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OFFSHORE

International Oil & Gas Magazine

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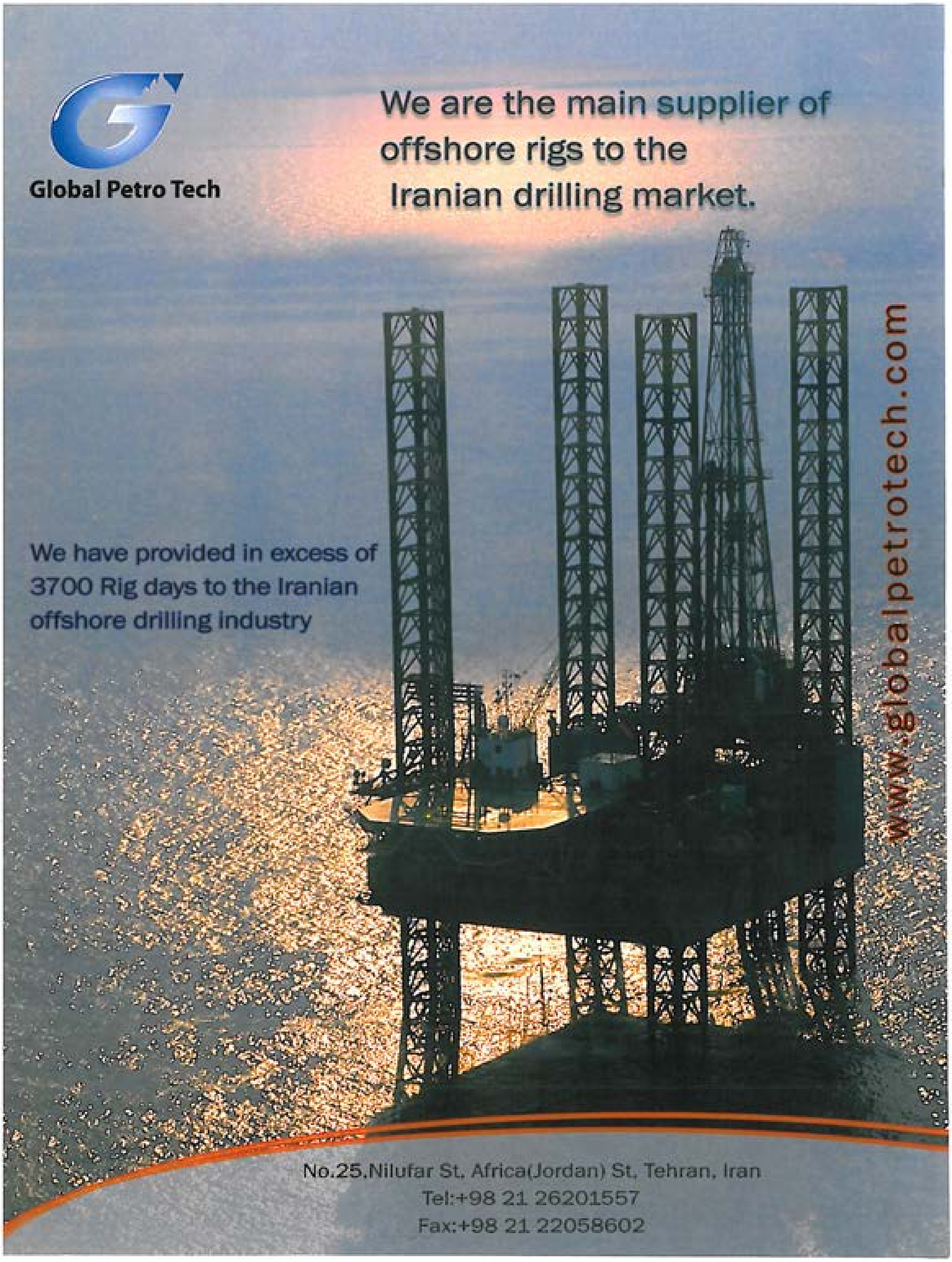
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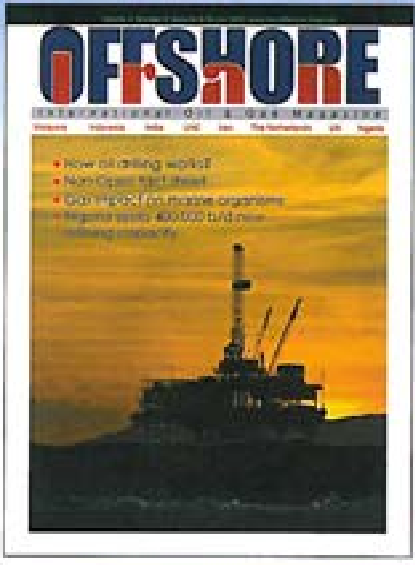

Cover story:

Scientists challenge major review of global reserves and warn that supplies will start to run out in four years' time. Scientists have criticised a major review of the world's remaining oil reserves, warning that the end of oil is coming sooner than governments and oil companies are prepared to admit.

(Refer to P.38)

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Petrobras budgets $1.5 billion for biofuels in 2008-12

Brazil's state-run Petroleo Brasileiro SA (Petrobras) plans to spend $1.5 billion on biofuels in 2008-12 with a focus on ethanol distribution and biodiesel production, Petrobras Chief Executive Jose Sergio Gabrielli de Azevedo said.

Petrobras will dedicate 46% of this total to pipelines, 29% to biodiesel, 4% to H-Bio, and 21% to other biofuels. Gabrielli told that Petrobras has formed a joint venture with Japanese firm Nippon Alcohol Hanbai for ethanol imports from Brazil. The JV is developing business models and Petrobras has signed memorandums of understanding with Japan to develop green field plants.

Earlier this year Petrobras also partnered with Mitsui to launch a feasibility study to increase ethanol and correlated product production and exports from Brazil to the international market. Currently Petrobras sells ethanol to Nigeria and Venezuela.

Gabrielli told that Petrobras also wants to build an ethanol pipeline from the midwestern and southeastern producing areas in Brazil to the port in Sao Paulo for exports. "Petrobras is also preparing to build ships in ethanol transport," he added.

Gabrielli said that although $1.5 billion on biofuels from the company's $112.4 billion investment over the next 7 years looked small overall, it was a relatively large sum compared with its peers. Petrobras is aspiring to export 4.7 million cu m/year of ethanol by 2012 to international markets, representing a 45.5%/year increase from 2008. "The ethanol production market is very mature," he said. "We are building three biodiesel plants now and we will probably do more."

According to Petrobras's 2008-12 strategic plan, it hopes to increase biofuel capacity from 329,000 cum/year in 2008 to 938,000 cum/year in 2012, and 1.2 million cum/year in 2015. Domestic demand in Brazil is expected to rise from 329,000 cum/year in 2008 to 1.3 million cum/year in 2012, and 2.7 million cu m/year in 2015.

The risk, however, is with technological breakthroughs for biofuels production, including technologies based on low value-added raw materials such as residual biomass. Petrobras is working on new technologies to position it as a leader in the field, Gabrielli said.

OMV to upgrade European refineries

OMV AG, Vienna, planning a program of upgrades in its European refineries, said it will shut down its 69,280 b/d Petrobrazi refinery in Romania for upgrades sooner than originally planned-in this year's fourth quarter instead of first quarter 2008.

In Germany, it plans to install an expanded cracker and new metathesis plant at its 72,000 b/d Burghausen refinery, work that will take 6 weeks in the fourth quarter. "Additional propylene will be delivered to Borealis, feeding the new Borstar propylene plant coming on stream at the same time," OMV said. In addition, the 262,300 b/d Bayernoil refinery in Germany will be restructured to improve plant configuration, OMV said.

In Austria the company will construct a thermal cracker in its 208,600 b/d Schwechat refinery in Vienna so it can process more heavy crude and reduce the amount of heavy fuel oil in the product slate.

A company spokeswoman told that OMV's strategy is to build on two hubs: a Western hub comprised of Schwechat, Burghausen, and Bayernoil that would have a refining capacity of 18.4 million tonnes/year and an Eastern hub of Petrobrazi and Arpechim in Romania, with a capacity of 8 million tonnes/year. Arpechim is operated by OMV's Romanian unit Petrom.

OMV said it also will begin preparations to construct a 360-km ethylene pipeline in southern Germany from Munchsmunster to Ludwigshafen that will connect the southeast Bavarian chemical triangle with the northwest European ethylene network at Ludwigshafen. The pipeline will be completed in third quarter 2008.

In Romania, the company will continue its modernization of production facilities to enhance efficiency and reduce production costs.

Philippines´ to vary energy sources, use more gas

Recently appointed Philippines´ Energy Secretary Angelo T. Reyes has promised to make more use of natural gas to vary the country´s energy sources and lessen its dependence on imported oil, estimated at some 325,000 b/d during 2006.

"Natural gas is the fuel of the future. [It] provides energy independence, stable and secure energy supply, and clean and efficient fuel. We are currently using this for power alone but we need to promote it in the transport, industrial, and commercial sectors," Reyes said.

He said several gas projects earmarked for construction will require $5 billion in investment during the next 7 years.

Among the projects Reyes said his department proposes is conversion of the Sucat, Limay, and Malaya coal-thermal power plants to gas-fired power facilities and construction of the 100-km Batangas-Manila I and 140-km Bataan-Manila II gas pipelines.

Plans also are under way for construction of new gas facilities in Central Luzon, Cebu, Agusan and Davao, and Palawan, while compressed natural gas facilities could be built in Luzon in areas such as Batangas, the Clark economic zone, and Cavite.

Reyes said gas constituted 29% of the country´s power generation mix in 2006, while coal and oil made up 27% and 8%, respectively.

InterOil gauges gas at Elk-2 appraisal well

InterOil Corp., Toronto, said it has achieved positive results from its Elk-2 appraisal well on PPL 238 in Papua New Guinea.

"We are now confident that the Elk structure contains sufficient gas to underpin the first train of an LNG plant, which will be built by Liquid Niugini Gas Ltd. adjacent to our refinery [planned at Port Moresby], and sufficient oil shows to justify sidetracking to confirm an oil leg," said InterOil Chairman and Chief Executive Phil Mulacek.

The Elk-2 well was programmed to test the entire 2,000 ft Puri and Mendi limestone section in a downdip position of the discovery well 2.9 miles away.

Drilling and testing at Elk-2 confirmed 4,452 ft of indicated hydrocarbon column from the highest known gas in Elk-1 to the lowest indicated hydrocarbons in Elk-2, InterOil said.

Mud logs indicated multiple gas zones, and there were multiple oil shows throughout a 594 ft column. In addition, the well had flowed gas and gas liquids during a drillstem test, the company said.

The target Puri and Mendi limestone reservoirs are much thicker than predrill estimates, it added.

The company intends to drill the Elk-2 well to total depth, log it, complete it, and test it.

"We will then sidetrack the well to intersect the potential oil leg structurally higher in the porous Mendi limestone section," Mulacek said.

LNG plant progress

InterOil has been designated as the preferred natural gas supplier for the planned Port Moresby LNG project, which consists of a two-train, 9 million tonne/year liquefaction plant having a nominal processing capacity of 1.6 bcfd of condensate and gas liquids, handling and storage facilities, and a gas pipeline from supply sources.

InterOil´s Elk and Antelope structures are the key gas resources for the project.

The company executed a shareholder agreement in July with Merrill Lynch Commodities and Pacific LNG to develop the LNG project. The partners agreed to establish PNG LNG as the holding company for Liquid Niugini Gas, which will own and operate the LNG facility.

The joint venture will proceed with contractor selection and front-end engineering and design work during this year.

LNG production is still on track to begin in 2012, InterOil said.

Kuwait counts on China links

Kuwait Foreign Petroleum Exploration Company hopes to increase its chances of securing more oil and gas reserves outside the country through teaming up with a Chinese state-backed partner, a senior executive of the Kuwait oil and gas explorer said.

Kuwait Foreign Petroleum, the overseas exploration unit of Kuwait Petroleum Corporation signed a non-exclusive memorandum of understanding with China's Citic Resources Holdings which calls for "closer co-operation in exploring oil and gas business venture opportunities in Indonesia and other countries".

The co-operative pact highlights the rising importance of China, the world's second-largest oil consumer after the US, in the global oil hunt. Beijing-backed, deep-pocketed Chinese oil companies have been aggressive in bidding for overseas upstream assets to feed the country's seemingly insatiable demand for energy."(The Chinese) can help us find good opportunities...With our knowledge and experience in the oil industry, together with the reputation of the Chinese companies, we will have higher chances in grabbing good opportunities," Abdullah Baroun, deputy chairman of Kuwait Foreign Petroleum, or Kufpec, said in an interview.

They haven't started looking at new projects as a joint entity, he said, "but we have looked at some projects separately... We will soon sit down and exchange information".

Shou Xuancheng, vice-chairman of Citic Resources, said in a Press release that the co-operation could "further strengthen (its) presence in South East Asian region".

Among Kufpec's other assets in Indonesia is a 40 percent stake in the Blora block in central Java, according to a statement issued by lead operator Swedish oil company Lundin Petroleum.

Official: New refineries planned for Southern Iran

New activities for developing the oil industry and implementing major projects in southern Iran will be launched in the near future, it was announced in Bandar Abbas in Iran's Hormuzgan province on Monday.

The Managing Director of National Oil Refining and Distribution Co., Mohammad Reza Nematzadeh, made the remark while talking to reporters on the sidelines of the inauguration of plans to increase the capacity of the Bandar Abbas-to-Isfahan pipeline in this southern port city.

New activities for developing the oil industry and implementing major projects in southern Iran will be launched in the near future, he added.

He further noted that two new refineries with total capacity of 660,000 barrels per day are to be built in Bandar Abbas.

The Persian Gulf Star refinery for treating gas condensate will handle 360,000 barrels per day condensate while a super-heavy crude oil refinery will be capable of treating 300,000 barrels per day, Nematzadeh said.

He noted that the construction contract for the Persian Gulf Star refinery has been signed. In addition, he said that engineering operations have begun and the project is to begin before the end of the current Iranian calendar year (started March 21, 2007).

He further announced that the super-heavy crude oil refinery planned for Hormuz is going through tender bid formalities and that the contractor will be chosen in a month. "The crude oil treatment capacity of Bandar Abbas refinery will increase from 232,000 to 300,000 barrels per day and an oil dock is being designed to be constructed in the near future," he said.

Nematzadeh further stated that to decentralize activities in Bandar Abbas, an undersea pipeline will be constructed between Bandar Abbas and Qeshm Island to facilitate transfer of crude oil in the near future.

He also noted that the plan for increasing capacity of Bandar Abbas-Isfahan pipeline was very important.

"The plan will be implemented through investing rls 2,000 billion to develop existing pump stations and will play a major role in transfer and distribution of various types of oil products," he added.

Libya launches gas licensing round in London

Libya has invited operators in London to bid for acreage under its fourth licensing round, but this time it focuses on natural gas. The deadline for applications is Nov. 30 (2007).

Libya's National Oil Corp. is offering 41 blocks off Libya, in the Sirt, Ghadames, Murzuq, and Cyrenaica basins, all of which are believed to be gas prone. NOC is keen to increase its gas production as international gas demand expands and consumers look to diversify gas supplies.

Libya holds 53 tcf of gas reserves, and its gas sector is relatively undeveloped. The country is hoping to boost gas production to 3 bcfd from 2.7 bcfd by 2010, with a potential for 3.8 bcfd by 2015.

NOC hopes another 70-120 tcf of gas can be found by 2020. It is eager to attract investment from larger operators that can bring integrated technology and knowledge to help increase oil and gas production following years of international sanctions.

Companies from Canada, Norway, Britain, Thailand, Japan, India, Algeria, and the UAE have so far shown an interest. Libya expects to name the winners on Dec. 9 in Tripoli.

Completing Interpretation of Orenburg Seismic Data

Aladdin Oil & Gas says structural interpretation of the 3D seismic that was shot earlier has been completed. Initial results indicate the presence of additional structures, previously not mapped on the main known producing formations of the field, and confirms the structures that have been drilled based on 2D seismic located near Orenburg, Russia.

In addition a new play, previously not interpreted on the field, has been mapped in the Lower Carboniferous (Tournaisian). This is a known producing formation in the neighboring field.

This substantially upgrades the reserves potential of the field and will be used for the planned drilling program. More detailed information will be released as it is available.

This first interpretation was done by the Russian seismic contractor. AOGC will now do an independent processing and interpretation of the data in the UK.

Output at northern Iraq field rising says DNO

The head of Norwegian oil producer DNO said production at the firm's field in northern Iraq was rising and he hoped a new oil law passed by the Kurdish regional authority would help secure future output.

DNO's chief executive Helge Eide said the company was now delivering around 6,000 barrels of oil per day from its Tawke field in the Kurdish north by tanker truck to local refineries.

"We expect test production to continue in August and have capacity to deliver more from the field, but that depends on the volumes we can sell in the local market," Eide said.

"We delivered what there was demand for in July, but that can well be thought to increase," he said.

DNO earlier said in a statement that its 55 percent share of production from the field rose to 3,196 barrels per day in July from 781 barrels in June.

DNO is the first foreign oil company to start drilling in post-war Iraq, where it has a production sharing deal with the Kurdistan regional authorities in the north.

Submiting bids for KNPC´s new oil refinery

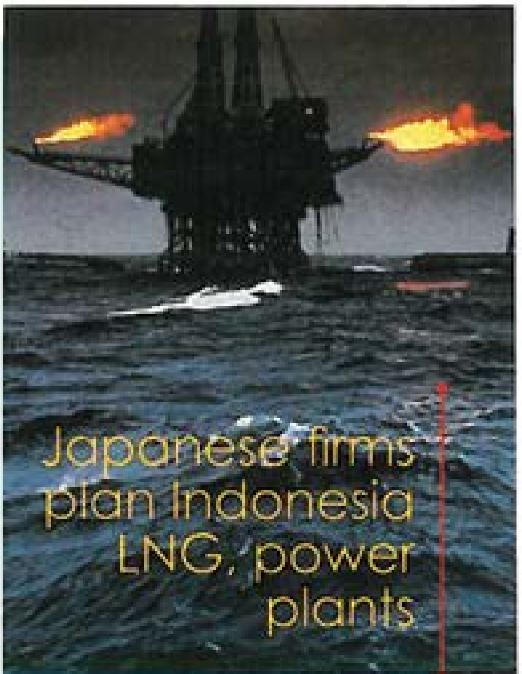
Eight international companies have submitted bids in response to a tender floated by the Kuwait National Petroleum Company (KNPC) to build a new oil refinery reports Al-Seyassah quoting an official oil source. "Eight international companies from among the qualified and specialized nine have submitted their bids. Some smaller companies are also expected to submit their bids before August which is the period fixed by KNPC for interested companies to submit their bids," said the source. KNPC invited international companies for a pre-qualification for participation in the project with an estimated cost of $5 billion, say sources.

The capacity of the new refinery is approximately 600,000 barrels per day and completion of this project together with another project for developing the existing oil refineries in Ahmadi and Mina Abdullah will take the total capacity of oil refineries to 1.20 million barrels per day, they explain. The new oil refinery is expected to replace Al-Shuaiba oil refinery in 2010, say sources, adding the project consists of treatment units as well as buildings, facilities and other installations.

Meanwhile, Kuwait National Petroleum Company (KNPC) recently announced a net profit of over $400 million for the first quarter of the current financial year, reports Al-Rai Al-Aam daily quoting a highly placed official in KNPC.

The company which posted a net profit of $2.1 billion in the last financial year is continuing its good performance said the source, adding KNPC showed a profit of $300 million dollars in the first two months of this financial year. Increasing prices of oil and oil products in the international markets are mainly responsible for this profit explained the source.

If the price of oil continues to stay in the current range KNPC can hope for even better profits than the last year added the official. KNPC is operating three oil refineries with a total production capacity of 920,000 barrels per day, said the source in conclusion.



Japanese firms plan Indonesia LNG, power plants

Major Japanese firms are expected to sign agreements for projects involving power generation and energy development in Indonesia. The signings will coincide with a visit to Jakarta by Japanese Prime Minister Shinzo Abe.

Mitsubishi Corp. plans to join with Indonesian state oil company PT Pertamina in the construction of a $1 billion natural gas liquefaction plant in Sulawesi aimed at producing 2 million tonnes/year of LNG as early as 2010.

In Sumatra, Sojitz Corp. and Kobe Steel Ltd. are considering feasibility studies with an unnamed Indonesian partner on liquefying coal to produce petroleum products,while Itochu Corp. and Kyushu Electric Power Co. expect to build an $800 million geothermal power facility in Sarulla in northern Sumatra by 2012.

Mitsui & Co. plans a $1 billion expansion project at a fossil fuel power plant in Paiton in eastern Java, while Marubeni Corp. expects to invest $750 million to build a fossil fuel power plant in Cirebon with operations to begin in 2011.

How oil gets to Central Europe

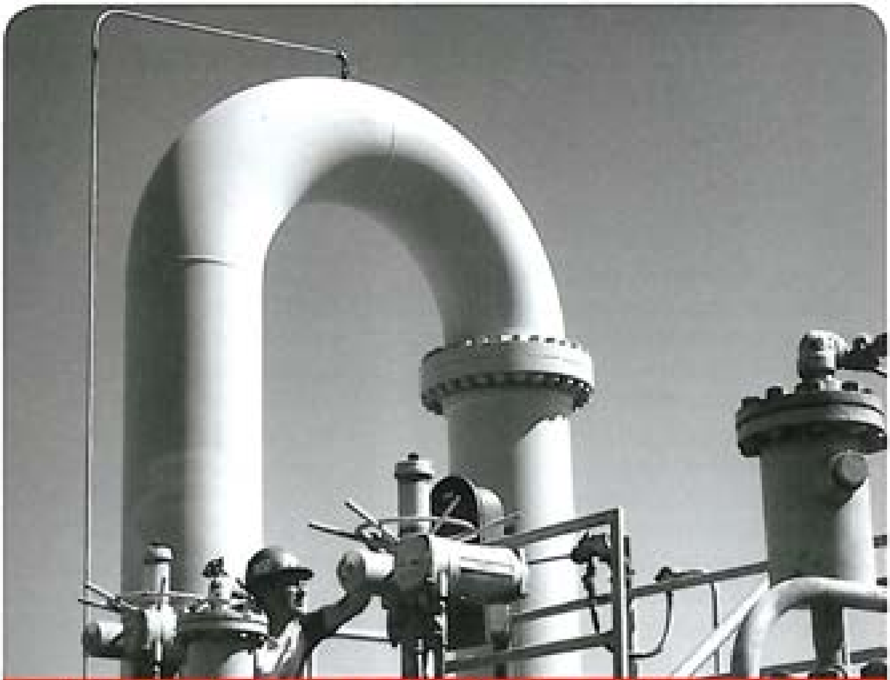
Russia supplies Germany with some 20 percent of its crude oil needs through its "Friendship" pipeline. But as this week's closure of that line shows, the supply is far from 100 percent reliable.

The Druszhba ("friendship") pipeline is one of the longest pipelines in the world and connects the oil fields in Western Siberia to the oil refineries in Europe. It is owned by the Russian pipeline monopolist Transneft.

Druszhba carries over 2 million barrels every day (159 liters - 42 gallons per barrel); 1.4 to 1.6 million barrels go directly to the European Union, the rest remains in Belarus.

The pipeline is divided into different branches in Belarus. The bigger northern branch connects to Germany via Poland. The southern branch crosses the Ukraine and leads to Czech Republic, Slovakia and Hungary.

Germany gets 500,000 barrels from this pipeline every day, a fifth of its total need. The companies Total, Shell and BP are the biggest customers of crude oil from this pipeline.



Trinidad and Tobago gas reserves show decline

The Ryder Scott audit of Trinidad and Tobago's natural gas reserves has revealed a 3.83 tcf decline since January 2005.

The report found that Trinidad and Tobago has 17.07 tcf of proved gas reserves, 6.23 tcf of probable reserves, and 7.76 tcf of possible reserves.

Energy Minister Lenny Saith said that with a usage rate of 4.6 bcfd, the Caribbean island nation has a production life of about 12 years. Saith said the solution is to increase exploration activities

Trinidad and Tobago's cabinet made four decisions arising from the survey results, according to Saith:

-Increase the rate at which decisions are made and blocks awarded for exploration.

-Do not move any gas-based project to the priority A category from the nonpriority B category.

-Get more geological information on potential areas to explore.

-Look at the taxation structure for exploration in high risk areas.

Saith said, "The survey is saying, Look at your taxation for exploration in high-risk areas, not exploration in low-risk areas. Look at your tax policy and determine if there is anything you need to do that will speed up [companies' willingness] to take risk in those high risk areas."

Saith said 16 new wells will be drilled within the next 15 months and insisted there would not be any new LNG trains built unless additional gas is discovered.

Trinidad and Tobago has four LNG trains and last year was responsible for 67% of total US LNG imports.

While there was a reduction in the 3Ps, the survey reported a 5 tcf increase in what it says could yet be discovered.

Ryder Scott reported that Trinidad and Tobago has a potential for an additional 37 tcf of gas awaiting discovery.

The increase in the figure resulted from the collection and processing of 3D data by Canada Superior and Petro Canada that showed there may be larger gas structures than originally thought in the blocks they are exploring.

NEWS

Growthing in Singapore's offshore

Singapore's marine and offshore industry has been experiencing significant growth. At the launch of the regional office of Japan's Mitsui Ocean Development & Engineering Co. (MODEC) Ltd.'s region office in Singapore, Ko Kheng Hwa, managing director of the Economic Development Board said he expects to see a 30% increase in the region's output above the $7.8 billion earned in 2006.

Singapore is also the largest oilfield equipment manufacturing site in Asia-Pacific, with companies like Schlumberger and Halliburton operating global plants on the island city state. Ko says Singapore has become the Asia-Pacific region's most comprehensive offshore engineering center, with capabilities in floating production, processing, subsea equipment, pipelines, and installation engineering. "The competitiveness and scale of our marine and offshore cluster are attracting more and more companies with sophisticated capabilities, such as MODEC, to expand their presence in Singapore, reinforcing our reputation as the Houston of the East,'" Ko said.

MODEC has chosen Singapore as its third Global Hub and Project Execution Centre, to complement Tokyo and Houston, establishing a 250-person regional office to carry out engineering work and operate FPSOs in Asia.

Peru heavy oil fields await development

Barrett Resources (Peru) LLC, based in Lima and registered in Delaware, retained a financial advisor to review alternatives to facilitate development of three large heavy oil fields in northeastern Peru.

The Peruvian government recently approved Barrett's initial development plan for Paiche, Piranya, and Dorado fields are on Block 67 in the Maranon basin. The analysis of strategic and financing alternatives should be completed by yearend.

The company said development would require 400 km of 16-in. pipeline and production could start in 2010, attaining 100,000 b/d thereafter.

The former Barrett Resources Corp., public Denver independent, discovered the three fields in 1998 and was unable to attract a partner with heavy oil development expertise before its sale to Williams Cos., Tulsa, in August 2001.

Three 7,000-ft discovery wells identified an estimated 90-313 million bbl of recoverable oil. Dorado cut 71 ft of pay with 14-16° gravity oil. Pirana cut 84 ft of oil pay with 12-21° gravity oil.

Saudis create security force for oil facilities

The kingdom of Saudi Arabia is investing $5 billion to create a 35,000-member security force to guard its oil infrastructure from terrorists.

Sources told a correspondent for Britain's Financial Times there are already 5,000 members undergoing training from the U.S. defense group Lockheed Martin.

Saudi officials reportedly made the move in response to fears of al-Qaida attacks for Riyadh's alliance with Washington and also out of concern for mounting tensions between Iran and the United States, the report said.

Saudi Arabia is the world's biggest oil exporter and has 25 percent of the world's proven oil reserves. It has more than 80 oil and gas fields and an estimated 11,000 miles of pipeline.

The 5,000 agents being trained are employed by Aramco, the state oil company, and will be joined by some 30,000 others in the next two years, the report said.

Terrorists have staged several attacks on the Saudi oil infrastructure but failed to cause major disruption of oil shipments, the newspaper said.

Eurogas&Calagry in Gulf of Gabes

Atlas Petroleum Exploration Worldwide 55% and Eurogas Corp., Calgary, 45% are progressing development and exploration on the 1 million acre Sfax permit in the Gulf of Gabes off Tunisia.

The companies have a 3-1/2-year farmout in place with Anadarko Petroleum Corp. since 2006.

The work involves development of three oil prospects and an exploration program.

A previous operator tested 612 b/d of oil from the El Garia carbonate in the 1990s at the first development prospect, Ras el Besh. The companies have a 30-year development concession, have taken possession of a production jackup, and are estimating the volume of oil in place before drilling a high-angle well.

The companies shot 60 sq km of shallow 3D seismic over Salloum, which another operator tested at 1,800 b/d of oil in 1997. Processing and interpretation will take 5 months.

An earlier well on the Jawhara structure tested at 1,200 b/d of oil.

Statoil installs Tordis subsea production system

Statoil ASA has installed the 1,250-tonne Tordis subsea production unit near Gullfaks field in the Norwegian North Sea, using the Saipem S7000 heavy-lift crane vessel.

The system is said to be the world's first subsea installation to separate water and sand from oil wells and pump them directly into the bedrock from the seabed, a process that needs no energy-intensive detour to a surface platform.

The project will improve oil recovery on Tordis to 55% from 49%, essentially producing an additional 35 million bbl of oil.

Marine operations in Tordis field will continue over the next few months, Statoil said. The seabed separator will be tied back now with pipelines and control cables to the Statoil-operated Gullfaks C platform, and subsea separation will begin this autumn.

Although the unit was successfully installed as planned, a man from Saipem fell overboard and died during the process when the Tordis structure was at a depth of 180 m. Statoil has launched an investigation.

Oil is transported from Tordis by pipeline to Gullfaks C, 11 km to the southeast, for processing, storage, and export.

OPEC steps up search for oil, gas

The world's biggest oil producers have boosted their search for oil and gas to one of the highest levels in two decades as prices neared record highs of more than $78 a barrel.

The Organization of Petroleum Exporting Countries, the group that controls three-quarters of global oil reserves, said its members operated 336 oil rigs last year, an increase of 11.5% since 2005, in response to strong demand from developing countries such as China and India.

The group's annual statistical bulletin shows that member countries were operating the second largest oil rig fleet since 1982, when oil prices hit an all-time high in today's money of about $90 a barrel.

US oil prices July 31th rose to $78.23 a barrel, just below the $78.40 nominal high. The number of oil rigs in operation is seen as one of the best estimates of investment trends. Oil producing countries rarely give out data on the amount of money they invest. OPEC is financing its capacity expansion on record revenues of $650 billion last year, up 22% from 2005.

The International Energy Agency, the industrialized countries' energy watchdog, recently warned of an oil "supply crunch" within five years as a result of accelerating consumption growth and output falls in mature areas such as the North Sea, and long delays in new production projects.

Iran & Iraq sign oil deal

Iran and Iraq have signed a deal to construct a new pipeline transferring crude oil and their products, the Iraqi Oil Minister announced.

The thirty-two inch wide pipeline will transfer crude oil from Basra's port in southern Iraq to the Iranian port of Abadan.

Iran will purchase 100,000 barrels of Iraqi crude for refining in the port of Bandar Abbas before selling it back to Iraq.

The Iranian Oil Minister Kazem Vaziri-Hamaneh, who was dismissed at the weekend(Aug 17th), will be replaced by the head of the state-owned National Iranian Oil Company (NIOC) Gholamhossein Nozari, who will become caretaker oil minister.

Hungary finally throws its weight behind Nabucco

Hungary appeared to change its policy on the Nabucco pipeline, a European Union-backed project aimed at reducing dependence on Russian gas, when Economy Minister Janos Koka said that his government backed the plan.

Koka, speaking to reporters ahead of international conference on the Nabucco project in Budapest, said that the conference demonstrated Hungary "is committed" to the pipeline.

Hungary had appeared to be leaning toward backing an extension of Russia's Blue Stream pipeline, with Prime Minister Ferenc Gyurcsany criticizing Nabucco for lacking a clear direction.

Both Nabucco and the Blue Stream extension are to carry gas to the EU via Turkey and the Balkans, with the main difference being that Nabucco would transport gas from the Middle East and Central Asia.

The EU is looking to reduce its dependence on Russian gas since supplies were interrupted following spats between Russia and transit nations Ukraine and Belarus.

Hungary, which is almost entirely reliant on Russian gas, was hit particularly hard by the interruptions.

Koka said that the Russian project would only cut technological risks and that a new pipeline was needed to diversify supply.

While Koka said that he now supports Nabucco, he also said that Hungary would use the conference to push for the pipeline to be opened up to third parties, including Russia.

The 4.6-billion-euro (US$6.36-billion), 3,300-kilometer Nabucco pipeline is scheduled for completion in 2012, although work is not due to start until 2009.

Replacesing NNPC head in Nigeria

Nigeria President Umaru Yar'Adua has removed Funso Kupolokun, group managing director of Nigeria National Petroleum Corp., from his post.

Yar'Adua has replaced him with the next most-senior executive, Abubakar Yar'Adua-of no relation to the president-until further notice.

The firing comes amid intense speculation in Nigerian media that the president was unhappy with the performance of NNPC, the allegations of corruption in awarding contracts and misappropriation of funds, and that Kupolokun was on his way out. However, the president did not give a reason for dropping him.

The president, who took the reigns of power on May 29, is committed to revamping Nigeria's energy sector.

Abubakar Yar'Adua was previously the company's executive director overseeing refineries and petrochemicals since 2003.

South Korea, Iraq to sign refinery deal

South Korea and Iraq have agreed to cooperate in energy projects across Iraq, according to a statement issued by South Korea's Ministry of Commerce, Industry and Energy.

The two sides agreed to explore oil and gas fields and to build a refinery, the statement said.

A delegation led by Commerce Minister Kim Young-Ju met their Iraqi counterparts, including Iraqi Oil Minister Hussain al-Shahristani, in Dubai to strengthen their cooperation in energy development projects.

Both countries will analyze the Sufaia oil field and the Siba gas field in Iraq in a joint study.

The Sufaia block, which has an estimated 95 million barrels of oil, produces 5,000-8,000 barrels a day of oil, while the Siba field has a 100 million barrels of condensate and natural gas equivalent to 600 million barrels of oil.

The two parties have also agreed to cooperate in developing natural gas deposits found alongside oil fields in southern Iraq, it said.

The South Korean government has recommended Hyundai Engineering & Construction Co. (000720.SE) and SK Engineering & Construction Co. in the front-end engineering design of a refinery in Karbala, a ministry official said.

"The initial agreement for their participation in the refinery project will soon be signed between Korea and Iraq," said the official.

Kim also asked Shahristani to help South Korean firms participate in the project to develop the Halfaya oil block, in the southeastern part of Iraq, which has a proven reserve of 3.4 billion-3.8 billion barrels, said the statement.

Cambodia to expand navy to safeguard oil Sites

Cambodia is planning to expand its naval presence in the Gulf of Thailand to provide better security for companies engaged in work at oil exploration and extraction sites, Defense Minister Tea Banh said.

"Security is important and it is our duty to provide safety to all companies running businesses in our country," Tea Banh told Kyodo News, adding that such a plan is under discussion.

He declined to elaborate.

But Yim Sovann, opposition lawmaker who chairs the National Assembly's defense commission, said the plan calls for the transfer of more than 1,000 ground forces to the navy.

"We need to post more troops along the coast in order to provide security to all oil exploration companies...We must protect the property of investors from terrorism," he said.

Defense Ministry sources suggested that the number of navy ships would be expanded under the plan. The current number of ships was not revealed, but in 2005, China gave Cambodia six patrol boats to combat smuggling and other crimes at sea.

Cambodia is expected to begin seeing benefits from exploitation of its offshore oil and gas resources in 2010.

In 2005, U.S. oil giant Chevron Corp. announced that it had discovered petroleum off Cambodia's shores in four of five wells drilled in Bloc A in the Gulf of Thailand.

Since then, firms from other countries such as Japan, China, South Korea, France, Kuwait, Brunei, Thailand and Russia have been reportedly seeking exploration licenses from the Cambodian government.

Nigeria seeks 400,000 b/d new refining capacity

Nigeria hopes to add 400,000 b/d of new refining capacity by 2011-12 with joint venture partners, according to Nigerian media reports.

Funsho Kupolokun, group managing director of Nigerian National Petroleum Corp. (NNPC), was quoted as saying the country is unlikely to meet its target of declaring 40 billion bbl of oil reserves from 35 billion bbl by 2010 because of violence in the Niger Delta that is rising operational costs and creating funding difficulties.

Alex Gorbansky, managing director of Frontier Strategy Group, told that Nigeria´s missing its target would add to the increasing uncertainty impacting the supply of both crude and refined products. "Project delays given major technical and bureaucratic challenges should be expected, particularly in emerging producing countries like Nigeria that have had significantly less industry expertise."

NNPC is in discussions with Royal Dutch Shell PLC, ExxonMobil Corp., Chevron Corp., Total SA, and Agip to set up two refineries, each with 200,000 b/d refining capacity. According to the News Agency of Nigeria, the refineries would be built in Okrika and Brass.

A source told OGJ that analysis has just begun to see if building new refineries "makes economic sense," adding, "We are a long way from making any kind of decision on our participation in a new refinery."

The reports quoted Kupolokun as saying the partners are working out the details, and NNPC is involved in producing a regulation mandating that oil producers refine a certain percentage of their production. Kupolokun admitted that previous directives to compel producers to refine 50% of their production locally had failed because they were not supported by legislation, adding: "When the regulation comes, they cannot give excuses."

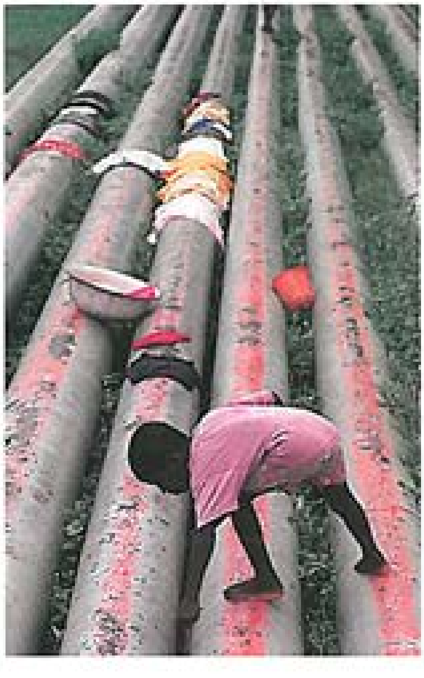
Speaking Aug. 6 at the annual Society of Petroleum Engineers conference and exhibition in Abuja, Kupolokun said continued violence in the Niger Delta had dissuaded potential companies from repairing the Chanomi Creek Channel pipeline that carries feedstock to the Warri and Kaduna refineries. These had operated at 70% and 75% capacity before militants damaged the pipeline in February 2005.

"I talk of Chanomi Creek today; I cannot even find a contractor that will do this job for me. We started with Willbros. They withdrew because of the problem. We went to Saipem…[but cost] has become an issue," Kupolokun said. Nigeria has been forced to import fuel products to meet its needs.

Nigeria´s hydrocarbons production has grown by only 5%/year over the last 10 years, Kupolokun said. To reach the 40 billion bbl reserves mark, Nigeria would need to find the equivalent of three giant finds, each the size of Bonga (600 million bbl of reserves) in the next 3 years. The target was set under the presidency of Olesegun Obasanjo who has now been replaced by Umaru Yar´Adua. Obasanjo´s government set the objective to raise oil production to 4 million b/d by 2010.

Another challenge facing Nigeria´s oil industry is replacing ageing assets which have been in place for the last 40 years.

Of course the fields are also maturing, assets are ageing, and the number of assets and facilities that have been put in place 40 years ago, all these translate to cost implications," Kupolokun added.



BP cedes Kovykta gas field stake to Gazprom

BP has ceded control of its majority stake in the massive Kovykta gas field in eastern Siberia to Gazprom as the Russian government further tightens its grip on the country's energy sector.

BP, Britain's largest company, put a positive spin on the deal, arguing that it has signed a "historic" strategic alliance with Gazprom, the world's largest gas producer, to jointly invest in projects and swap assets around the world. It has also secured an option to buy a 25 per cent stake, plus one share to get voting rights, in Kovykta within a year. The value of the stake will be independently verified when and if the option is exercised.

Tony Hayward, the recently appointed chief executive of BP, said: "This historic agreement lays the ground for powerful co-operation between BP, TNK-BP and Gazprom."

The state-controlled Gazprom will pay between $700m (£350m) and $900m for TNK-BP's near-63 per cent stake in Rusia Petroleum, the company that holds the licence to mine the Kovykta field, as well as a 50 per cent stake in the company that is constructing the regional gas field. TNK-BP is a joint venture between BP and a group of Russian billionaires, and is the third-largest oil producer in country.

BP has come under increasing pressure from the Russian government over recent years, culminating in a threat to revoke the licence awarded to Rusia Petroleum. Russia's natural resources ministry has repeatedly said that the field has failed to produce enough gas to satisfy the original licence conditions related to the Kovykta field, which is estimated to have as much gas as Canada. The threat has been widely interpreted as the Russian government's latest attempt to regain state control of energy assets. Royal Dutch Shell ceded control of its $22bn Sakhalin-2 project to Gazprom last December after the government raised concerns over environmental damage related to the project.

When TNK-BP originally won the licence 15 years ago, it assumed that demand from the local market would justify its investment in the $20bn project. However that demand has failed to materialise, hampering TNK-BP's plans, because it is prohibited from piping gas to foreign markets as Gazprom has a monopoly on exporting gas out of Russia. BP has held negotiations with Gazprom in the past to explore opportunities to pipe the gas into China and South Korea; however, it is only recently that observers have faced up to the prospect of BP exiting the project completely.

BP's sale of its stake in Kovykta will draw a line under the controversy, allowing the British company to consider ways in which it can exploit its strategic alliance with Gazprom. The option will give the company a chance to retain exposure to the project once the Russian company has further developed the field, although it is unlikely that it will be fully exploited until the middle of the next decade. Mr. Hayward said earlier this week when asked about Kovykta: "I consider this issue to be no more than one of those bumps in the road."

Mr Hayward said that BP and Gazprom would initially look for projects of at least $3bn, arguing that the potential for further growth "could be very significant". He said the alliance would be mutually beneficial for both companies, both inside and outside Russia, and that it would look for suitable investment opportunities "across all geographies". Gazprom has recently said it wants to supply gas to the UK market, although BP has no downstream gas operations in the country.

Analysts were not impressed with the price paid for the stake in Kovykta, arguing that the valuation of its controlling stake was unattractive, given the huge potential of the field and the $450m that TNK-BP has already invested in developing the asset.

Australia gets $800 million boost to offshore exploration

Australian Resources Minister, Ian Macfarlane, announced a boost to petroleum exploration in Australian waters, with 11 new offshore permits awarded to exploration companies.

A total of 21 bids were received for the 11 areas and these exploration programs are worth more than $800 million.

"The high number of bids and the huge investment companies are prepared to make shows the great interest in Australian offshore petroleum exploration," Mr. Macfarlane said.

"More than $800 million will be invested over the next six years to explore Australian oil and gas opportunities, taking total investment in the 2006 offshore petroleum acreage release to almost $2.2 billion."

The areas are in Commonwealth waters off Western Australia, Tasmania and the Northern Territory and include four permits in Designated Frontier Areas (DFAs).

"Companies which take on the greater risk of exploring in DFAs are eligible for favourable tax rates because it is in these unexplored frontier areas that we expect to find major new oil or gas reserves," Mr. Macfarlane said.

This year has seen a significant increase in the number of new companies applying to explore in Australian waters.

"It's good to see new players in the market. It demonstrates that the government initiatives to boost exploration are working," Mr. Macfarlane said.

The 11 new permits are:

- Two permits in the Northern Arafura Basin, off Northern Territory, to Samson International (Australia) Pty Ltd;
- One permit in the Sorell Basin, off Tasmania, to Santos Offshore Pty Ltd;
- Five permits in the Bonaparte Basin, off Western Australia, to CNOOC Australia E&P Pty Ltd; Total E&P Australia; Goldsborough Energy; and Reliance Industries Ltd; and
- Three permits in the Carnarvon Basin, off Western Australia, to Woodside Energy Ltd and Hess Exploration (Carnarvon) Pty Ltd; and Gerald Nelson.

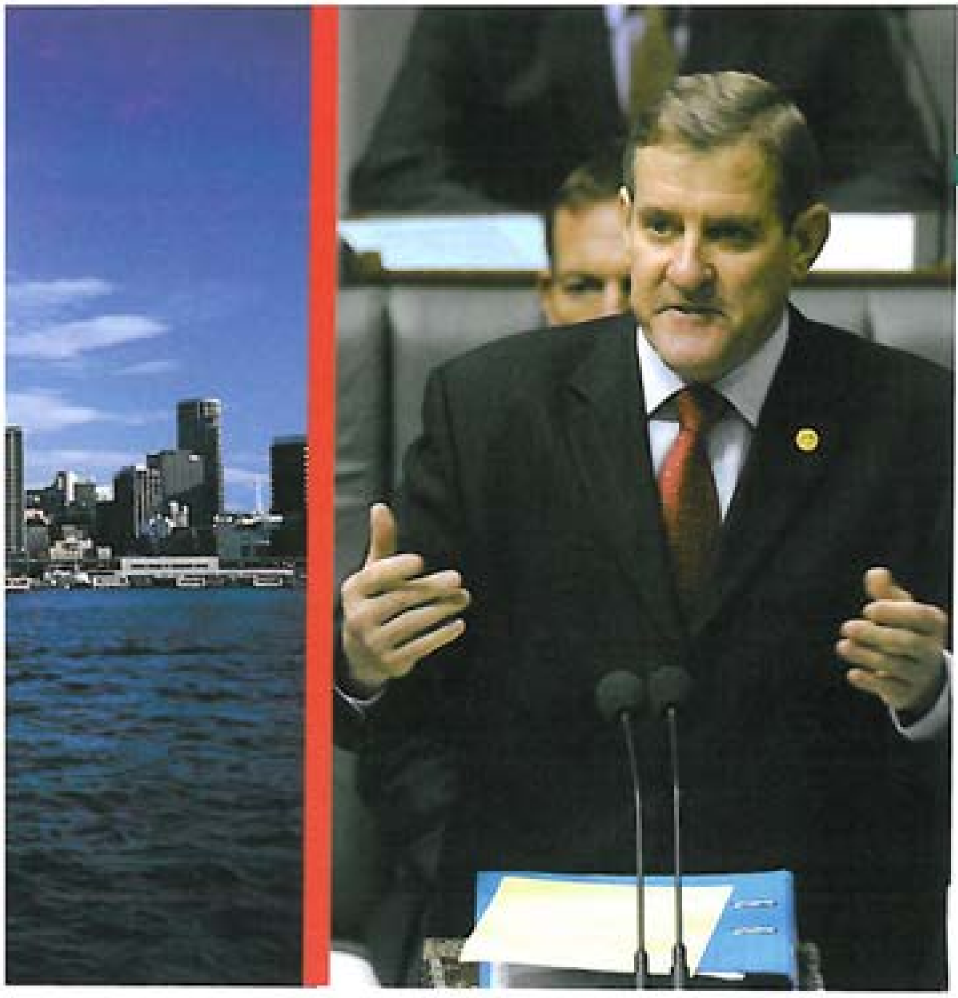
Under the work program bidding system, applicants are required to nominate a guaranteed minimum <dry hole' exploration program for each of the first three years of the permit term and a <secondary' program for the remaining three years. Each component of the program must be completed in the designated year or earlier. Permits are awarded for an initial term of six years and may be renewed twice for periods of five years.

Permit NT/P74 (released as NT06-3) in the Northern Arafura Basin has been awarded to Samson International (Australia) Pty Ltd. The company proposed a guaranteed work program of 1400km 2D seismic and geotechnical studies at an estimated cost of $2.78 million. The secondary work program consists of two exploration wells and 400km2 3D seismic survey at an estimated cost of $33 million. There were no other bids for this permit.

Permit NT/P75 (released as NT06-4) in the Northern Arafura Basin has been awarded to Samson International (Australia) Pty Ltd. The company proposed a guaranteed work program of 2200km 2D seismic survey and geotechnical studies at an estimated cost of $4.18 million. The secondary work program consists of two wells and 700km2 3D seismic survey at an estimated cost of $35 million. There were no other bids for this permit.

Permit T/48P (released as T06-5) in the Sorell Basin has been awarded to Santos Offshore Pty Ltd. The company proposed a guaranteed work program of 700km 2D seismic survey and geotechnical studies at an estimated cost of $2.2 million. The secondary work program consists of one well, geotechnical studies and 300km2 3D seismic survey at an estimated cost of $35.9 million. There were no other bids for this permit.

Permit WA-400-P (released as W06-



13) in the Carnarvon Basin has been awarded to Gerald Nelson. Mr Nelson proposed a guaranteed work program of 227km 2D seismic reprocessing; 40km2 3D survey and geological studies at an estimated cost of $1.29 million. The secondary work program consists of two exploration wells and a 40km2 3D seismic survey. There were no other bids for this permit.

Permit WA-401-P (released as W06-10) in the Carnarvon Basin has been awarded to Gerald Nelson. Mr Nelson proposed a guaranteed work program of 104km 2D seismic reprocessing, 45km2 3D seismic survey and geotechnical studies at an estimated cost of $1.4 million. The secondary work program consists of two exploration wells and 45km2 3D seismic survey at an estimated cost of $25 million. There were no other bids for this permit.

Permit WA-402-P (released as W06-2) in the Bonaparte Basin has been awarded to Total E & P Australia. The company proposed a guaranteed work program of 1000km 2D seismic reprocessing, geotechnical studies, 754km2 new 3D seismic survey and 3D seismic interpretation at an estimated cost of $13.2 million. The secondary work program consists of one exploration well and geotechnical studies at an estimated cost of $59.4 million. There were two other bids for this area.

Permit WA-403-P (released as W06-3) in the Bonaparte Basin has been awarded to Total E & P Australia. The company proposed a guaranteed work program of 1984km2 3D seismic survey, 3D seismic interpretation, geotechnical studies and two exploration wells at an estimated cost of $144.4 million. The secondary work program consists of geotechnical studies at an estimated cost of $7.2 million. There was one other bid for this area.

Permit WA-404-P (released as W06-9) in the Carnarvon Basin has been awarded to Woodside Energy Ltd and Hess Exploration (Carnarvon) Pty Ltd. The companies proposed a guaranteed work program of 2748km2 3D survey, geotechnical studies and nine exploration wells at an estimated cost of $196.2 million. The secondary work program consists of geotechnical studies and one exploration well at an estimated cost of $21.8 million. There were four other bids for this permit.

Permit WA-405-P (released as W06-5) in the Bonaparte Basin has been awarded Reliance Industries Ltd. The company proposed a guaranteed work program of 3200km 2D reprocessing, geotechnical studies, 500km 2D seismic survey and 600km2 3D seismic survey at an estimated cost of $9.6 million. The secondary work program consists of geotechnical studies and one exploration well at an estimated cost of $20.16 million. There was one other bid for this permit.

Permit WA-406-P (released as W06-1) in the Bonaparte Basin has been awarded to CNOOC Australia E&P Pty Ltd. The company proposed a guaranteed work program of 400km2 3D seismic survey, geological studies and five exploration wells at an estimated cost of $81.3 million. The secondary work program consists of 400km2 3D seismic survey, geological studies and five exploration wells at an estimated cost of $80.8 million. There were two other bids for this permit.

Permit WA-407-P (released as W06-4) in the Bonaparte Basin has been awarded to Goldsborough Energy. The company proposed a guaranteed work program of geotechnical studies and 1400km 2D seismic survey and 2000km 2D reprocessing at an estimated cost of $2.75 million. The secondary work program consists of seismic interpretation, geotechnical studies and one exploration well at an estimated cost of $15.6 million. There were no other bids for this permit.

Offshore marine services names Steve Taylor to head Dubai ops.

Offshore Marine Services has appointed Steve Taylor as Director of Operations of their Dubai business unit. The creation of this new position follows the recent establishment of the company's operations in Dubai which mark a significant international expansion for OMS.

Sandy Macklin, OMS Director of International Development comments: "The launch of our services in Dubai indicates a period of vital growth in terms of Offshore Marine Services operations on a global basis, and the appointment of Steve Taylor plays an integral role in this development."

"Our Dubai business unit is a crucial addition to our company which currently operates worldwide from Aberdeen, Malta, Singapore, New Zealand and Perth, Australia. Our aim is to further enhance and develop the levels of expertise and resources within our overall international operations through our Dubai business, whilst also achieving independent profitability for this unit. Our operations in Dubai open up a significant opportunity to draw and build on labor sources and skills sets within this geographical area, which will play a vital role in our objectives for future growth."

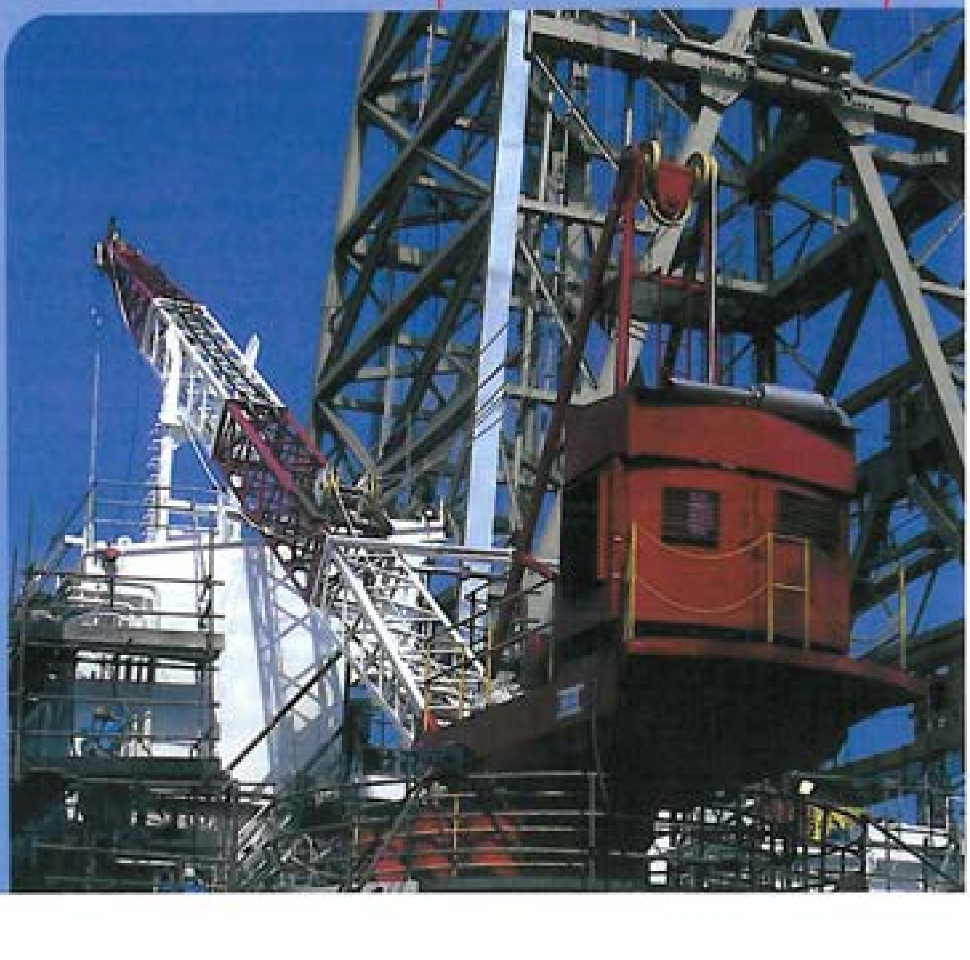
With a strong knowledge of the industry having previously held the position of European HR Manager with Santa Fe Drilling for 23 years, Steve Taylor joins OMS from his role as Global HR manager for Precision Drilling International. Steve also brings significant expertise from his roles as Vice Chairman of the IADC (North Sea Chapter) Human Resources Forum and Chairman of the UKDCA, an industry committee set up to address UK industrial relations issues.

Sandy continues: "Bringing a wealth of experience and understanding of the industry to his position, Steve's appointment is fundamental in driving forward the success of our operations in Dubai. Steve will assume overall responsibility of this unit and will be key in optimizing the opportunities which can be developed in this area including growth within Offshore Marine Service's international drilling and marine business."

OMS will be one of the anchor tenants of Dubai Maritime City, the world's first purpose built city designed specifically to serve and enhance the marine and offshore oil & gas industries. It is an integrated mixed use development encompassing commercial, industrial, academic, residential and lifestyle components. Spread across 227 hectares, the multidimensional maritime center is a man-made peninsula which will re-define the global maritime community.

The Offshore Marine Services group offers a global solution to the industry's manning and marine requirements. Core activities are the worldwide recruitment and supply of experienced personnel to the offshore drilling and marine industries, this includes offshore support vessel crewing, manning and management. The company also owns and operates its own fleet of offshore supply and FPSO off-take vessels.

OMS Group companies are strategically positioned worldwide and currently operate out of Aberdeen, Malta, Singapore, New Zealand and Perth, Australia.



Cyprus

expects keen interest as oil bid deadline looms

Cyprus hopes several companies will seek a license to explore for oil and natural gas off its southern shores before Aug 16th deadline, an official said.

The invitation for tenders, made despite a growing row with Turkey, ends at 2:30 pm (1130 GMT). Shortly afterwards, the commerce and industry ministry will announce the applicants.

Six companies, including Russian and Chinese firms, have shown a keen interest in securing a license, but none of the major multinationals is expected to bid.

Commerce ministry official Solon Kasinis told state radio the government would be "satisfied with four to five applications" to explore 11 of the 13 blocks within Cyprus's exclusive economic zone.

A decision will be made by the end of the year. A second round for the remaining blocks will be launched in 2008.

Cyprus has warned that Turkey's continued threats over oil exploration could mean obstacles being placed in the path of across Ankara's EU accession bid.

Cypriot Foreign Minister Erato Kozakou-Marcoullis said Turkey could not continue trying to derail Cyprus' oil search by threateningly demanding it stop the venture.

Ankara has reiterated that it will secure its "legal rights and interests" in the region if Cyprus proceeds with oil and gas exploration.

And the breakaway Turkish Republic of Northern Cyprus (TRNC), recognised only by Ankara, has also spoken out.

Presidential spokesman Hasan Ercakica said that "in case such developments continue, it is natural to expect the escalation of tension in the eastern Mediterranean."

February's launch of the licensing round came just two days after Ankara announced its own plans for oil and gas exploration in the eastern Mediterranean - a move that triggered protests from the Cypriot government.

Cyprus is offering licenses for an area of about 70,000 square kilometres (28,000 square miles).

Estimated oil deposits are put at around eight to 10 billion barrels.

Cyprus has also signed gas and oil exploration and exploitation deals with Cairo and Beirut, triggering strong objections from Ankara.

Turkey has warned Egypt and Lebanon to delay the deals, saying they infringe on the rights of the TRNC.

In reaction, Cyprus lodged protests with the United Nations and the European Union.

Cyprus, an EU member state, has been divided since 1974 when Turkey seized and occupied its northern third in response to an Athens-engineered coup in Nicosia seeking to united the island with Greece.

China's increasing hold over Kazakh oil

Grunts and shouts echo through a spacious sunlit gymnasium as a dozen teenage boys fire their fists and perfect their kicks.

The brand new martial arts school is China's gift to the children of Kazakhstan's oil rich province of Kyzlorda, a place where Beijing has been flexing its energy muscle.

Outside the school, and as far as the eye can see, lies the monotonous landscape of the Central Asian steppe.

Colourless grass pokes out of the dry land, but just beneath the surface lies Kazakhstan's vast oil and gas reserves.

Just a year and a half ago, the oil and gas fields belonged to a Canadian company. But then, in a highly controversial takeover, China's state oil company CNPC became the main shareholder of PetroKazakhstan.

It was an important acquisition; the $4.2bn (£2bn) deal became Beijing's largest purchase here. But China's shopping spree in Kazakhstan's energy sector is only just beginning.

From petrol stations to refineries and now even a 1,000km (620 mile) long pipeline, the first one ever to go to mainland China, the list of Beijing's acquisitions is growing by the day.

"Our relationship with Kazakhstan is a priority for us, and our foreign policy," says Wang Bing, a spokesperson for the Chinese embassy in the country's economic capital Almaty.

"We are co-operating on many levels, and of course energy is very important. The new pipeline, for example, is hugely significant for both China and Kazakhstan.

"It is the first oil pipeline into mainland China, and it's good for Kazakhstan too, as it has allowed Kazakhstan to diversify export routes," Wang Bing said.

Competing for Kazakh oil

Kazakhstan is about to become one of the world's top oil producers, and as the scramble for its resources intensifies, the country's president, Nursultan Nazarbayev, says the game is fair, and that Russia, China and the West are all welcome to invest.

"The United States, Russia and China are all interested in Kazakhstan, and we don't want to allow a conflict of interest here," Mr Nazarbayev told the BBC.

"That's why we chose a multi-vectoral foreign policy. The United States is investing in oil and gas, Russia is a hugely important neighbour and partner, and we share a 1,700km border with China, so that relationship is also very important. But we treat everyone equally," Mr Nazarbayev added.

This policy has helped Kazakhstan's economy to grow faster than any other in the former Soviet Union.

The country's ability to turn to Beijing has also given President Nazarbayev a bargaining power when it comes to dealing with the West.

But as China looks for energy to drive its growing economy, it is also becoming more aggressive in securing reserves, and that threatens the gentle geopolitical balance that President Nazarbayev is keen to keep.

New Great Game

There are plenty of signs that the Chinese are already getting an upper hand in Central Asia.

Unlike Western oil firms, Chinese state oil companies do not have to operate on a commercial basis.

Many analysts believe China grossly overpaid for the PetroKazakhstan purchase, seeing the deal as a perfect example of Beijing's willingness to pay over the odds and stifle competition.

And, according to the energy consultant Robert Corzine, there is more bad news for the West.

"The Chinese tend to act very much like Western oil companies acted in the 1920s - that what was their oil, was their oil... and no one else could get hold of it," Mr Corzine said.

"I think that the concern of Western companies is not that the Chinese are trying to develop oil reserves outside their country - that's only natural. The problem is that this oil goes directly to China and not to the global market," Mr Corzine said.

Historically, Central Asia has always been the battleground of the Great Game, the struggle for resources and influence between the great powers.

The game now has a new, and an increasingly powerful player, and it has come to Central Asia with its own rules.

And that means fewer opportunities for the West at a time when it, too, is desperate for more access and resources.

India lowers Krishna Godavari gas find estimates

India has dramatically reduced the estimated size of recent gas discoveries in the Krishna-Godavari (KG) basin of Andhra Pradesh, which could diminish the area's attraction to the world's top energy players.

The seventh round of bidding for 85 oil and gas blocks under the New Exploration Licensing Policy (NELP-VII), which includes blocks in the Cauvery basin, was originally scheduled for last April, postponed until later this month, and now pushed back again to November.

Two of the country's state-run explorer-producers, Oil & Natural Gas Corp. (ONGC) and Gujarat State Petroleum Corp. (GSPC), earlier had announced discoveries off the hydrocarbon-rich Indian East Coast but later were forced to concede that the finds were much lower than initially projected.

ONGC cut to less than one-tenth the estimated size of its KG basin find—to 56.6 billion cu m (bcm) from 595 bcm it had forecast in December 2006, while GSPC slashed even more drastically the potential size of its gas finds to 39.1 bcm, from 566 bcm it had reported in June 2005.

The admissions were a victory for Director-General of Hydrocarbons V.K. Sibal, who had been bitterly criticized by ONGC for refusing to accept the size of ONGC's KG basin gas discovery, which it originally compared to the huge gas find of Reliance Industries in the same basin.

The large disparity between the two sets of figures has induced experts to urge the Indian authorities to tighten the norms for announcing oil and gas discoveries to prevent exploration companies from overreporting or extracting economic and political capital from such new finds.

The revised ONGC and GSPC figures also threaten to undermine New Delhi's claims that India will soon have a gas surplus and become a net exporter of the fuel. Gas supply in the country was expected to reach 188 million standard cu m/day (MMscmd) by 2009-10, a significant rise from the present level of 80 MMscmd.

India also has been encouraging power and fertilizer plants to switch to gas from naphtha to cut costs. But those plans may now go awry, given that there will be less domestic gas production than was initially projected.

Gas imports

The country imports 70% of its crude oil requirements and is able to meet half its gas demand of 170 MMscmd via its domestic production. The deficit in gas consumption is covered by LNG imports from countries such as Qatar.

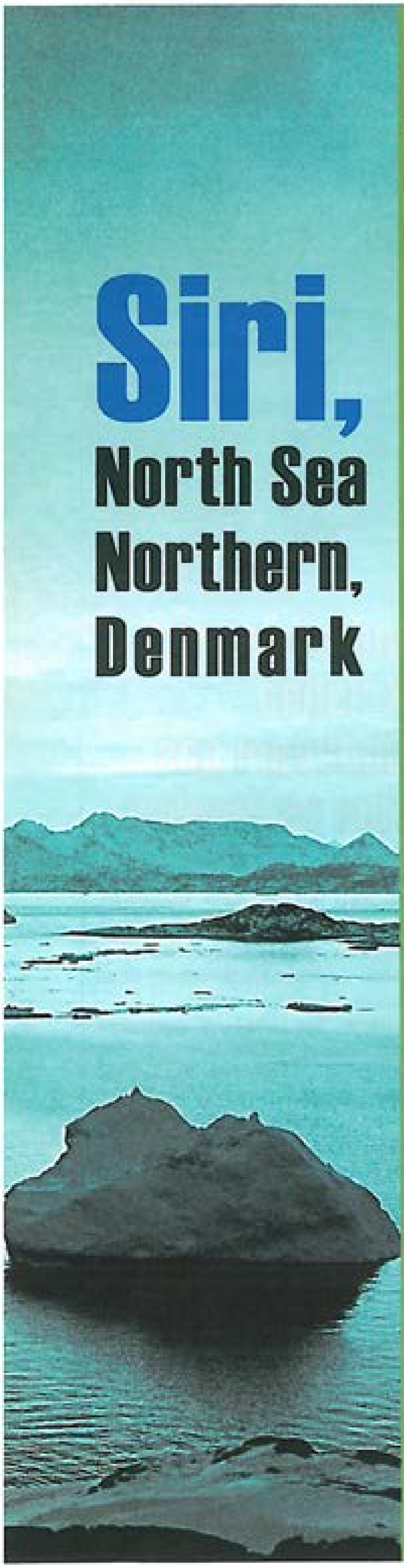
Prospects of accessing international gas sources have brightened with progress in talks on the Iran-Pakistan-India pipeline, a recent agreement with Algeria for LNG, and Indian plans to join the $13 billion trans-Saharan gas pipeline.

Turkmenistan also recently said it is interested in building a gas pipeline across Afghanistan to Pakistan and India (OGJ, July 23, 2007, Newsletter). India is still hopeful of buying gas from Myanmar, despite China's moves to secure supplies from the country on an exclusive basis.

ONGC has kicked off negotiations with ExxonMobil Corp. to import 8 million tonnes of LNG from Russia's Sakhalin gas fields.

Finally, Indian Petroleum Minister Murli Deora announced in July that the country would source 1.25 million tonnes of LNG from Algeria by 2009. State-controlled Petronet LNG is to secure gas from Sonatrach, a move that would add gas supplies to those already on contract from Qatar.

Despite these moves to secure sufficient gas, India's hopes of selling all blocks in the Cauvery basin at a good price under NELP-VII may suffer a setback because of its laxity in earlier announcements of the size of gas finds.



Siri, North Sea Northern, Denmark

Siri is located in block 5604/20 in the north-western part of the Danish sector of the North Sea, about 220km from the coast. The field lies at a depth of 2,070m in Palaeocene sandstone and has recoverable reserves of 60 million bbls.

EXPLORATION

The initial exploration well was drilled in Siri Central at the end of 1995. This was followed by an appraisal well in August 1996, also in the central part of the structure. A third appraisal well was subsequently drilled on neighbouring Siri North.

DEVELOPMENT

In 1996, Kvaerner Oil and Gas (KOGAS) won the EPCI (engineering, procurement, construction and installation) contract for the fast-track field development strategy. This was based upon a purpose-built three-legged fully integrated jack-up platform design, which contained wellheads, process equipment and living quarters. The platform stands on the top of a steel storage tank.

The EPCI project cost for the Siri platform and offloading system (not including the drilling) is just above two billion Norwegian Kroner. The operational life of Siri is estimated to be at about ten years. This provides the design basis for the topsides equipment. Because the jack-up platform can be removed and re-used, the platform life has been set at 20 years.

JACKET

The platform's legs are 104m long, have an outer diameter of 3.5m and weigh 800t each. Their wall thickness varies from 65mm to 110mm. They are composed of 390MPa steel.

The upper parts of the legs have 460mm-diameter jacking holes spaced at 1,750mm. The legs stand in 13m-deep sleeves in the tank structure. In order to provide restraint between the tank and the legs, the gap between the legs and the sleeves is grouted.The jacking system has a hydraulic ram pin-in-hole mechanism, with three jacking units placed around each leg. Each unit contains two hydraulic rams operating on a beam, which houses one jacking pin.

The three beams are welded together to form a ring. The upper stationary holding ring is connected to the top of the jack house, while a movable lower working ring is located around each leg. Each leg was installed as a complete unit with piping located inside while the deck was a float at the Rosenberg yard in Stavanger. Two floating shearleg cranes were also used simultaneously for this operation.

HULL

The hull measures 50x60m and is 6.7m high. The topsides equipment is enclosed in small 500t modules, while the hull itself contains diesel and water storage, electrical rooms, general storage, ventilation and communication rooms.

At the bow of the hull are two 12m-long fork structures, which are used for securing the wellhead tower structure. The forks are 1.4m high and support the well manifolds. The living quarters are cantilevered out 7m, on the opposite side of the platform. During normal operations, 21 people man the platform. The living quarters can accomodate 60 people in single cabins and who are there to mainly cater for the maintenance and well work-over operations.

TANK

The tank measures 50x66m and is 17.5m high. It has an effective storage volume of 50,000m³. The base of the tank includes skirts of 1.6m and 2m in depth, which divide the underside of the tank into compartments.

Internally, the tank consists of a main tank and three separate buoyancy compartments, located around the leg sleeves. These are used to provide tilt and depth control during the lowering of the tank to the seabed. Stability was assisted by 5,000t of concrete ballast inserted in the bottom of the tank. The tank was built by Daewoo, in South Korea and transported to Stavanger on the heavy-lift vessel MS Swan.

FLARE TOWER

The flare tower is located in one corner of the platform. Its 96m height is dictated by its closeness to the drilling rig.

ETCO
secure Petronas contract in Malaysia

In a contract worth an estimated US$1 million, CETCO Oilfield Services Company will supply Petronas with permanent and temporary water treatment packages for its Pulai A platform in Peninsular Malaysia.

Petronas required a water treatment process that would ensure produced water from the Pulai A platform met with regulations outlined by the Malaysian Department Of Environment (DOE) for levels of oil in water, and complied with overboard discharge legislation. CETCO Oilfield Services Company was initially invited by Petronas Cargali Sdn Bhd (PCSB) to carry out a field trial of their patented CrudeSep technology onboard the Pulai A platform in September last year.

The trial allowed CETCO to test and tailor its technology to meet the needs of Petronas and gain field trial experience in the Malaysian region. The permanent fluid treatment package for Pulia A will see CETCO supply a dual 36 inch diameter CrudeSep vessel package to treat a flow rate of 15,000 bbls/day to ensure a discharge of less than 30 ppm oil in water.

Whilst this permanent package is being manufactured, CETCO has supplied a temporary equipment package to the Pulai A platform. This comprises of a RFV 4000 DF CrudeSorb adsorption skid, hose package and specialist manpower to manage the system.

Commenting on the value of this contract for CETCO Oilfield Services Company, Thomas Blyth, Asia Pacific sales manager said: "Petronas is an important client for us. With significant operations throughout Malaysia, we were delighted to be invited by them to test our technology on its Pulai A platform and thus provide an effective, long term water treatment solution.

"During the field trials we achieved an oil in water overboard discharge level of less than 2ppm from the Pulai A produced water supply. Regulations outlines by DOE stipulate that the overboard oil in water content needs to below 30 ppm, the fact we achieved levels of less than 2ppm signifies the huge potential that our CrudeSep technology has to offer."

Mohd Suhaizan Yusof, field engineer for Petronas added: "We are delighted with the success of the water treatment package that CETCO has provided us with. Not only has the technology package proven itself as a valuable means by which to treat waste water, CETCO's personnel have worked very professionally and promptly, tailoring a package that has exceeded our requirements.

Continuing, Mohd stated: "We are looking forward to having a permanent water treatment system installed on the platform and I have no doubt we will retain a professional working relationship with CETCO Oilfield Services – already we are looking to install CETCO's equipment on one of our other platforms in the Malaysian region."

The CrudeSep vessel will be provided as part of an entire water treatment package. Employees from CETCO's new office in Kuala Lumpur will, in conjunction with personnel from the UK, provide project management support.

CETCO Oilfield Services Company specialise in the removal of hydrocarbons and other contaminants from offshore and onshore wastewater streams produced during oil and gas operations.

Storms

in Gulf of Mexico spur preventative measures offshore

Hit with a one-two punch, the hurricane season for the Gulf of Mexico had been quiet for 2007 – that was until Tropical Storm Erin and Hurricane Dean. Tropical Storm Erin, which hit the southern coast of Texas, was quickly followed by the looming threat of Hurricane Dean. Currently labeled a Category Four hurricane, Dean is expected to hit Belize and Mexico's Yucatan Peninsula Monday evening.

Passing over the islands of St. Lucia and Dominica, Hurricane Dean has already been blamed for the deaths of three people: an elderly man, as well as a mother and her seven-year-old son.

According to the National Hurricane Center, Hurricane Dean is located about 125 miles southwest of Grand Cayman. Currently traveling west-northwest, Hurricane Dean contains sustained winds of 150 mph with hurricane-force winds extending outward up to 60 miles. The storm is expected to reach a Category Five on the Saffir-Simpson scale within 24 hours.

These storms have already taken a negative affect on the oil and gas industry, specifically on production in the Gulf of Mexico. The Minerals Management Service (MMS), which monitors oil and gas production in the Gulf of Mexico, reported that 13 platforms and five drilling rigs were evacuated of all personnel due to Tropical Storm Erin.

MMS announced that it activated its Continuity of Operations Plan for Hurricane Dean. The plan was put into place to monitor the affect the storm will have on oil and gas production.

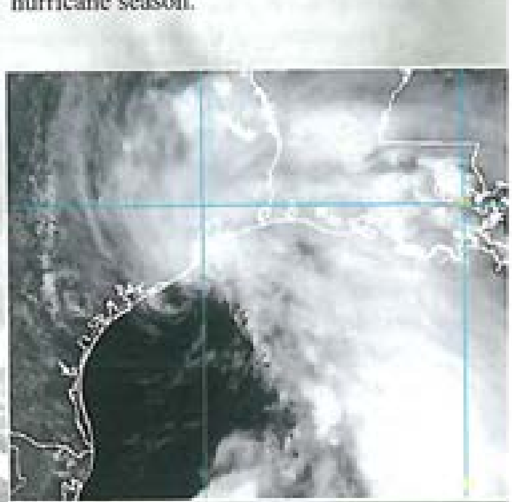
The group reports that companies have begun evacuating Gulf of Mexico rigs and platforms, as well as shut-in oil and gas production, in preparation for the storm and to prevent any safety or environmental issues.

The MMS announced that the staff from six production platforms in the Gulf of Mexico were evacuated, while personnel from three rigs had bee n evacuated.

MMS reported that approximately 1.8 percent of the Gulf of Mexico's oil production, or about 23,000 barrels of oil per day, had been shut-in by Sunday. It also estimated that about 0.7 percent of the natural gas production in the Gulf of Mexico had been shut-in, which is about 54 million cubic feet of gas a day.

Noble Corporation, an international contract drilling services company, evacuated approximately 650 people from its six deepwater rigs in the Gulf of Mexico. "We've evacuated all of our deepwater gulf fleet as of now," said John Breed, Noble Corporation's spokesman. While the company's No. 1 priority of safety hasn't changed over the years, the trend toward deepwater has affected the company's logistics for evacuating its personnel, he explained. It takes more time to evacuate the rigs because they are farther away, so the decision to evacuate is made earlier.

Hurricane Dean is the first hurricane for the 2007 Atlantic hurricane season, which spans June through November. As many as nine hurricanes have been predicted to form during this year's hurricane season.



Oil price dilemma

Oil is headed straight to $100 a barrel, Venezuelan President Hugo Chavez said hours after prices surged to an all-time high near $79.

But others remember the price collapses of the last four years and wonder if markets are headed for a repeat.

US crude recently climbed to a record high of $78.77 a barrel, surpassing the previous peak of $78.40 reached in July 2006.

Prices have since fallen more than $2, trading near $76 a barrel, as some analysts warn of a market correction.

"There will most likely be a sharp correction as prices are exceptionally high now," said Davide Tabarelli, chairman of energy research and consultancy company Nomisma Energia. "The market will sooner or later move back to equilibrium."

Since 2003, the oil market has entered into a sharp correction phase after climbing to its highs for each year. After reaching last year's peak, prices tumbled 36 per cent in the following six months to below $50 a barrel.

Analysts said this latest rally has been fuelled mostly by an influx of new investment money, instead of any big fundamental news such as hurricanes or Middle East tensions.

"We've been lacking bullish news for a while. When the correction starts, it could go very quickly," said Olivier Jakob of Petromatrix. "Going back to $60-$65 is not that far-fetched."

Compared with the rest of the energy complex, US crude stands alone in its rally.

Prices for gasoline, fuel oil and other petroleum products have fallen since mid-July as US refiners ramp up production and stockpiles rise. This has caused refinery profit margins to narrow.

Even US crude's fellow benchmark, London Brent crude, has eased after reaching a 12-month high of $78.40 in mid-July.

Traders have taken note

NYMEX crude oil speculators have pared their record high net long positions, showing a reluctance to extend bullish bets on the market.

"Funds adding length of late, contributing to the upside, are now somewhat on the defensive and ... a significant pullback appears in the works," said Mary Haskins of MF Global Energy.

But for every major correction in the last five years, prices eventually recovered and surged to new record highs.

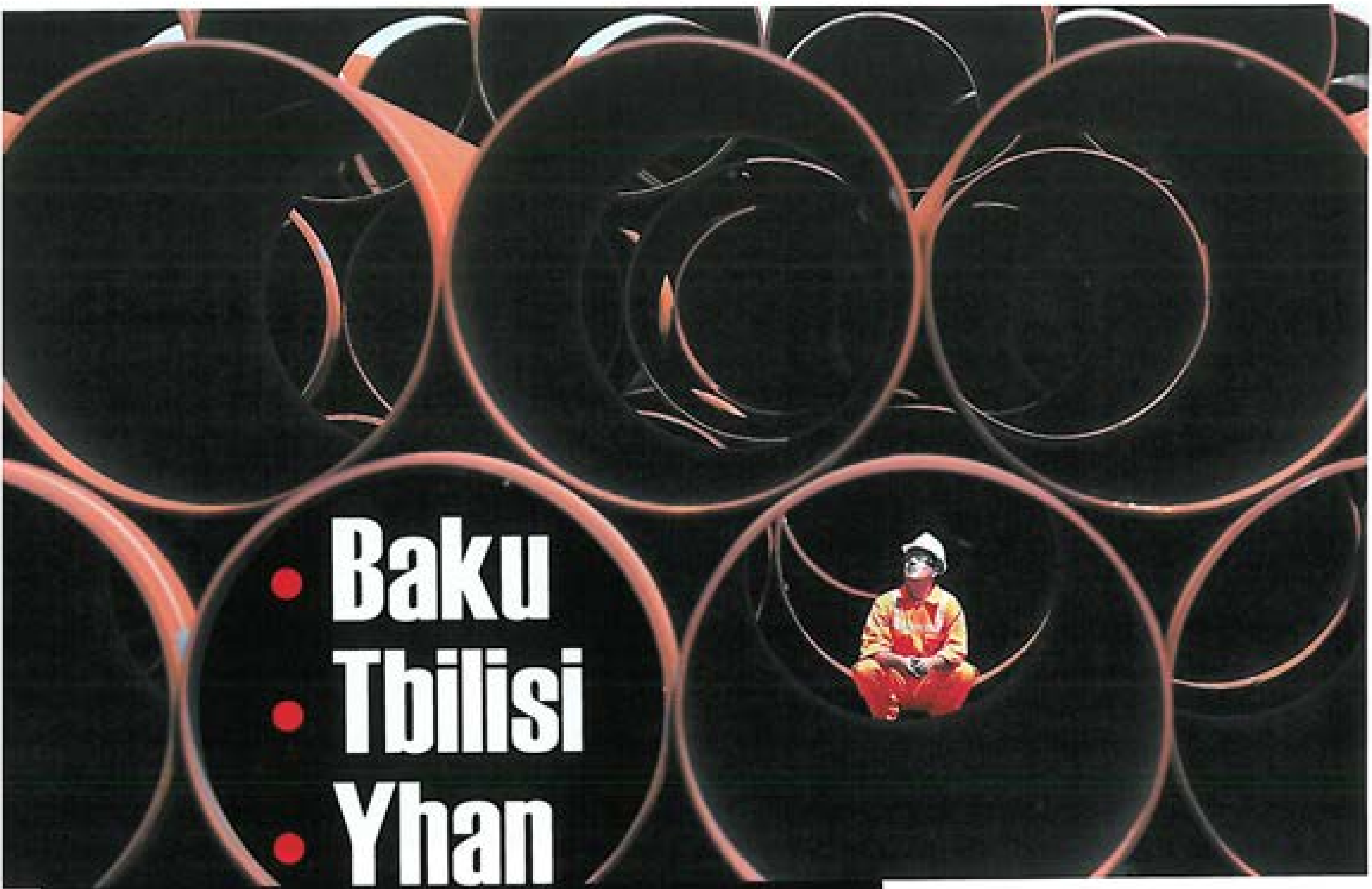
As for this summer, the output cuts that Opec announced last year remain in place, the Atlantic hurricane season still poses risks to US oil rigs, while geopolitical tensions in the Middle East and West Africa linger.

Chavez is not alone in believing oil's rally will continue. Goldman Sachs said last month prices could reach $95 by the end of the year.

US oil's rally to record prices this summer may have further to run as refiners ramp up production to rebuild inventories in the giant market.

US refiners struggled this summer with a series of outages that muted demand for crude feedstock and drained product stocks as the world's top consumer entered its peak gasoline demand season.

But with downed units coming back on line, refiners' thirst for crude is on the rise and may push prices higher, analysts said.



Baku • Tbilisi • Yhan pipeline project underway

A series of projects being carried out in the Caspian region over the next five years will result in a near fivefold increase in Azerbaijan's oil production. The Baku-Tbilisi-Ceyhan (BTC) pipeline project will give Azerbaijan, which was one of the first oil- producing countries in the world, easy access to the global crude oil market. The US$2.95 billion BTC line is capable of transporting one million barrels a day from Caspian shores to the Mediterranean for export to the US and Europe. The BTC pipeline will be laid in the next three years, taking oil from the offshore Azeri-Chirag-Guneshli oilfields in Azerbaijan, via Georgia, to Turkey's Ceyhan terminal – a distance of 1,720km – from where the ships can carry the oil to international markets.

The pipeline will cross more than 1,500 rivers and will climb to a high point of 2,700 metres before returning to sea level at Ceyhan. The physical construction work will commence in the first quarter of 2003 and will be completed by 2005 to coincide with the next phase of development of the giant Azeri-Chirag-Guneshli oilfield.

The BTC project is being managed by BP on behalf of an international group of investors. In August 2002, the BTC pipeline's owners created 'The Baku-Tbilisi-Ceyhan Pipeline Company' ('BTC Co.'), which will construct and operate the BTC oil pipeline. The BTC Co. shareholders are currently BP, State Oil Company of the Azerbaijan Republic (SOCAR), Unocal, Statoil, Turkiye Petrolleri AO (TPAO), Eni, TotalFinaElf, Itochu, INPEX, ConocoPhillips and Amerada Hess. In September 2002, the BTC was sanctioned in a ceremony that was held to celebrate the start of the construction phase of the project. The presidents of Azerbaijan, Georgia and Turkey attended this event, which marked a major milestone in the pipeline's realisation.

The contract awards (to Greek-based Consolidated Contractors International Company (CCIC) for pipelay in Azerbaijan, and Franco-British Spie Capag/US Petrofac for pipelay in Georgia and facilities in both countries) were the result of a meticulous screening process that narrowed down a field of 120 companies to eight that were invited to tender. Importing some 155,000 tonnes of steel pipe for the Azerbaijan section alone is a challenge. Despite being on the Caspian Sea, Azerbaijan is land-locked, so the pipe from Japan will be transported to the port of Poti on the Black Sea and then by rail to Azerbaijan. Additional contracts have been awarded by BOTAS Petroleum Pipeline Corporation, BTC's contractor for the Turkey contract, including awards for pipelay, pump stations and the terminal in Ceyhan.

The route for the BTC pipeline has been chosen with great care to avoid disturbance to both natural environments and populations in the area. The entire length of the line will be buried and will carry oil unseen and unheard past neighbouring communities. Full environmental and social impact assessments (ESIAs) were conducted for the BTC project and were followed by a two-month consultation period with a wide circle of stakeholders including national and local authorities, non-governmental organisations, the media and local communities. The assessment documents describe the existing environmental and social conditions along the pipeline route, predicted effects of these activities and the measures that will be taken to prevent and mitigate any negative impacts on the ecology and population. The ESIAs were submitted to relevant government bodies in Azerbaijan, Georgia and Turkey and have been approved. This will allow construction of the BTC pipeline to commence in 2003 for the route selected in the detailed engineering phase.

The next step was to begin the land acquisition process in all the three countries. Having selected the optimum route, the project team began the task of securing the rights that would allow access to each section of the route for construction and for reinstatement of the land immediately afterwards. This involved negotiations with almost 20,000 landowners and users whose land will be crossed during construction. In Azerbaijan alone, survey teams interviewed 7,000 landowners to record the existing condition of the land and to ascertain the concerns of people about the project. A key objective is to minimise the impact on daily life and to leave the smallest footprint possible while construction teams are working on any given section. All landowners and users will receive fair compensation for any damage or loss of income, and there will be a clearly defined method for resolving any dispute that might arise.

Throughout construction and reinstatement, the project will provide temporary employment opportunities for local people - often in areas of high unemployment. It is expected that the pipeline will provide around 10,000 jobs at the peak of the construction phase. Where land is required for the project, either on a permanent or temporary basis, landowners and people using the land will receive compensation for this and for any loss of income, which will be determined through a transparent process.

The construction of the BTC oil pipeline is currently one of the greatest projects in the oil sector of the world economy. This challenging project will make a positive difference by bringing significant benefits to the region. By avoiding the Bosphorus Strait, it will relieve the inevitable growth in oil-related traffic and associated environmental risks, will create substantial revenues for the transit countries and will help strengthen economic and political links between Azerbaijan, Georgia, Turkey and the West. In addition, the BTC project will generate short-term construction and long-term operation employment opportunities for supply of goods and services by local businesses, and will provide community and environmental investment programmes.

Baku-Tbilisi-Ceyhan Pipeline Facts

- 1,760km long
- Eight pump stations
- Rises to a height of 2,800 feet
- 42 inches wide in Azerbaijan and Turkey, 46 inches in Georgia
- Capable of pumping one million barrels per day
- To be operated by BTC Co. for 20 years
- Costing US$2.95 billion in total
- Construction will commence first quarter of 2003
- Transportation starts spring 2005

Dubai's Kampac Oil signs Dh5.8b Ghana rail contract

Dubai-based Kampac Oil Company, which heads a consortium that has won a Dh5.8 billion ($1.6 billion) railway project in the western part of Ghana, has announced the signing of 35-year concession agreement with the Ghana Railway Corporation.

Charles Ampofo, Chairman-Kampac Oil ME (Kampac group) in the presence of Ghanaian Minister of Ports, Railways and Harbour Christopher Ameyaw Akumfi, signed the Western Rail Line contract that involves the construction of 800km of new rail line and the rehabilitation of 400 km of existing line.

The new line, the construction of which will commence from December 1, 2007, will run from the town of Takoradi to Hamile in the Upper West Region, while the redevelopment job is for the existing line from Takoradi to Kumasi. The first phase of the contract - redevelopment of 400km rail line - is scheduled to complete in 18 months while the entire 800km new line will be commissioned in 48 months.

Attending the signing ceremony was a delegation from the UAE comprising Kampac Oil Company's directors and consortium partners besides top Ghana government officials.

Minister Akumfi said the ambitious contract, which heralded a new era in cross-border investment and economic cooperation between the United Arab Emirates and Ghana, was part of his government's policy of extending railway lines throughout the country. "The awarding of this contract marks the fulfillment of government's policy to extend the country rail network to the northern parts of the country," he said. This is in line with the government's efforts at extending the rail network beyond Kumasi to ensure a very efficient rail network to boost trade and investment.

"It will also promote cross-border trade and economic activity through improved land transport linkages and improve air passenger and freight linkages across Africa's sub-region," the Minister said.

Under the terms, Kampac Oil ME will design, build, operate and transfer the 800km rail line from Takoradi to Hamile in the Upper West Region to the government. Kampac has secured the mineral and mining rights for key proven reserves valued in excess of $2 billion as part of the concession.

The new standard gauge line will start from Takoradi through Manso, Tarkwa, HuniValley, Dunkwa, Awaso, Nyinahim, Sunyani, Techiman, Bole, and Sawla, Wa to Hamile.

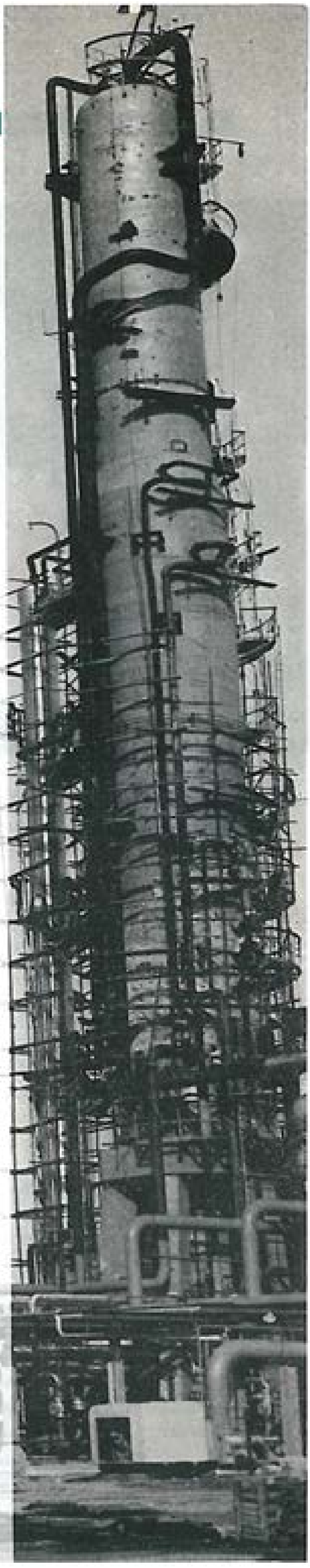
The UAE-based organisations of the consortium include the Jebel Ali-based Gulf African Project Co. Ltd., Dubai-based Suresh Trading Co., Other consortium partners are China National Machinery Import and Export Corporation, Transtech Engineering Corporation, Manferrotaal, Rail One from Germany, Pasiner Edustrial Tesisler Sanayi Ve Ticaret A.S., R.H Railway Consultants, Consolidated Power Projects (Ptg), Geneva-based Optima Asset Management Co., and Smice International.

Charles Ampofo, said the ambitious project was aimed at bringing up the capacity of the key Western Line freight corridor, inland port, and cross-border linkages quickly to re-capture lost freight revenue.

Ampofo said the project seeks to strengthen the country's key freight corridor while stemming the railway network's traffic woes and revenue loss. The project also envisages rehabilitating and maintaining the existing Western Line. Part of the project is the opening of an inland port at Boankra Kumasi aimed at reducing customs clearance pressure at the Tema and Takoradi ports by redirecting freight inland to increase rail traffic and revenue. The expansion of the Takoradi deep-water port facility and plans to reduce congestion at the Tema port are also part of the project.

The project financing was backstopped by the assignment of $2 billion worth of mineral and mining rights in Ghana to the consortium on an exclusive basis.

Kampac Oil Company, a subsidiary of the Kampac Group that was established in 1988, has seen a steady growth over the last decade with 15 offices in 15 countries around the globe. It has diversified business interests.



Chinguetti oil field, Mauritania

The Chinguetti field lies off the coast of the Islamic Republic of Mauritania, North West Africa, in Block 4, PSC (Production Sharing Contract) area B, approx. 80km west of the Mauritanian coastline and 90km from the capital, Nouakchott. It is operated by Woodside Mauritania on behalf of AGIP, Hardman Petroleum, Fusion Oil and Gas and Roc Oil. The development works under a PSC with the Mauritanian Government.

Chinguetti was discovered in 2001. Geologically, Chinguetti is a faulted anticlinal structure with an area of around 12km² and a diameter of 4.5km. It is dominated by a major east-west trending normal fault with a maximum throw in excess of 250m at the crest. The reservoir is located 1,300m to 1,900m below the seafloor. The development consists of three main gas discoveries, at Chinguetti, Tiof and Banda. Estimated recoverable oil reserves are put at 120 million bbl (19 million m³). The total development cost has been estimated at $500 million.

DRILLING

The Chinguetti development has 21 exploration, appraisal and development wells. These will include one commitment well in the Dorade prospect in PSC area C2 and five exploration wells in PSC areas A and B. The operator will also drill up to four appraisal wells on the Tiof discovery.

In addition, the development drilling programme on Chinguetti itself will involve up to six oil production wells, four water injection wells and one gas injection well in Phase 1 development.

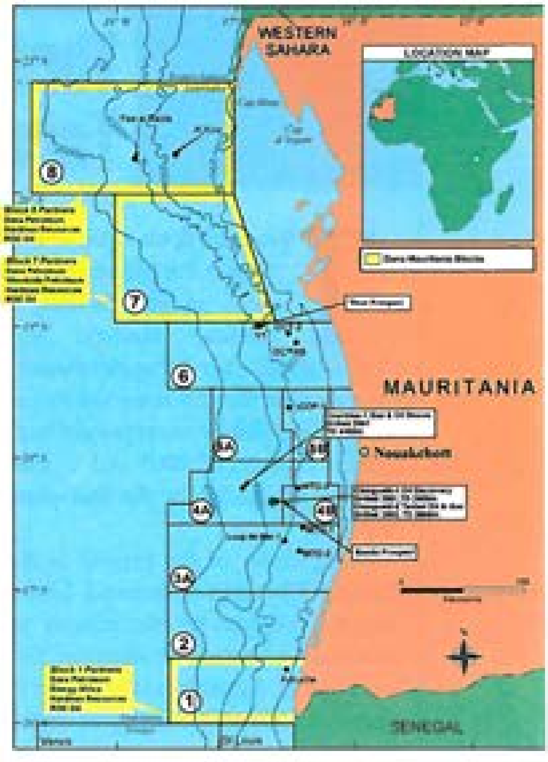
The drilling will be carried out by two deepwater drilling units - the West Navigator and the Stena Tay. The West Navigator will batch-drill the top hole sections before the Stena Tay commences the bottom hole target sections. The West Navigator will start with the exploration wells Dorade, Capitaine, Tevet and the Tiof-A appraisal well, before moving on to the Tiof-3 appraisal well on the Tiof discovery.

The field will be developed by an FPSO, located approximately 5km from the centre of the field, in a north-east or south-east trending direction. Chinguetti will produce from six production wells from three drilling centres / manifolds at start-up. Production is expected to begin in 2006 at about 75,000b/d. Field life is expected to be in the order of 8 to 15 years.

FPSO

Chinguetti will be developed from a Floating Production Storage and Offloading system. Oil will enter the FPSO via flexible flowlines and risers. Surplus gas not required for fuel will be returned to a reservoir via a gas injection well located several kilometres outside the field and connected to the manifold by a gas injection line. Produced formation water separated from the oil will be treated and discharged overboard.

Woodside will use the converted trading tanker Berge Helene. The Berge Helene was built as a tanker at Chantiers de L'Atlantique in France. It has a 384.75m overall length or 330.77m between perpendiculars, a breadth of 51.87m and a depth of 27.34m. It has a 21.37m draught. It registers 137,578t gross, 103,583t net and has a deadweight of 274,467t. It is designed to withstand the 100yr storm condition of 6.1m waves. The Berge Helene has a storage capacity of up to 1.6 million barrels of oil.



The vessel is powered by two Stal-Laval steam turbines, which total 32,445bhp. These are linked by triple and double-reduction gears to a single screw shaft. The ship has a service speed 16 knots.

In 2001-02, the tanker was converted at the Jurong shipyard in Singapore. The oil and gas processing facilities were provided by ABB Offshore Systems. It has an External Turret Production system (ETP). Bergesen awarded Advanced Production and Loading (APL) the contract for the single point mooring (SPM) system. Berge Helene was reclassified by Det Norske Veritas and approved for use as a permanently moored vessel for oil field production for at least another ten years.

REPORT

Three oil fields in Taranaki Basin, New Zealand

Three oil fields - Tui, Amokura and Pateke reserves located in PEP 38460, the offshore Taranaki basin, New Zealand - are being developed in phases under the Tui Area Oil Project. Work on the $204 million project began in fourth quarter of 2005 and is scheduled for completion by the first quarter of 2007.

The operator of the project is New Zealand Overseas Petroleum Limited and the contract for the project was awarded to Prosafe Production Services Pty Ltd. Australian Worldwide Exploration Ltd (AWE) is responsible for the funding.

During 2003-04, a joint venture of AWE New Zealand Pty Ltd and New Zealand Overseas Petroleum Limited discovered the three adjoining oil fields 40km from the coastline. New Zealand's Ministry of Economic Development (MED) approved the final terms of the petroleum mining permit (PMP 38158). The Tui Area Oil Project will supply the Asia Pacific region including refineries on Australia's east coast.

The light sweet Tui Area oil is very similar to that of reservoirs at Maui field, offshore Taranaki, and Bass Strait. Though the output from the four wells is expected to dwindle gradually, the payback on the initial capital will be quite high. New discoveries on the nearby reserves will also result in additional gain for the project.

PROJECT SPECIFICATIONS

According to projections, the recoverable oil reserves in the three fields will be 26.8 million barrels and the initial outflow is likely to be 50,000bopd. The development works includes the drilling of four wells 120m deep into the subsea. The wells will be connected to a Floating Production, Storage and Offloading vessel (FPSO).

Due to a shortage of suitable offshore drilling rigs, a contract was awarded to Diamond Offshore for the use of Ocean Patriot semi submersible rig.

Other prospects, including Tieke and Taranui, have been identified within the Tui area on the existing 3D seismic grid. According to AWE, the major plan will also include the development of five wildcat exploration wells beginning from the third quarter of 2006. This exploration programme will be carried out in conjunction with the four development wells.

As per the MED approval, the drilling operation on two exploration wells will be completed within two years from the date of permit. This will be the subject to the prior agreed rig day rates and the option slots on Ocean Patriot.

WORK IN PROGRESS

The works on subsea fabrication and installation began in the fourth quarter of 2005. The drilling operation on the four wells will begin in the fourth quarter of 2006 and scheduled to be completed within six months.

FPSO

An FPSO vessel will be used for maximising the oil recovery. Its oil storage capacity will be 700,000 barrels and the unit has been designed to cater to different types of offtake oil tankers. The four wells will be linked to the FPSO which will handle 120,000 barrels of oil per day.

Under the charter arrangement, Prosafe is responsible for the FPSO operation for an initial period of five years. The contract value is $178 million.

KEY PLAYERS

The stakeholders of Tui Area Oil Project and PEP 38460 JV are AWE New Zealand Pty Ltd (20%), New Zealand Overseas Petroleum Limited (45%), Mitsui E&P New Zealand Ltd (12.5%), NZOG via Stewart Petroleum Company Ltd (12.5%) and WM Petroleum Ltd Pan Pacific (10%).

Shah Deniz South Caspian Sea, Azerbaijan

The Shah Deniz oil field lies between Mobil's Oquz, Chevron's Asheron and Exxon's Nakhchiuan fields. Its name can be translated as King's Sea'.

The prospect is situated in the South Caspian Sea, off the Azerbaijan shore, approximately 70km south-east of Baku. It lies in water depths ranging from 50m in the north-west, to 600m in the south-east. The contract area covers approximately 860km².

RESERVES

The Shah Deniz structure lies 35km south-east of the Bahar field and 70km south-west of the supergiant Gunashli-Chirag-Azeri oilfield complex. With a vertical relief of over 1.5km (1 mile), the mapped structure encloses an area in excess of 300km². The main reservoir rocks within the structure are expected to be at a total depth of 5km to 6.5km and they have been folded into a relatively simple dip-closed anticline structure.

Reserve estimates have been calculated at between 1.5 to 3 billion barrels of oil (250 to 500 million tonnes) and 50 to 100 billion m³ of gas. Development of the reserves at depths of 600m have been made using technology originally developed for the northern North Sea and the Gulf of Mexico.

SEISMIC

In the summer of 1997, over 22,000km of modern 3D seismic data was acquired about the Shah Deniz PSA contract area, by the Azerbaijan seismic company, Caspian Geophysical. After the data had been acquired using their ship, the MN Baki, Caspian Geophysical processed it in their centre in Baku.

SUBSURFACE GEOLOGY

Immediately prior to the 3D data acquisition, additional data was compiled, concerning the water depth and the near-surface conditions over Shah Deniz. This detailed bathymetry provided information on the faults associated with mud diapir collapse, shallow gas, debris flows 1,000m below the seabed and modern-day features such as mud volcanoes and seabed channels. In total, 12 separate mud volcanoes have been identified. The largest of these, north of the reservoir, produces a major debris flow over 5km wide.

EXPLORATION

The three-year exploration programme for Shah Deniz is on schedule and all of the significant milestones have been achieved.

DRILLING

Two exploration wells will be drilled to fulfil the drilling obligation of the PSA.

Starting the drilling programme, the well SDX-1 was spudded in July 1998 using the semisubmersible Dada Gorgud. Well SDX-1 is located 70km south of Baku at location E on the north-east flank of the structure, in 135m-deep water. Plans envisage drilling the top hole down to a depth of approximately 2,500m before setting the 13 3/8in casing.

This rig is not capable of drilling the lower sections of the Shah Deniz wells due to limitations with the derrick capacity and the well-control equipment.

SHELF 5

The Shelf 5 rebuild was carried out in the KMNF Shipyard in less than 18 months. This involved the removal of 4,000t of equipment. Water-depth capability was increased from 280m to 700m and the variable deck load was extended to 3,200t; 9.6MW of power and 15,000psi BOP were installed.

FRONT-END STUDIES

In advance of the results of the first well, Shah Deniz is undertaking conceptual engineering studies now, so as to be in a position ready to determine the most economical concept for the production of hydrocarbons. In March 1998, Caspian Resource Development, a joint venture of Amec Process and Energy, Fluor Daniel and JP Kenny, as well as subcontractors Gipromorneftegas and the Caspian Drilling Company (SOCAR/Santa Fe), was awarded a contract for conceptual engineering services.

It is envisaged that the field will be exploited in a phased development, involving shallow-water platforms and subsea systems in deeper waters, tied back to the platforms.

REPORT

OPEC

cuts have buoyed price, but at a cost

Organization of Petroleum Exporting Countries crude oil output cuts have succeeded in stabilizing prices, but likely haven't cut deeply enough into global stockpiles to sanction a production increase at the group's Sept. 11 meeting.

"As I see it at this time, there's enough crude in the market," OPEC's Secretary General Abdalla El-Badri said.

He appeared to hint that OPEC will officially keep output restraints in place when it meets at its Vienna headquarters in less than two weeks and take up the issue again at its scheduled Dec. 5 meeting in the United Arab Emirates.

"We'll review the market and we'll see what we can do in September, but the picture at this time is not clear. It will be clear to me in December what's going to happen in the American economy," he said, referring to unfolding credit crunch that has sparked fears of an economic slowdown.

Traditional price hawks Iran and Venezuela have in recent days called for OPEC to continue output restraints.

OPEC's de facto leader, Saudi Arabia, the world's biggest oil exporter, typically has yet to tip its hand ahead of the meeting.

On July 11, Saudi Oil Minister Ali Naimi said prices near $72.50 a barrel weren't justified because "there is a good balance between supply and demand." He said then that the level of inventories - "higher than they have been in the past five years" - were "very, very comfortable."

Indeed, an Energy Matters review of the oil market since Oct. 20, 2006 - when OPEC agreed to its first production cuts in two years - shows the group revived prices, at a hefty cost in revenue and market share, but hasn't significantly dented global inventories.

Data from the International Energy Agency, the energy watchdog of the major industrialized nations, show that inventories held by those nations in October 2006 were sufficient to cover 54 days of demand.

In its latest report, dated Aug. 10, IEA said stocks at the end of June remained at 54 days cover. IEA's next report, measuring end-July stocks, isn't due until Sept. 12, a day after OPEC convenes its ministerial conference.

Pre-Meeting OPEC-IEA Talks

OPEC's El-Badri is set to meet Nobuo Tanana, the incoming IEA executive director, on Sept. 5, sources close to the talks said, but it's unclear what's on the agenda.

IEA has repeatedly pressed OPEC to increase oil output, warning that world oil demand is likely to outpace supply

this winter and the gap will widen if OPEC decides not to raise crude production on Sept. 11.

OPEC's caution in the current environment speaks to the hard lessons learned from the ill-timed decision in Jakarta in November 1997. A move to lift output quotas by 10% corresponded with the start of the Asian financial crisis and an unusually warm winter in the Northern Hemisphere. In the following months, prices fell by nearly 50% to below $11 a barrel in December 1998 and didn't recover to pre-Jakarta levels until late summer 1999 after several OPEC output cuts.

Prior to the Jakarta meeting, the IEA had projected that global oil demand would rise by 3.3% on the year in the fourth quarter of 1997. In reality, it grew only 2.4%. In the first quarter of 1998, global demand rose just 0.8% on the year, against the IEA's projection of 3.1% growth.

Last autumn, acting to staunch a downward spiral in prices, OPEC acted to cut output beginning Nov. 1 by 1.2 million barrels a day and lifted the size of the cut to 1.7 million barrels a day from Feb. 1, 2007.

The price of OPEC's reference basket of crudes fell by more than one-third from an early August 2006 high of $72.68 to $54.10 on Oct. 4, spurring the cut agreement. The basket price rebounded to a record $73.67 this July 20.

Energy Matters tracked OPEC's basket price over the 220 days since the Oct. 20, 2006 cut agreement and compared it with the same period prior to the agreement. Remarkably, prices have stabilized to average $61 a barrel since the cut was decided, just 66 cents, or 1%, below the prior 220-day period, dating back to mid-December 2005.

Revenues Down $86 Million A Day

Since the OPEC cut agreement, the average front-month crude oil futures price on the New York Mercantile Exchange is down 5.1%, compared with the prior 220 days.

OPEC's basket tracks a broader variety of crude and is more representative of the market than Nymex prices, which can be subject to wide swings around contract expiration and due to heavy speculative trading.

Output from the 10 OPEC members (excluding Iraq and Angola) in the group's quota system fell by 1.1 million barrels a day, or 4%, from levels in the 220 days prior to the cut agreement. Output restraints and lower prices cut the value of OPEC-10 production by 5%, or $86 million barrels a day, to $1.62 billion a day.

Based on IEA data, global oil demand averaged 1.2%, or 1 million barrels a day higher since the output agreement, than in the 220 days before the deal. Despite the rising demand, the cuts meant OPEC's share of the global market slid to 31.2% from near 33% before the deal.

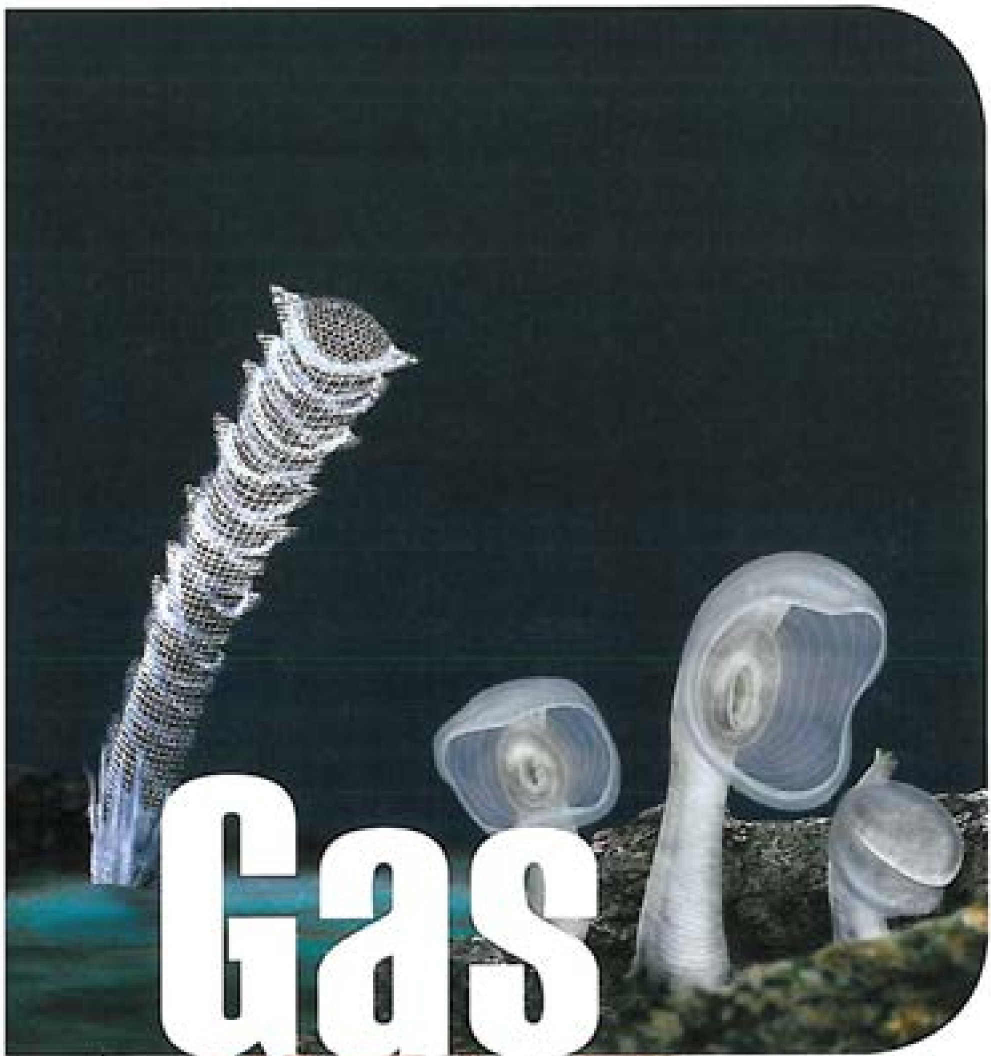
The value OPEC's oil revenues were further hit by a 6.6% decline in the value of the dollar (the currency in which oil is priced globally) against the euro. On average, the dollar was equal to 80.5 euro cents prior to the cut and just 75.2 euro cents since the cut.

OPEC may chalk up the costs to the price of doing business and find them cheap, compared with the impact of a post-Jakarta-size price collapse.

All these factors combine to make a powerful argument for OPEC to hold the line on production - officially - while some countries may ease more barrels into the market ahead of a likely December policy review.

Antoine Halff, energy analyst at Fimat USA in New York, said OPEC's apparent success in stabilizing prices isn't shared equally.

"I guess one could argue it's been a success for the (OPEC) countries that have been struggling to keep production going even at reduced rates," he said. "Having Saudis and ... others with spare capacity agree to cut their own output has stemmed the bleeding for the likes of Iran, Nigeria and Venezuela."



Gas impact on marine organisms

ANALYSIS

The first important feature of interaction between gaseous traces and marine organisms is the quick fish response to a toxic gas as compared with fish response to other dissolved or suspended toxicants. Gas rapidly penetrates into the organism (especially through the gills) and disturbs the main functional systems (respiration, nervous system, blood formation, enzyme activity, and others). External evidence of these disturbances includes a number of common symptoms mainly of behavioral nature (e.g., fish excitement, increased activity, scattering in the water). The interval between the moment of fish contact with the gas and the first symptoms of poisoning (latent period) is relatively short.

Further exposure leads to chronic poisoning. At this stage, cumulative effects at the biochemical and physiological levels occur. These effects depend on the nature of the toxicant, exposure time, and environmental conditions. A general effect typical for all fish is gas emboli.

These emerge when different gases (including the inert ones) oversaturate water. The symptoms of gas emboli include the rupture of tissues (especially in fins and eyes), enlarging of swim bladder, disturbances of circulatory system, and a number of other pathological changes.

These general features of fish response observed in the presence of any gas in the water environment are likely to be found for saturated gas hydrocarbons as well. Available materials derived from the medical toxicology of methane and its homologues support this suggestion.

Medical toxicology distinguishes between three main types of intoxication by methane:

- light, results in reversible, quickly disappearing effects on the functions of central nervous and cardiovascular systems;
- medium, manifests itself in deeper functional changes in the central nervous and cardiovascular systems and increase in the number of leukocytes in the peripheral blood; and
- heavy, results in irreversible distur-

bances of the cerebrum, heart tissues, and alimentary canal as well as acute form of leukocytosis.

These types most likely adequately describe the general patterns of methane effects in vertebrates. However, its features in respect to ichthyofauna remain to be studied. Fish resistance to the presence of gas at different life stages is of special interest. With most toxicants, the most vulnerable periods are the early life stages. The question of whether this general pattern is typical for saturated hydrocarbons still remains open. The importance of this issue in assessing biological effects of natural gas in the water environment is quite obvious.

During toxicological studies of different gases, including methane and its derivatives, one must take into consideration the influence of other factors (especially temperature and oxygen regime) that can radically change the direction and symptoms of the effect. In particular, increasing temperature usually intensifies the toxic effect of practically all substances on fish because of the direct correlation between the level of fish metabolism and water temperature.

From the physiological perspective, this can be explained not only by the general intensification of fish metabolism but also by the increased permeability of the tissues for the poisons and increased oxygen consumption under high temperatures. Thus, toxicant concentrations that do not cause any effect under low temperatures can become lethal with increasing water temperature.

This circumstance should be taken into consideration during ecotoxicological assessment of the potential impact of natural gas and other toxicants, especially when studies are conducted in high latitudes. In such regions, methane hydrates may be accumulated during the winter and dissociate during the increased temperatures in the summer.

This may be followed by the releasing of free methane with corresponding environmental consequences.

Another critical environmental factor that directly influences the gas impact on water organisms is the concentration of dissolved oxygen.Numerous studies show that the oxygen deficit directly controls the rate of fish metabolism and decreases their resistance to many organic and inorganic poisons.This decrease sometimes depends more on the species characteristics and the rate of their gas metabolism rather than on the nature of the poison. From the physiological perspective, such a phenomenon is explained by the fact that the level of hemoglobin in fish blood and the rate of blood circulation through the gills increase under oxygen deficit. Clearly, such effects are of special interest when interpreting the data on fish response to natural gas in situations of significant change in the oxygen regime (e.g., during eutrophication of water bodies or seasonal and weather variations of the oxygen content).

Field and laboratory studies

Field and experimental studies support the previously described general pattern of fish response to the presence of methane and its homologues in the environment. In the Sea of Asov, researchers conducted detailed observations after accidental gas blowouts on drilling platforms during summer-autumn of 1982 and 1985 [GLABRYB-VOD, 1983; AzNIIRKH, 1986]. The results of these observations indicate the existence of a cause-effect relationship between mass fish mortality and large amounts of natural gas input into the water after the accidents.

Fish in the zones of the accidents developed significant pathological changes. In particular, they displayed impaired movement coordination, weakened muscle tone, pathologies of organs and tissues, damaged cell membranes, disturbed blood formation, modifications of protein synthesis, radically increased total peroxidase activity, and some other anomalies typical for acute poisoning of fish. These pathological changes were found even in the fish collected at a considerable distance from the place of accident. Similar anomalies were observed in fish (flounder, sturgeon) kept for 4-5 days in the net cages in the direct vicinity of the mouth of the accidental gas well. Fish caught on the control stations and fish kept in the control cages did not show any deviations from the norm.

Significantly, some fish showed species-specific features of response to natural gas exposure. For example, flounder was more sensitive to the effect of natural gas than sturgeon. In 1982 and 1985 respectively, 69% and 28% of the

flounders kept in the experimental net cages died. However, no sturgeon mortality was observed for the time of the experiments.

Besides the ichthyotoxicological data, studies on gas accidents in the Sea of Asov give some idea about the methane pollution of the water environment and its possible impact on the benthic and pelagic communities. Methane represented over 95% of the released gas. It was present in water in concentrations of 4-6 mg/l directly near the accidental well and in concentrations of 0.07-1.4 mg/l at a distance of 200 m from the platform. The increased content of this gas (0.35 mg/l) was also found 500 m from the well in the windward direction. These results suggest that methane and its homologues can stay in the water environment for a rather long period and spread over considerable distances.

Similar conclusions were made based on observations in the Gulf of Mexico, where the areas around offshore drilling rigs had extremely high concentrations of methane and ethane in the water [Sackett, Brooks, 1975].

Information about the effects of methane and its homologues on water communities is very limited. Data indicate that benthic ecosystems have been disturbed and their trophic structure has changed in areas of methane seepage on the shelf of the North Sea and near the shore of California. Dense populations of Beggiatoa sp. were found in bottom sediments of these areas.These microorganisms use oil and gas hydrocarbons as a food source. In turn, they can become the base of the food chain for other benthic organisms [Davis, 1988; Howard, Thomsen, 1989].

Such symbiotic communities and ecosystems dependent on methane oxidation by microorganisms (mainly Methylococcaceae) appear to be typical for areas with high levels of methane in the bottom environment. In particular, they were recently found in areas of gas hydrate formation and gas seepage in the Black Sea and the Sea of Okhotsk [Galchenko, 1995]. The enzyme systems of bivalve mussels that were part of these ecosystems acquired some specific features due to the close symbiosis with methane-oxidizing bacteria.

The results of field studies around the accidental gas well in the Sea of Asov [AzNIIRKH, 1986] suggest that gas affects zoobenthic organisms more than the bacterioplankton and phytoplankton. In areas with a high concentration of methane, the biomass of benthos declined, in particular, because of the mollusk mortality. Some declining of the zooplankton biomass also occurred in the vicinity of the accidental well.

However, the high variability of the zooplankton parameters and insufficient amount of available data do not allow us to make any reliable conclusion.

Experimental toxicological studies of the effects of methane and its homologues on water organisms are very limited. Some of them describe the responses of fish and zooplankton to bottled gas (mainly propane) exposure [Sokolov, Vinogradov, 1991; Umorin et al., 1991; Patin, 1993]. One of the studies suggests that under experimental conditions, low-molecular-weight hydrocarbons (methane and others) do not cause harmful effects on marine phytoplankton even at high water concentrations [Sackett, Brooks, 1975].

Laboratory experiments conducted at the Russian Federal Research Institute of Fisheries and Oceanography [Patin, 1993] imitated the conditions of gash (accidental) releases of bottled gas into the water environment. They revealed that immediately after beginning the gas input into the water, fish (young specimen of carp) showed obvious signs of excitement and increased motor activity.

They scattered along the experimental vessels. The fish also stopped swallowing atmospheric air, probably because the air bladder was filling with the gas released into the water. Under the impact of subsequent gas releases, fish motor activity slowed, most specimens went down to the bottom, their movements became sluggish, and any re-

sponses on physical stimulation (knocking, touching) disappeared.

By the end of the experiments, which lasted 60-120 minutes, the fish school behavior was totally disturbed. Some specimens sluggishly and chaotically moved toward the surface. Some settled on the bottom. Most fish showed signs of a balance disturbance and turned on their side.

Studies of behavioral responses to the presence of gas showed a rather high olfactory sensitivity of the fry of bream, perch, and other fish [Sokolov, Vinogradov, 1991]. For example, avoidance effects were clearly seen when concentrations of dissolved gas ranged from 0.1-0.5 mg/l. The threshold concentrations were lower (and hence the sensitivity of behavioral response was higher) for the fry of bream than for the fry of perch. After repeated exposure of fish fry to the short-term impacts of the threshold gas levels, the sensitivity of all fish increased. Avoidance effects were observed in the presence of 0.02-0.05 mg/l of gas. When gas levels rapidly increased, avoidance responses were suppressed. This led to the quick death of the fish.

The concentrations of bottled gas that caused the death of 50% of the fish during 48 hours (LC50) equaled 1-3 mg/l [Umorin et al., 1991]. For zooplankton, this concentration during a 96-hour exposition was 5.5 mg/l without air pumping and 1.75 mg/l with it. These results suggest that fish are more vulnerable to the effects of methane homologues than zooplankton. They also indicate that acute toxic gas effects in fish start under minimum concentration of about 1 mg/l, which approximately match the results from field observations as previously described. Some other studies give similar values of LC50 (96 hour) of natural gas for zooplankton, zoobenthos, and fry of marine fish (0.6-1.8 mg/l) [Borisov et al., 1994; Kosheleva et al., 1997].

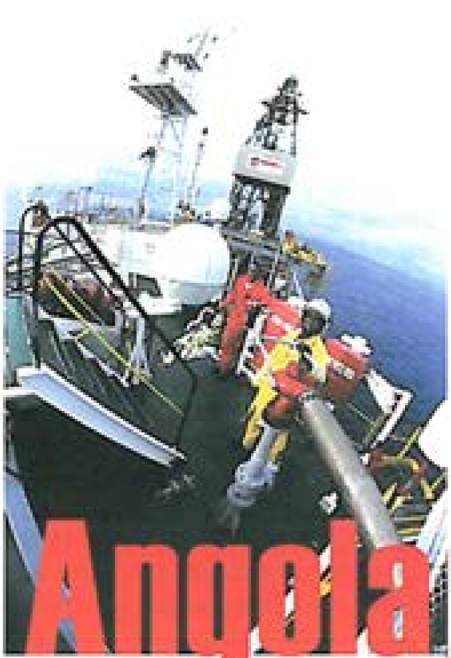
Another critical environmental factor that directly influences the gas impact on water organisms is the concentration of dissolved oxygen. Numerous studies show that the oxygen deficit directly controls the rate of fish metabolism and decreases their resistance to many organic and inorganic poisons.

The picture of fish response to the exposure of methane and its homologues in the water agrees with the general pattern of organismal response to any toxic or stress impact. This pattern involves consequent stages of indifference, stimulation (excitement), depression, and death of the organism [Metelev, 1971; Patin, 1979; Lukyanenko, 1983]. The previously described experiments suggest that along with the general pattern, some specifics of fish response to the acute impact of natural gas can be distinguished.

Another feature of fish response to the gas exposure is a relatively short period between the first contact with gas and persistent signs of their poisoning (latent phase). The duration of this phase in acute experiments is 15-20 minutes.

After this time, clear symptoms of acute poisoning indicate the beginning of the lethal phase. This includes the loss of movement coordination, disturbances of breathing, and others [Patin, 1993]. In gas concentrations of 1 mg/l and higher, lethal effects are clearly seen after 1-2 days of exposure.

Thus, in spite on the lack of research, especially under chronic exposure, the observations of both fish behavioral responses and fish mortality suggest a relatively low resistance of ichthyofauna to the presence of natural gas in the water environment. The high speed of primary responses, their clear manifestation, and their relatively short latent phase indicate a possibly damaging impact on the central nervous system of fish. Some data show the likelihood of higher resistance of zooplankton and benthos to the impacts of methane and its homologues. However, their responses still must be studied in the future.



Angola operators aim for 2008 target

Angola, the second largest oil producer in sub-Saharan Africa, is expected to reach 2 MMb/d by 2008. Significant activity recently will help the country achieve this goal.

Dating back to 1999, BP made its first of six discoveries to be developed on Block 18. Development of the Greater Plutonio Project, which consists of Galio, Cromio, Paladio, Plutonio, Cobalto, and Platina fields, began in 2004.

Lying in water depths of 1,200 - 1,500 m, the development will consist of a single spread-moored FPSO linked by risers to a network of subsea flowlines, manifolds, and wells. First production is targeted for 2007.

Perhaps the most notable deepwater field off Angola is ExxonMobilâ€™s Kizomba Project in Block 15, which comprises the Hungo, Chocalho, Kissanje, Dikanza, Mondo, Saxi, and Batuque fields. Their combined recoverable reserves approach 2 Bboe. Each of these oil wells taps into multiple high quality reservoirs.

The Kizomba A Project, which is in 1,005 â€" 1,280 m of water, comprises the Hungo and the Chocalho Fields. It has total recoverable resources of about 1 Bbbl and began producing more than 130,000 b/d in August 2005.

The Kissanje and Dikanza fields are part of the Kizomba B Project and are in Block 15 in 1,000 m of water. The Kizomba B Project is expected to recover nearly 1 Bbbl at a production rate of 250,000 b/d. It began producing five months ahead of schedule in July 2005. A fixed platform and subsea wells linked to an FPSO are developing the project. Oil treatment and storage is done on the FPSO.

Kizomba C,which in under development, will exploit the Mondo, Saxi, and Batuque fields using two FPSOs, which have combined resources of over 615 MMbbl.

In January 2007 Chevronâ€™s subsidiary, Cabinda Gulf Oil Co. Ltd. (CABGOC), announced a significant oil discovery in deepwater Block 14, the Lucapa discovery well. Block 14 is in the Lower Congo Basin. It covers 2,414 km in water depths extending from 182-1,828 m.

There have been 10 discoveries in Block 14 since 1997: Kuito (1997), Benguela (1998), Belize (1998), Landana (1998), Lobito (2000), Tomboco (2000), Tombua (2001), Gabela (2002), Negage (2002), and Lucapa (2006). The Kuito Field began its first phase of production on Dec. 15, 1999.

CABGOC drilled its latest well in October 2006 in 1,201 m of water to a total vertical depth of 3,340 m and encountered more than 85 m of oil in Miocene-age sands.

Further drilling in addition to geologic and engineering studies to appraise the field and assess its potential reserves will follow Lucapa.

In January 2006 Chevron started oil production from the Belize Field in deepwater Block 14. The Benguela, Belize, Lobito, and Tomboco fields form the BBLT Development, which is 80 km offshore in approximately 396 m of water. It is being developed in two phases.

Phase 1â€"Benguela Belize â€"â€" combines an integrated drilling and production platform hub facility supported by a compliant piled tower. The compliant piled tower is the first application of this structural technology outside the US Gulf of Mexico. Phase 2 â€"â€" Lobito Tomboco â€"â€" will produce via subsea wells tied into the central production hub.

Cabinda Gulf Oil Co. Ltd. operates Block 14 with 31%, Sonangol Pesquisa & ProduÃ§Ã£o, SARL 20%, ENI Angola Exploration BV 20%, TotalFinaElf Exploration & Production Angola 20%, and Galp-ExploraÃ§Ã£o e ProduÃ§Ã£o PetrolÃfera, Ltd. 9%.

Cabinda and its partners also announced first crude oil production from the Landana North reservoir in the Tombua-Landana development area.

First oil was achieved in June 2006 from the Landana North No. 1 subsea well that is tied back to the BBLT compliant piled tower. This tieback to BBLT allows early production, as well as the gathering of important reservoir information.

The 46-well project, 80 km offshore in more than 366 m of water, will employ a compliant piled tower with one subsea center. The projected peak production from the completed development is approximately 100,000 b/d by 2010.

Much activity was reported from Block 17 in 2006. Deepwater Block 17 is Totalâ€™s principal producing asset in Angola.

It is composed of three major production zones: Girassol, Dalia, and Pazflor.

In October, Sonangol and Total reported that the Orquidea-2 appraisal well confirmed and expanded the potential of the Orquidea discovery in Block 17.

Located approximately 2 km from the Orquidea-1 discovery well (discovered in 1999) and drilled in a water depth of 1,165 m, Orquidea-2 identified and confirmed the Miocene objectives encountered by Orquidea-1 and also identified deeper Oligocene reservoir levels. The Oligocene and Miocene objectives are both oil bearing.

The Orquidea structure is near the Lirio, Cravo, and Violeta finds. This dual drilling success confirms the potential for development of a fourth production zone in Block 17, for which preliminary design is underway. The production zone is in the northwestern area of Block 17 and will complete the Girassol and Dalia zones, to be followed soon by the Pazflor production zone.

TotalFinaElf began oil production in the Dalia Field on Block 17 in December 2006.

The Dalia Field is 125 km off the coast of Zaire province in 1,300 m of water. Discovered in January 1997, the development is being produced with an FPSO, much like its Block 17 neighbor, Girassol.

However, unlike Girassol, Daliaâ€™s four reservoirs contain low temperature acidic 22Â°API Miocene crude, which makes the development quite different from Girassol. Dalia was developed with 67-71 wells; almost double that of Girassol.

Next to come onstream will be the Rosa development project in 2007. The Rosa development, discovered in 1998 on Block 17 in 1,300 - 1,500 m of water, requires 25 subsea wells -- 14 producers and 11 injectors â€" tied back to the Girassol FPSO anchored 15 km away.

Modifications to the FPSO will increase the yearly average production rate to 250,000 b/d.

Saipem 10000 is currently working for Total on the Rosa development through August 2009 after which it will move to Nigeria and work for Eni.

Rosa is the second field to be tied back to the Girassol FPSO after the Jasmim Field in late 2003.

The Girassol FPSO is in 1,400 m of water 150 km off the coast of Angola, between the cities of Soyo and Luanda. It produces 200,000 b/d from the Girassol Field alone.

Sonangol is also the Block 17 concessionaire. Total E&P Angola, operator, has a 40% interest in Block 17, alongside partners Esso Exploration Angola (Block 17) Ltd. 20%, BP Exploration (Angola) Ltd. 16.67%, Statoil Angola Block 17 AS 13.33%, and Norsk Hydro Dezassete a.s. 10%.

Sonangol is developing the Gimboa Field in Block 4/05, 137 km off Angola in 700 m of water. The Gimboa Field will be produced by an FPSO with a storage capacity of 1,800,000 bbl and a production capacity of 60,000 b/d. The FPSO will be delivered in early 2008, when the first oil is expected.

Angola has plenty of opportunities to expand its oil production. BP is currently evaluating development options for the numerous Block 31 discoveries. Back in September 2002, BP Exploration Angola confirmed a deepwater discovery, Plutao-1A, about 400 km northwest of Luanda.

The Plutao-1A was drilled to 4,452 m in 2,020 m of water. Twelve more discoveries followed.

Most recently, BP drilled the Terra discovery well. BP contracted GlobalSantaFeâ€™s Jack Ryan drillship to drill this discovery in 2,328 m of water, which reached 6,118 m TVD. Well test results indicate anticipated flow capacity in excess of 5,000 b/d under production conditions. This is the third discovery in Block 31 where the exploration well has been drilled through salt to access the oil bearing reservoir beneath.

Oil deposits are commonly associated with salt throughout the world; Angola is no exception. Salt distorts the seismic image and as a consequence, salt-affected areas require significant amounts of additional seismic processing and interpretation prior to drilling.

According to BP, the Tera discovery reinforces the potential for multiple developments on this block. The operator is studying development concepts for developing Block 31.

Sonangol is the concessionaire of Block 31. BP Exploration (Angola) Ltd. is the operator with 26%. The other interest owners in Block 31 are Esso Exploration and Production Angola (Block 31) Ltd.

25%, Sonangol E.P. 20%, Statoil Angola AS 13.33%, Marathon International Petroleum Angola Block 31 Ltd. 10%, and TEPA (BLOCK 31) LIMITED, (a subsidiary of the Total Group) with 5%.

Another possibility for future development is Totalâ€™s ultra-deepwater Block 32. Total declared the Gindungo well a discovery after drilling in 1,444 m of water and successively testing the field at rates of 7,400 and 5,700 b/d from two separate zones. This discovery is in the eastern portion of Block 32, about 64 km from the Girassol Field in Block 17.

Total has made a total of nine discoveries in Block 32, most recently two in February 2007.

Drilled in a water depth of 1,977 m, the Manjericao well tested more than 5,000 b/d of oil from Oligocene oil bearing reservoirs. This discovery is in the central part of Block 32. It demonstrates that there is additional resource potential in the previously unexplored central area of Block 32.

Drilled in a water depth of 1,673 m, the Caril well also encountered Oligocene oil bearing reservoirs. The well was tested from a selected interval and produced at a rate of 6,300 b/d of light oil.

This discovery is in the northeastern part of Block 32.

Ultra-deep exploration work conducted in 2005 and 2006 confirmed the potential of Block 32. After the discoveries of Gindungo in 2003 and Canela and Cola in 2004, the positive results from the Gengibre and Mostarda wells drilled in 2005 confirmed the existence of a probable major production structure in the east-central section of the block.

Conceptual development studies were initiated in 2005 for development of these discoveries.

According to Total, complementary technical studies are being carried out to fully evaluate these promising drilling results, and further exploration drillings are underway and planned across the block.

Sonangol is the Block 32 concessionaire. Total operates the block with a 30% interest, alongside Marathon Oil Co.

30%, Sonangol EP 20%, Esso Exploration and Production Angola (Overseas) Ltd. 15%, and Petrogal 5%.

Scientists warn:

World oil supplies are set to run out faster than expected

Scientists challenge major review of global reserves and warn that supplies will start to run out in four years' time.

Scientists have criticised a major review of the world's remaining oil reserves, warning that the end of oil is coming sooner than governments and oil companies are prepared to admit.

BP's Statistical Review of World Energy, appears to show that the world still has enough "proven" reserves to provide 40 years of consumption at current rates. The assessment, based on officially reported figures, has once again pushed back the estimate of when the world will run dry.

However, scientists led by the London-based Oil Depletion Analysis Centre, say that global production of oil is set to peak in the next four years before entering a steepening decline which will have massive consequences for the world economy and the way that we live our lives.

According to "peak oil" theory our consumption of oil will catch, then outstrip our discovery of new reserves and we will begin to deplete known reserves.

Colin Campbell, the head of the depletion centre, said: "It's quite a simple theory and one that any beer drinker understands. The glass starts full and ends empty and the faster you drink it the quicker it's gone."

Dr. Campbell, is a former chief geologist and vice-president at a string of oil majors including BP, Shell, Fina, Exxon and ChevronTexaco. He explains that the peak of regular oil - the cheap and easy to extract stuff - has already come and gone in 2005. Even when you factor in the more difficult to extract heavy oil, deep sea reserves, polar regions and liquid taken from gas, the peak will come as soon as 2011, he says.

This scenario is flatly denied by BP, whose chief economist Peter Davies has dismissed the arguments of "peak oil" theorists.

"We don't believe there is an absolute resource constraint. When peak oil comes, it is just as likely to come from consumption peaking, perhaps because of climate change policies as from production peaking."

In recent years the once-considerable gap between demand and supply has narrowed. Last year that gap all but disappeared. The consequences of a shortfall would be immense. If consumption begins to exceed production by even the smallest amount, the price of oil could soar above $100 a barrel. A global recession would follow.

Jeremy Leggett, like Dr Campbell, is a geologist-turned conservationist whose book Half Gone: Oil, Gas, Hot Air and the Global Energy Crisis brought " peak oil" theory to a wider audience. He compares industry and government reluctance to face up to the impending end of oil, to climate change denial.

"It reminds me of the way no one would listen for years to scientists warning about global warming," he says. "We were predicting things pretty much exactly as they have played out. Then as now we were wondering what it would take to get people to listen."

In 1999, Britain's oil reserves in the North Sea peaked, but for two years after this became apparent, Mr. Leggett claims, it was heresy for anyone in official circles to say so. "Not meeting demand is not an option. In fact, it is an act of treason," he says.

One thing most oil analysts agree on is that depletion of oil fields follows a predictable bell curve. This has not changed since the Shell geologist M King Hubbert made a mathematical model in 1956 to predict what would happen to US petroleum production. The Hubbert Curveshows that at the beginning production from any oil field rises sharply, then reaches a plateau before falling into a terminal decline. His prediction that US production would peak in 1969 was ridiculed by those who claimed it could increase indefinitely. In the event it peaked in 1970 and has been in decline ever since.

In the 1970s Chris Skrebowski was a long-term planner for BP. Today he edits the Petroleum Review and is one of a growing number of industry insiders converting to peak theory. "I was extremely sceptical to start with," he now admits.

"We have enough capacity coming online for the next two-and-a-half years. After that the situation deteriorates."

What no one, not even BP, disagrees with is that demand is surging. The rapid growth of China and India matched with the developed world's dependence on oil, mean that a lot more oil will have to come from somewhere. BP's review shows that world demand for oil has grown faster in the past five years than in the second half of the 1990s. Today we consume an average of 85 million barrels daily. According to the most conservative estimates from the International Energy Agency that figure will rise to 113 million barrels by 2030.

Two-thirds of the world's oil reserves lie in the Middle East and increasing demand will have to be met with massive increases in supply from this region.

BP's Statistical Review is the most widely used estimate of world oil reserves but as Dr Campbell points out it is only a summary of highly political estimates supplied by governments and oil companies.

As Dr Campbell explains: "When I was the boss of an oil company I would never tell the truth. It's not part of the game."

A survey of the four countries with the biggest reported reserves-Saudi Arabia, Iran, Iraq and Kuwait-reveals major concerns. In Kuwait last year, a journalist found documents suggesting the country's real reserves were half of what was reported. Iran this year became the first major oil producer to introduce oil rationing - an indication of the administration's view on which way oil reserves are going.

Sadad al-Huseini knows more about Saudi Arabia's oil reserves than perhaps anyone else. He retired as chief executive of the kingdom's oil corporation two years ago, and his view on how much Saudi production can be increased is sobering. "The problem is that you go from 79 million barrels a day in 2002 to 84.5 million in 2004. You're leaping by two to three million [barrels a day]" each year, he told The New York Times. "That's like a whole new Saudi Arabia every couple of years. It can't be done indefinitely."

The importance of black gold

- A reduction of as little as 10 to 15 per cent could cripple oil-dependent industrial economies. In the 1970s, a reduction of just 5 per cent caused a price increase of more than 400 per cent.
- Most farming equipment is either built in oil-powered plants or uses diesel as fuel. Nearly all pesticides and many fertilisers are made from oil.
- Most plastics, used in everything from computers and mobile phones to pipelines, clothing and carpets, are made from oil-based substances.
- Manufacturing requires huge amounts of fossil fuels. The construction of a single car in the US requires, on average, at least 20 barrels of oil.
- Most renewable energy equipment requires large amounts of oil to produce.
- Metal production - particularly aluminium - cosmetics, hair dye, ink and many common painkillers all rely on oil.

Alternative sources of power

Coal

There are still an estimated 909 billion tonnes of proven coal reserves worldwide, enough to last at least 155 years. But coal is a fossil fuel and a dirty energy source that will only add to global warming.

Natural gas

The natural gas fields in Siberia, Alaska and the Middle East should last 20 years longer than the world's oil reserves but, although cleaner than oil, natural gas is still a fossil fuel that emits pollutants. It is also expensive to extract and transport as it has to be liquefied.

Hydrogen fuel cells

Hydrogen fuel cells would provide us with a permanent, renewable, clean energy source as they combine hydrogen and oxygen chemically to produce electricity, water and heat. The difficulty, however, is that there isn't enough hydrogen to go round and the few clean ways of producing it are expensive.

Biofuels

Ethanol from corn and maize has become a popular alternative to oil. However, studies suggest ethanol production has a negative effect on energy investment and the environment because of the space required to grow what we need.

Renewable energy

Oil-dependent nations are turning to renewable energy sources such as hydroelectric, solar and wind power to provide an alternative to oil but the likelihood of renewable sources providing enough energy is slim.

Nuclear

Fears of the world's uranium supply running out have been allayed by improved reactors and the possibility of using thorium as a nuclear fuel. But an increase in the number of reactors across the globe would increase the chance of a disaster and the risk of dangerous substances getting into the hands of terrorists.

Action required for UK Oil & Gas

The UK Offshore Operators Association(UKOOA)has called for government and industry action to address signs suggesting that the UK offshore oil and gas province is becoming less competitive and less able to attract the investment.

UKOOA published its 2006 Activity Survey Report,which summarises the exploration, investment and production plans of North Sea oil and gas operating companies over the next three years.

While exploration and appraisal activity remains encouragingly strong, the report also disclosed high cost inflation, a 250,000 barrel per day fall in expected production and signs of a drop in capital investment in 2007 after three years of growth, by £1-1.5bn to around £4-4.5bn. This raises concerns that the UK oil and gas basin could be finding it more difficult to compete for global investment, said UKOOA.

Malcolm Webb, UKOOA's chief executive, said: 'The survey provides a more challenging perspective on the future of the UK continental shelf than we have seen for some years. Whilst the strong level of exploration activity is welcome, the more rapid than expected decline in production; the significant cost inflation in 2006 and the forecast of a reduction in investment in 2007 are worrying."

"Even after 40 years, the UK offshore continues to be an active oil and gas basin. Strong exploration and appraisal activity, firm plans to recover a further 10.3 billion barrels of oil equivalent (boe) and an overall reserves potential of up to 26 billion boe should allow the industry to continue making a crucial contribution to UK security of energy supply for many years to come."

"But sharply rising costs mean that the mature UK continental shelf is increasingly exposed to lower oil and gas prices. The current low price of gas, which accounts for about 45% of total UK production, may make gas production from certain parts of the North Sea more troublesome, if sustained. High cost inflation combined with typically small opportunities and increased tax rates (now 75 percent at the top end) must make it harder to attract investment into the North Sea. Margins are shrinking, particularly in the Southern Gas Basin and in the older Northern oil fields, and if steps are not taken to improve the industry's competitiveness, the implications for future production and secure indigenous energy supplies could be serious. Both the industry and government have their responsibilities in this."

UK oil and gas capital investment was £5.6bn last year, its highest since 1998, while the year was also successful for exploration. Despite a decline in the number of exploration and appraisal wells drilled (69 down from 78 in 2005), there was a commercial success rate of 35 percent, showing the potential to deliver around 500 million boe, averaging 15 million boe per discovery. Exploration and appraisal activity is forecast to pick up in 2007, with up to 80 wells anticipated over the next 12 months.

However, despite prolonged high investment, UK oil and gas production fell by nine percent in 2006 and is projected to be 250,000 boepd lower on average than previously forecast over the remainder of this decade. The drop in production is primarily attributed to poorer reservoir performance but also delays in new project start-ups and increased maintenance. This is not good news for the industry or for Treasury as it equates to a drop in tax revenues of around £1bn a year over these years based on recent oil prices.

Operating costs in the UK offshore now average at $9-10/boe, compared with $5–6/boe three years ago while the costs of bringing new North Sea developments into production look set to rise to around $25/boe over 2007-9.

Uncertainties regarding the fiscal and regulatory treatment of decommissioning, combined with high oil prices, have impacted asset trading. There were 17 deals reported in 2006, half that of 2005.

'The combination of cost pressures, declining production and any premature drop in investment risks shortening the life of the basin,' said Malcolm Webb.

"It is possible that some of the production lost over the next few years may ultimately be recovered provided sufficient new projects come on stream. But this will require sustained investment to maintain pace in exploration, new development and maximising recovery from existing fields. I believe the government needs to reconsider the risk reward balance, with a new fiscal and regulatory regime better suited for the second half of the life of the UKCS, and the industry simply must address its cost base."

Speaking at the launch of the report at a UKOOA business breakfast in Aberdeen, Thorsten Fischer, Senior Economic Adviser specialising in the Energy Sector at The Royal Bank of Scotland (RBS), which sponsors the 2007 UKOOA Breakfast Series, said: 'The UKCS offers remarkable opportunities, not least because it is politically stable.

It is all the more important that regulatory and tax policies remain predictable.

Oil companies, like any other business, need planning security and prefer to operate in a stable environment, where the rules are well known.

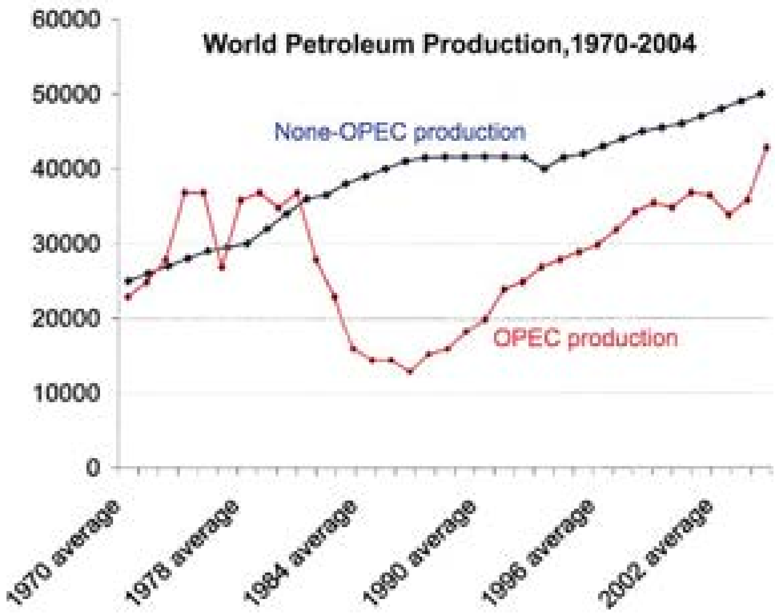
This is particularly true for the issue of decommissioning.

'UK companies, in particular small and medium size businesses, have acquired considerable expertise in exploiting mature fields, and stand to benefit from increased demand for their services. The know-how that these companies have developed also positions them as formidable competitors when it comes to supplying technology to offshore and deepwater projects outside the North Sea.'

The survey provides a more challenging perspective on the future of the UK continental shelf than we have seen for some years

The current low price of gas, which accounts for about 45% of total UK production, may make gas production from certain parts of the North Sea more troublesome, if sustained

Non-OPEC fact sheet



Non-OPEC countries (countries not members of OPEC - the Organization of the Petroleum Exporting Countries) produced 60 percent of the world's oil (total liquids) in 2004, down from 62 percent in 2003.

Since 1970, non-OPEC production as a share of world total oil production reached a high of 71 percent in 1985 and a low of 48 percent in 1973, with a 60 percent average.

Non-OPEC countries share the following characteristics:

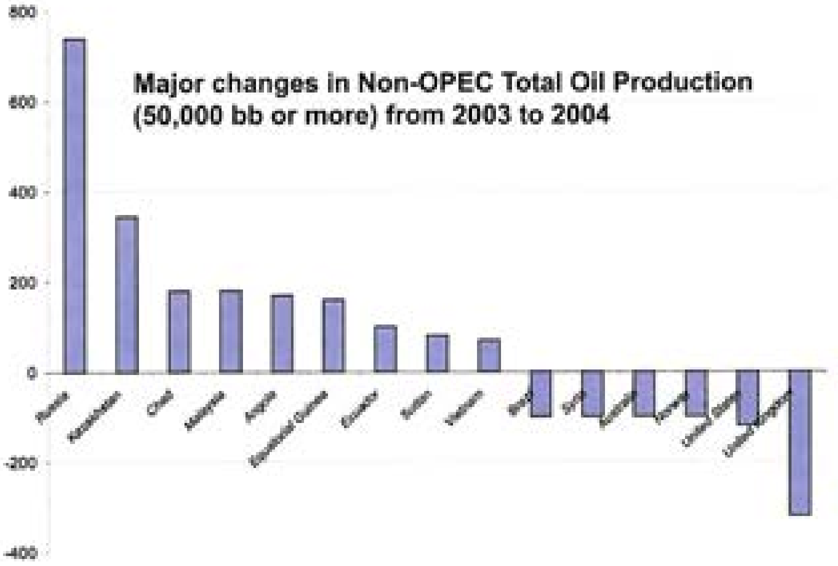
- Most non-OPEC countries are net oil importers. Of the 204 non-OPEC countries and non-independent territories for which EIA maintains data, 173 (85 percent) were net oil importers in 2004. Even large producers can also be large (net) importers.
- Because most major non-OPEC countries have private oil sectors (Mexico is one notable exception), their governments generally have very little control over production levels. Companies react to international price expectations, exploring and drilling more and in higher cost areas when prices are high, and focusing on lower-cost production when prices are low. Russia has private companies in its oil sector for the most part; however, the export pipeline network is controlled by the state-owned company Transneft. The Russian state has been more active in the sector in recent years, and state-owned Rosneft has expanded by taking over Yukos' largest unit in late 2004.
- Private companies do not hold back profitable production, and maintain very little spare production capacity. Hence, in the case of a significant world oil production disruption, OPEC (rather than private oil companies) would be the primary immediate source of additional oil to displace the loss, other than oil in storage facilities or strategic reserves (note that the decision to use strategic reserves is made by policymakers, who may not decide to use such reserves even in the case of a sizable disruption).
- Non-OPEC production costs tend to be higher than OPEC lifting costs, which makes non-OPEC production more vulnerable to price collapses.

Prolonged periods of low prices can drive higher cost producers out of business, and make major oil companies focus less on higher cost areas.

World oil production

The world's oil supply comes from a wide variety of sources. While the Middle East (home to the largest OPEC producers) was the largest producing region in 2004, with 29 percent of total world production, North America accounted for 19 percent, with the remaining 52 percent dispersed fairly evenly throughout the globe. OPEC member countries together accounted for about 40 percent of world total oil production in 2004, up from 38 percent in 2003.

Of the 14 countries that produced more than 2 million bbl/d of total liquids in 2004, seven were OPEC members. The remaining seven were not OPEC members, including: the United States (the world's third-largest total oil producer for the year); Russia; Mexico; China; Canada; and North Sea countries Norway and the United Kingdom. It should be noted that the United States' total liquids production



is boosted by the very large refinery gain that occurs there - over one million bbl/d in 2004.

Of the world's top net oil exporters, OPEC countries are strongly represented. Ten of the 14 countries exporting more than one million barrels per day of total oil (net) in 2004 were OPEC members. Russia, Norway, Mexico, and Kazakhstan are the world's largest non-OPEC net oil exporters. The United States is the world's largest net oil importer. China is also a net oil importer, while Canada and the United Kingdom are smaller net oil exporters.

(Note: EIA does not have 2004 data for worldwide gross oil exports, and computes net oil exports from production and consumption data.)

Top World Oil Producers and Oil Net Exporters 2004 Tables

Non-OPEC oil production is expected to rise during the next 2 years, though not enough to keep pace with total world oil demand growth. The greatest increases are expected in the former Soviet Union (FSU), including Russia (though less growth from Russia than in the previous two years) and the states bordering the Caspian Sea, and in other non-OECD producers, particularly Angola and Brazil. Brazil is expected to become a net exporter sometime in the next two years. (view a table of world production data).

Production Coordination with OPEC?

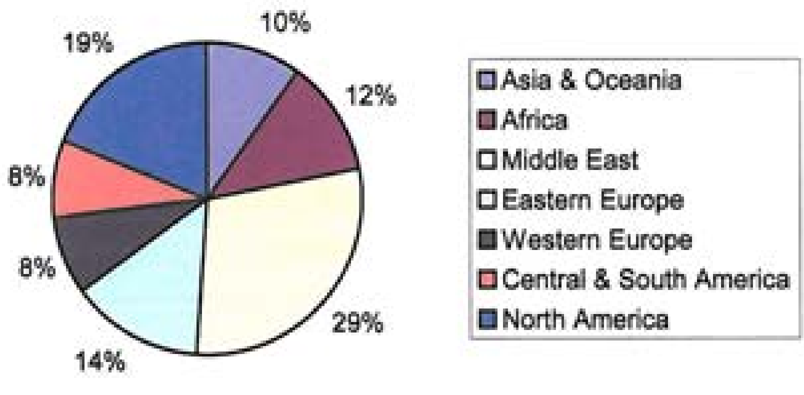
A few non-OPEC countries that share some traits of OPEC countries sometimes have indicated that they would coordinate production policies with OPEC (though they have not always actually carried out these policies). While the stated volumes of non-OPEC production (or export) restrictions have usually been small, the participation of these non-member countries can make member countries more likely to maintain their own output restriction policies. Therefore, non-OPEC coordination with OPEC often has carried a significance beyond what the output data might imply. It should be noted that the absence of low oil prices since early 2002 have meant that non-OPEC producers have seen little reason to restrain output of late - there has been no explicit cooperation with OPEC to cut production and/or exports since 2002.

Mexico, Norway, Russia, Oman, and Angola have announced intentions to cut production or exports in the past, but it is extremely unlikely that any of them would do this in the current price environment. Indeed, on June 16, 2005, oil ministers of Mexico and Norway announced that they have no spare capacity and asserted that all of the world's spare capacity that might remain lies in OPEC countries.

World oil Consumption

Of the estimated preliminary 82.5 million bbl/d of oil the world consumed in 2004, OPEC countries together consumed about 7 million bbl/d, or 8.5 percent of total consumption. Most of

World Oil Production by region, 2004



ANALYSIS

the world's largest oil consumers are also net oil importers. Of the world's top ten oil consumers in 2004, only Russia and Canada were net oil exporters. The remaining top consumers also are listed as the world's largest oil importers, with the exception Brazil, which was the 18th largest net oil importer in 2004.

PROVEN CRUDE OIL RESERVES

It is generally agreed that the location of proven world crude oil reserves is far more concentrated in OPEC countries than current world oil production.

Note that estimates of reserves vary; EIA does not assess oil reserves, but does list several independent estimates here. According to one independent estimate (Oil and Gas Journal), of the world's 1.28 trillion barrels of proven reserves, 885 billion barrels (69 percent) are held by OPEC, as of January 2005. The non-OPEC reserves include Canadian non-conventional reserves.

Not including Canada, according to this estimate the world's proven oil reserves are about 1.1 trillion barrels, of which OPEC holds 84 percent. In the future, the inclusion of non-conventional oil reserves for other countries may also significantly impact OPEC member Venezuela, as well as non-OPEC countries such as Australia.

Non-conventional reserves are generally more expensive to produce than conventional crude oil reserves and may require special facilities and technologies. Because non-OPEC countries' smaller reserves are being depleted more rapidly than OPEC reserves, their overall reserves-to-production ratio -- an indicator of how long proven reserves would last at current production rates -- is much lower (about 26 years for non-OPEC and 83 years for OPEC, based on 2004 crude oil production rates). This implies increased OPEC production as a proportion of world production over the long term.

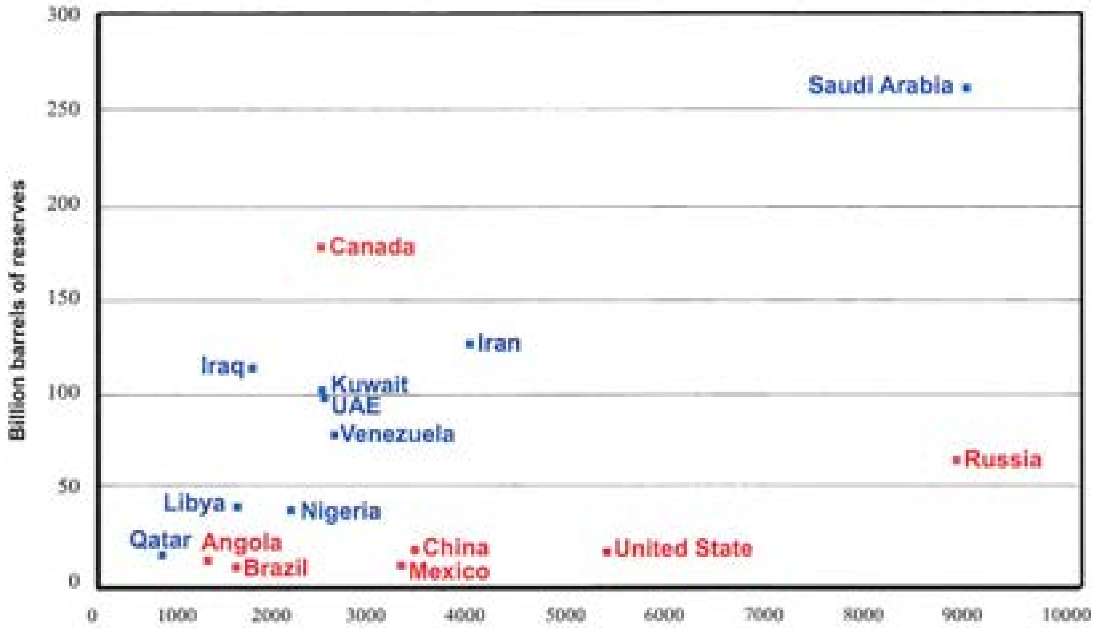
REFINED PRODUCTS

As of January 2005, 89 percent (73.4 million bbl/d) of the world's 82.4 million bbl/d of crude oil refinery capacity was located in non-OPEC countries.

Countries with high petroleum demand tend to have large refinery capacities. The United States has far more refinery capacity than any other country, with 149 of the world's 691 refineries, and a crude oil refinery capacity of about 16.9 million bbl/d (not including territories). Russia's refinery capacity stands at an estimated 5.4 million bbl/d. Japan (4.7 million bbl/d) and China (4.6 million bbl/d) are the only remaining countries with refinery capacities exceeding 3 million bbl/d.

There are several countries that are important to world trade in refined petroleum products despite very low (or non-existent) levels of crude oil production. For instance, Caribbean nations (including U.S. and European territories) have very limited oil production (233,000 bbl/d in 2004), but refinery capacity of about 1.7 million bbl/d. Much of this refined product is exported to the United States. Other countries that are important sources of refined petroleum products yet have very limited domestic production include the Netherlands, South Korea, and Singapore.

January1,2005 Crude Oill Reserves and 2004 crude Oil production



MARKET WATCH:

Storm worries raise energy prices

Energy prices continued to climb Aug. 15 as two tropical storms posed potential threats to oil and gas facilities in the Gulf of Mexico and along the Gulf Coast.

Tropical Storm Erin was downgraded to a tropical depression when its winds fell to 35 mph, lower than the 39 mph threshold for tropical storms, as it made landfall Aug. 16 at Copano Bay, 25 miles northeast of Corpus Christi, Tex. The National Hurricane Center said the storm continued to move west-northwest at 12 mph and was expected to dump 4-10 in. of rain along a corridor between San Antonio and Austin. A flash flood watch was issued for 33 Texas counties through Aug. 17, which could affect movements of drilling rigs in those areas.

Shell Oil Co., Houston, earlier evacuated 188 workers from offshore facilities in the Gulf of Mexico ahead of that storm and shut in 5 MMcfd of natural gas production from North Padre Island 927 field 75 miles southeast of Corpus Christi. Production will remain shut-in until crews return to the site, the company said.

Valero Energy Corp., San Antonio, said Erin's heaviest rains and strongest winds missed the company's 340,000 b/d refinery in Corpus Christi. "Operations at the refinery continued as planned through the storm and remain at expected levels this morning, and we expect no disruptions to production," Valero said.

Meanwhile, Tropical Storm Dean in the Atlantic Ocean strengthened overnight into the first hurricane of the 2007 season, with sustained winds of 80 mph, putting it in Category 1 on the Saffir-Simpson scale. At 8 a.m. Aug. 16, it was 415 miles east of Barbados in the Lesser Antilles and moving west at 24 mph. Hurricane warnings were issued for Dominica and St. Lucia, with a hurricane watch in effect for the islands of Martinique, Guadeloupe, Saba, and St. Eustatius. Most computer models project Dean possibly moving over Jamaica during the weekend and towards the northern Yucatan Peninsula in Mexico.

Valero said, "We are continuing to monitor Hurricane Dean. Operations at our Aruba refinery have not been affected."

In other action, the Energy Information Administration reported commercial US crude inventories fell 5.2 million bbl to 335.2 million bbl in the week ended Aug. 10. Wall Street analysts were expecting a draw of 2.5 million bbl. Gasoline stocks dropped 1.1 million bbl to 201.9 million bbl, vs. a consensus of an 800,000 bbl pull in the same period. Distillate fuel inventories inched up by 200,000 bbl to 127.7 million bbl, well below the 1.3 million gain expected.

"For the third time in a row, the US weekly statistics on crude oil have come out tighter than expected but for the third time in a row the statistics-induced rally has been sold into," said Olivier Jakob, managing director of Petromatrix GMBH, Zug, Switzerland.

Energy prices

The September contract for benchmark US sweet, light crudes gained 95¢ to $73.33/bbl Aug. 15 on the New York Mercantile Exchange. The October contract escalated by $1.19 to $73.21/bbl. On the US spot market, WTI at Cushing, Okla., was up 95¢ to $73.34/bbl. Heating oil for September delivery advanced by 4.44¢ to $2.03/gal on NYMEX. The September contract for reformulated blend stock for oxygenate blending (RBOB) advanced by 3.5¢ to $2.01/gal.

The September natural gas contract fell 7.6¢ to $6.86/MMbtu on NYMEX.

On the US spot market, however, gas at Henry Hub, La., jumped up 40¢ to $7.30/MMbtu. EIA reported Aug. 16 the injection of 21 bcf of natural gas into US underground storage during the week ended Aug. 10. That was at the low end of the consensus by Wall Street analysts and down from injections of 42 bcf the prior week and 37 bcf during the same period a year ago. US gas storage is now just over 2.9 bcf, up 108 bcf from year-ago levels and 371 bcf above the 5-year average.

In London, the September IPE contract for North Sea Brent crude increased by $1.13 to $71.64/bbl. Gas oil for the same month escalated by $18 to $633/tonne.

The average price for the Organization of Petroleum Exporting Countries' basket of 11 reference crudes gained 87¢ to $68.58/bbl on Aug. 15.

INTEC

leads subsea processing

INTEC Engineering is conducting a Subsea Processing Joint Industry Study (JIP) to ascertain the current status, future direction, and general applicability of key elements of subsea processing equipment and technology. These key elements include: subsea separation, pumping, and compression and the power and controls required to implement them. This effort is a part of INTEC's focus on Long Distance Delivery Management to enhance operators' oil and gas assets.

INTEC leads the JIP on behalf fifteen study participants who represent a cross-section of the entire industry and serve as a Steering Committee to guide the work:

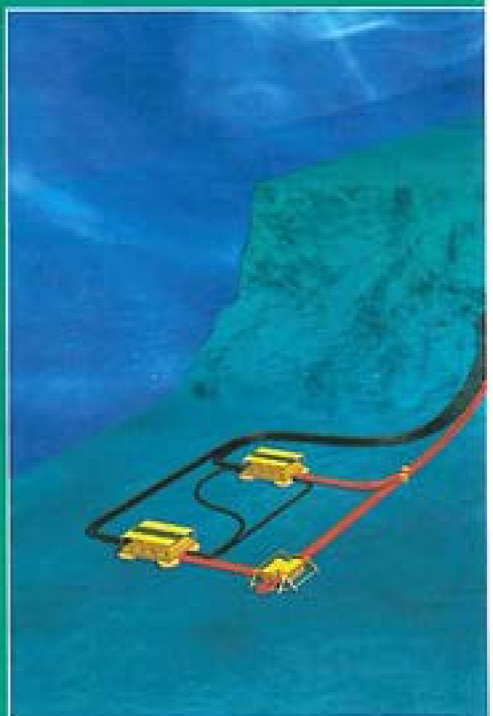
PARTICIPANT COMPANY	INDUSTRY FUNCTION
BHP Billiton	Operator
Cameron	Supplier
Devon	Operator
FMC	Supplier
Granherne	Consulting/Engineering
HFG	Operator
HMC	Installer
Husky	Operator
INTEC	Consulting/Engineering
Nexen	Operator
PetroSA	Operator
Petrobras	Operator
Statoil	Operator
Vanco	Operator
Woodside	Operator

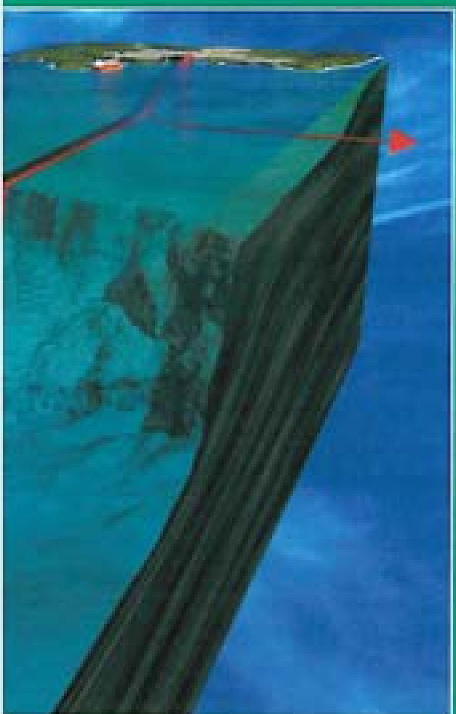
With "conventional" subsea production system designs, reservoirs are typically depleted to only approximately 30% recovery. With full implementation of subsea processing and depending upon several factors, hydrocarbon recover of approximately 60% could be attained.

While some elements of subsea processing have been in development and limited operation for years, most operators still do not believe that current field application data demonstrates that the financial and operational risks associated with deploying subsea processing are acceptable. Most operators, rather than deploying subsea processing technologies to capture these gains, typically shut in wells and move to new prospects with lower technical and/or economical risk.

Doubts aside, our study has found that subsea processing component and equipment technology appears able to withstand most of the operational challenges of deepwater and long distance tie-backs. The basic technology appears to be fundamentally ready, but testing and real-world application is required to further development and prove that the equipment has moved beyond the drawing board.

Subsea multiphase pumping stands to provide immediate benefit by offsetting pressure loss due to water depth or production offset distance. For low pressure operation (at pump inlet), high gas volume fractions can result in poor multiphase pumping efficiency (positive displacement pumps) or low pump head (rotodynamic pumps). For such applications, gas/liquid separation can be placed upstream from the pump inlet allowing the resultant fluid streams to be handled separately: single-phase (or low GVF) pumps for the liquid stream





and free-flow or compression for the gas.

Subsea separation can be used to avoid topside separation facilities, thereby reducing topsides structure and payload requirements, to remove water from the production stream, or to separate gas from liquid subsea. Subsea separation systems will differ from their topsides counterparts in that additional technologies will be needed to reduce the volume of low pressure gas handled by the separator, thereby avoiding excessive size and weight of the deployed equipment. Also, as with topsides separators, sand will tend to accumulate in subsea separators. Special equipment will be required to remove and dispose of sand without requiring shutdown or expensive workovers. As systems are installed and operated, including a large North Sea system being installed in 2007, application experience will help prove and advance technology in the realm of solids management, metering, and controls.

Of the three primary subsea processing technologies, gas compression applications are likely to lag the others, yet component hardware exists and significant projects are in development for installation in less than 5 years. Very long offset gas developments, particularly those in harsh environments, are expected to spur application of subsea gas compression.

Ancillary technologies are ahead of the industry in many cases. Power delivery and high voltage connections are two disciplines that are already applied subsea, and are awaiting application and development opportunities from the oil industry.

Advances in power generation/delivery systems will be needed for very deep water and for very long offsets.

As with any subsea production system but especially true for deep-offset (deepwater and/or long offset) subsea production systems, the deployment of subsea processing requires an integrated systems approach. Operators' needs and suppliers' capabilities will continue to evolve and will result in viable subsea processing systems over time. There appears little doubt that subsea processing will produce viable systems within the next 5 years, particularly as there are multiple systems due for installation this year and others are in active planning.

A few industry pioneers have confidence in the basic engineering and field development principles involved, are comfortable with the technical and financial risks, and are deploying subsea processing equipment to meet development goals. Others may be less confident in the technology but will accept a somewhat higher level of risk for the opportunity of financial rewards and industry exposure resulting from operational success. The number of operators deploying some form of subsea production system will increase.

INTEC also hosted a media advisory conference at this year's OTC to discuss subsea processing opportunities. Joining INTEC on the panel were Bjorn-Andre Egerdahl of Statoil, Mauricio Werneck of Petrobras, David Morgan of Cameron and Tom Munkejord of FMC, each of whom represented a JIP participant.

The conference was organized under the auspices of SPE as a communication service to the industry to discuss major challenges and issues shaping the offshore industry. INTEC's Uri Nooteboom opened the conference and Tom Choate served as moderator. Each of the panelists shared highlights of new developments in their respective companies to advance and apply new subsea processing technologies.

The JIP was lead by Tom Choate with support from Michael Padilla, Mac McKee, Tim Turner and Adolfo Lopez.

This phase of the Subsea Processing JIP effort will be completed in mid-year 2007. After JIP reports have been issued to Participants, they will be available for purchase to non-Participants. Further stages of the JIP are being considered for 2008.

Subsea Processing Enables Marginal Field Development

Subsea processing has moved traditional topsides fluid processing to the seafloor.

These new technologies have made development of deepwater and ultra-deepwater fields in harsh environments a reality. Subsea processing includes subsea boosting (subsea pumps), subsea compression (subsea compressors), subsea seawater injection (subsea water injection pumps), and subsea separation (subsea separators, sand injectors, produced water injection).

According to Per Arne Haug, vice president Products & Subsea, Grenland Group-Technology Division, "you want to have the installation on the seabed where it is not exposed to the severe environment. In frontier regions like in Barents Sea, subsea processing is an enabling technology."

In ultra-deepwater, subsea processing equipment such as subsea pumps and compressors has significant cost advantages, as well. "It certainly has interest in ultra-deepwater. The interest comes from the potential of tying it back to existing infrastructure or to an onshore processing plant, like Ormen Lange," Haug explains.

Subsea Processing Technologies

Subsea boosters have been around since the late 1990s. Statoil was one of the first to use the boosters at its Lufeng Field in the South China Sea. Subsea boosters assist in increasing or maintaining production levels of mature offshore fields and allow economic development of marginal fields using subsea tiebacks to existing infrastructures both on- and offshore. Using subsea boosting technology increases pressure on the seabed with a pump that draws down the wellhead pressure to increase production. A booster pump also can be used to enhance flow assurance through increased velocity.

Another exciting technology is subsea compression. According to Statoil, the company will be the first to use seabed compression to produce more gas from the Åsgard Field in the Norwegian Sea for commercial purposes. When boosting the pressure in the gas flow, the seabed compressor will compensate for dropping pressure in the reservoir. Gas production from Åsgard is expected to increase by 25% when this technology is employed. Installation of the compressor on the seabed is scheduled for 2012 or 2013. Qualification of the seabed technology will take place around 2012.

Haug points out that Hydro also will employ seabed compression on its Ormen Lange Field sometime between 2012 and 2015. Ormen Lange will be a pioneer project on the Norwegian Continental Shelf. The field is in an area of the Norwegian Sea where climatic and oceanographic conditions make it one of the most challenging development projects in the world.

The Ormen Lange Field is being developed as a subsea tieback to shore.

The initial development will consist of two templates. Each template will be connected to two pipelines transporting the gas to the shore terminal.

The shore terminal is at Nyhamna, on the island of Gossen close to Molde.

The processed gas will be exported through a new 1,200 km long pipeline to the UK market.

For the initial production phase, gas from Ormen Lange will flow to Nyhamna by means of reservoir pressure. Later in the production phase, offshore compression will be required to maintain the production level and to recover the anticipated gas and condensate volumes. Base case for such offshore compression facility is an offshore platform.

The permanent subsea compression station will be installed in 860 m of water using electrical power from shore.

The permanent long step-out power supply will transport the required electrical power and the control signals from shore and 120 km to the subsea compression station at Ormen Lange.

There will be two subsea compression pilot programs – the subsea compression station pilot and the long step-out power supply pilot. Aker Kværner Subsea AS will engineer, procure, and construct a full-size subsea compression station pilot, and GE Aibel AS will engineer, procure, and construct a long step-out power supply pilot.

After delivery, the two pilots will be tested for 2 yrs at the Ormen Lange gas treatment facility at Nyhamna to qualify the subsea compression technology for commercial use. The subsea compression pilot, if qualified, represents one of the four compressor trains required for permanent subsea compression of the Ormen Lange Field. The long step-out power supply pilot represents the equipment required to supply electrical power and control signals to the permanent subsea compressor station 120 km from shore.

According to Hydro, the qualification of the subsea compression system is not a necessity for gas export from Ormen Lange, but a business opportunity for Ormen Lange to develop a viable and cost effective subsea compression system competing with a compression platform as the future compression alternative for Ormen Lange. It also represents a significant technology step for the industry.

A third technology is subsea injection, which involves injecting water from the sea directly into the reservoir to increase the pressure in the reservoir and thereby stimulate production.

Unlike subsea injection, subsea separation separates water or sand from the crude to reduce the volume transported from the well to process facility.

"You want to take out the water from the oil for several reasons," Haug explains. "One is to eliminate problems from hydrates in tiebacks and the other is it is inefficient to bring the water up to the platform and separate it there and re-inject it to the reservoir from the platform."

Haug cites Statoil's Tordis Field as an example of subsea separation.

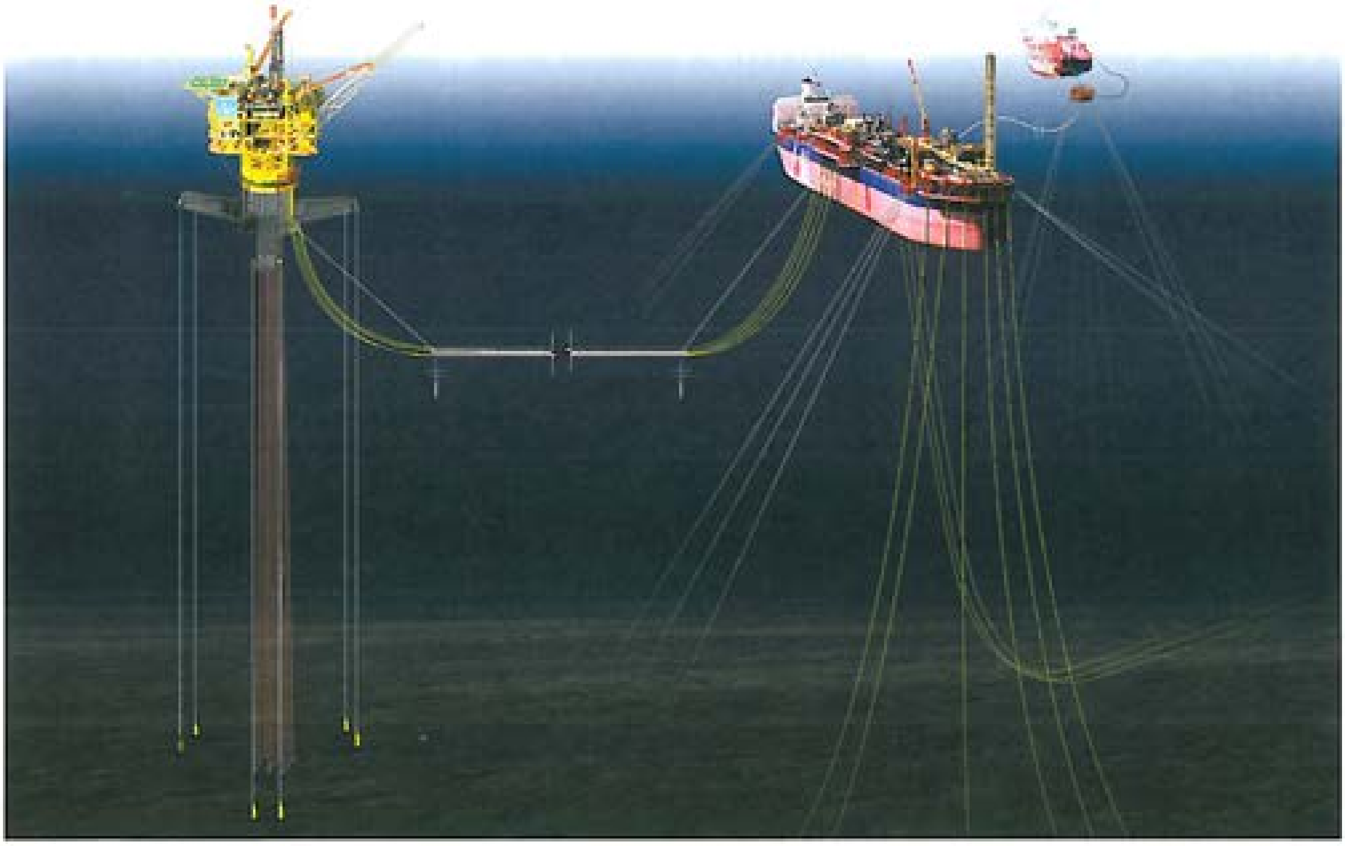
The Tordis Field lies in Block 34/7 in the Tampen area of the Norwegian North Sea. It came online in 1994. In 2005, Statoil contracted FMC Kongsberg to deliver a subsea separation station to improve oil recovery on Tordis.

This represents the first adoption of a full-scale subsea separation. Tordis is tied back to Statoil's Gullfaks C platform. The improved oil recovery project was expected to boost its recovery factor from 49 – 55%.

Seabed to Downhole

Subsea boosting has been around for a number of years. Subsea compression and subsea separation will be implemented in the near future, but Haug reveals that a more reliable way of subsea processing is on the horizon.

"Subsea processing will turn into downhole processing, where you process down in the wells. You don't even bring it to the seabed, you separate out the water downhole."



Broadband Satellite Communications for Oilfield Operations

David Myers

Oilfield exploration and production facilities operate in unforgiving environments-blistering deserts, arctic fields and the open ocean. Hundreds of miles from the nearest town or mark of civilisation, basic necessities such as electricity, clean water and reliable communications cannot be taken for granted. Everything that workers need must either be brought with them or made on site.

Harsh conditions and remote locations combine to make a reliable communications system more than just a luxury – it becomes a lifeline.

With the right system and service provider, a true 'always-on' broadband satellite connection can be much more than just a means of basic communications. It can enable your oilfield facility to harness the power of emerging broadband applications and realtime remote management tools.

From an operational perspective, these broadband applications can reduce costs by enabling realtime decision-making from central operations centres and by minimising downtime.

From a safety and security perspective, a satellite communications solution can offer the ability to authenticate an employee's identification or to respond immediately to an emergent situation.

Additionally, satellite solutions can help improve the morale of personnel on extended assignments by providing access to e-mail and public telephone services for staying in touch with their families.

Considerations for Selecting a Satellite Solution

Evaluating the choices in satellite communications for remote locations may seem daunting at first, but the range of offerings can quickly be narrowed by answering a few key questions.

- Is the service truly high-speed broadband?
- Does the service support both broadband data and voice?
- Does the service have global coverage?
- Is the technology employed field-proven for tough environments?
- Does the service offer 'business grade' guarantees?
- Can communications costs be predicted and controlled?

Most 'mass market' satellite communication services available cannot meet the stringent requirements of oilfield environments. Hand-held satellite phone services provide an excellent substitute for cellular mobile phones when outside of the metropolitan infrastructure, but the data services, if available, are generally rather slow at 20kbps or less.

INMARSAT, an established service primarily for the maritime industry, offers excellent global coverage. However, as with mobile satellite phones, data rates are generally slow and not well-suited to broadband applications. Both hand-held satellite phones and INMARSAT systems are metered services, charging the user by the minute or megabyte, making telecom costs for the remote operation highly variable and unpredictable.

Other seemingly inexpensive two-way satellite services that do offer flat-rate burstable broadband connectivity are more oriented towards residential or small office environments. Intended to provide Internet access for mass markets, these offerings do not provide traditional voice services or connection to the public telephone network. Coverage areas for mass market satellite Internet service providers (ISPs) are usually limited to more populated areas, without the availability for international or offshore applications.

Perhaps the most important consideration is that all of the aforementioned services are 'best effort' innature, offering no guarantees as to uptime, network availability or minimum data rates. Likewise, the equipment used to provide the services is generally of a consumer electronics quality – not adapted to resist extreme temperatures or corrosive environments. While such services definitely have a market and a customer following, they are not well-suited to the mission critical and harsh environments found in the oilfield and energy industry.

Robust Satellite Solutions from Cap Rock Communications

The right satellite communications solution comes from a seasoned company with a history of providing mission-critical communications to harsh environments. CapRock Communications, for example, understands the unique needs of people and organisations working in harsh and remote locations, like oilfield exploration and production (E&P). By providing robust satellite communication services for broadband networking, digital telephony and real-time video, CapRock can ensure that its customers' messages get there – no matter where they may be.

With both standard 'off the shelf' and custom- developed satellite communications services, CapRock provides a complete turn-key solution. All required equipment, bandwidth, technical support and maintenance are rolled into a worry-free flat-rate monthly service.

CapRock meets the selection criteria for remote communications by providing a robust service that encompasses:

- true broadband services with burstable and committed information rates (CIRs);

- a portfolio of standard and custom solutions for voice and data communications;
- global coverage and multiple operations centres for international support;
- robust field equipment and redundant teleport facilities for high reliability;
- customer service focus backed by service level agreements; and
- a technology-independent service to protect against obsolescence and control costs.

CapRock provides complete data, voice and video telecommunications services through its privately owned and managed global infrastructure.

With multiple interconnected teleports in Houston, Aberdeen, Honolulu and Macae, CapRock has the unique ability to be a single-source solution for remote satellite communications anywhere on the globe. Supported by a 24/7 network operation centre (NOC), in-house engineers and a large, international staff of field technicians, CapRock customers enjoy a satellite communications solution designed exclusively for the challenging environments in which they operate.

Technologies for Extending a Network Beyond the Edge

When selecting a satellite communications solution for a harsh or remote location, the top priority is reliability – making sure that the service will work when needed most. With this in mind, CapRock is constantly evaluating the right technologies for the task. Partnering only with best-of-breed providers, CapRock creates an integrated system designed to be dependable in the field.

By being technology- independent, CapRock can harness the benefits of new technologies as they become proven. This allows rapid migration to new standards without exposing customers to the risks associated with adopting a 'next generation' technology.

In addition to selecting the right technology partners, CapRock is focused on designing its services to meet the growing demand for corporate networks to reach as far into the field as possible. CapRock's standard satellite services are unique compared with other providers in that they are designed to be extensions of the corporate network. Unlike most satellite services that are asymmetrical with high speed on the downstream, but relatively slower speeds on the upstream, CapRock's standard packages provide symmetrical connections - where the data rate is the same in both directions. Additionally, all CapRock standard packages come with both a minimum committed information rate (CIR) as well as the ability to burst to even greater broadband speeds. Other providers are often vague about the data rate specifications of their satellite services. CapRock's commitment to high performance connections means that information technology (IT) and network managers can have the same confidence in their satellite connections as they do in traditional terrestrial links like frame relay, fractional-T or symmetric digital subscriber line (SDSL).

To complete the notion of providing an 'extension of the corporate network', CapRock employs its own state-of-the-art IPxpress™ network architecture, based on multi-protocol label switching (MPLS) technology for Internet protocol (IP) networks. IPxpress is CapRock's unique virtual networking architecture that enables secure portability of customer data and applications across any site in the CapRock network.

Customers can move from one location to the next and their applications, IP addresses and even voice over Internet protocol (VoIP) telephonenumbers will 'follow' them to the new location. The real customer benefit from CapRock's IPxpress architecture is that it makes the satellite connection transparent to the customer corporate network. An ethernet port on an oil platform in the middle of the North Sea looks, feels and behaves just like one back at corporate headquarters.

Experience to Meet Today's Challenges-Insight into Tomorrow's Opportunities

Another often overlooked consideration is selecting a satellite communications provider that has both the experience and staying power to be there when you need it most. CapRock has been providing 'industrial grade' telecommunications to the world's most extreme locations with unparalleled reliability for more than 20 years. Today, many of the world's best-known oil and energy companies, and the drilling and production contractors that support them, rely on CapRock for round-the-clock satellite communications.

This trust comes not just from a breadth of experience, but also from the fact that CapRock continues to be a growing company looking for innovations that bring the power of broadband applications to the most remote locations. Over the past two decades, CapRock has experienced dramatic growth, but the company's core mission has remained steadfast. With remote telecommunications expertise and a commitment to stringent systems engineering and industry-leading reliability, CapRock leverages its global presence to be a premier provider of satellite telecommunications and networking services for harsh and remote locations virtually anywhere in the world.

Evaluating Oil and Gas Projects

Marvin Fergus

With oil and gas prices skyrocketing, many investors are looking for opportunities to directly invest in oil and gas drilling projects.

Private placement drilling projects offer high net-worth/high income investors tax deductions and high income potential. But drilling for oil and gas is a risky business. This is true because a substantial portion of wells that are drilled either do not hit commercial reserves or the well being drilled/completed experiences unexpected problems.

Sophisticated oil and gas project investors realize that they may have to participate in several projects in order to obtain a paying interest in a well. So the rewards of a producing well will necessarily have to make-up for losses on past projects as well as future projects that may come up dry or prove uneconomical to produce.

This being the case, you'll want to invest in deals that offer a promising chance for success. As a registered professional geoscientist with the State of Texas with over 15 years experience originating, evaluating, leasing and financing oil and gas ventures for other oil companies and for my own account, I've come up with three key areas I believe investors should look at when evaluating an oil and gas drilling project: People, Deal Structure, and Production Projections.

Who Am I Doing Business With?

As a geologist, when I evaluate an oil and gas drilling project, I look first at the people who originated the deal. When oil prices are high, more and more people enter the oil business and start assembling and marketing oil and gas deals.

Therefore, look first at the company offering the project to determine how long they have been in the oil business and in what capacities. Here, I would look for a company with at least five years experience in managing projects. This criterion will help keep you out of deals with people who are inexperienced and less likely to manage the project properly.

Next, I would make sure there is a petroleum geologist on the project manager's staff. This is the person who will look at the geology and related data on a project and give their evaluation of its likeliness for success. While prospect-generating geologists are almost always reputable, they will have a certain natural bias towards their project. But while they may be focusing on a good prospect, there may be even better prospects elsewhere.

A full-time, on-board petroleum geologist has the latitude to select from many projects opportunities.

When looking at the project management company, also ask to talk with prior investors. Whether the well produces or not, investors want to be kept informed. This includes receiving timely progress reports as well as monthly well production and year-end reports. Sadly, not all companies are prompt in providing monthly progress reports or supplying essential year-end information that's needed for filing timely tax returns. So ask to talk with the project manager's prior investors who have participated in both non-producing and producing oil and gas drilling projects.

How Is The Project Structured?

There are nearly as many ways to put together an oil and gas investment in a drilling project as there are oil companies in the industry. But regardless of the project's structure or complexity, each can be boiled down to answering two simple questions: Who gets what percent of the revenue over the projected life of the well, if the well produces? And, is the anticipated cost of drilling and completing the well within a reasonable range?

Most private placement oil and gas drilling projects have the following parties involved when it comes time to share revenues from a producing well. These include the landowner or mineral owner, the project manager, and the investor group which is financing all the cost of drilling, completing, and producing the well. Let's look at these in turn:

Traditionally, the landowner or mineral owner receives between 12.5% to 25% of the total production revenue of a producing well without paying any costs. This is called a royalty interest.

The remainder of the revenue interest is divided up between the project manager and the investor group. When the deal is structured with a royalty interest greater than 25% it is usually because someone has carved out an overriding royalty interest.

On the cost side we are looking at the cost of buying the lease, drilling, and completing the well. The investor pays these costs on either an actual invoice cost basis or a fixed amount set by the project manager. Actual invoice cost allows the project manager to come back to the investors with additional investment demands in the event of unexpected additional drilling and/or well completion costs. However, this rarely happens because the project manager will add a contingency to his estimates that usually cover any overruns. This contingency will be returned if not used. If the investor is concerned about being on an invoice cost basis and wants his risk certain or capped, he should participate on a fixed cost basis. When a deal is capped or turn-keyed, the prudent project manager will add a reasonable allowance to the drilling and completion budget to cover unexpected expenses. This additional allowance will usually be more than the contingency mentioned above.

If costs overrun this additional padding, the project manager will have to pay the additional expenses out of his pocket. If the well drilling and completion costs come in below budget, the project manager will keep the difference. The padding acts like an insurance policy paid for by the investor. The investor has a cap on his liability and the project manager assumes the added risk. The project manager should provide the drilling and completion costs estimate, called an AFE (Authorization for Expenditure), to the investor. A few calls to service companies and the drilling contractor used by the project manager could possibly reveal the extent of any markup on a turnkey basis. In the State of Louisiana, the Louisiana Mid-Continent Oil and Gas Association, www.lmoga.com, offers average drilling cost information for previously drilled wells in areas based on depths. So it's not too hard to get a pretty good feel for the amount of drilling/completion costs for any well.

Does the Projected Monthly Production Justify the Money You Are Investing?

In an established oil and gas area the petroleum geologist makes the production projections on a payout based on his or her analysis of the production of nearby wells. My simple rule of thumb is that you want to see projections that (at current oil and gas prices) will return your entire investment in 24 months or sooner. If the projected production doesn't support a 24-month return or better on the investment, the investment risk is too high given the expected return. Allowing for the fact that a good portion of all wells drilled will be non-producing, you want to make certain that the ones that do produce make up for the ones that do not.

Additional Considerations

Be wary of the project manager that claims to have hit nine of the last ten wells, or anything similar.If that were true, they would not need your money to help spread the risk since there wouldn't be any risk.

Be careful of multiple well projects on the same acreage. Only by completing a well do you gain the necessary information you need to determine if a second well should be drilled on the same project acreage.

Conclusion

Investing in a single oil and gas drilling project should not be looked at as a one-shot proposition. Most investors will have to experience a certain number of non-producing projects before they hit a producing project. When you do hit that producing well you want to be in partnership with people you trust, and you want to be in a project that's fair, and one that has a good likelihood for paying back your investment in short order. I believe the above guidelines will go a long way towards helping you achieve those objectives.

High Performance Corrosion Resistance?

Kirtan Dhami

Corrosion is a very serious issue in oil and gas companies who are into oil exploration by means of platforms. The damage due to corrosion sometimes accounts to thousands of dollars. For this reason, major metallic equipments and parts must be protected from corrosion resistance.

Although commonly used methods of corrosion protection viz hot dip galvanized , molycote , cadmium plating are there over years in the market , a demand and requirements Is there for a superior high performance coating for specific applications and saline water resistance where all the traditional methods tend to fail. Here emerges the market for Fluoropolymer / PTFE coated fasteners and equipments which represents an innovative alternative.

Introduction

There are various corrosion levels of saline water immersed offshore structures

1. Buried in Soil
2. Under water Zone (UZ)
3. Intermediate Zone (IZ)
4. Splash Zone (SZ)
5. Atmospheric Zone (AZ)

The highest level of corrosion is found in the UZ, IZ and SZ areas of any offshore structure.

Corrosion protection is done via Active Protection, Passive Protection and Temporary Protection.

Active Protection is controlled at the design stage by means of Material Selection and Construction Details.

Temporary Protection is done where the equipment is not critical and a change in design is possible. Passive Protections is done via the means of Coatings and Surface Protection Methods.

Typical Saline Water Conditions

1. 3.5 % Sodium Chloride
2. Temperature is around the range of 50 Degree C to 80 Degree C
3. Alternate wetting and drying cycles
4. High Concentration of Salts
5. Salt Deposits–Salt absorbed in moisture is more corrosive as it in wet conditions
6. Presence of Oxygen along with the Salt

The problem with Traditional Coating Methods

Extensive testing and field use have proven that the future of coated fasteners lies with Fluoropolymer Coatings.

Previously, hot dip galvanized, cadmium or zinc plated fasteners were considered the standard. But these coatings could not stand up to the corrosive atmospheres prevalent in Many industries. After 500 hours of salt spray testing (ASTM B117), fasteners coated with these Conventional methods showed severe corrosion and, in some cases, failure.

Fasteners coated with BLINEX FILTER COAT PVT LTD Fluoropolymer coating withstood these harsh conditions with no noticeable deterioration.

Even after as many as 1,000 hours, TEFCOTTM - Fluoropolymer / PTFE coated fasteners still could be easily disassembled.

What is Fluoropolymer Coatings?

Fluoropolymer coatings are blends of high performance resins and Fluoropolymer lubricants.Most of the useful properties of Fluoropolymer are due to fluorine, the most electro-negative element and the most reactive non- metal.

Its atomic radius is the smallest next to hydrogen, and it forms extremely strong bonds with other elements. When reacted with Carbon in Fluoropolymer, the extremely strong, tight bond produces an extraordinary combination of properties. These single coat thin films provide excellent corrosion and chemical resistance. Other benefits of Fluoropolymer coatings include reduced friction, resistance to galling, non stick, non wetting, electrical resistance and abrasion resistance. Fluoropolymer coatings are applied to fasteners and various OEM components to provide a longer life before replacement.

At present Fluoropolymer /PTFE coatings solutions are supplied and marketed by Whitford Plastics UK (Brand–Xylan®) and DuPont (Brand–Teflon®)

Extraordinary Properties

- Chemically inert Nontoxic
- Non-wetting
- Nonstick
- Low Coefficient of Friction
- Highly fire resistant
- Low dielectric constant
- High temperature ratings (-100 Degree C to + 260 Degree C)

Technical Data-PTFE/Fluoropolymer Catings

Use Tempratures:-100 C to+260 C	Adhesion: 5B(ASTM D3359-95)
Corrosion Resistance:	Dielectric Strength:500 volts per mil
Salt Spray(ASTM B117) ... up to 1000 hrs(Nuts not frozen)	Elongation:35%-50%
Pencil Hardness:5H-6H(ASTM D3363-92A)	Tensile Strength:4000 psi
Kinetic Friction Coefficient: 0.06-0.8	Operating pressure:Up to 100000 psi
Thickness: nominal 0.001in.(1 mil)	Kesternich Test:Nuts not frozen after 30+cycles(DIN 50018)
Impact: 160 in.lb.(ASTM D2794-93)	

Why Would Coating Bolts Make Sense In Some Situations?

1. Cleaning and painting of bare steel bolts in the field is likely to be difficult, expensive, and in some cases, not feasible.

2. The plain bolts, after stuffing in the holes, are expected to sit out in the weather for an extended period of time and get dried out and rusty, making correct tightening difficult or impossible.

3. Release or retightening of the bolt within the foreseeable future is necessary (Wind turbine support shafts).

4. Atmospheric corrosion is expected to be aggressive.

Coating Process

BLINEX FILTER COAT PVT LTD has perfected the Fluoropolymer fastener coating process. Surface preparation of the fastener prior to coating is a very important step. We use the latest industry accepted methods to thoroughly clean all contaminants from the fasteners. Manufacturing oils, rust and scale are removed to ensure the highest quality coating.

Superior corrosion resistance is created by the application of a series of coatings.

A metallic base coat is applied first, followed by an adhesion coat. The adhesion coat creates a chemical bond between the base coat and the top coat. The top coat, a heat cured Fluoropolymer coating containing PTFE, is used to seal the two under coatings and give easy on/ easy off characteristics.

Comparisons with other Coatings

Black, cadmium plated, and hot dipped galvanized bolts will freeze when subjected to the corrosive environments found in manufacturing plants, offshore oil rigs etc. Most often removing the nuts requires a cutting torch. With BLINEXTM Fluoropolymer coating these same nuts and bolts exhibit easy on and easy off characteristics increasing worker safety.

Cadmium plated and hot dipped galvanized bolts provide similar corrosion resistance. These coatings have undergone the standard salt fog test (ASTM B117) and have been rated at 96 hours of corrosion resistance. With a BLINEXTM Fluoropolymer coated bolt that rating jumps to as much as 1000 hours. The additional corrosion resistance allows fasteners to be disassembled quickly, saving lost down time and man-hours.

Galvanizing produces a coating that is uneven, rough and thick. The rough surfaces make assembly difficult and a tight even tension on each bolt impossible. If used in sealing joints such as flanges, heads or inspection covers, the inconsistent tension forms an uneven fit resulting in a high probability of leaks. With a BLINEXTM Fluoropolymer coated bolt, tighter more consistent tensions are achieved with less required torque.

Where Fluoropolymer/PTFE Coatings Works?

BLINEX FILTER COAT PVT LTD has solved problems in many industries and applications. Due to its unique benefits, Fluoropolymer Coating has been applied to various types and grades of fasteners.

The water works industry takes advantage of the superior corrosion resistance properties by coating Hex-head bolts for underground service. Stainless steel fasteners, used in many different industries, are coated for lubricity and anti-galling.

The most widely used application is on B7 studs with 2H nuts. These fasteners are commonly used by turnaround groups, operations and maintenance departments, and contractors at many chemical plants, refineries, and offshore platforms. The coating's chemical resistance, and easy on/easy off characteristics are perfect for these environments.

Conclusion

The costs entailed with other bolt coatings can be staggering when factors such as man-hours, down time, safety and equipment damage are considered. Bolts coated with BLINEXTM Fluoropolymer coating prove to be longer lasting, safer and more cost effective than any other coated bolt. The properties frequently make Fluoropolymer the product of choice when metals and less expensive plastics fail or where long term reliability is required. Fluoropolymer are often used to solve existing problems or to develop new technology. Despite a relatively extra cost, Fluoropolymer have frequently been used to substantially reduce overall system cost.

Techniques to Reduce offshore oilfield drilling wastes

Jonathan Wills

There are several ways to reduce the volume of drilling waste produced and to minimise its effects on the sea.

Using less toxic alternatives

It is a favoured solution in both Europe (OSPAR. 2000. Draft Measures Proposed by the OSPAR Working Group on Sea-based Activities (SEBA), February 2000. Annex 7(6.5b): Draft OSPAR Decision 2000/? on a Harmonised Mandatory Control System for the Use and Reduction of the Discharge of Offshore Chemicals.

OSPAR, Amsterdam. See also: CEFAS. 2000. Guidelines for the UK Revised Offshore Chemical Notification Scheme in Accordance with the OSPARCOM Harmonised Offshore Chemical Notification Format. http://www.cefas.co.uk/ocns.

London.) and North America, where governments and industry are continually searching for improved and less harmful offshore drilling fluids. SBMs, most of which failed to satisfy European standards, were such an attempt to deal with the problem at source and the US may yet prove that some forms of SBMs really are an environmentally acceptable alternative to OBMs. For WBMs, improvements to the purity of stock chemicals, and measurement of their toxicity prior to mixing into the drilling fluid, are among the most promising prospects for environmental improvement in cases where waste discharge is unavoidable.

Cleaning onboard prior to discharge

It is also a rapidly-developing technology. The crude shale-shakers and sieves once employed to separate solids from drilling fluids after use have been superseded by much more efficient equipment that can greatly improve the separation of mud from cuttings and oil from produced water. Technology exists, but has not yet been widely adopted offshore, that can very largely remove the residual pollutants in cuttings and, particularly, in produced water. The obstacles are financial rather than technical. Whether such equipment is installed and used offshore is, of course, a matter for government enforcement.

Shipment of wastes ashore

It is for recycling, landfill and/or incineration is one of the options being considered for dealing with the very large accumulations of contaminated drill cuttings in the North Sea. It is already used to dispose of some ongoing waste streams and thus prevent the build-up of new drill cuttings piles on the seabed.

While making a contribution to both the environment and the local economies of North Sea coastal regions, (In the UK, for example, new equipment to process cuttings and other wastes shipped ashore from North Sea fields has recently been installed in Peterhead, Aberdeen and Shetland (where one firm has been handling contaminated cuttings (waste for over 10 years). See, for example: Burgess & Garrick. 2000. Waste Management. Website:http://www.burgess-garrick.co.uk/about.htm Lerwick) the air pollution, landfill space demands and energy costs associated with transporting, processing and disposing of the material seem likely to influence governments in favour onsite re-injection technology as a more practical and cost-effective method - wherever geological conditions are suitable.

Re-injection Offshore

Cuttings re-injection (CRI) is a waste disposal technique where drill cuttings and other oilfield wastes are mixed into a slurry with water and pumped at high pressure down an injection well.

Sometimes it is necessary to grind up the particles in the slurry to make them finer. The hydraulic pressure can also be used to break open layers in the rock to make subsequent injection easier and to contain the wastes in a defined area -

hence the term slurry fracture injection commonly used in the US and Canada, where the technique was pioneered. (For accounts of early work on re-injection, see:

1. Beak Consultants and Imperial Oil Limited 1974. Disposal of waste drilling fluids in the Canadian Arctic. APOA project no.73. APOA, Calgary.

2. Dome Petroleum Limited 1974. Interim guidelines for waste management in exploratory drilling in the Canadian north. Dome Petroleum Ltd., Calgary.

3. French, H. M. 1980. Terrain, Land Use and Waste Drilling Fluid Disposal Problems, Arctic Canada. Arctic 33:794-806.

4. Friesen, G.1980. Drilling Fluids and Disposal Methods Employed by Esso Resources Canada Limited to Drill in the Canadian Arctic. Proceedings of a Symposium: Research on Environmental Fate and Effects of Drilling Fluids and Cuttings, Lake Buena Vista, Fla.: PP. 53-69. American Petroleum Institute. Washington, DC.

5. Lam, L. 1982. Report on Offshore Oil and Gas Drilling Fluid Disposal in the Canadian North Technical Report No. 3.6. A Survey of Methods of Waste Fluid Treatment and Disposal for Canadian Offshore Drilling. Canadian Superior Oil Ltd.

6. Canada Dept. of Indian Affairs and Northern Development, Environment Canada, Canada Dept. of Fisheries and Oceans, Industry/Government Working Group on Disposal of Waste Fluids from Petroleum Exploratory Drilling in the Canadian North, and Arctic Petroleum Operators Association. 1982. Report on offshore oil & gas drilling fluid disposal in the Canadian North. Yellowknife, N.W.T. 7. Hillman, S.O. 1983. Drilling Fluids: Disposal in the Alaskan Beaufort Sea. Issues of the 80's: Twelfth Annual Arctic Environmental Workshop held at Fairmont, British Columbia, May 8th-11th, 1983, p.162-166.)

One of the clearest explanations of CRI is by the British company Gidatec (See the Gidatec website at http://www.gidatec.co.uk/Cuttings.htm for more details), which describes it as "a cost effective means of complying with environmental legislation concerning discharges of oily wastes" and says it has "proven to be viable in many different areas and formations around the world, with the most activity in the North Sea, Alaska, Gulf of Mexico and Venezuela":

Re-injection of drill cuttings normally involves collection of the waste from solids control equipment on the rig, followed by transportation to a cuttings processing station. Cuttings are slurried in this unit by being milled and sheared in the presence of water, usually seawater. The resulting slurry is then disposed of by pumping it into a dedicated disposal well, or through the open annulus of a previous well into a fracture created at the casing shoe set in a suitable formation. Operations are usually batch by nature and carried out at low pump rates (2.0 - 8.0 bpm). These kinds of operations have been carried out all over the world, with disposal into many different types of strata.

On logistical and cost grounds the means of disposing of waste cuttings from [offshore] platform based operations can usually be narrowed down to one of two choices. These are either re-injection into a dedicated disposal well, which if newly drilled can be re-completed as a producer at a later date, or re-injection through the annulus of a well drilled prior to the current live well.

Drilling and cuttings disposal into the same well is possible but to date, because of well control concerns, it is not a preferred option with operators.

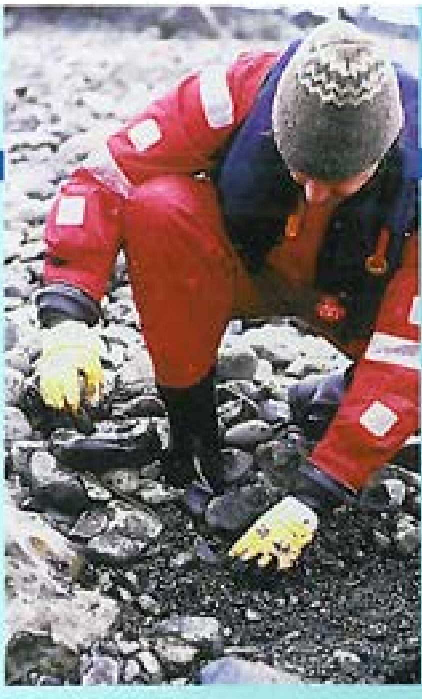
Sequential annulus injection is invariably the preferred means of disposing of cuttings, particularly in offshore locations. This is because of its flexibility and that it avoids the cost of drilling a dedicated disposal well. For cost reasons, dedicated re-injection wells are usually only practical on land or in shallow water. They do have advantages, however, including ease of cleaning out with coiled tubing in the event of plugging, can be designed to accommodate high volumes of waste, the ability to inject larger sized solids and a reduced risk of tubing plugging. Even so, unless annular cuttings re-injection is not viable, for example because of lack of annular access to a suitable deposition horizon, drilling a dedicated disposal well is usually ruled out on cost grounds. Thus, annular re-injection of waste cuttings is invariably the method of choice. Typically the 13 3/8" by 9 5/8" annulus is selected as the disposal location.

One of the first oil companies to make extensive use of cuttings re-injection was BP. The company had opened up its Alaska North Slope oilfields by using "reserve pits" - a euphemism for holes in the ground where drillers dumped almost anything. Within a few years BP had a serious environmental problem on its hands, as poisonous wastes began to leach out of the pits and spread across the

The crude shale-shakers and sieves once employed to separate solids from drilling fluids after use have been superseded by much more efficient equipment that can greatly improve the separation of mud from cuttings and oil from produced water

tundra on top of the permafrost. (United States Department of the Interior (DOI), Fish and Wildlife Service (FWS). 1987. Effects of Prudhoe Bay Reserve Pit Fluids on Water Quality and Macroinvertebrates of Arctic Tundra Ponds in Alaska. US DOI Biological Report 87(7). Washington D.C.) Although it was out of sight from most people, the pollution in the Arctic wilderness north of the Brooks Range was not out of mind. As controversy grew about the oil industry's plans to drill in the Arctic National Wildlife Refuge (ANWR) critics pointed to the mess at the reserve pits as evidence that BP's environmental credentials were suspect.This caused serious public relations problems for BP and its compradors in the Alaska State Legislature and business community. During the late 1980s and early 1990s the company cleaned up the pits, volunteered its services to deal with other organisations' waste dumps (some dating from World War II and earlier) and, to some extent, salvaged its reputation among American environmentalists. The results certainly looked impressive and showed what an organisation like BP could achieve when management and workers were given the resources to do a thorough job. (1. Taylor, S. 1998. Status of North Slope Environmental Protection (video presentation), BP Exploration, Anchorage. 2. Minton, R. C. and Secoy, B. 1992. Annular Reinjection of Drilling Wastes. IADC/SPE Paper 25042. Society of Petroleum Engineers, Richardson, Texas. 3. Brasier, F. 1992. Injection Control Regulations - Federal Framework and Alaska Regulations. Proceedings of a Seminar on Subterranean Disposal of Drill Cuttings and Produced Water. Stavanger). By 1993 the E&P Forum could boast: "In Alaska the injection of cuttings and waste fluids has led to much smaller drilling pads, and therefore less impact from the rig rites, and less heavy traffic transporting materials across the tundra. (E&P Forum. 1993. Guidelines for the Planning of Downhole Injection Programmes for Oil Based Mud Wastes and Associated Cuttings from Offshore Wells. Report No. 2.56/187. E&P Forum, London) There were also economic benefits because the reserve pits had been costing about $2,000,000 per well, whereas grinding and downhole injection cost about $500,000 per well thereby saving about $1,500,000 per well. (ADEC informant, pers. comm.. 2000.)

BP was also in the forefront with CRI offshore. In January 1991 BP engineers injected 5,700 barrels of drilling wastes 5,100 feet below the bottom of the Gulf of Mexico, in tests at the Ewings Bank platform. In the Norwegian sector of the North Sea, BP was involved in a case study on the Gyda oilfield from July 1991 (Molland, G. 1992. Re-injection of Cuttings on Gyda. Proceedings of a Seminar on Subterranean Disposal of Drill Cuttings and Produced Water. Stavanger). In September that year BP did a test injec-



tion of 1,500 barrels of waste from the Clyde platform in the UK sector. Other case studies on CRI were carried out in the early 1990s by Conoco in the southern North Sea (January - March 1992) and the Gulf of Mexico (Block EC56, December 1991 - January 1992), by Statoil on the Norwegian Gullfaks field (October 1991) and by Amoco, also in the Norwegian sector, on the Valhall oilfield (January 1992). (E&P Forum. 1993. op. cit.) These, however, were all described as case studies, tests or experiments.

By 1993 CRI was such a well-established technique offshore that- the E&P Forum produced detailed guidelines (Ibid) for operators planning to use it for OBM wastes and oil-contaminated drill cuttings. The document gave examples of the kinds of problems staff might encounter and, in addition to practical advice, laid down recommended procedures for monitoring and reporting reinjection work. The working group that drew up the guidelines included two representative of Exxon, alongside experts from Agip, Amoco, BP, Chevron, Elf, Enterprise Oil, Statoil, Texaco and Total.

They agreed that re-injection had "a successful history to date, particularly in Alaska and the Gulf of Mexico" but in Europe it had "only recently been evaluated". They described a Drilling Engineering Association project, with 12 operator sponsors, that had "been involved in developing the concept" between 1990 and 1993 and added:

Injection has been adopted by operators in the Norwegian and UK sectors of the North Sea, and is seen as a viable route to oily waste disposal.

The adoption of this approach to the disposal of oilfield wastes is particularly attractive since it means that the overall environmental impact of operations is minimised. Injection offers a cost effective disposal option with minimal energy utilisation.

This view is confirmed by a review of the extensive literature on the subject in the public domain. (For example, see the following: 1. Lal, M. and Thurber, N. 1989. Drilling Wastes Management and Closed-Loop Systems. In Engelhardt, F. R. et al. (eds). 1989. Drilling Wastes.

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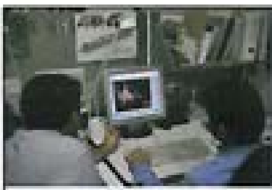

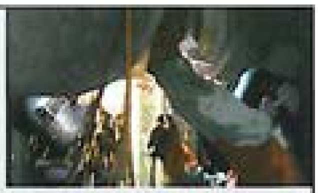

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Oil spills in the marine environment

Fate and behavior of oil in the marine environment

Complex processes of oil transformation in the marine environment start developing from the first seconds of oil's contact with seawater.

The progression, duration, and result of these transformations depend on the properties and composition of the oil itself, parameters of the actual oil spill, and environmental conditions. The main characteristics of oil transformations are their dynamism, especially at the first stages, and the close interaction of physical, chemical, and biological mechanisms of dispersion and degradation of oil components up to their complete disappearance as original substances. Similar to an intoxicated living organism, a marine ecosystem destroys, metabolizes, and deposits the excessive amounts of hydrocarbons, transforming them into more common and safer substances.

Physical transport.

The distribution of oil spilled on the sea surface occurs under the influence of gravitation forces.

It is controlled by oil viscosity and the surface tension of water. Only ten minutes after a spill of 1 ton of oil, the oil can disperse over a radius of 50 m, forming a slick 10-mm thick. The slick gets thinner (less than 1 mm) as oil continues to spread, covering an area of up to 12 km2 [Ramade, 1978]. During the first several days after the spill, a considerable part of oil transforms into the gaseous phase.

Besides volatile components, the slick rapidly loses water-soluble hydrocarbons. The rest - the more viscous fractions - slow down the slick spreading.

Further changes take place under the combined impact of meteorological and hydrological factors and depend mainly on the power and direction of wind, waves, and currents. An oil slick usually drifts in the same direction as the wind.

While the slick thins, especially after the critical thickness of about 0.1 mm, it disintegrates into separate fragments that spread over larger and more distant areas. Storms and active turbulence speed up the dispersion of the slick and its fragments. A considerable part of oil disperses in the water as fine droplets that can be transported over large distances away from the place of the spill.

Dissolution

Most oil components are water-soluble to a certain degree, especially low-molecular-weight aliphatic and aromatic hydrocarbons. Polar compounds formed as a result of oxidation of some oil fractions in the marine environment also dissolve in seawater.

Compared with evaporation, dissolution takes more time. Hydrodynamic and physicochemical conditions in the surface waters strongly affect the rate of the process.

Emulsification.

Oil emulsification in the marine environment depends, first of all, on oil composition and the turbulent regime of the water mass. The most stable emulsions such as water-in-oil contain from 30% to 80% water. They usually appear after strong storms in the zones of spills of heavy oils with an increased content of nonvolatile fractions (especially asphaltenes). They can exist in the marine environment for over 100 days in the form of peculiar "chocolate mousses". Stability of these emulsions usually increases with decreasing temperature. The reverse emulsions, such as oil-in-water (droplets of oil suspended in water), are much less stable because surface-tension forces quickly decrease the dispersion of oil. This process can be slowed with the help of emulsifiers - surface-active substances with strong hydrophilic properties used to eliminate oil spills. Emulsifiers help to stabilize oil emulsions and promote dispersing oil to form microscopic (invisible) droplets. This accelerates the decomposition of oil products in the water column.

Oxidation and destruction.

Chemical transformations of oil on the water surface and in the water column start to reveal themselves no earlier than a day after the oil enters the marine environment. They mainly have an oxidative nature and often involve photochemical reactions under the influence of ultraviolet waves of the solar spectrum. These processes are catalyzed by some trace elements (e.g., vanadium) and inhibited (slowed) by compounds of sulfur. The final products of oxidation (hydroperoxides, phenols, carboxylic acids, ketones, aldehydes, and others) usually have increased water solubility. An experimental research showed that they have increased toxicity as well [Izrael, Tsiban, 1988]. The reactions of photooxidation, photolysis in particular, initiate the polymerization and decomposition of the most complex molecules in oil composition. This increases the oil's viscosity and promotes the formation of solid oil aggregates [GESAMP, 1977; 1993].

Sedimentation.

Some of the oil (up to 10-30%) is adsorbed on the suspended material and deposited to the bottom.

This mainly happens in the narrow coastal zone and shallow waters where particulates are abundant and water is subjected to intense mixing. In deeper areas remote from the shore, sedimentation of oil (except for the heavy fractions) is an extremely slow process.

Simultaneously, the process of biosedimentation happens. Plankton filtrators and other organisms absorb the emulsified oil. They sediment it to the bottom

with their metabolites and remainders.

The suspended forms of oil and its components undergo intense chemical and biological (microbial in particular) decomposition in the water column. However, this situation radically changes when the suspended oil reaches the sea bottom. Numerous experimental and field studies show that the decomposition rate of the oil buried on the bottom abruptly drops. The oxidation processes slow down, especially under anaerobic conditions in the bottom environment.

The heavy oil fractions accumulated inside the sediments can be preserved for many months and even years.

Microbial degradation.

The fate of most petroleum substances in the marine environment is ultimately defined by their transformation and degradation due to microbial activity. About a hundred known species of bacteria and fungi are able to use oil components to sustain their growth and metabolism.

In pristine areas, their proportions usually do not exceed 0.1-1.0% of the total abundance of heterotrophic bacterial communities. In areas polluted by oil, however, this portion increases to 1-10% [Atlas, 1993].

Biochemical processes of oil degradation with microorganism participation include several types of enzyme reactions based on oxygenases, dehydrogenases, and hydrolases. These cause aromatic and aliphatic hydrooxidation, oxidative deamination, hydrolysis, and other biochemical transformations of the original oil substances and the intermediate products of their degradation.

The degree and rates of hydrocarbon biodegradation depend, first of all, upon the structure of their molecules. The paraffin compounds (alkanes) biodegrade faster than aromatic and naphthenic substances. With increasing complexity of molecular structure (increasing the number of carbon atoms and degree of chain branching) as well as with increasing molecular weight, the rate of microbial decomposition usually decreases.

Besides, this rate depends on the physical state of the oil, including the degree of its dispersion. The most important environmental factors that influence hydrocarbon biodegradation include temperature, concentration of nutrients and oxygen, and, of course, species composition and abundance of oil-degrading microorganisms. These complex and interconnected factors influencing biodegradation and the variability of oil composition make interpreting and comparing available data about the rates and scale of oil biodegradation in the marine environment extremely difficult.

Aggregation.

Oil aggregates in the form of petroleum lumps, tar balls, or pelagic tar can be presently found both in the open and coastal waters as well as on the beaches. They derive from crude oil after the evaporation and dissolution of its relatively light fractions, emulsification of oil residuals, and chemical and microbial transformation. The chemical composition of oil aggregates is rather changeable. However, most often, its base includes asphaltenes (up to 50%) and high-molecular-weight compounds of the heavy fractions of the oil.

Oil aggregates look like light gray, brown, dark brown, or black sticky lumps. They have an uneven shape and vary from 1 mm to 10 cm in size (sometimes reaching up to 50 cm). Their surface serves as a substrate for developing bacteria, unicellular algae, and other microorganisms.

Besides, many invertebrates (e.g., gastropods, polychaetes, and crustaceans) resistant to oil's impacts often use them as a shelter.

Oil aggregates can exist from a month to a year in the enclosed seas and up to several years in the open ocean [Benzhitski, 1980]. They complete their cycle by slowly degrading in the water column, on the shore (if they are washed there by currents), or on the sea bottom (if they lose their floating ability).

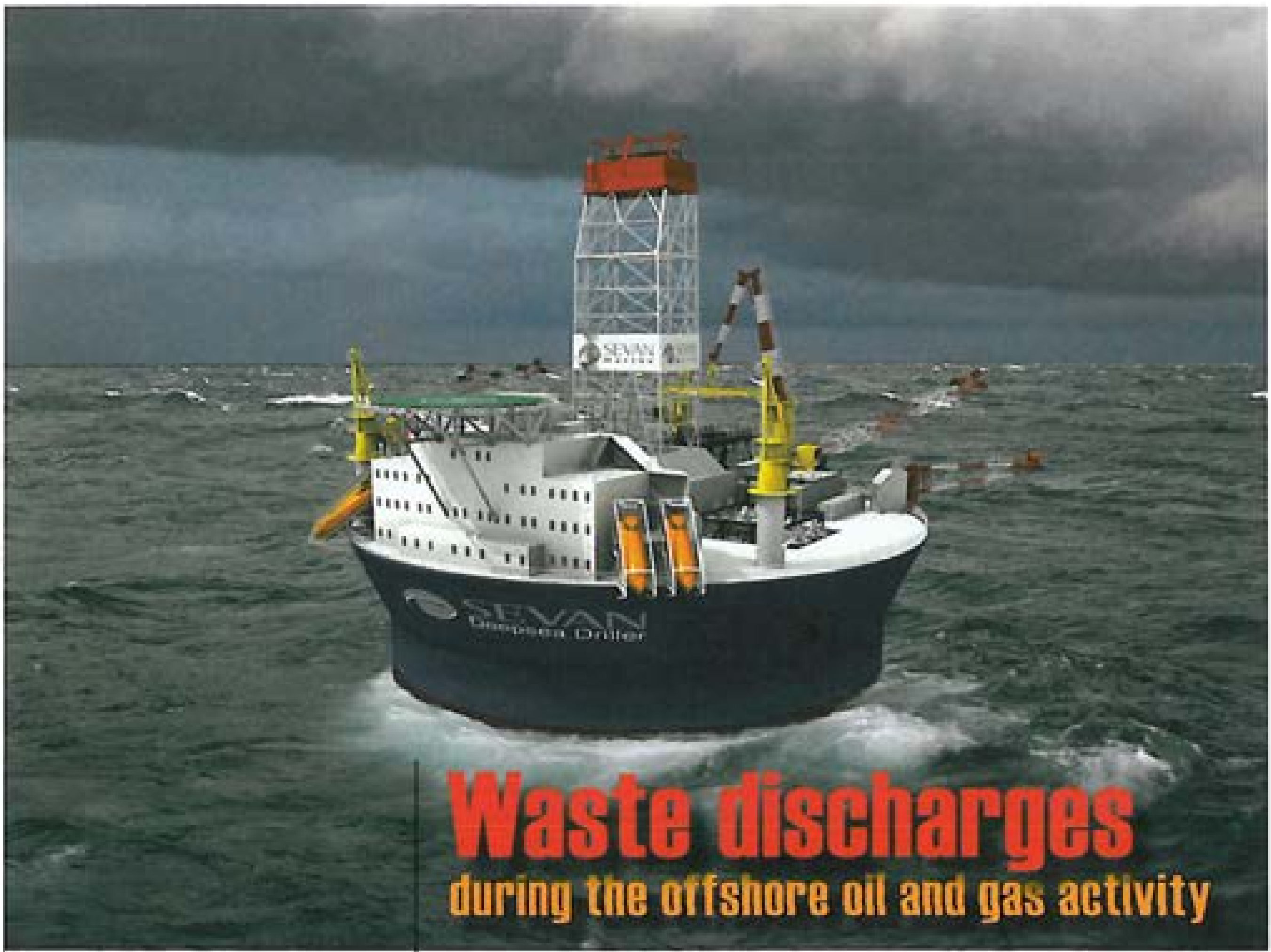
Self-purification.

As a result of the processes previously discussed, oil in the marine environment rapidly loses its original properties and disintegrates into hydrocarbon fractions.

These fractions have different chemical composition and structure and exist in different migrational forms. They undergo radical transformations that slow after reaching thermodynamic equilibrium with the environmental parameters.

Their content gradually drops as a result of dispersion and degradation. Eventually, the original and intermediate compounds disappear, and carbon dioxide and water form.

Such self-purification of the marine environment inevitably happens in water ecosystems if, of course, the toxic load does not exceed acceptable limits.



Waste discharges

during the offshore oil and gas activity

Below you will find information on waste discharges, including discharges of drilling muds and cuttings, produced waters and atmospheric emissions during the offshore oil and gas activities. Click on the links at the end of this page to find more information about Environmental Impact of the Offshore Oil and Gas Industry.

Sources, types, and volumes of waste discharges

Practically all stages and operations of offshore hydrocarbon production are accompanied by undesirable discharges of liquid, solid, and gaseous wastes.

The proportions and amounts of discharged wastes can change considerably during production. For example, the amount of solid drilling cuttings usually decreases as the well gets deeper and the hole diameter becomes correspondingly smaller. The volumes of produced waters increase as the hydrocarbon resources are being depleted and production moves from the first stages toward its completion. Drilling in the upper layers of bottom sediments (up to approximately 100 m) can be done without using complex drilling fluids. In such cases, seawater with additives of special clay suspensions can be used instead.

The discharges of produced waters considerably dominate over other wastes.

Produced waters include formation water, brine, injection water, and other technological waters. Formation water and brine are extracted along with oil and gas. Injection water is pumped into the injection wells in hundreds of thousands of tons for maintaining the pressure in the system and pushing the hydrocarbons toward the producing wells. All of these waters are usually polluted by oil, natural low-molecular-weight hydrocarbons, inorganic salts, and technological chemicals. These waters need to be cleaned before they are discharged into the sea. Such cleaning under marine conditions is a complicated technical task. Special separation units on the platforms are used for oil separation. Depending on its quality, the produced water is either discharged into the sea or injected into the disposal well. Sometimes the oil-water mixtures are transported along the pipelines to onshore separation units.

Produced waters, including injection waters and solutions of chemicals used to intensify hydrocarbon extraction and the separation of the oil-water mixtures, are one of the main sources of oil pollution in the areas of offshore oil and gas production. It is significant that, as a hydrocarbon reservoir is being depleted, the ratio between the water and oil fraction in the extracted product increases, and water becomes the prevailing phase. At the same time, both the volumes of discharged waters and the difficulties of their treatment increase.

Inevitably, all kinds of drilling are associated with drilling wastes, including drilling muds and cuttings. Drilling cuttings are removed from drilling muds and cleaned in special separators. The amount of oil left on cuttings after cleaning is much higher when using oil-based fluids. Separated drilling muds and cleaning fluids used to treat cuttings are partially returned to the circulating system. Drilling cuttings and the rest of the drilling muds are either dumped overboard or transported to the shore for further treatment and disposal, depending on the situation and ecological requirements. The first variant is the most usual and is practiced almost everywhere, while the second one still remains an unrealized (or seldom realized) ecological requirement.

Recently, a technology was developed to remove the drilling wastes, especially cuttings, by reinjecting their slurry into a geological formation. This gives some hope to achieving zero discharge of oil-containing wastes during offshore oil and gas production. Some other measures (such as slim-hole drilling) to reduce discharges, particularly in environmentally sensitive locations, are being investigated by the industry.

The environmental hazard of drilling muds is connected, in particular, with the presence of lubricating materials in their composition. These lubricating substances usually have a hydrocarbon base. They are needed for effective drilling, especially in case of slant holes or drilling through solid rock.

The lubricants are added into the drilling fluids either from the very beginning as a part of the original formulations or in the process of drilling when the operational need emerges.

In both cases, the discharges of spent drilling muds and cuttings coated by these muds contain considerable amounts of relatively stable and toxic hydrocarbon compounds and a wide spectrum of many other substances.

One of the potential sources of oil pollution is produced sand extracted with oil. The amount of produced sand coated by oil can vary a lot in different areas and even during production in the same area. In some cases, it constitutes a considerable part of the extracted product.

Most often, this sand is cleaned of the oil and dumped overboard at the well site. Sometimes, it is baked or calcified and transported to the shore.

The other discharges into the marine environment (deck drainage, sanitary and domestic wastes, and so on), do not play essential roles in the environmental situation in the areas of oil and gas developments. They are treated and disposed in accordance with the norms regulating discharges from the ships.

Chemical composition of discharged wastes

As noted earlier, the spectrum of chemicals entering the marine environment at different stages of oil and gas production is very wide. They include many hundreds of individual compounds and their combinations. Broadly speaking, all can be divided into two large groups. The first group consists of the extracted oil and gas hydrocarbons, which the following chapters will discuss in detail. The second group, which this section will review, unites the rest of the natural and technological components used at different technological stages.

Drilling fluids and cuttings.

Drilling wastes deserve special attention. The volume of drilling wastes usually ranges from 1,000 to 5,000 m3 for each well. Such wells can number into dozens for one production platform and many hundreds for a large field.

Drilling cuttings separated from drilling muds have a complex and extremely changeable composition. This composition depends on the type of rock, drilling regime, formulation of the drilling fluid, technology to separate and clean cuttings, and other factors. However, in all cases, drilling fluids (muds) play the leading role in forming the composition of drilling cuttings.

No precise, standard formulation exists for drilling fluids. Their composition depends on the needs of the particular situations. These differ considerably in different regions and may even radically change during each drilling process while drilling rocks of very different structure (from solid granite formations to salt and slate strata). At present, two main types of drilling fluids are used in offshore drilling. They are based either on crude oil, oil products, and other mixtures of organic substances (diesel, paraffin oils, and so on) or on water (freshwater or seawater with bentonite, barite, and other components added). During the last 10 years, the preference is given to using the less-toxic water-based drilling fluids. However, in some cases, for example during drilling of deviated wells through hard rock, using oil-based fluids is still inevitable. The oil-based fluids, in contrast with the water-based ones, are usually not discharged overboard after a single application. Instead, they are regenerated and included in the technological circle again.

Practically all stages and operations of offshore hydrocarbon production are accompanied by undesirable discharges of liquid, solid, and gaseous wastes

Originally, the oil-based drilling muds included diesel fuel as their base component due to its availability and low cost. However, starting in the 1980s, especially after many countries prohibited the use of diesel in drilling muds, the oil companies started to develop new formulations that replaced diesel oil with less hazardous substances. Alternative drilling fluids are composed mainly from low-molecular-weight, less toxic and more water-soluble, aromatic compounds and substances of paraffin structure. Research in this direction continues at present. Products of animal, vegetable, or synthetic origin are tested in order to find the optimal base for drilling fluids.

Recently, a new generation of drilling fluids based on the products of chemical synthesis with ethers, esters, olefins, and polyalphaolefins has been developed [Burke, Veil, 1995]. Such drilling fluids allow highly deviational or horizontal drillings to be conducted.

From the environmental perspective, the most important fact is that they have low toxicity as compared with other drilling formulations. In spite of the relatively high cost of the synthetic-based drilling fluids, their technological and environmental advantages open wide possibilities for their effective use in oil and gas production.

Each component of a drilling fluid has one or several chemical and technological functions. For example, barite ($BaSO_4$) is used to control and regulate hydrostatic pressure in the well.

Emulsifiers (alkyl-acrylate sulfonate, alkylacryl sulfate, and others) form and maintain emulsions. Sodium and calcium chlorides create conditions for maintaining an isotonic osmotic balance between the water phase of the emulsion and surrounding formation water. Organophilic clays (such as amine treated bentonite clay) as well as organic polymers and polyacrylates ensure the optimal fluid viscosity necessary for drilling under different geological conditions. Sodium sulfite, ammonium bisulfite, zinc carbonate, and other oxygen scavengers are pumped into the well to prevent the corrosion of drilling equipment in the oxidizing environment. Lime is added to increase the pH of drilling fluids, which helps to reduce corrosion and stabilize the emulsions in the muds.

As a result of many technological operations and procedures, drilling muds and cuttings are saturated with hundreds of very different substances and compounds. It is their discharges into the sea that pose one of the main ecological threats during offshore oil production. In particular, many countries express concern regarding biocides, which are used to suppress microflora in the drilling and other circulating fluids. The list of such compounds includes over one hundred names. The most widespread biocides used in the oil and gas production practice include sodium salts of hypochlorite, formalin releasers, and glutaraldehyde as well as biguanidine and quaternary ammonium, and a number of other compounds.

The composition of some compounds is not always known. Some biocides are highly toxic. Many countries either discourage (for example, in case of carbamates and thiocarbamates) or prohibit (for example, in case of dichlorophenols and pentachlorophenates) their use by the offshore oil and gas industry.

Drilling discharges also contain many heavy metals (mercury, lead, cadmium, zinc, chromium, copper, and others) that come from components of both drilling fluids and drilling cuttings. Chapter 6 gives the ecotoxicological assessments and comparison of different drilling fluids and drilling cuttings.

Produced waters.

Produced waters usually include dissolved salts and organic compounds, oil hydrocarbons, trace metals, suspensions, and many other substances that are components of formation water from the reservoir or are used during drilling and other production operations. Besides, produced waters can mix with the extracted oil, gas, and injection waters from the wells. All of the above make the composition of the discharged produced waters very complex and changeable. It is practically impossible to speak about some average parameters of this composition, especially because reliable and complete analytical studies of these wastes are very rare.

Petroleum hydrocarbons are always present in produced waters, especially when the latter are mixed with other technological waters and solutions.

However, the levels of oil in discharges vary extremely. They depend not only on the specific technological situation but on the fractional composition of the oil and the effectiveness of the oil/water separation methods as well. The oil separators mainly remove particulate and dispersed oil, while dissolved hydrocarbons in concentrations from 20 mg/l to over 50 mg/l go overboard as part of the discharged waters [Somerville et al., 1987; GESAMP, 1993]. The volumes of such discharges reach thousands of tons of oil a year.

Another characteristic of the chemical composition of most produced waters is their very high mineralization.

It is usually higher than the seawater's salinity reaching up to 300 g/l. Such mineralization is caused by the presence of dissolved ions of sodium, potassium, magnesium, chloride, and sulfate in produced waters. Besides, produced waters often have elevated levels of some heavy metals [Neff et al., 1987] as well as corrosion inhibitors, descalers, biocides, dispersants, emulsion breakers, and other chemicals.

Recent studies have revealed that produced waters frequently contain naturally occurring radioactive elements and their daughter products, such as radium-226 and radium-228.

They are leached from the reservoir by formation waters and are carried to the surface with produced waters, oil, and gas. During contact with seawater, these radionuclides interact with sulfates, precipitate, and form a radioactive scale. In spite of a relatively low level of radioactivity, concern exists that this process can create centers of increased radioactive risk. This phenomenon has become a focus of attention in a number of countries. Applying the regulations defined by some international agreements, such as the London Dumping Convention (1972), that do not allow discharges of radioactive material into the marine environment are considered to be justified in this case [GESAMP, 1993].

Other wastes. Large quantities of produced waters, drilling muds, and drilling cuttings, discussed above, as well as discharges of storage displacement and ballast waters are the source of regular and long-term impacts of the offshore industry on the marine environment.

Besides these discharges, sometimes the need arises to conduct a one-time discharge of short duration. Such situations include, in particular, chemical discharges during construction, hydrostatic testing, commissioning, pigging, and maintenance of the pipeline systems.

The pipeline discharges usually contain corrosion and scale inhibitors, biocides, oxygen scavengers, and other agents. The volumes of these wastes can be rather considerable. In the North Sea, they reach up to 300,000 m3 of treated water discharged over a short period (hours to days) [GESAMP, 1993]. The discharge regime usually ensures that the dilution decreases the concentration and toxicity of the wastes to safe levels beyond a 500-meter radius from the place of discharge [Davies, Kingston, 1992].

Similar situations emerge during other technological and maintenance activities. Examples include cleaning and anticorrosion procedures, discharging the ballast waters from the hydrocarbon storage tanks, well repairing, well workover operations, replacing the equipment, and others. These discharges often contain surface-active substances, such as lignosulfonates, lignites, sulfo-methylated tannins, and many other chemicals with about a hundred names.

a technology was developed to remove the drilling wastes, especially cuttings, by reinjecting their slurry into a geological formation

Atmospheric emissions

Although the atmospheric emissions accompany most of the oil and gas operations, this factor has not gained any special attention in the context of offshore developments. The available information is very limited and controversial. At the same time, in some areas of onland production, for example in Western Siberia and near Astrakhan in Russia, this source of pollution poses a serious threat to the water and onland ecosystems and to human health. For example, in the Nizhnevartovki region (Tumen area), the atmospheric emission of hazardous substances from the Samotlorskoe oil field development in 1989-1992 varied from 0.38 million to 1.1 million tons a year [Krupinin, 1995].

The high content of hydrogen sulfide (6-30%) and other toxic substances in the natural gas and atmospheric emissions on the Orenburgskoe and Astrakhanskoe gas condensate fields created situations close to ecological catastrophes [Karamova, 1989].

Atmospheric emissions take place at all stages of oil and gas industry's activities. The main sources of these emissions include:

- constant or periodical burning of associated gas and excessive amounts of hydrocarbons during well testing and development as well as continuous flaring to eliminate gas from the storage tanks and pressure-controlling systems;
- combustion of gaseous and liquid fuel in the energetic units (diesel-powered generators and pumps, gas turbines, internal combustion engines) on the platforms, ships, and onshore facilities; and
- evaporation or venting of hydrocarbons during different operations of their production, treatment, transportation, and storage.

In spite of the fact that some countries now prohibit flaring of oil-associated gases, it remains one of the major sources of atmospheric emissions in the world. These gases are dissolved in the crude produced oil. As the pressure goes down, they bubble out in amounts up to 300 m3 for each ton of extracted oil.

The associated gases give about 30% of the gross world production of gaseous hydrocarbons. However, because of the undeveloped technology and lack of required capacities and equipment on many field developments, up to 25% of all associated gases are flared. In Russia alone, the volumes of annually burned (flared) oil-associated gases reach up to 10-17 billion cubic meters [VNIIP, 1994]. Astronauts have witnessed that the view of the gas-burning torches, for example above Western Siberia or the Persian Gulf, is an impressive proof of the large scale of human economic activity and, we would add, of its bad management as well.

Components of atmospheric pollution caused by oil and gas development include gaseous products of hydrocarbon evaporation and burning as well as aerosol particles of the unburned fuel.

From the ecological perspective, the most hazardous components are nitrogen and sulfur oxides, carbon monoxide, and the products of the incomplete burning of hydrocarbons. These interact with atmospheric moisture, transform under the influence of solar radiation, and precipitate onto the land and sea surfaces to form fields of local and regional pollution.

Clear evidence of the impact of atmospheric emissions on the marine environment from the offshore flaring was found, in particular, during well testing in the Canadian zone of the Beaufort Sea. Here, the ice surface around the test site where intensive flaring of combustible wastes occurred was polluted by atmospheric fallout of heavy oily residue. The chemical composition of the residue was similar to one of the higher-molecular-weight fractions of produced oil [GESAMP, 1993].

According to some estimates [Kingston, 1991], up to 30% of the hydrocarbons emitted into the atmosphere during well testing precipitate onto the sea surface and create distinctive and relatively unstable slicks around the offshore installations. The results of the aircraft observations in the North Sea indicate that such slicks are found with an average frequency of 1-2 cases per every hour of flight [ICES, 1995].

Technical means to rectify and prevent atmospheric pollution during offshore oil and gas production are practically identical to the analogous methods that are widely and often effectively used on land and in other industries.

However, offshore atmospheric emissions thus far have not gotten the deserved attention, probably due to the remoteness of these developments from densely populated places.

How oil drilling works?

In 2005 alone, the United States produced an estimated 9 million barrels of crude oil per day and imported 13.21 million barrels per day from other countries. This oil gets refined into gasoline, kerosene, heating oil and other products. To keep up with our consumption, oil companies must constantly look for new sources of petroleum, as well as improve the production of existing wells. How does a company go about finding oil and pumping it from the ground? You may have seen images of black crude oil gushing out of the ground, or seen an oil well in movies and television shows like "Giant," "Oklahoma Crude," "Armageddon" and "Beverly Hillbillies." But modern oil production is quite different from the way it's portrayed in the movies.

here we will examine how modern oil exploration and drilling works. We will discuss how oil is formed, found and extracted from the ground.

Oil is a fossil fuel that can be found in many countries around the world. In this section, we will discuss how oil is formed and how geologists find it.

Forming Oil

Oil is formed from the remains of tiny plants and animals (plankton) that died in ancient seas between 10 million and 600 million years ago. After the organisms died, they sank into the sand and mud at the bottom of the sea.

Over the years, the organisms decayed in the sedimentary layers. In these layers, there was little or no oxygen present. So microorganisms broke the remains into carbon-rich compounds that formed organic layers. The organic material mixed with the sediments, forming fine-grained shale, or source rock. As new sedimentary layers were deposited, they exerted intense pressure and heat on the source rock. The heat and pressure distilled the organic material into crude oil and natural gas. The oil flowed from the source rock and accumulated in thicker, more porous limestone or sandstone, called reservoir rock. Movements in the Earth trapped the oil and natural gas in the reservoir rocks between layers of impermeable rock, or cap rock, such as granite or marble.

These movements of the Earth include:

- Folding -Horizontal movements press inward and move the rock layers upward into a fold or anticline.
- Faulting -The layers of rock crack, and one side shifts upward or downward.
- Pinching out - A layer of impermeable rock is squeezed upward into the reservoir rock.

Finding Oil

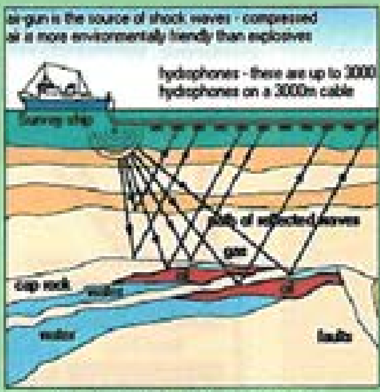
The task of finding oil is assigned to geologists, whether employed directly by an oil company or under contract from a private firm. Their task is to find the right conditions for an oil trap -- the right source rock, reservoir rock and entrapment. Many years ago, geologists interpreted surface features, surface rock and soil types, and perhaps some small core samples obtained by shallow drilling. Modern oil geologists also examine surface rocks and terrain, with the additional help of satellite images. However, they also use a variety of other methods to find oil. They can use sensitive gravity meters to measure tiny changes in the Earth's gravitational field that could indicate flowing oil, as well as sensitive magnetometers to measure tiny changes in the Earth's magnetic field caused by flowing oil.

They can detect the smell of hydrocarbons using sensitive electronic noses called sniffers. Finally, and most commonly, they use seismology, creating shock waves that pass through hidden rock layers and interpreting the waves that are reflected back to the surface.

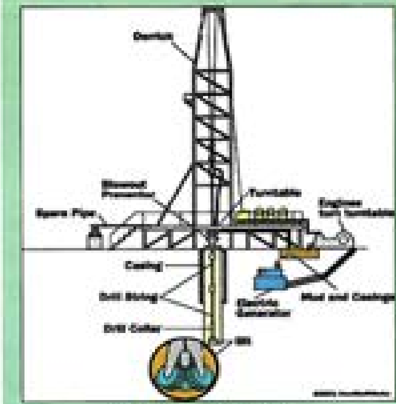
In seismic surveys, a shock wave is created by the following:

- Compressed-air gun - shoots pulses of air into the water (for exploration over water)
- Thumper truck - slams heavy plates into the ground (for exploration over land)
- Explosives - drilled into the ground (for exploration over land) or thrown

Close-up of reservoir rock (oil is in black)



Searching for oil over water using seismology



Anatomy of an oil rig

overboard (for exploration over water), and detonated

The shock waves travel beneath the surface of the Earth and are reflected back by the various rock layers. The reflections travel at different speeds depending upon the type or density of rock layers through which they must pass. The reflections of the shock waves are detected by sensitive microphones or vibration detectors-hydrophones over water, seismometers over land.

The readings are interpreted by seismologists for signs of oil and gas traps.

Although modern oil-exploration methods are better than previous ones, they still may have only a 10-percent success rate for finding new oil fields. Once a prospective oil strike is found, the location is marked by GPS coordinates on land or by marker buoys on water.

Preparing to Drill

Once the site has been selected, it must be surveyed to determine its boundaries, and environmental impact studies may be done. Lease agreements, titles and right-of way accesses for the land must be obtained and evaluated legally. For off-shore sites, legal jurisdiction must be determined.

Once the legal issues have been settled, the crew goes about preparing the land:

1. The land is cleared and leveled, and access roads may be built.

2. Because water is used in drilling, there must be a source of water nearby. If there is no natural source, they drill a water well.

3.They dig a reserve pit, which is used to dispose of rock cuttings and drilling mud during the drilling process, and line it with plastic to protect the environment. If the site is an ecologically sensitive area, such as a marsh or wilderness, then the cuttings and mud must be disposed offsite - trucked away instead of placed in a pit.

Once the land has been prepared, several holes must be dug to make way for the rig and the main hole. A rectangular pit, called a cellar, is dug around the location of the actual drilling hole. The cellar provides a work space around the hole, for the workers and drilling accessories. The crew then begins drilling the main hole, often with a small drill truck rather than the main rig.

The first part of the hole is larger and shallower than the main portion, and is lined with a large-diameter conductor pipe. Additional holes are dug off to the side to temporarily store equipment when these holes are finished, the rig equipment can be brought in and set up. Depending upon the remoteness of the drill site and its access, equipment may be transported to the site by truck, helicopter or barge. Some rigs are built on ships or barges for work on inland water where there is no foundation to support a rig (as in marshes or lakes).

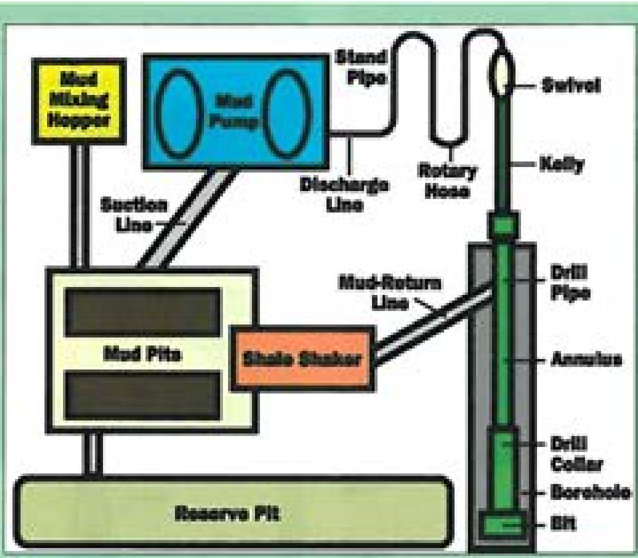
In the next section, we'll look at the major systems of an oil rig.

Oil Rig Systems

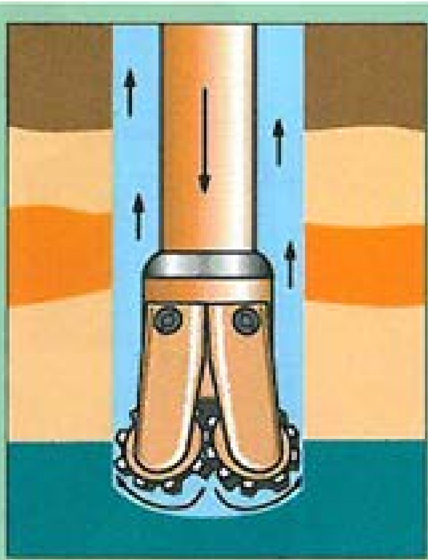
Once the equipment is at the site, the rig is set up. Here are the major systems of a land oil rig:

Power system

- large diesel engines - burn diesel-fuel oil to provide the main source of power



Drill-mud circulation system


Mud circulation in the hole

• electrical generators - powered by the diesel engines to provide electrical power

• Mechanical system - driven by electric motors

• hoisting system - used for lifting heavy loads; consists of a mechanical winch (drawworks) with a large steel cable spool, a block-and-tackle pulley and a receiving storage reel for the cable

• turntable - part of the drilling apparatus

• Rotating equipment - used for rotary drilling

• swivel - large handle that holds the weight of the drill string; allows the string to rotate and makes a pressure-tight seal on the hole

• kelly - four- or six-sided pipe that transfers rotary motion to the turntable and drill string

• turntable or rotary table - drives the rotating motion using power from electric motors

• drill string - consists of drill pipe (connected sections of about 30 ft / 10 m) and drill collars (larger diameter, heavier pipe that fits around the drill pipe and places weight on the drill bit)

• drill bit(s) - end of the drill that actually cuts up the rock; comes in many shapes and materials (tungsten carbide steel, diamond) that are specialized for various drilling tasks and rock formations

• Casing - large-diameter concrete pipe that lines the drill hole, prevents the hole from collapsing, and allows drilling mud to circulate

• Circulation system - pumps drilling mud (mixture of water, clay, weighting material and chemicals, used to lift rock cuttings from the drill bit to the surface) under pressure through the kelly, rotary table, drill pipes and drill collars

• pump - sucks mud from the mud pits and pumps it to the drilling apparatus

• pipes and hoses - connects pump to drilling apparatus

• mud-return line - returns mud from hole

• shale shaker - shaker/sieve that separates rock cuttings from the mud

• shale slide - conveys cuttings to the reserve pit

• reserve pit - collects rock cuttings separated from the mud

• mud pits - where drilling mud is mixed and recycled

• mud-mixing hopper - where new mud is mixed and then sent to the mud pits

• Derrick - support structure that holds the drilling apparatus; tall enough to allow new sections of drill pipe to be added to the drilling apparatus as drilling progresses

• Blowout preventer - high-pressure valves (located under the land rig or on the sea floor) that seal the high-pressure drill lines and relieve pressure when necessary to prevent a blowout (uncontrolled gush of gas or oil to the surface, often associated with fire)

Drilling

The crew sets up the rig and starts the drilling operations. First, from the starter hole, they drill a surface hole down to a pre-set depth, which is somewhere above where they think the oil trap is located. There are five basic steps to drilling the surface hole:

1. Place the drill bit, collar and drill pipe in the hole.

2. Attach the kelly and turntable and begin drilling.

3. As drilling progresses, circulate mud through the pipe and out of the bit to float the rock cuttings out of the hole.

4. Add new sections (joints) of drill pipes as the hole gets deeper.

5. Remove (trip out) the drill pipe, collar and bit when the pre-set depth (anywhere from a few hundred to a couple-thousand feet) is reached.

Once they reach the pre-set depth, they must run and cement the casing - place casing-pipe sections into the hole to prevent it from collapsing in on itself.

The casing pipe has spacers around the outside to keep it centered in the hole.

The casing crew puts the casing pipe in the hole. The cement crew pumps cement down the casing pipe using a bottom plug, a cement slurry, a top plug and drill mud. The pressure from the drill mud causes the cement slurry to move through the casing and fill the space between the outside of the casing and the hole. Finally, the cement is allowed to harden and then tested for such properties as hardness, alignment and a proper seal.

In the next section we'll find out what happens once the drill bit reaches the final depth.

Testing for Oil

Drilling continues in stages: They drill, then run and cement new casings, then drill again. When the rock cuttings from the mud reveal the oil sand from the reservoir rock, they may have reached the final depth. At this point, they remove the drilling apparatus from the hole and perform several tests to confirm this finding:

- Well logging - lowering electrical and gas sensors into the hole to take measurements of the rock formations there
- Drill-stem testing - lowering a device into the hole to measure the pressures, which will reveal whether reservoir rock has been reached
- Core samples - taking samples of rock to look for characteristics of reservoir rock

Once they have reached the final depth, the crew completes the well to allow oil to flow into the casing in a controlled manner. First, they lower a perforating gun into the well to the production depth. The gun has explosive charges to create holes in the casing through which oil can flow. After the casing has been perforated, they run a small-diameter pipe (tubing) into the hole as a conduit for oil and gas to flow up the well. A device called a packer is run down the outside of the tubing. When the packer is set at the production level, it is expanded to form a seal around the outside of the tubing. Finally, they connect a multi-valved structure called a Christmas tree to the top of the tubing and cement it to the top of the casing. The Christmas tree allows them to control the flow of oil from the well.

Once the well is completed, they must start the flow of oil into the well. For limestone reservoir rock, acid is pumped down the well and out the perforations. The acid dissolves channels in the limestone that lead oil into the well. For sandstone reservoir rock, a specially blended fluid containing proppants (sand, walnut shells, aluminum pellets) is pumped down the well and out the perforations. The pressure from this fluid makes small fractures in the sandstone that allow oil to flow into the well, while the proppants hold these fractures open. Once the oil is flowing, the oil rig is removed from the site and production equipment is set up to extract the oil from the well.

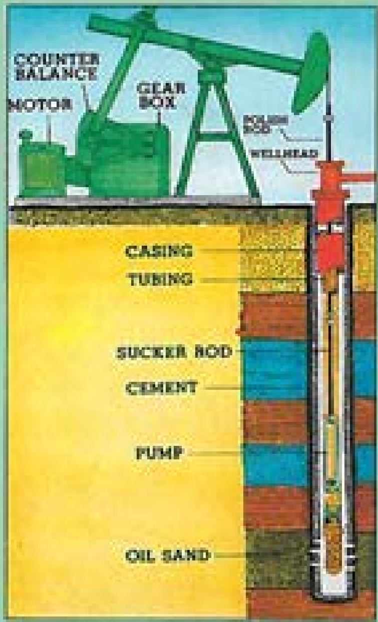
Extracting the Oil

After the rig is removed, a pump is placed on the well head.

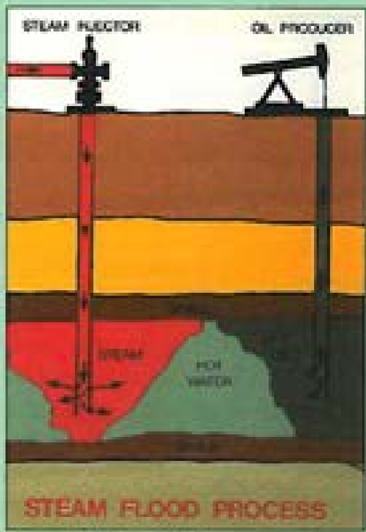
In the pump system, an electric motor drives a gear box that moves a lever. The lever pushes and pulls a polishing rod up and down. The polishing rod is attached to a sucker rod, which is attached to a pump. This system forces the pump up and down, creating a suction that draws oil up through the well.

In some cases, the oil may be too heavy to flow. A second hole is then drilled into the reservoir and steam is injected under pressure. The heat from the steam thins the oil in the reservoir, and the pressure helps push it up the well. This process is called enhanced oil recovery.

With all of this oil-drilling technology in use, and new methods in development, the question remains: Will we have enough oil to meet our needs? Current estimates suggest that we have enough oil for about 63 to 95 years to come, based on current and future finds and present demands.



Pump on an oil well



Enhanced oil recovery

EDUCATION

Some Basic Energy Information

There has been an enormous rise in energy demand since the middle of the last century. That increase has resulted from not only rapid industrial development but also population growth.

Between 1850 and 1970, world population multiplied by 3.2 times, and total energy use increased more than 12-fold.

Despite the importance of energy to every aspect of our lives, many Americans are not adequately armed with the basic energy knowledge to make informed decisions or determine what can be done to manage and conserve energy resources. In this article, we'll attempt to provide teachers with some basic energy information. We've done our best to highlight key points in an impartial manner. But with an issue this complex and dynamic, it's not possible to cover everything in an article of this length. Energy is indeed "fuel for thought" and will continue to be so for many years to come.

The poster back includes hands-on activities related to alternative energy resources and other activities that will help students develop their understanding of energy, its importance to and impact on our world, and the tough decisions that they - as our future scientists, policymakers, and voters - might have to face.

The Current Picture

More than 90 percent of the energy produced and consumed in the world today is from nonrenewable sources. Such resources as coal, oil, natural gas, and the uranium used for nuclear power cannot be replaced as they are used, or can only be replaced very slowly by natural processes. Each of these sources has both benefits and drawbacks in terms of the ways it can be used, the jobs it provides, and the effects it has on the environment. For example, today most fossil fuels are relatively plentiful and inexpensive. But combustion of fossil fuels generates numerous air pollutants as well as gases that may contribute to global climate change.

Now, let's take a quick look at each of the traditional energy resources.

Coal was formed from the remains of plants that lived in vast swamps some 350 million years ago. The decay of

Northeast Wyoming's Powder River Basin is the largest coal-producing region in the United States, comprising thick seams of low-sulfur coal overlain by minimal overburden. This field produced 354 million tons of coal in 2001.

the plants in these swamps (similar to today's peat bogs) provided the carbon-rich materials that were subsequently buried under sediments. Over time, the sediments became rock and their weight generated heat and pressure on the material below, transforming the carbon of the decayed plants into coal.

The United States, with about 25 percent of the world's coal reserves, uses this plentiful and cheap fossil fuel primarily to generate electricity. However, coal is also used as a primary energy source on many industries, including steel, cement, and paper. Over its long history, coal mining has posed hazards not only to its workforce but also to the environment. thanks to stricter regulations, improvements have been made, but disturbances to soil, water, vegetation, and other resources during extraction can still be significant. The burning of coal at electric-generating plants also contributes to air particulates and acid rain. With modern technologies and tighter controls, it is possible to remove some noxious gases, but coal is still responsible for some 35 percent of world carbon dioxide emissions from fossil fuels.

Petroleum formed from the remains of tiny organisms that lived in seas and rivers millions of years ago. As in the coal-formation process, burial by sediments prevented the remains from rotting, and heat and pressure turned them into what we know as petroleum or crude oil. Oil is a versatile liquid that serves as the lifeblood of our transportation system: In the United States, more than half of it is refined into gasoline, jet fuel, and diesel fuel. Heating oil and propane are also derived from petroleum, as are a wide range of other products, from plastics and tires to synthetic fabrics and crayons. Petroleum, however, has a major drawback–it can spill. Tanker spills during ocean transport can significantly impact marine and coastal environments over a wide area. Even more oil is spilled each year during and after use, and via storm runoff.

In August 2001 alone, the Madden Gas Field in Central Wyoming's Wind River Basin produced over 236 million cubic feet of natural gas per day from six formations at depths of 900 to 7,700 m.

Of concern to the United States in particular is the fact that only about two percent of the world's oil reserves lie within its borders. If demand continues to rise, the United States could be importing two-thirds of its oil by 2010.

New technologies that allow for enhanced recovery from existing oil wells, along with drilling in new areas, may provide additional domestic supplies, but reliance on foreign supplies will almost certainly continue for the foreseeable future.

Natural gas was formed in much the same way as petroleum; in general, higher temperatures and greater pressures underground favored the formation of natural gas. Used to heat more than half the homes in the United States, natural gas is also the fuel of choice for many industries. Like petroleum, natural gas is a vital raw material for various products, including fertilizers, plastics, and medicines. Compared to petroleum and coal, natural gas burns much more cleanly. On the negative side of the ledger, natural gas is composed primarily of methane, one of the greenhouse gases that may contribute to global climate change. Also, leaks from natural gas pipelines and storage facilities may release enough methane to counteract its "clean-burning" advantage.

Nuclear energy is also considered "traditional"–at least since 1945. Nuclear energy comes from nuclear fission, the splitting of the atom. Only a few naturally occurring isotopes, such as uranium-235 and plutonium-239, are easily fissionable. Nuclear energy is used primarily to produce electricity. Just as in a fossil-fuel-powered plant, heat (from fission) boils water, which creates steam that turns a turbine-generator. Since there is no carbon and no burning takes place, nuclear power does not emit carbon dioxide into the atmosphere.

But other health and environmental hazards are associated with nuclear power. From mining of uranium through fuel processing to waste disposal, the use of nuclear energy involves radioactive material. Exposure to radiation can cause genetic mutations, serious illness, and even death. The threat of accidents and the possibility that nuclear materials could get into the wrong hands contribute substantially to public fears about this resource. Even the normal operation of a nuclear power plant creates low-level radioactive waste in the form of ordinary trash, tools, clothing, and other contaminated items that must be carefully isolated from other materials.

No long-term solution to the disposal of highly irradiated spent fuel assemblies has yet been widely accepted. Currently, all spent fuel in the United States is stored at the power plant at which it was used. However, in February 2002, the President recommended to Congress that a geologic repository at Yucca Mountain in Nevada be developed as a disposal site for spent fuel and other high-level nuclear waste.

Hydropower is a traditional energy source that provides a notable amount of electricity and other power worldwide.

Since it is a form of renewable energy, however, it is covered in the section that follows.

For the foreseeable future, fossil fuels will continue to power our planet. There is little doubt that demand for energy will continue to grow. But as traditional resources become depleted and as concerns grow about their impact on the environment, the quest for alternative energy sources becomes more compelling.

Powering the Next Generation

Almost all renewable energy resources originate in the sun. Non-hydropower renewable energy currently accounts for only four percent of U.S. energy and two percent of the electricity supply.

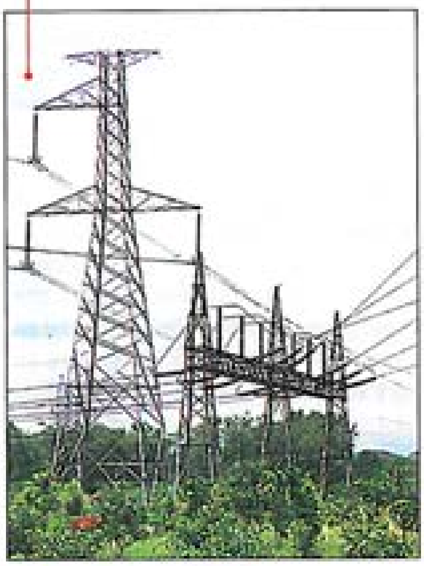
Hydropower provides an additional 10 percent of production and seven percent of electricity. In the last decade, the growth in U.S. renewable energy production outpaced all sources except for nuclear energy.

Barriers to renewable energy development include high up-front costs and higher power costs. For example, electricity produced from natural gas currently costs three cents per kilowatt-hour, compared to about six cents for solar energy. But the generating costs for renewable energy are shrinking, and surveys show that Americans are increasingly supportive of non-polluting power.

Hydropower

Ancient peoples used the energy in flowing water to operate machinery. Today, U.S. hydropower is used primarily to produce electricity, especially in the western states.

The Trans-Alaska Pipeline, which is about 1.2 m in diameter, has carried more than 11 billion barrels of oil 1,280 km across Alaska from the North Slope to the Port of Valdez, crossing three mountain ranges and more than 800 rivers and streams along the way. After six years of preconstruction effort, the pipeline took about three years to construct, requiring 515 federal permits.



Hydropower is produced by channeling the flow of rivers or by storing water in reservoirs behind dams and directing it through turbines. There is no pollution of the types associated with the burning of fossil fuels. Hydropower is clean, renewable, and domestically produced, yet it supplies less than 20 percent of the world's electricity. Advocates of hydropower cite the recreational benefits derived from reservoirs and the provision of water for irrigation.

On the other hand, dams disrupt river ecosystems, causing upstream flooding and downstream flow depletion. Water redistribution adversely affects many habitats and can make it impossible for anadromous fish such as salmon to travel upstream to spawn. Though fish ladders have helped mitigate this problem, there is still growing public opposition to dams.

Solar Energy

This most basic source of energy is produced in the sun's core by nuclear fusion. The slight mass lost in this process is emitted as radiant energy; though less than one percent of it reaches the Earth, in 30 minutes it can provide a year's worth of human energy needs. The amount of solar energy a specific place receives depends on such factors as the season and proximity to the equator.

Humans have long used sunlight to cook food and heat water and homes. Today, solar energy is still used for those purposes and to provide hot water for industries such as laundries.

Photovoltaic cells, made of semiconducting materials, are used to collect solar energy and generate electricity.

Solar electrical plants are not suited to locations with scarce or unreliable sunlight. Large solar plants can also involve clearing of land for infrastructural components.

Wind Energy

Wind is moving air produced by uneven solar heating of the Earth's surface. Wind power has long been used for grinding grain and pumping groundwater.

Windmills' modern equivalent, tall wind turbines, use wind energy to generate electricity. Turbines catch the wind with blades mounted around a shaft to form a rotor. On the downwind side of the blade, blowing wind forms a low-pressure pocket, which pulls the blade, turning the rotor to spin an electrical generator.

Wind power is now the fastest-growing energy source worldwide. However, land clearing for vast "wind farms" may produce environmental concerns. Many predict that wind energy will provide more U.S. electrical production as new turbine designs enhance economic and environmental viability.

Geothermal Energy

Geothermal energy comes from intense heat within the Earth, which also produces hot springs, geysers, and volcanoes.

Geothermal resources are found where the Earth's crust is relatively thin.

The only widely used type of geothermal energy is hydrothermal, produced when subsurface water contacts hot rock and turns to steam, which is piped to the surface. In some cases, water or steam is used directly to heat homes or provide process heat for businesses. In a typical geothermal electric plant, steam is piped to a turbine to power an electrical generator.

Geothermal development has disadvantages, particularly the hydrogen sulfide gas emitted during extraction. Many of the same environmental concerns surrounding exploitation of oil and gas may also impact the development of geothermal resources, which must be similarly drilled and piped to the point of use. The advantage to geothermal energy, however, is that it does not produce pollution when used.

Biomass, Biopower

Biomass is any modern organic matter used as an energy source. The most common examples are wood, bioenergy crops, and organic wastes such as agricultural residues. Unlike other renewable energy sources, biomass can be burned or converted directly into liquid biofuels.

All biomass is solar energy transformed through photosynthesis. Biomass energy is usually released by burning, and less often by bacterial decay and fermentation. If vegetation is regrown as biomass is used, the net release of carbon dioxide due to the burning of biomass is zero.

Today, wood stoves are used worldwide for heating and cooking, making biomass one of the most common energy resources. Biopower is the burning of biomass to generate electricity. Waste-to- energy biopower plants use organic garbage as a feedstock, which reduces the amount of waste entering landfills.

Toxic substances may enter the atmosphere when municipal waste is incinerated, so contaminants should be removed for treatment before waste incineration. As landfill sites become harder to find, waste-to-energy plants may be an increasingly attractive option.

Biofuels

Alternative fuels offer another application for biomass technology. Crops can be fermented to produce liquid biofuels, the most common of which are ethanol and methanol. Today these alcohols are relatively high-cost, and oil prices would have to double to make them a cost-effective alternative. But gasohol, a mixture of just 10 percent ethanol and 90 percent gasoline, is highly cost-competitive and can be used in a traditional gasoline engine. It also has higher octane than gasoline and is far cleaner-burning. The air pollution savings from the increased use of ethanol and/or gasohol could be significant.

Scientists debate the consequences and benefits of genetically modified crops and forests that are managed for biomass resources.

Biogas

Biogas is methane produced from animal waste and by the decay of organic garbage. Because of current natural gas prices, biogas is usually flared as waste.

Located on the Columbia River between Oregon and Washington, the Bonneville Dam has been in operation since 1938. The dam is one of many that provide hydroelectric power to the Pacific Northwest.

More productive uses include onsite burning of biogas for heating of livestock barns and greenhouses.

Most experts agree that with some additional guidelines and new technologies, biomass can be part of a "greener" U.S. power portfolio.

Hydrogen (Fuel Cells)

Fuel cells chemically convert pure hydrogen or hydrogen-rich fuel into electricity, a process so efficient that 80 percent of the fuel's energy is used. Currently, the most economical hydrogen sources for fuel cells are hydrocarbons. When pure hydrogen is used, a fuel cell produces only electricity and water.

First used in the U.S. space program, fuel cells resemble batteries. Electricity is produced by a chemical reaction between a hydrogen-based fuel and an oxidant inside the fuel cell. Fuel cells can produce electricity as long as they are supplied with fuel.

Fuel cells can be used in applications ranging from electric vehicles to large power plants. Fuel cell power plants tend to have fewer emissions than traditional power plants, even when fossil fuels are used as a hydrogen source, so are well suited to congested urban areas.

Overall cost reductions must be achieved before fuel cells are competitive with internal combustion engines, and the size and weight of fuel cell systems must be decreased to accommodate consumer vehicles. Significant research and development have already been completed, and the automobile industry is aggressively exploring fuel cells.

Using Less, Doing More

Balanced community energy plans incorporate conservation and efficiency initiatives.The challenge is usually not one of inadequate technology but of public misperception and persistent behaviors.

The key is finding the right blend of education, incentives,and regulation to encourage communities to use approaches that have already proven effective.

Practicing "The Three <Rs'"-Reduce usage and potential waste; Reuse (rather than discard) materials; and Recycle materials-helps households and businesses to save energy. Along with lessening landfill waste and conserving natural resources, following the Three Rs decreases pollution by reducing the need to manufacture, distribute, and use materials from raw resources.

In 1999, for example, U.S. recycling activities prevented about 64 million tons of materials from ending up as waste. Curbside recycling programs served roughly half the U.S. population.

Some communities even have "pay-as-you-throw" programs, with waste collection fees based on the amount discarded—a direct economic incentive to generate less waste.

Today, the United States recycles 28 percent of its waste, almost double the level of 15 years ago. Recycling of specific materials, such as aluminum, has

During non-winter months, solar photovoltaic arrays provide clean, quiet electricity for bunkhouses, storage sheds, and other buildings at BLM's remote Chicken, Alaska, Field Station.

grown even more. Purchasing recycled materials closes the recycling loop and makes recycling programs successful.

Energy efficiency increases when energy conversion devices, such as appliances or car engines, undergo technical changes that allow them to provide the same service while using less energy.

Residential and commercial buildings account for more than a third of U.S. energy demand. The energy efficiency of buildings can be enhanced through the use of insulation, appropriate landscaping, and design improvements.

For example, super-insulated houses in bitterly cold climates stay comfortable using only their occupants' body heat. More than 100,000 such houses now exist worldwide.

Efficient lighting saves on air conditioning and electricity. Compact fluorescent light bulbs (CFLs) are cooler-burning, and use only one-fourth the energy of standard bulbs. While initially expensive, CFLs soon pay for themselves via reduced energy bills, and they last 10 times as long as standard bulbs. Most commercial building owners still are not taking full advantage of such efficient technologies unless local utilities provide financial incentives.

Air conditioners and other appliances need not squander energy either. Today's most efficient new appliances typically use half the energy of the most wasteful appliances. The average U.S. household could reduce its energy bills if it maximized use of efficient appliances, which would also result in notable savings in greenhouse gas emissions. Homeowners can evaluate their homes' energy efficiency via the U.S. Department of Energy's website at www.homeenergysaver.lbl.gov.

Excellent opportunities also exist to lessen vehicles' use of fossil fuels, including raising federal Corporate Average Fuel Economy (CAFE) standards for gasoline-powered cars and light trucks. New hybrid cars can achieve an impressive 112 km per gallon using a combination of gas and electric drive trains and ultra-light bodies.

Even high fuel prices haven't changed Americans' car-buying or driving habits. Car sales are on a record pace, and customers are still buying mostly trucks and sport utility vehicles (classified as light trucks for purposes of CAFE). According to The New York Times, 1996 was the first year in which the cars entering junk-yards actually got better mileage than those rolling off dealer lots.

People also tend to drive alone: Half of the savings due to automobile fuel efficiency increases from 1972 to 1992 were canceled out by decreases in vehicle occupancy. Greater dissemination of car-pool and public transportation information to commuters, as well as employer-provided incentives, would help to lower the number of single-occupancy cars on the road.

For most industries, energy is a small part of operating costs, so there is little incentive to conserve. But cogeneration is an area where industry could save both energy and money. Process steam from boilers can do double duty, first for the industrial process and then to run a turbine for electricity. This allows up to 90 percent of the energy in fuel to be used productively.

Providing electricity, light, heat, or mechanical energy near their point of use lessens the need for transmission lines and pipelines. Such "distributed" energy may use renewable resources, or it may incorporate alternative uses of traditional energy, such as natural gas micro-turbines for small businesses.

The wood chip gasifier at Vermont's 50 megawatt McNeil Generating Station can process 200 tons of wood chips per day. Hot sand is used to heat the wood chips to about 830°C, at which point the wood breaks apart into its constituent chemicals. The result is a clean-burning gas that fuels a turbine to produce electricity.

Cosponsored by the Department of Energy and the Ford Motor Company, the "FutureTruck" competition challenges student teams from top North American universities to reengineer sport utility vehicles for low emissions and improved fuel economy. Teams employ cutting-edge automotive technologies, including fuel cells and alternative fuels, to retain vehicle performance, utility, safety, and affordability.

Energizing Opportunities

The issue of how best to meet the world's energy demands is complicated. Energy education and literacy are key to the process: Only an informed public can make useful contributions to discussions of energy issues.

Economic, environmental, and behavioral factors must be considered simultaneously, so we often face tough choices beyond a simple "either/or." And the choices we make will have an enormous effect on the kind of world we leave to future generations.

Fortunately, we are also presented with vast opportunities to make a difference today. Studying and working with energy sources can help us develop a new sensitivity to the flow of energy in the world around us, and a deeper appreciation for energy's interconnected elements and impacts.

There are almost limitless possibilities for scientific exploration and innovation in the fields of energy technology, energy efficiency, and conservation, especially as applied to renewable and alternative energy resources.

Energy use and conservation are areas where individuals of almost any age can have an immediate, positive impact on our world. In fact, in many cases, concerned students are actually leading their parents, teachers, and other adults to a greater awareness of the environmental, economic, and other impacts and benefits that can result from personal behaviors. In this regard, energy can provide an arena in which young people can show the way.

In some cases, energy conservation in buildings can be achieved via measures taken outside their walls. Here, students are planting shade trees near their Sacramento, California, school to help reduce the need for energy-gobbling air conditioning.

Teams of middle school students ready their solar-powered model race cars at the annual Colorado Junior Solar Sprint. The Colorado competition is part of the National Junior Solar Sprint, a classroom-based, hands-on educational program sponsored by DOE's National Renewable Energy Laboratory.

Seaway extending global reach with rapid transit heavy-lift vessel

North sea platform construction has tailed off over recent years, causing Seaway Heavy Lifting to shift its focus. Currently, it is more active in the Mediterranean, Middle East, and India, but in 2010, it aims to go global.

The vehicle for this campaign is the Oleg Strashnov, a heavy-lift monohull crane vessel under construction at the Merwede Shipyard, close to Rotterdam.

"Their price was more expensive than what you might expect from a Far East yard, but we were more confident in the quality of their work, and their ability to deliver the vessel on time," says Richard den Hollander, Seaway's Marketing Manager, Middle East & India. "After the sea trials, we aim to go straight to an offshore project in 2010."

The Oleg Strashnov will be capable of 5000-metric-ton (5,511-ton) single lifts, either on anchors or in dynamic positioning mode, and its novel hull shape should allow it to reach transit speeds of up to 14 knots. This is 5 knotes faster than Seaway Heavy Lifting's existing crane vessel, the Stanislav Yudin, already one of the fastest construction vessels around, according to den Hollander. At that pace, the new vessel could transfer swiftly between far-flung locations, allowing Seaway Heavy Lifting to pitch for mid-size istallation jobs anywhere in the world.

The concept had been on the drawing-board for some time before Gusto MSC started conceptual engineering studies in mid-2005. Seaway Heavy Lifting contracted Wartsila for the engines and propulsion equipment in summer 2006, but only awarded the main vessel construction contract 2007 spring.

"We took our time about going out to tender," den Hollander says, "because we wanted a good handle on what we needed to order to ensure that the vessel had the highest quality equipment and a more reliable delivery date and end price. We also commissioned model tests with Marin in Holland to verify the vessel's speed and dynamic behavior, and the results confirmed our computer model."

Investment timing was driven by market trends, he adds. "What we saw was that the environment was becoming more and more important in terms of limiting gas flaring , CO2 emissions and so on, resulting in heavier topsides. Also, the operators were looking to develop more complicated fields in new production areas more remote from the traditional energy provinces. Both those factors were creating a need for more processing equiopment on platforms. At the same time, offshore hook-up was becoming very, very expensive, with a lack of specialist labor complicating matters for fabricators.

"If however, a vessel were available for 5,000 metric ton(5,511 ton) lifts-below the normal volume range of the largest crane barges- we flet this could be a great advantage for companies looking to develop isolated fields in remote areas provided the vessel had a very high transit speed."

Seaway claims this will be archieved by means of the patented hull-shape. The vessel will be 183m(600ft) long, with a breadth of 47 m (154 ft), and a draught varying from 8.5 m(27.9 ft) while in transit up to 13.5 m(44.3 ft)on location.

Its fully revolving offshore crane, also designed by Gusto MSC,will be equipped for lift heights of 100 m(328 ft) for the 5,000 metric ton(5,511 ton) main hook, and 132 m(433 ft) for the 800 metric ton (882 ton) auxiliary hook. This represents the highest hook heights attainable for monohull crane vessels and will facilitate a range of tasks, from dual hook upending of large jackets to heavy deck installations and deepwater templates, as well as smaller modules at high platform elevations, the company says.

Power will be provided by six 4.5 MW main engines, with two 5 MW azimuthing underwater aft propulsion thrusters, two 3.5 MW

SPECIAL REPORT

Seaway Heavy Lifting

azimuthing DP thrusters amidships, and two 1 MW bow thrusters. The Kongsberg DP-3 system will ease the installation of heavy topsides and deepwater structures such as templates, TLP/spar foundations, as well as the more traditional lifts in infrastructure –congested fields. The eight–point-mooring system comprises 2,200 m (7,218 ft) long mooring wires and 15 metric ton (16.54 ton) Delta Filper anchors.

At peak periods, the vessel will be able to accommodate 395 personnel.Although it is being offered primarily as a heavy lift vessel, space also has been left for an underdeck firing line, with the capacity to accommodate heavy J-lay equipment.

The Oleg Strashnov will have a design life of 40 years, and Seaway Heavy Lifting is looking for payback on its investment within a reasonable time, den Hollander says. Market reception so far looks promising, he adds. "We have had already quite a lot of attention from oil companies, both IOCs and NOCs, about its availability," den Hollander says.

In preparation for the new vessel, Seaway Heavy Lifting has been stepping up recruitment. Staff numbers at headquarters in Zoetermeer, close to The Haugue, have increased, with icreasing numbers set to be hired over the next 18 month. The company is on the hook-out in particular for project managers, project engineers and structural engineers. "Ultimately," says den Hollander,"we will grow to around 150 office staff when have the new vessel in operation.

"Over the last few years, this has been a company where people were strongly focused on working closely together to get the job done in an informal environment and thus creating an excellent atmosphere. We have a very low turnover of staff, and our people are highly motivated. They have had opportunities in recent years to work in Middle East, Mediterranean, India, as well as the North Sea, and that simulation keeps the work and the company attractive for them."

South Pars phases 9 & 10 topsides installation by the Stanislav Yudin

To date SHL (Seaway Heavy Lifting) has been involved in all the offshore phases of the South Pars development. In December 2007, SHL utilised the Stanislav Yudin and successfully carried out SPD10 and SPD11 topsides installation for phases 9 and 10 respectively of POGC's South Pars development.

SHL's client, IOEC, successfully provided the structures safely to the offshore sites ensuring no valuable offshore installation time of the marine spread was lost.
At both locations SHL's scope consisted of:

- removal of temporary drilling decks
- installation of guiding system for safe installation of topsides protecting the conductors
- installation of topsides weighing close to 2400mT
- installation of heli-decks
- installation of bridges weighing 170mT
- miscellaneous completion works

The structures were designed and built by IOEC using high strength steel (420MPa) being one of the success factors in keeping the weight within limits thus enabling the Stanislav Yudin to install the topsides.

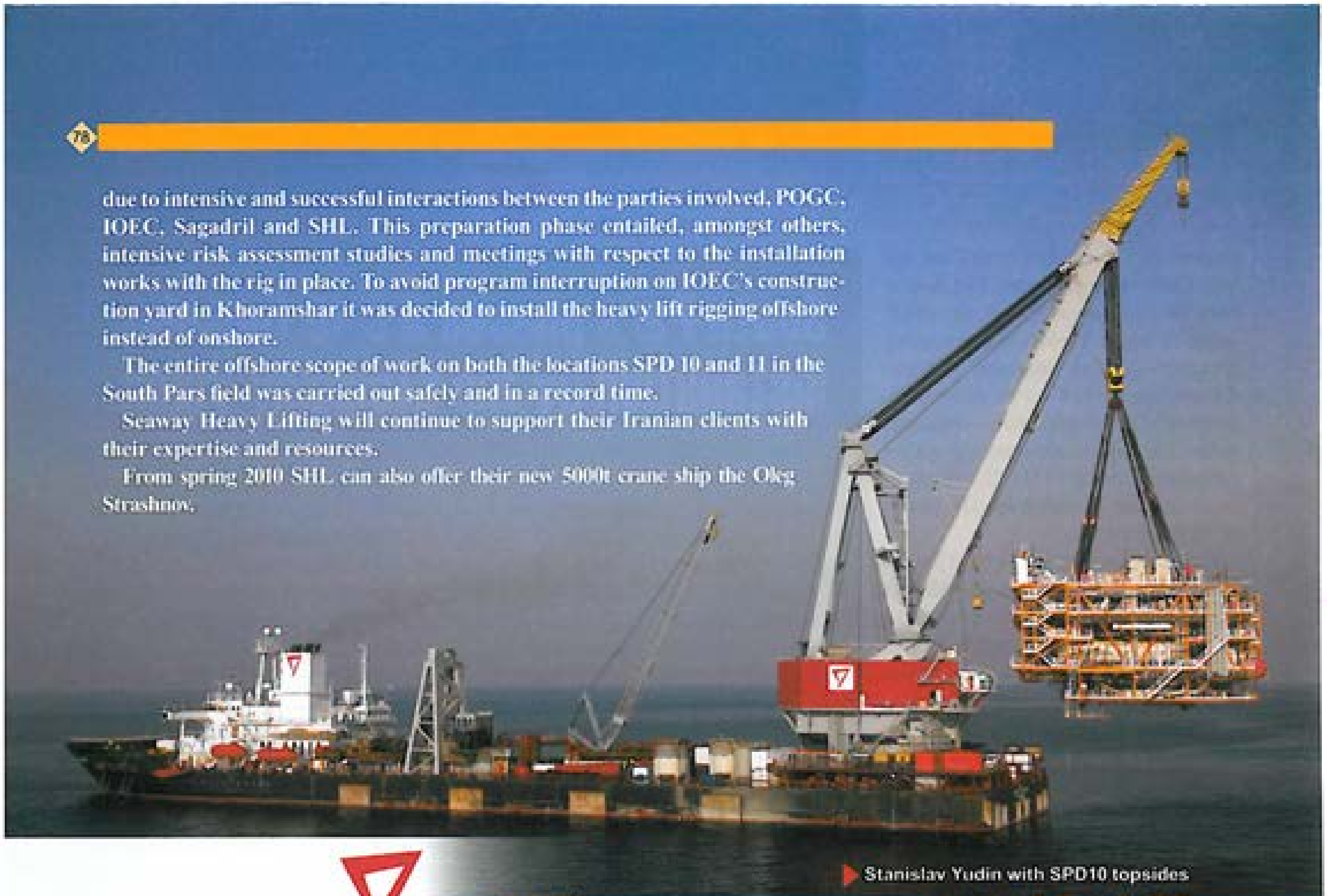
From an installation point of view there were three main challenges, namely:

1 - topsides weight & size
2 - installation without demobilizing the drill rig
3 - schedule for drill rig and crane ship

IOEC managed to meet the criteria of the first challenge and as a result the second challenge could be met by mobilising the Stanislav Yudin which, with its revolving capability, was able to install the topsides without demobilising the drill rig "SAGADRIL 2".

With respect to the drilling operations and also the overall project cost and risks, utilising the Stanislav Yudin saved a mobilisation and demobilisation of the rig and even of more importance, avoided repositioning of the rig at its existing seabed impressions, which is always a difficult and risky operation. For an operation with a drill rig in place, a crane ship with revolving capacity is necessary due to its ability to manoeuvre with precision when approaching the drill rig and the jacket with its conductors elevated above the jacket. The third challenge was met

SPD 10 jacket and Sagadrill 2



due to intensive and successful interactions between the parties involved, POGC, IOEC, Sagadril and SHL. This preparation phase entailed, amongst others, intensive risk assessment studies and meetings with respect to the installation works with the rig in place. To avoid program interruption on IOEC's construction yard in Khoramshar it was decided to install the heavy lift rigging offshore instead of onshore.

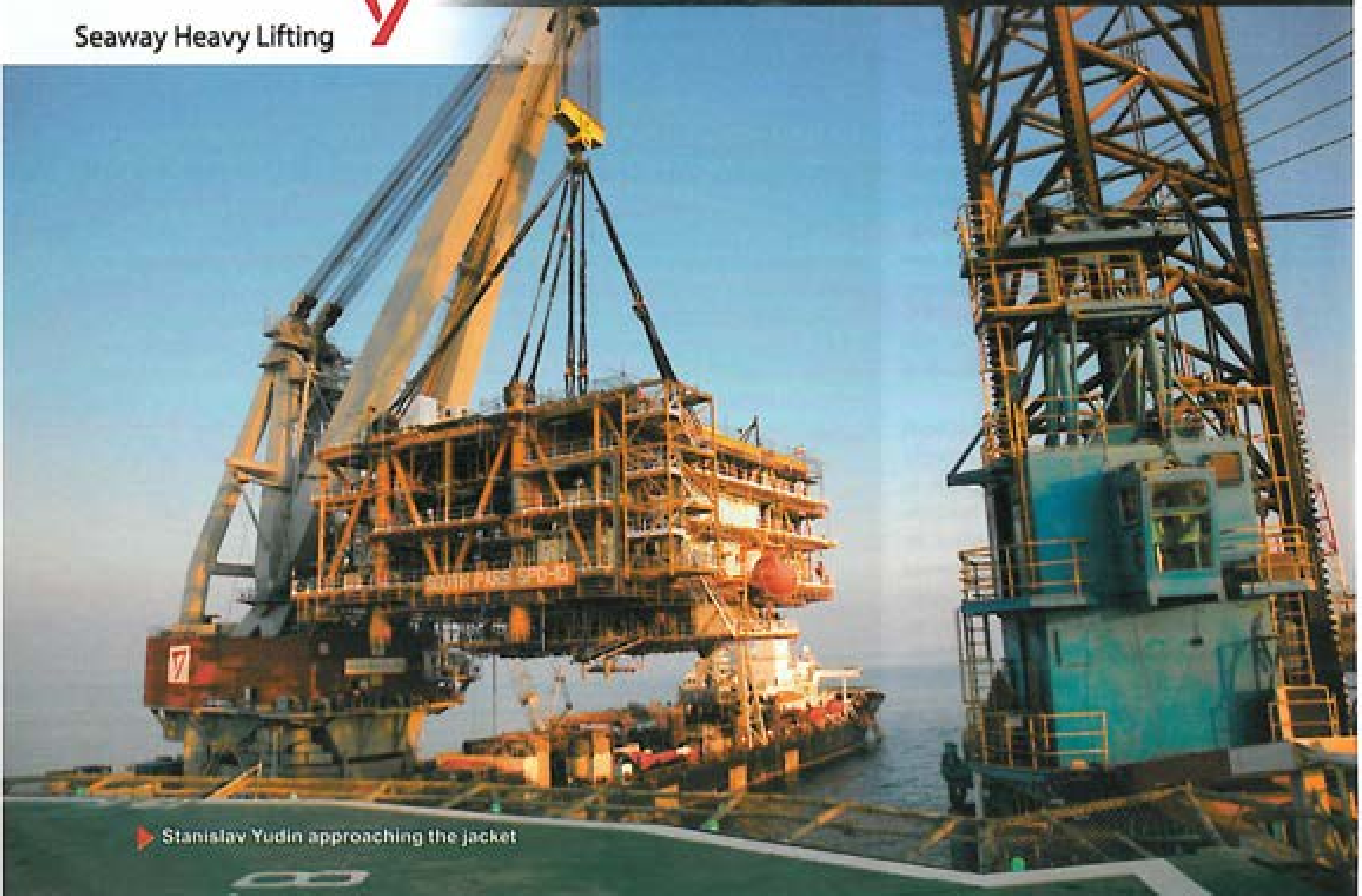
The entire offshore scope of work on both the locations SPD 10 and 11 in the South Pars field was carried out safely and in a record time.

Seaway Heavy Lifting will continue to support their Iranian clients with their expertise and resources.

From spring 2010 SHL can also offer their new 5000t crane ship the Oleg Strashnov.

Stanislav Yudin with SPD10 topsides

Seaway Heavy Lifting



Stanislav Yudin approaching the jacket

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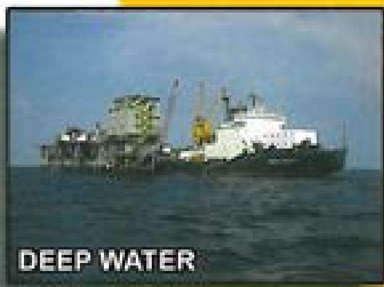

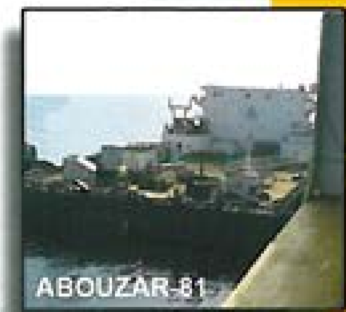

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