tyra's oil prospects were marginal but horizontal drilling has shown a better potential for oil production. In 1991 oil and condensate output totalled 1.39 million cubic metres. Application for a further development plan for Tyra was presented to the authorities at the end of September.

The Valdemar field, which will be processed on the Tyra centre, is spread over 200 square kilometres, the largest in size to date. It is due to start up in 1994, when three horizontal wells will be required and a STAR.

Greenland and the Faroe Islands

Greenland and the Faroe Islands, both of which have home rule government, have separate agreements on exploration and production of hydrocarbons.

A Mineral Resources System for Greenland is based on the joint decision making powers of the Greenland Home Rule Authorities and the Danish government. These relate to major and what are described as essential decisions in exploration and production.

Greenland will receive 50 percent of any revenue from exploration and production, while the government of Denmark will continue to pay for the administrative costs of overseeing licensing, day-to-day operations and keeping an office in Greenland.

Greenland and Denmark have also agreed that exploration must be promoted and intensified. There will be a number of licensing rounds in the next decade, the deadline for the first round applications being 15 January next year.

The Faroe Islands, on the other hand, will receive all the revenues arising from oil and gas discoveries, and they will be responsible for their costs, as the result of a recent agreement between the Danish government and the Faroese Home Rule.

If significant income from hydrocarbons arises in the future, then adjustment of the yearly transfer from Denmark will be negotiated between the Danish government and Faroese Home Rule Authorities.

Currently there is no prospective exploration around the Faroe Islands but there has been seismic activity in water depths of 400 metres to the south.

Downstream

The changes in Denmark's energy policies since the early 1970s and the availability of increasing volumes of natural gas have reduced the scope of the downstream oil market.

Heavy fuel oil lost its power-station business during the 1970s to cheaper coal. Since 1979, inland consumption of fuel oil for other purposes has lost to coal and natural gas 80 percent of the five million tonnes a year it was then selling.

In Denmark some 50 percent of the residential heating market is connected to district heating networks. When natural gas was introduced to the market in 1984, without a tax, it was sold at the equivalent price of heating oil including an excise duty. Today that constitutes 60 percent of the consumer price, reports the Oliebranchens Fællesrepræsentation, the Danish Petroleum Industry Association.

Because the tax element has been used to only a limited degree competitively, the association say that natural gas made slow in-roads into the home heat market. But natural gas is now seen as a real threat.

The 1990 Heat Supply Act began the conversion of district heating plants into small-scale combined heat and power (CHP) units, mainly fuelled by natural gas. By 1994, more than 30 large coal-fired and natural gas-fired district heating plants will have been converted from separate heat production to CHP, mostly using natural gas.

Between 1994 and 1998 the local authorities will convert all remaining district heating plants to natural gas CHP, although the use of biomas will be allowed. Subject to approval a 400 MW gas-fired and a 400 MW coal-fired power stations are to be built by 2000.

The expansion of electricity production capacity will come from CHPs and large natural gas fired power plants. Denmark has hopes of an electricity export market.

Energy use constant

Although the composition of total energy has changed, the amount of energy used has remained essentially constant since 1979. Nevertheless, Danish GNP has increased by 35 percent in the same period.

'For good reasons Denmark, which was 93 percent committed to oil in the early 1970s, is no longer dependent on the Middle East,' said Jørgen Pøsborg, Director, the Danish Petroleum Industry Association.

'The price to society of that change has, however, been high. A large part of the conservation efforts are worthwhile only in consideration of the heating oil tax, the more exotic substitutes for oil are justified from an environmental conservation point of view only. The natural gas project remains a white elephant. The final result is an energy bill for Denmark which is at least five billion kroner higher annually than it needs to be.

Mr Jørgen Pøsborg

'Natural gas was never a good proposition for Denmark. The country is not very densely populated and the main centres, like Copenhagen, are far from the natural gas fields offshore. And then these main centres are sensibly enough using waste heat from power plants.

'For the future there is some potential growth for transportation fuels, but clearly the fuel and heating oil market remains in steady decline.

'It is somewhat ironic that Denmark has become almost self-sufficient in oil, but we do not want to use it. We export our fuel oil at bargain prices and substitute it with high cost alternatives. A somewhat masochistic approach.' he said.

EC harmonisation on tax has made petrol in Denmark very much cheaper than in Norway and Sweden and even cheaper than in Germany. The practice of Danish motorists crossing into Germany for a fill-up has stopped.

Retail market

Over 25 years the number of retail outlets in Denmark has halved to 3,000 but the outlets have become more important — as shops.

'While ordinary shops must close at 5.30pm, the law allows petrol stations to sell a stated list of goods after that time, for example, water but not wine; cake but not meat,' said Mr Pøsborg. 'This has become a useful business.

'Some supermarkets do sell petrol, but the retail outlet does not have their challenge of highly discounted petrol, as in the UK. Competition among the brands, however, is fierce with some going for heavy discounting at the pump while other brands issue their own credit cards — the use of which obtains for the motorist a discount.'

There are Danish brands among the petrol wholesalers but the main players are Statoil, Shell, Q8 and Texaco. Petrol is at present the preferred car fuel.

The tax on petrol has come down but taxes on cars, which include taxes for different weights and types of vehicle, are high. The combination of weight and motor fuel taxes means that a motorist has to be travelling about 25,000 km a year before he has a price advantage in switching to diesel. A would-be LPG motorist would need to be travelling 50,000 km a year before he would profit from the change.

The capacity of the three refineries in Denmark, operated by Shell, Kuwait and Statoil, are well matched to demand and are competitive in the international market where they sell most of their fuel oil.

In the implementation of EC environmental controls for the storage and distribution of petroleum products, the oil companies in Denmark are ahead of schedule, reports Mr Pøsborg. This includes the installation of floating roofs on storage tanks and the collection of vapour emissions during delivery.

A recent review of energy policies and programmes of member countries by the International Energy Agency said that Denmark had made significant achievements in energy efficiency since the early 1970s. In its recommendations, it said that in the course of re-examining the tax system, Denmark should give serious consideration to a balanced level of energy related taxes to foster energy efficiency among all end-use sectors.

Even though natural gas receives more indirect support than in other European countries, the Danish government has taken the view that as a comparatively young industry it still requires such help. ■

. . . technical report

Exploration and Production

The Code of Practice on Well Control during the Drilling and Testing of High Pressure Wells was published at the end of August.

A contract has been given to WS Atkins to examine an envelope of parameters which cover the majority of operational conditions routinely encountered when drilling a subsea well. A contribution to the study costs has been made by HSE.

A project to investigate the background into incidents of overpressure in high pressure heat exchangers on offshore platforms has been approved.

Refining and Marketing

Following an earlier IP initiative the United Kingdom has been allocated the convenorship of a CEN working group which will produce a standard for unpressurised road tankers. The Institute will provide the secretariat for the working group.

A second printing of the Guidelines for the Design and Operation of Gasoline Vapour Emission Controls has been produced to meet demand. Panel A is categorising types of service stations according to the variables affecting pressure drop during vapour balancing operations before setting up a programme of testing.

At the request of HSE, Electrical Committee, in conjunction with Panel A — Service Stations, is forming a working group to discuss and resolve with HSE and local petroleum authorities, issues of common concern related to electrical installations at service stations. A similar working group formed from Electrical Committee and Panel C-Conveyance is being set up to enable a speedy response to be given to enquiries from the Department of Transport and HSE related to revision of the electrical provisions of ADR.

Work is in progress on drafting a Code of Practice dealing with on-board truck computers to provide guidance on the design and operation of such systems.

A working group from the Safety Committee, DOC-6, has drafted a Code of Practice for the safe uplift of petroleum product, normally off-specification material from retail filling stations and customer tankage. Publication will be in 1993.

New sections on tank spacing and thermal radiation flux levels have been incorporated into the Fire Precautions Code which is currently being edited and re-ordered into a cohesive and consistent format before issue for comment to industry and outside bodies such as HSE.

It has been decided to recommence work on the User Guidelines to H_2S Hazards in the Storage and Handling of Heavy Fuel Oil.

Measurement

A small working group has drafted Petroleum Measurement Paper No 5: User Guidelines for Standard Temperature Accounting, providing guidelines for the application of standard temperature accounting systems in the petroleum industry. Guidance is provided on the adoption of practical options at petroleum installations and covers the basic concepts, measurement parameters, data requirements and operating and calculation procedures. The Committee Draft has already been circulated for initial comment and will shortly be balloted. Early publication is expected.

PMM Part XIV: Statistics for Static and Dynamic Measurement. The text has been edited and the drawings redrafted. Publication should be in the fourth quarter.

Test Method Standardization

The extensively revised text of the IP Test Method Book has been submitted to the publishers and is on target for publication early next year.

Moves are taking place to publish a companion volume which will provide of a compilation of petroleum product specifications. A questionnaire prepared in conjunction with BSI is being distributed. The aim is to publish the specifications volume in 1994.

A review of the BS 2000 Series has been completed, and recommendations accepted by ST and PTC/13 Committees. Three methods will be published in November. Sixteen methods are to receive public comment. Thirty three methods will receive editorial change. Four methods will be withdrawn.

Health and Environment

A proposal for a follow-up of the 1991 IP Epidemiology study has been developed. Several mortality patterns found in the study would be investigated together with any possible relationship to exposure to oil products. This study will also investigate cancer incidence ratio amongst workers by linking with UK cancer registration data. This is the first time this kind of investigation will have been undertaken in the petroleum industry.

The final draft of the Code providing guidelines for the investigation of possible contamination of land by petroleum products is nearing completion and will be issued for comment to industry and outside bodies such as Dept of Environment and National Rivers Authority in the near future.

Two research projects are near to completion: 'Fate and effects of marine oil pollution in UK waters' and 'Growth and population of esculantas around oil installations in Sullom Voe" Both these projects are at the committee review stage and will be published later this year.

Recent problems with cargoes of middle distillates has prompted a half-day workshop 'Current problems or microbial spoilage of bulk distillate fuels' to be held at the IP on the 3 December.

The work on biofilms research project has been completed and copies of the report are in the IP library.

General

The first printing of the Consultant List Handbook has been sold and a second updated printing produced. ■

John Hayes, Technical Director

Pressure balanced valves for safety

In a serious plant fire, where flammable fluids or water are being passed through the line, the ability of the valves to withstand fire and continue to seal down the line is critical for safety. Any significant leakage through the valve seat or glands may add fuel to the fire or disrupt the water supply or pressure.

The 'Super-H' pressure-balanced plug valve, manufactured by Serck Audco Valves, has gained the new British Standard fire tests BS 6755 Part 2 fire certificate, following extensive fire tests at the company's Newport factory. The tests, certificated by Lloyd's, used a purpose-built test rig, where valves were subjected to a 30 minute burn period at flame temperatures of up to 1,000°C. Leakage to atmosphere was measured by a load cell and leakage along the line was also monitored.

The results showed that leakage through the valve seat in a fire was under one per cent of the permitted level, with no detectable leakage to atmosphere.

In the past, UK valve manufacturers tested valves to the only available standard, BS 5146. Designed for soft-seated valves, this allowed for the PTFE seat rings melting and letting the line pressure force the ball valve onto its metal seat to form a tight seal.

But under BS 6755 Part 2, the difficulties for ball valves which use soft seat materials have increased considerably, with the introduction of a closed valve test and an increase in the test pressure to 75 percent of CWP. The result is that steam pressure in the ball valve's cavities can reach 500 bar, a much higher pressure than the valves were designed for, which has resulted in ball valves' bolting failing, covers blowing and the seat rings breaking up and permitting line fluid to escape downstream to the fire.

With no soft seat material, and metal-to-metal seating, the Super-H pressure-balanced plug valve has no such problems. The importance of fire safety to the oil, gas and petrochemical industries puts this valve type firmly to the fore for safety applications.

Heating system for pipelines

Jimi-Heat Ltd, have designed and manufactured a trace heating system especially for use on pipes conveying heated liquids or slurries over long distances at process plant sites, marine terminals or fuel oil pipelines.

The system utilises the JTLS heater tape, which is a double insulated silicon rubber heating tape with tinned copper conductors and an optional outer braid. The tape, which operates on an unusually long circuit length, can be either pre-fabricated at the factory or terminated on site.

The system reduces the number of electrical inputs required to the very minimum. A pipeline of 600 metres can be powered by one three phase 415V supply, while for longer lengths the system can be run on a high voltage supply up to 750V (running three traces down the pipeline at typical loadings of 20w/m of tape).

For intermediate areas such as tank farms, the system incorporates basic cut-to-length zone heating tapes.

Lower water costs for refineries

Refineries and chemical sites reliant on mains water yet with other supplies nearby, perhaps too highly saline for their processes, may benefit from a service now offered by Ionics (UK) Ltd.

In certain circumstances, particularly where brackish or organically 'contaminated' alternatives to townswater are available, Ionics will 'own and operate' demineralisation plant within the refinery with a contract to produce water for a predetermined period at a more favourable cost than existing supplies.

Similarly, pilot demineralisation units are available for users of existing ion exchange plant who may wish to expand their existing capacity or switch to alternative supplies, such as raw river water or boreholes, without the cost of a major new installation.

Survival garment launched

An entirely new tank entry vest, designed to assist the survival and evacuation of personnel who get into difficulties when working in enclosed tanks or spaces, either at sea or on shore, has been introduced by safety equipment specialists, AIM Safety.

Originally developed to meet the needs of one of the UK's largest oil tanker operators. Made from a bright fluorescent yellow material for easy visibility in dark areas, the vest incorporates a rugged load-bearing harness with a Tri-D ring for snap-on lifeline attachment, to enable the wearer to be rapidly lifted out of the tank in an emergency.

Also incorporated are pouches carrying escape breathing apparatus for use should the wearer unexpectedly encounter a pocket of foul air or noxious gas. An audible oxygen alarm is included to warn the wearer when the air quality remains below an acceptable standard.

Constructed from a cool mesh fabric to minimise heat stress, the tank entry vest thus provides a safeguard against the possible risk of toxic fumes plus a full evacuation harness in the one easily worn garment.

Computerised service station administration

The Mannesman Kienzle's Station Management System the SMS 2020 is a computer aided service station administrative system which incorporates management control and planning features as well as all the standard daily activities.

The SMS 2020, together with the software package KITAS (a service station accounting system), instantly captures transactions from all sectors of the conpany and updates analyses (eg takings and turnover per shift, current stock of wet and dry goods, sales analyses etc). Consequently, the Station Manager has at his fingertips an immediate overview of station activities.

The configuration may comprise one or many operator work stations plus a central unit. Each work station consists of a combined pump and POS console, customer display, cash drawer, receipt/journal printer, card reader and hand or desk scanner. The POS/Work Station performs all the functions of a modern point of sale system including the automatic handling and processing of bank (ie ec-card), credit, fleet and company cards as well as the automatic capturing of transactions sold via scanner. Multiple currencies and exchange rates are also catered for. The same console also controls all refuelling transactions, defines the form of pump operation (ie full serve, self serve), authorises and bars dispensers etc. A comprehensive security system ensures only authorised personnel may carry out specific operations.

The master station which comprises the central processing unit, a screen and printer, may be located away from the work stations and can perform cash balancing, invoicing, reordering and printing of reports during normal opening hours. Even during peak periods the Service Station manager can commence analysing, balancing and utilising the planning/accounting functions.

Engine oil top-ups

Complete oil changes are a part of vehicle servicing and drivers are often responsible for checking and topping up oil levels, but how easy is it for them to perform this task? The oil level is more likely to be kept correctly topped up if the means of doing so are quick and easy.

The new 'Oilpak' system from Cookson and Zinn Limited might be the answer. Sited adjacent to the fuel dispensing pumps it provides a simple, clean, secure and accountable method of issuing top-up engine oil. Tank, electric pump and dispenser all in one transportable unit.

Capacities can be geared to suit but are generally in the range of 750–1500L. Compact, portable, clean, this storage facility can both increase efficiency and provide an accurate means of indicating usage of dispensed oil.

In addition, the unit can be connected to most computerised control systems and will enable fairly complex statistics to be kept.

Digital thermometer range

Digitron are introducing a new high accuracy range of microprocessor based digital thermometers. There are 6 thermometers in the series catering for a wide range of temperature monitoring needs.

The microprocessor based design, manufactured with the latest SMT technology, offers a number of benefits for the user. Temperature ranges are wide, type K thermocouples: $-200^{\circ}C$ to $+1350^{\circ}C$, type T thermocouples: $-250^{\circ}C$ to $+400^{\circ}C$ and type J thermocouples: $-180^{\circ}C$ to $+750^{\circ}C$.

Accuracy is high at $\pm 0.2^{\circ}C$ ± 0.1 percent of the reading ± 1 digit and there is automatic, periodic self-calibration of the instrument to minimise long term drift effects.

Floodlighting systems for hazardous areas

Prompted by calls for increased safety in electrical equipment operating in Zone 1 danger areas, such as gas and petrochemical installations, ABB Control has launched a new range of explosion proof (Ex) floodlights.

Designated PX, the series, which ranges from 250W–1000W, uses a three chamber configuration with separate enclosures for lamp, control gear and terminal box.

This arrangement ensures that the high temperatures generated by the lamp do not adversely affect the control gear. Whilst the basic unit is certified EEx d II B, an optional increased safety terminal box provides the unit with EEx de IIB certification. The system's ballast has a range of taping to adjust for the mains supply within the limits 220V–250V, (50/60Hz).

The floodlight has a robust design, which affords IP66/67 ingress protection according to IEC regulations. This allows application across a range of environments from onshore petrochemical installations to the harshest offshore conditions.

The lamp housings are highly resistant to corrosion, consisting of copper free aluminium enclosures, borosilicate glass, and a PTFE protected threaded aluminium collar.

Portable sampling system

Crude oil shipments contain water in amounts ranging from trace levels to several percent. Water content can be determined by static or dynamic sampling techniques. However, automatic in line sampling provides much more accurate analysis and prevents disputes over the sources of the water measured in the ship or shore tanks. On Line Systems have designed the 'Portable Automatic Sampling System' (PASS) to provide this capability. Now, buyers, sellers and ship operators can obtain proportional and representative samples at the exact point of cargo transfer during loading or discharge of oil cargoes.

Designed for mounting at the ship's manifold, the PASS is also suitable for installation directly on oil pipelines. This approach provides accurate assessment of the water content of crude oil, heated oils, or refined product transfers.

PASS is a completely pneumatic system consisting of six components:

1. The spool piece sandwiched between the ship's manifold flange and the loading arm or hose.
2. The sampling probe for taking sample grabs from the main lines.
3. The flow measuring pitot tube complete with a differential pressure transmitter.
4. The control unit which houses the totally pneumatic control system including the pneumatic supplies, air logic and indicators to operate the sampling system.
5. The pneumatic circular chart recorder for continuously measuring and recording the flowrate, pressure and temperature.
6. The sample receiver that collects the composite sample.

It is designed according to the automatic sampling requirements of ISO 3171 and ASTM, API and IP standards.

Coal gas project given go-ahead

The US Department of Energy has authorised the Encoal coal gasification project to proceed to a full scale operation.

The project is sponsored by Shell Mining Co at Triton Coal Co's Buckskin mine near Gillette, Wyoming.

Total cost of the Encoal project is $72.6 million, with DOE providing 50 percent. Authorisation means that DOE will provide as much as $10.6 million during Encoal's operations phase.

The project employs a process called LFC, of liquids from coal. The technology was developed by SGI International, La Jolla, California, a member of the Encoal project.

The LFC process treats low rank coal — low sulphur coal with a high moisture content that lowers its heating value — to make two products.

One product is a solid, the other a liquid. The solid product is a high BTU, low moisture, low sulphur coal that can be burned in plants and meet the strictest emission standards. The liquid product is similar in quality to a low sulphur No. 6 fuel oil that can be used directly as a boiler fuel or as a refinery feedstock to produce specialty fuels.

When fully operational, the plant will be able to produce 180,000 tons per year of solid coal-like fuel and 150,000 bbl/year of liquids. A commercial scale plant would be about 10 times the size of the Encoal demonstration unit.

Two companies have agreed to buy fuels produced at the Encoal plant. Wisconsin Power & Light will buy about 30,000 tons of solid fuel for use at its coal fired power plants. Texpar Energy Inc. will buy as much as 135,000 bbl/year of liquid fuel for sale to industries.

Jacket for offshore protection

A.I. Covers have launched a new deluge-resistant valve insulation designed for offshore use.

The Iso-Cover features a double gasketed sealing system and hood which keeps sea-water off valves during routine deluge operations and in high seas.

The jacket has withstood water sprayed up to 1200psi during development trials with no water penetration through into the interior of the cover — thus avoiding corrosion problems.

The jacket features include a water-resistant sealant on all seams and extension pieces at either end which seal inside and draw down to form a water-tight closure.

Mr Spano, Managing Director of A.I. Covers said: 'The covers can be fitted in minutes, slipping over valves and other equipment and secured via the simple fastenings — this also allows easy removal for maintenance and repair. They are available in standard sizes or made to order.'

A.I. Covers is based in Rugeley, Staffordshire and manufactures the ISo-Covers at its purpose-designed plant.

Contact List

A.I. Covers Ltd	0889 575700
Cookson and Zinn Ltd	0473 823061
Mannesmann Kienzle	0483 771182
ABB Control Limited	0203 368500
Digitron Instrumentation Ltd	0992 587441
Serck Audco Valves	0952 820333
Jimi Heat Ltd	0923 234477
AIM Safety	0202 885252
Ionics (UK) Ltd	081 879 1474
On Line Systems, Italy	(39) 35/571062

Institute News

Benevolent Fund

The Institute of Petroleum Benevolent Fund was established as a permanent fund, with independent finances, in 1958 and a new Trust Deed was agreed in 1986. Before 1958, it was maintained by the Institute.

The fund exists to provide financial and other help to present or former members of the Institute of Petroleum and their families and dependent relatives who are in financial need.

The Management Trustees are the President, the Honorary Treasurer, the Honorary Secretary and the Director General of the Institute, for the time being. In addition, there are two General Trustees who are currently long-standing members of the Institute, with experience of the Institute and its membership.

Applications for support are dealt with as and when received. When considered appropriate, a visit is made to the person making the application. The General and Management Trustees meet annually to review the finances of the Benevolent Fund.

In 1991, income from investments, interest on deposits and donations and legacies, totalled £8,018. Expenditure on grants, audit fee and sundry expenses (£5) totalled £3,343. There was, therefore, £4,675 new money available for investment. The market value of net assets of the Benevolent Fund at 31 December 1991 totalled £81,043. The auditors are Ernst & Young.

Applications for assistance are invited from members, former members, the families and dependent relatives of members, former members and deceased members, who are in need. Please draw this notice to their attention.

Obituary

MR JOHN LOWEIN CBE

John Lowein, Chairman and Chief Executive of Mobil Oil Company Limited from 1980 to 1987 died peacefully on Friday 6 November after a short illness.

Mr Lowein joined Mobil in 1950 and held a number of senior appointments in the company in London, New York and Tokyo (where he became Vice President, Mobil Sekiyu KK). He became a fellow of the Institute of Petroleum as well as a Fellow of the Institute of Secretaries, a Vice President of the UK Petroleum Industry Association and of the Oil Industries Club.

He was awarded the CBE in 1986.

New Collective Members

Masons Solicitors
30 Aylesbury Street, London, EC1R 0ER. Telphone: 071-490 4000.
IP Nominated Representative: Ms Ann Kilvington, Senior Assistant Solicitor.

Masons is an international law firm, with offices in London, Bristol, Manchester, Brussels and Hong Kong, as well as affiliations in Beijing, Cairo and the Cayman Islands. The firm provides services to the energy, construction, engineering and technology industries, including contract advice and drafting, environmental and health and safety law and general commercial and property advice. The firm specialises in dispute resolution, including litigation, arbitration and alternative dispute resolution procedures.

Nissho Iwai Petroleum Co (UK) Ltd
9 Berkeley Street, London W1X 5AD. Telephone: 071-495 0100.
IP Nominated Representative: Mr Toshihiro Nishi, Managing Director.

Nissho Iwai Petroleum Co (UK) is the petroleum arm of Nissho Iwai Corporation, Tokyo, engaged in various activities, including exploration, project organisation, trading and investment.

Geraghty & Miller International Inc
Conqueror House, Vision Park, Histon, Cambridge CB4 4ZR. Telephone: 0223 236950.
IP Nominated Representative: Dr B Crook, Managing Director.

G&M, subsidiary of Geraghty & Miller Inc, Plainview, USA, provides a full environmental consulting service to clients involved with refining, transportation, storage and distribution of petroleum-based products. The company's capabilities include comprehensive environmental audit assessment and hydrocarbon remediation services, as well as advising clients on regulatory compliance, property transfer and interfacing with regulatory agencies.

Delft Instruments Tank Gauging BV
PO Box 812, Rontenweg 1, Delft 2600 AV, Netherlands. Telephone: +31 15 698500.
IP Nominated Representative: Mr H M van Voorden, Manager Commercial Operations.

Delft Instruments Tank Gauging BV, a member of the Delft Instruments NV Group, specialises in tank gauging systems, both for large above ground and underground storage tanks, for example, refineries, depots, terminals and forecourts.

KBC Advanced Technologies
KBC House, Churchfield Road, Weybridge, Surrey KT13 8DB. Telephone: 0932 856622.
IP Nominated Representative: Mrs H J Bates, Management Information/Library.

KBC is a worldwide organisation with consulting and technology centres in Weybridge, UK, Singapore, New Orleans and New Jersey, USA. The company specialises in the provision of a unique range of services that develop high value but low cost opportunities for clients in the oil, gas and petrochemical industries. This includes profit improvement programmes, strategic analyses, project development and production support simulation tools. The KBC role is to serve clients by helping them improve the competitive position of their manufacturing operations.

Alpha Thames Engineering Ltd
Essex House, Station Road, Upminster, Essex RM14 2SU. Telephone: 0708 229229.
IP Nominated Representative: Mr D E Appleford, Managing Director.

Alpha Thames specialises in project engineering and development of subsea processing systems and associated products, as well as project management and engineering design services.

Lehman Brothers International
International Energy Department, 5th Floor, One Broadgate, London EC2M 7HA.
IP Nominated Representative: Mr W Piasio.

Lehman Brothers International is a division of American Express, with many thousands of employees worldwide. The International Energy Department offers a crude oil broking service, based in London.

Institute News

New Members

Mr TM Adams, Ashurst Morris Crisp, Broadwalk House, 5 Appold Street, London EC2A 2HA.
Mr M Andrews, BOC Process Systems, The Engineering Centre, 30 Priestley Road, Guildford, Surrey GU2 5YH.
Mr MJ Barber, 102 New River Crescent, Palmers Green, London N13 5RJ.
Mr RD Barrett, 7 Foxglove Close, Blaxton, Doncaster, South Yorkshire DN9 3PR.
Mr MC Batiste, Officers Mess, Petroleum Centre, West Moors, Wimborne, Dorset BH21 6QS.
Mr DA Bennett, Texaco Ltd, 1 Knightsbridge Green, London SW1X 7QJ.
Mr L Bernstone, 8 Sherwood Drive, Quarry Bank, Brierley Hill, W Midlands DY5 1UW.
Mr L Wilson Berry, Texaco Ltd, 1 Knightsbridge Green, London SW1X 7QJ.
Mr BA Bigwood, Bigwood Mechanical Services, Unit 3, Vallance By-Ways Gatwick, Lowfield Heath Road, Charlwood, Horley, Surrey RH6 0BT.
Dr GW Black, Altra Consultants Ltd, 7 Albin Terrace, Aberdeen AB1 1YP.
Dr OA Boakye-Dankwa, Trg & Development Department, Ras Lanuf Oil & Gas Processing Co Inc, PO Box 1971, Benghazi, Libya.
Mr C Bond, AMEC Offshore Developments Ltd, City Gate, Altens Farm Road, Nigg, Aberdeen AB1 4LT.
Mr FD Breen, 5 Langdale, Stewartfield, East Kilbride, Glasgow G74 4RP.
Mr D Brindle, 12 Woodside Grove, Stockton-on-Tees, Cleveland TS18 5EG.
Mr JA Brindle, John Brindle Oils & Chemicals, PO Box 59, Burton-on-Trent, Staffs DE13 8EL.
Mr GA Broughton, Sessnie Croft, Methlick, Ellon, Aberdeenshire AB41 0DL.
Dr S Burke, 77 Gloucester Road, Aldershot, Hants GU11 3SQ.
Mr BWE Buswell, 12 Shendish Edge, Apsley, Hemel Hempstead, Herts HP3 9SZ.
Mr RJB Carryer, Oakwood Environmental, The Limes, Combe Lane, Wormley, Godalming, Surrey GU8 5SX.
Mr Y-C Cheung, Room 2504, Fu Pong House, Tai Wo Hau Estate, Tsuen Wan, New Territories, Hong Kong.
Mr NP Clarke, 146 Kinross Close, Cinnamon Brow, Warrington, Cheshire WA2 0UR.
Mr AR Cobb, PE International plc, Park House, Wick Road, Egham, Surrey TW20 0HW.
Mr JC Cobbin, 21 Foresters Close, Cheshunt, Waltham Cross, Herts EN7 6TF.
Mr JT Collins, 66 Glenfield Drive, Kirk Ella, Hull, N Humberside HU10 7UL.
Mr RB Colomb, Texaco Ltd, 1 Knightsbridge Green, London SW1X 7QJ.
Mr JA Cotton, 152 Sheepwalk, Paston, Peterborough PE4 7BL.
Mr G Cowperthwaite, Greenleas, Old Inn Road, Findon, Aberdeen AB1 4RN.
Mr K Davison, 67 Church Road, Shoeburyness, Southend on Sea SS3 9EX.
Mr AJ Dixon, 1c Augusta Road, Penarth, S Glam CF6 2HL.
Mr G Douglas, 23 Eider Road, Newburgh, Ellon, Aberdeen AB41 0FD.
Mr JA Ellison, Bollaard 16, 4847 AZ, Teteringen, Netherlands
Mr PJC Emerick, Philip Emerick & Company, 3 Observation Court, 84 Princes Street, Ipswich, Suffolk IP1 1RY.
Mr PR Emery, Esso Petroleum Co Ltd, Lab 23, Fawley Refinery, Fawley, Southampton SO4 1TX.
Mr BO Fasina, PO Box 24876, Mapo, Ibadan, Oyo State, Nigeria.
Dr MJ Fawcett, British Gas, London Research Stn, Michael Road, Fulham, London SW6 2AD.
Mr JN Fawkes, 31 Weare Gifford, Shoeburyness, Southend on Sea SS3 8AB.
Mr AJ Foster, 35 Gloucester Place, Peterlee, Co Durham SR8 2HB.
Dr C Gibson-Smith, Lansdowne, White Lane, Guildford, Surrey GU4 8PR.
Mr MS Green, 41 Bowens Wood, Linton Glade, Croydon CR0 9LQ.
Flt Lt RJ Hale, 1 Osprey Close, Hartford, Huntingdon, Cambs PE18 7UX.
Mr ID Holden, BP Oil Grangemouth Ltd, PO Box 30, Bo'ness Road, Grangemouth, Stirlingshire FK3 9XQ.
Mr GF Hrubecky, Nordic Systems Inc, 1044 Rangeview Road, Mississauga, Ontario, Canada.
Mr IWG Hughes, Long Cottage, Steels Lane, Oxshott, Surrey KT22 0QH.
Mr MP Hyslop, Whessoe Varec Ltd, Heighington Lane, Newton Aycliffe, Co Durham DL5 6XZ.
Mr F Jenkins, Petroleum Open Learning, Blackness Avenue, Altens, Aberdeen AB1 4PG.
Mrs I Lee, 34 Mortons Fork, Blue Bridge, Milton Keynes MK13 0LA.
Mr BC Lenete, Lenette Inspection Services Ltd, Rose Cottage, Milton of Cushine, Alford, Aberdeen AB33 8HW.
Mr WD Lindsay, 13 Eilean Rise, Ellon, Aberdeenshire AB41 4LW.
Mr DJ Macdonald, 8 Greenfield Place, Lerwick, Shetland ZE1 0AQ.
Mr AM Mackenzie, Qatar General Petroleum Corpn, (EPD/171) PO Box 47, Doha, Qatar.
Miss I Mack, 50 Kilmartin Way, Hornchurch, Essex RM12 5NB.
Mr N Malliris, 37 Cedarway, Whitehills Estate, High Henworth, Tyne & Wear NE10 8LD.
Mr B T Martin, 33 Queen's Gardens, London W5 1SE.
Mr SM Matthews, 4 Grendon Gardens, Penn, Wolverhampton, West Midlands WV3 7NQ.
Mr GC McKenna, Redmoss Croft, Moss Side, Barthol Chapel, Inverurie, Aberdeenshire AB51 0BY.
Mr A McPherson, AMEC Offshore Development Ltd, City Gate, Altens Farm Road, Nigg, Aberdeen AB1 4LJ.
Mr B Molland, Kennels Croft, Netherley, Stonehaven, Kincardineshire AB3 2RA.
Mr GS Moore, 25 Northcote Road, Croydon, Surrey CR0 2HX.
Mr RW Mould, Laurel Cottage, 13 Caxton Av, Coombelands, Addlestone, Weybridge, Surrey KT15 1LJ.
Mr SG Music, 10 Talbot Road, Flat 15, London W2 5LH.
Mr DJ Neil, 7 Beech Hall Drive, Macclesfield, Cheshire SK10 2EF.
Mr S O'Byrne, 11 Sittingbourne Close, Sutton, Humberside HU8 9XQ.
Mr FX O'Connor, Blugas Ltd, Tolka Quay Road, Dublin 1, Ireland.
Mr BA Ojo, NISSCO Ltd, PO Box 322, Warri, Delta State, Nigeria.
Mr D Owen, 161 Welholme Road, Grimsby, South Humberside DN32 9LR.
Mr AW Owens, Rue du Vieux Moulin 88, 1160 Brussels, Belgium.
Mr SE Oyibo, Nigerian Agip Oil Co Ltd, PO Box 923, Port Harcourt, Nigeria.
Mr IS Paterson, Enterprise Oil plc, Grand Buildings, Trafalgar Sq, London WC2N 5EJ.
Mr API Perigo, 21 Prince Street, Netherton, Dudley, W Midlands DY2 9EH.
Mr MB Phoenix, Toyota Tsusho Corpn, 150 Holborn, London EC1N 2NS.
Mr MR Plaisance, Diamond M Odeco, Howe Moss Drive, Kirkhill Ind Estate, Dyce, Aberdeen AB2 0GL.
Mr DP Plom, 145 Goodman Road, Chadwell St Mary, Grays, Essex RM16 4TL.
Mr RL Roberts, 7 Tordene Path, Balloch, Cumbernauld, Glasgow G68 9AL.
Dr JF Rogers, BP Oil Grangemouth Refinery Ltd, PO Box 30, Bo'ness Road, Grangemouth, Stirlingshire FK3 9XQ.
Mr KB Ronsberg, 8 Burnhead, Blairs, Aberdeen AB1 5YX.
Mr MN Saleh, Arab Petroleum Pipelines Co, (SUNMED) c/o TNT Mailfast CAI/110000/NOI PO Box 66, Hounslow, Middx TW5 9BR.
Mr TN Savage, Oakes Villa, Saltburn Road, Invergordon, Ross-shire IV18 0AW.
Mr O Shonekan, 5 Goldney Road, Maida Vale, London W9 2AP.
Mr PJ Small, 187 Headland Court, South Anderson Drive, Aberdeen AB1 7HZ.
Mr RE Sommerstedt, Bear Stearns UK Ltd, 1 Canada Street, London E14 5AD.
Mr B Spence, 86 Cathedral Road, Chadderton, Oldham, Lancs OL9 0RG.
Mr DP Spratt, Faradays Electrical Contractors Ltd, Unit B, No 1 School Lane, Chandlers Ford, Eastleigh, Hants SO5 3OG.
Mr M Straughen, General Manager, AMEC Offshore Developments Ltd, City Gate, Altens Farm Road, Nigg, Aberdeen AB1 4LT.
Mr SY Tang, Flat 1-C, 9/F Woodview Court, 75 Kung Lok Road, Kwun Tong, Kowloon, Hong Kong.
Mr G Thain, AMEC Offshore Developments Ltd, City Gate, Altens Farm Road, Nigg, Aberdeen AB1 4LJ.

Institute News

Mr GK Thorn, American Express Bank Ltd, 60 Buckingham Palace Road, London SW1W 0RR.
Mr A Trenfield, Contracting Manager, Faradays Electrical Contractors Ltd, Unit B, 1 School Lane, Chandlers Ford, Eastleigh, Hants SO5 3DG.
Mr T Varnakulasingham, PO Box 452, Seria Brunei Darussalam 7004, Brunei.
Mr GE Vaughan, Log Sup Bn, Officers Mess, Ward Barracks, Salisbury, Wilts SP4 9LT.
Mr MJ Wastell, 126 Victoria Rise, London SW4 0NW.
Mr S Wears, Dakka Engineering Services Ltd, 9 Usk Avenue, Calf Close Estate, Jarrow, Tyne & Wear NE32 4DH.
Mr GM White, SG Warburg Securities, 1 Finsbury Avenue, London EC2M 2PA.
Mr K White, Kevin White Financial Planning, 118 Ashley Road, Hale, Altrincham, Cheshire WA14 2UN.
Mr TKY Wong, Flat E, 3/F Chiu Kwan Bldg, 8 Ping Shing Lane, Kwun Tong, Kowloon, Hong Kong.
Mr DW Woolham, P&O Roadtanks Ltd, Station House, Stamford New Road, Altrincham, Cheshire WA14 1ER.

Students

Mrs MM Browne, 14 Wayside Drive, New Waltham, Grimsby, S Humberside DN36 4LW.
Miss Y Gharagozlou, 43 Harington Gardens, London SW7 4JU.
Dr SC Grimmer, Department of Geology, Imperial College, Prince Consort Road, London SW7 2BP.
Mr RK Gupta, 26 St Joseph's Drive, Southall, Middlesex UB1 1RL.
Mr SS Johansen, Imperial College, Department of Mineral Research Engineering/U.G, Royal School of Mines, Prince Consort Road, London SW7 2BP.
Mr O Lolomari, MRE Department (UG 3) RSM, Imperial College, Prince Consort Road, South Kensington, London SW7 2BT
Mr SB McCloskey, 59 Vale Road, Eglinton, Londonderry, Northern Ireland BT47 3BE.
Mr J Mottashed, 16 Irving Mansions, Queen's Club Gardens, West Kensington, London W14 9SL
Miss M Palanivelu, UG Pet Engineering, Department of Mineral Resources Eng, Imperial College, Prince Consort Road, London SW7 2BP.

Student Prize Winners

Mr JS Keites, 4 Broadacre Close, Ickenham, Uxbridge, Middlesex UB10 8BL.
Mr RI Smith, BP Exploration, Farburn Industrial Estate, Dyce, Aberdeen AB2 0PB.

Deaths

William Boyle, born 1927.
Leslie A Heiser, born 1922.
Donald McLennan, born 1941.
Alan Muir, born 1926.
Charles Prince, born 1934.
William N Scott, born 1926.
Brig R C Thorpe, born 1923 (Committee Member, IP Southern Branch).

In 1991 a major project to embroider 600 church kneelers was begun to celebrate Chester Cathedral's 900th anniversary this year.

Each kneeler illustrates some aspect of work activity within the diocese. The Institute of Petroleum kneeler was the suggestion of Mrs Joyce Skerrett and is particularly appropriate because of the oil industry and Institute links with Stanlow.

Mrs Skerrett with the completed IP kneeler.

UK Deliveries into Consumption

September 1992 — Tonnes

Products	*Sep 1991†*	*Sep 1992**	*Jan–Sep 1991†*	*Jan–Sep 1992**	*% change*
Naphtha/LDF	221,265	286,254	2,462,935	2,479,828	1
ATF—Kerosine	613,770	638,512	4,652,896	5,148,145	11
Motor Spirit	1,957,412	2,022,147	17,942,737	17,890,127	0
of which unleaded	828,166	972,216	7,247,565	8,252,285	14
Super unleaded	100,109	124,664	854,508	1,042,610	22
Premium unleaded	728,057	847,552	6,393,057	7,209,675	13
Burning Oil	158,257	219,903	1,659,619	1,717,348	3
Derv Fuel	895,860	972,759	7,942,373	8,212,223	3
Gas/Diesel Oil	563,598	648,691	5,902,301	5,766,613	−2
Fuel Oil	893,801	802,677	9,155,168	8,228,444	−10
Lubricating Oil	63,091	72,740	569,885	605,419	6
Other Products	602,319	615,346	5,393,647	5,192,114	−4
Total above	5,969,373	6,279,029	55,681,561	55,240,261	−1
Refinery Consumption	495,875	509,633	4,523,506	4,523,502	0
Total all products	6,465,248	6,788,662	60,205,067	59,763,763	−1

†Revised with adjustments *Preliminary n/a Not Available

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MacGregor Engineering have appointed two new directors, **Mr Steve Chisholm,** Director/ General Manager and **Mr Jim Millar,** Technical Director. MacGregor Engineering is involved as principal contractor in a number of rig upgrading and conversion projects.

Chem Systems has made the following appointments in its London office — **Dr Neil Checker,** Director, **Mr Phil Hunt,** Director and **Mr Edward Osterwald,** Principal.

Mobil have announced a reorganisation of its sales, marketing and administration activities in Europe into three profit activities: Refining, Fuels Marketing and Lubes Marketing. Local managers will coordinate their various activities with managers in Mobil Europe Limited.

Mr Bill Greenhalgh has joined BVMI Process Engineering in the new post of Sales Engineer. Mr Greenhalgh has wide experience in the valve, actuator and process industries, and he will be concentrating on the processing and petrochemical markets in his new position.

Burgoyne Consultants Ltd, safety management specialists, have acquired the services of **Dr Mike Willison,** a chartered chemist. Dr Willison will retain his connections with the University of Manchester Institute of Science and Technology where he is Senior Consultant to the Environmental Technology Centre Industrial Service.

Mr Bruce Harrick has joined Polaris International from Seismograph Service Limited as Technical Manager. Mr Harrick has 20 years experience in the operation and design of systems for seismic vessels.

Noble Denton have promoted **Mr Richard Bush,** former Engineering Manager of Noble Denton Aberdeen, to General Manager of the Noble Denton Oslo office. In Aberdeen **Mr Peter Cook** remains the Marine Manager. **Mr Mike Shea** takes over as Manager of Naval Architecture and Structural Engineering Services and **Ms Ciaran McIntyre** becomes Manager of Risk, Safety and Marine Engineering Services.

Mr Peter Loughead returns to the Department of Trade and Industry from the Treasury, to become Head of the Coal Review Team.

Snamprogetti Limited, process engineering contractors, have made the following appointments. **Mr Brian Elkins,** above left, is appointed as Marketing and Commercial Director with responsibility for all marketing and sales activities together with both pre-contract and contractual activities. The position vacated by Mr Elkins is filled by **Mr David Lloyd** who is promoted to Director of Operations. Mr Lloyd will be responsible for all project activities within the company and takes charge of the Safety and Reliability Group. **Mr Roy Barton,** above right, has joined the company as Subsea Project Manager.

Geoteam UK Limited have appointed **Mr Allan Richardson,** above, to the position of Branch Manager in Great Yarmouth. He has worked for Geoteam for four years as Senior Engineer and Party Chief aboard the company's survey vessels.

The Health and Safety Executive (HSE) have appointed **Dr Martin Pantony** as Director of Technology with HSE's Offshore Safety Division. Dr Pantony worked for Shell Chemicals as a chemical engineer before joining HSE in 1974. He was previously Head of HSE's Major Hazards Assessment Unit.

BRS Tankfreight's Petroleum Sector, headed by **Mr Neil Ripley,** has named the national account managers who will develop the sector's major areas of business. They are: **Mr Frank Willis,** national account manager for the bitumen sector; **Mr Dennis Arnold,** national account manager for the LPG sector; **Ms Jackie Carroll,** national account manager for the lubricants sector; **Mr Mike Pounder,** national account manager for the Gulf Oil contract and **Mr Ian McDonald,** national account manager for the fuels division.

Chevron UK Ltd, operator of the Ninian oil field has announced four new managerial appointments to the Ninian Third Party Project. **Mr Paul Seligman,** formerly Manager Completions and Pipelines — Alba Project, is appointed Project Director Ninian Third Party Project. In this new position he will be responsible for planning, construction and start-up of facilities to handle production from the Staffa, Lyell and Strathspey Fields on the Ninian Central and Southern platforms. **Mr Roger Banks** is appointed Project Manager — Ninian Southern Platform and **Mr Mike Christensen,** Project Manager — Ninian Central Platform. **Mr Martin Nash,** currently Manager Purchasing is appointed Project Services Manager — Third Party Project.

Mr Ian Jack, Manager, Acquisition Services, British Petroleum, has been elected Vice President of the 1992/93 Executive Committee of the Society of Exploration Geophysicists.

ALTRA Consultants Limited have appointed **Mr Gordon McLellan** as Commercial Director. A chartered accountant, Mr McLellan has over 25 years experience in senior management roles within the oil and gas industry and will be responsible for developing consultancy within the fields of process, facilities engineering and safety and the environment. Mr McLellan previously worked for BP and has worked as a consultant to Shell, BP and Scottish Power. In addition, he held directorships of Seaway UK and Pallion Engingeering, Sunderland.

Open Forum on Power Generation

Joint Information for Energy Group/ Energy Economics Discussion Group Meeting

4 pm — 7 pm
Wednesday 6 January 1993

Institute of Petroleum
61 New Cavendish Street
London W1M 8AR

How should our electricity be generated? The cases for gas, coal, nuclear and alternatives will be presented and debated.

For further information please contact Catherine Cosgrove on 071-636 1004.

FREE *ALL WELCOME*

Elf Enterprise was formed last year as a joint venture between Elf Aquitaine and Enterprise Oil. The Company operates the Claymore and Scapa Fields and Flotta Terminal and is now in its final stages of preparation for the redevelopment of the Piper Field which is set to come on-stream in the near future followed by the Saltire and Chanter Fields. As a result of this increase in activity, the following opportunity has arisen within our Facilities Engineering Group.

Metering Engineer

Primarily this position would involve verifying offshore production metering data on a monthly basis; providing assistance to Flotta Terminal in resolving measurement problems; carrying out engineering studies/conceptual designs; supervising specialist surveys and preparing Design Basis documents, Project Plans, Engineering Workscopes and Engineering Reports; and providing technical support to other disciplines within Facilities Engineering and Operations Departments.

Educated to degree level in an engineering discipline you will have a minimum of 2 years' metering experience in an oil industry, petrochemical or continuous process environment. A thorough knowledge of the various national, international and regulatory authority standards and codes of practice relating to flow measurement is essential.

A competitive salary is offered along with a comprehensive benefits package which includes pension scheme, free life assurance and generous relocation assistance, where appropriate. A sports complex and social club and subsidised staff restaurant are also situated on-site.

Please write, enclosing full CV and salary details, to:
Steve Smith, Elf Enterprise Caledonia Ltd,
1 Claymore Drive, Bridge of Don, ABERDEEN AB23 8GB

Elf Enterprise

Open all hours.

Our pipelines are open to other gas suppliers who need to get gas to their customers in industry and commerce.

In the last year the number of sites supplied with gas by competitors using the British Gas pipeline system has increased from fewer than 1,000 to more than 5,000. Over one-third of all the gas used in the firm industrial and commercial market is now supplied by competitors of British Gas. And the competition continues to grow.

From October 1st we have extended our transportation service to include more customers than ever. That's because the open market to competition now incorporates customers who use between 2,500 and 25,000 therms of gas a year.

In addition we will be offering new services such as gas storage and low-cost interruptible gas transportation. So now, British Gas really is open for business in a big way.

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If you would like a copy or more information, please dial Freephone 0800 220358 or write to: John Huggins, Director, Gas Transportation, 22nd Floor, Millbank Tower, London SW1P 4QP.

British Gas