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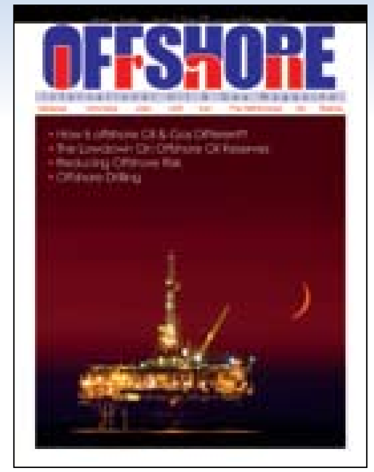

Cover story:
The Upstream Oil and gas sector is an international market, with investment and operational decisions increasingly determined against world norms, heavily influenced by both the current world oil and gas price and anticipated price for its impact on new offshore and inshore field developments.
(Refer to P.40)

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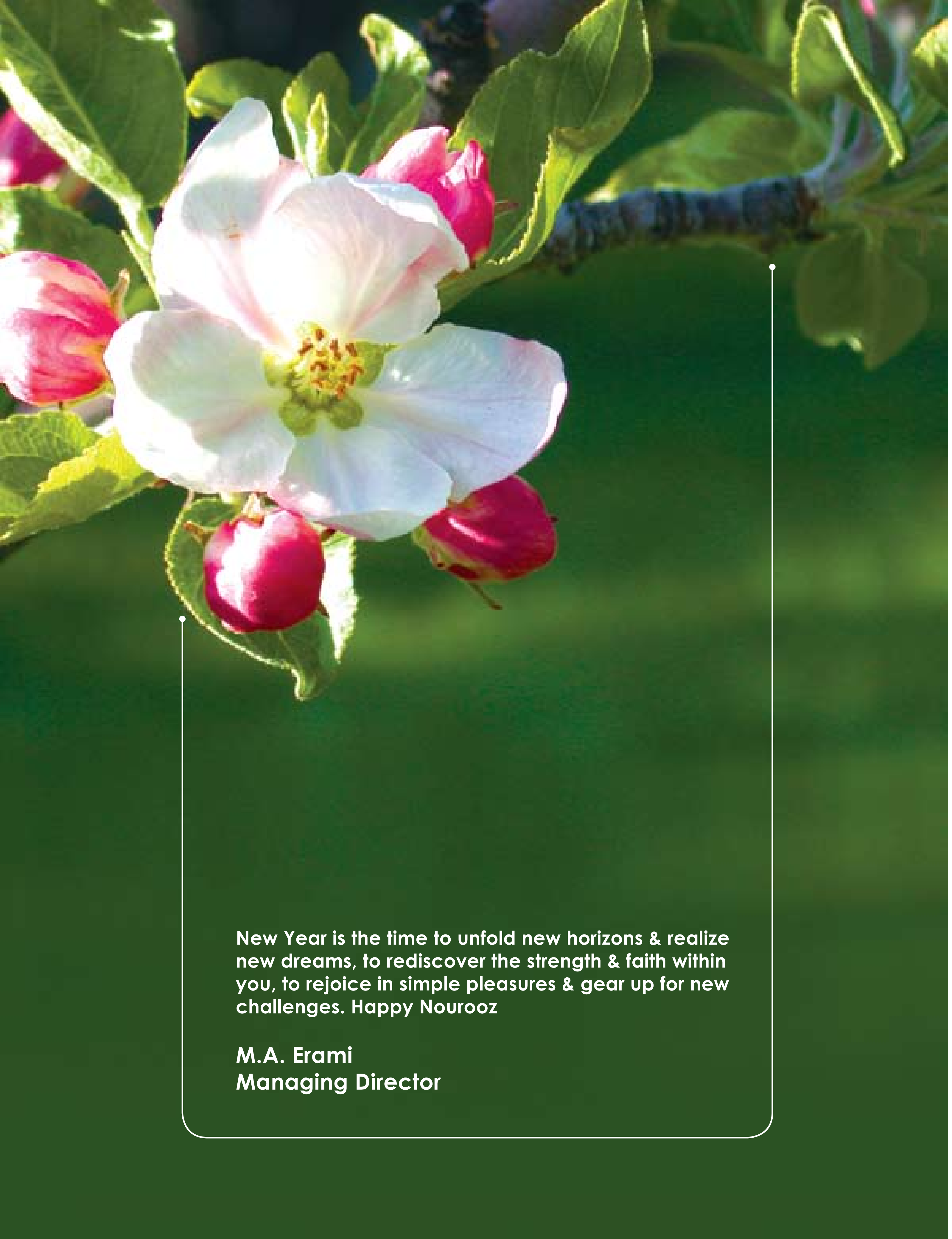


Iran Breaks Ground On Kermanshah Refinery-Oil Ministry

Iran broke ground on the construction of its 150,000 barrel a day Anahita refinery in western Kermanshah province, the Oil Ministry's Shana news agency reported.

Iran's Social Security Organization, Retirement Fund and the National Iranian Oil Refining and Distribution Co. each respectively hold 55%, 25% and 20% of the project, according to Shana.

The refinery will need an estimated \$3.13 billion in investment, and is slated to produce 5.2 million liters of gasoline per day, 1.3 million liters a day of super gasoline, 4.9 million liters a day of kerosene, 2.7 million liters per day of kiln oil, 350 tons per day of liquid gas, 280 tons a day of sulfur and 5,000 barrels a day of tar, Shana reported.

The types of heavy and light oil feedstock the refinery will use will determine its production capacity for gasoline, Shana said.

Eighty-five percent of the refinery's feedstock will be provided by the country's North Dezful oilfield and 15% from Iran's Naft-Shahr, Maleh-Kouh and Serkan oilfields, according to Shana.

The Anahita refinery is scheduled to begin operations by the second half of 2012, Shana said.

India to go legal on Farsi block stake

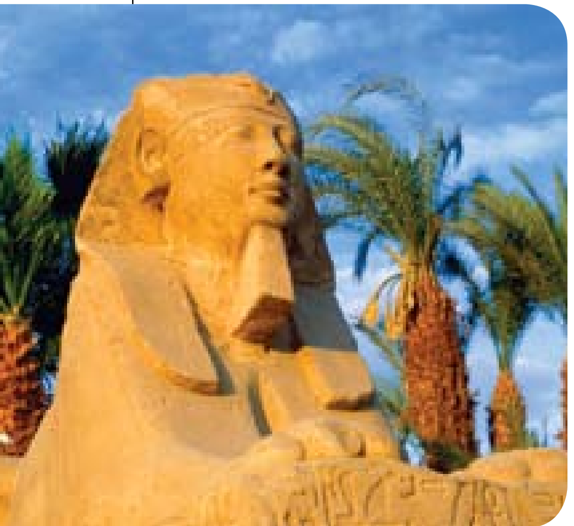
India's Petroleum Ministry is looking at legal options to determine whether it could claim and bring home gas discovered by three Indian state-owned oil and gas companies, ONGC Videsh Ltd. (OVL), Indian Oil Corp. (IOC) and Oil India Ltd. (OIL), in Iran's Farsi block. The consortium was awarded 100 per cent participating interest in the Farsi block in 2002. Both OVL and IOC hold 40 per cent each and the remaining 20 percent is held by OIL.

Gas production on the field is anticipated in 2012, but whether or not the consortium will be given development rights by the Iranian government has yet to be cleared since it was only given a contract for exploration. It is unclear whether companies operating in Iran can claim a share in discovered hydrocarbon, but it is understood that the Iranian government will reimburse the companies' investments.

The consortium has a 35 per cent rate of return on investments during the exploration phase whereby it spent nearly US\$100 million. But should Iran decide to grant a development contract to the Indian companies, an estimated US\$3 billion will be spent to produce oil and gas from the Farsi block.

Other options being considered by OVL is to swap the gas with oil while looking at the possibility of developing LNG facilities in Iran even as future gas imports from the proposed US\$8-billion Iran-Pakistan-India (IPI) gas pipeline project has yet to materialize.

Recoverable gas reserves from the block are estimated at 12.8 Tcf, which is almost equivalent to recoverable gas reserves from Reliance Industries' eastern offshore D6 block in the Krishna-Godavari basin. The Farsi block is also understood to hold more than a billion barrels of oil with a recovery rate of 10 per cent.



J.P. Bussell to drill a duplicate for Shell

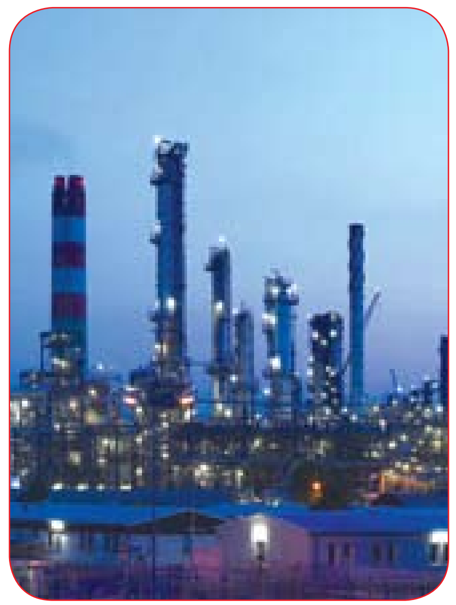
Shell Egypt has just sent a letter of intent to Rowan Companies for the new Rowan jackup J. P. Bussell.
J.P. Bussell will be used for two wells in the Northwest Demiatta region in the Egyptian Mediterranean that should take around 20 months to drill. The contract also has the option for three extra wells to be drilled.
Drilling is due in the third quarter of next year and the two-well deal should raise for Rowan somewhere in the region of US$111 million.
The option wells are at mutually agreeable day rates and would require another 30 months to drill.
Rowan jackup J. P. Bussell is in the Rowan's Sabine Pass facility in Texas for final outfitting. The rig should be finished in early November and should begin operations in the Gulf of Mexico soon after before starting in Egypt.
Rowan CEO Danny McNease said, "We are dedicated to increasing value for our shareholders over the long-term and believe that the continued execution of our strategic plan to expand and diversify our drilling operations throughout the world gives us the best opportunity for doing so."

In order to justness Interest, Key Energy spends $35MM in Geostream

Key Energy Services, Inc. has complied to invest almost $35 million in Geostream Services Group in exchange for a fifty percent (50%) justness interest in the Company. Geostream, which is headquartered in Moscow, provides drilling and workover services and sub-surface engineering and modeling in the Russian Federation. Key also has the right to purchase the other 50% of the equity interests of Geostream at a future date. Geostream will use the capital invested by Key to purchase drilling and other equipment to expand its business and service offerings.
Dick Alario, Key's Chairman and CEO, commented, "This investment is another step in our plan to expand Key's international business. The Russian market is one of the fastest growing oilfield services markets in the world and we are excited to enter this partnership with a well-respected service company like Geostream. This company's management, under the leadership of Dr. Boris Levin, has many years of oil and gas industry experience, is well known in the Russian oilfield services industry, and its client list includes both Russian and international oil & gas companies. Dr. Levin's prior success with U.S. investors in this market gives us great confidence that we have found the right partner for our expansion into the Eastern Hemisphere."
Key's investment in Geostream is contingent upon the approval of a Russian Federation regulatory authority. Upon receipt of regulatory approval, Key will invest approximately $18 million for a 26% equity interest in Geostream. The remaining investment of approximately $17 million is expected to occur in the first quarter of 2009, increasing Key's total ownership to 50% of Geostream.

Production down 9.2% in the January to August 2008 period

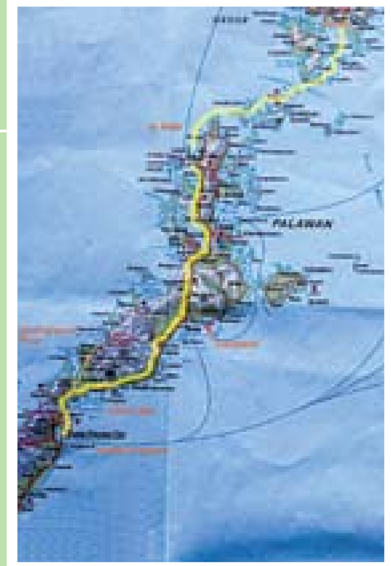
Oil production totalled 84.6 million barrels in the first eight months of 2008, down 9.2% relative to the same period in 2007. The decrease is mainly the result of a notable decline in production at the White Rose and Terra Nova fields.
Hibernia produced 33.2 million barrels of oil in the January to August period, down 2.3% over the same period of 2007.
Terra Nova produced 26.8 million barrels of oil in the first half of 2008, representing a 12.6% decline over the same period of 2007. Production is being constrained due to mechanical problems with one of the FPSO's main power generators.
White Rose produced 24.6 million barrels of oil in the January to August 2008 period, down 13.8% from 28.5 million in the same period of 2007.
The Department of Finance's April 2008 forecast projects annual oil production to decrease to 111.2 million barrels, down about 17% over 2007. Further information on the province's oil and gas industry is available at The Economy 2008.



Saudi Aramco selects Velosi to inspect facilities

Velosi's Saudi Arabian unit was awarded a five-year general inspection services contract with Saudi Aramco effective from July 2008 until the second quarter of 2013.
Under the new Saudi Aramco contract, Velosi will provide inspection services, known as Quality Management Systems Services (QMS), for Saudi Aramco's capital projects during the design, procurement and construction of industrial and non-industrial facilities both offshore and onshore.
The work will include field inspection and testing, reviewing of quality submittals, and design packages, providing inspection at supply vendors, conducting QMS audits and providing quality reports. There is also an option for the contract to be extended for a further three years.

Repairs on FPSO be settled by GPC



Galoc Production Company (GPC), the Operator of the Galoc Field offshore Palawan, Philippines, confirmed that the Mooring and Riser System has been successfully repaired and reconnected following damage incurred during Typhoon Frank (Fengshen) in late June. Integrity testing and ROV inspection of the sub sea equipment has revealed indications of accelerated corrosion of some hydraulic fittings and the decision has been made to replace these prior to introduction of hydrocarbons into the riser system. The associated work program is underway with field activities scheduled, subject to suitable weather conditions, first oil is expected in mid September.
The Galoc field is located in Service Contract SC14-C in 290m of water approximately 65km north west of Palawan. The development involves the construction of two sub sea completed horizontal wells, with extended reservoir contacts, tied back to a FPSO facility via a short seabed pipeline and mid-water riser system. Most likely, oil reserves as estimated at time of commitment to the development in 2006 is approximately 10 million barrels. The reserves estimate and requirement for additional wells and facility capacity will be reassessed following an analysis of results from both development drilling and initial field production performance.

KSA could face Opec pressure to decrease supply

The world's top oil exporter, Saudi Arabia, may come under pressure from within the Opec ranks to reduce supplies to prevent a further fall in crude prices when the group meets on September 9.

The extra Saudi oil and decreasing demand from slowing economies in the West have helped lower prices to $117 a barrel from a record high of $147.27 in July. The drop has prompted Opec price hawks Iran and Venezuela to suggest a cut in supplies.

While Opec is unlikely to change its official supply target at the meeting in Vienna, it is pumping almost 1 million barrels per day (bpd) more than the target largely because of an increase from Saudi Arabia.

"I think there will be pressure on Saudi Arabia to rein in some of its recent unilateral increases," said Julian Lee, analyst at the London-based Centre for Global Energy Studies.

"It all depends on what level of prices Saudi Arabia wants to see."

Saudi Arabia, the only producer with any significant spare capacity, has not said in public what Opec should do at the meeting, its first since March.

The group, which pumps two in every five barrels of oil, is likely to stop short of cutting its formal supply target because fuel demand rises in the fourth quarter due to winter and such a move would anger consumer nations.

"It would be politically difficult for Opec to push through anything formal," said Catherine Hunter, energy analyst at Global Insight in London.

"But that does not rule out them trimming physical supply."

Register output for Bahrain's refinery

Bahrain's refinery output amounts by four per cent to top a record 271,000 barrels per day (bpd) over the first six months of this year, compared with the same period last year.

It has a production capacity of 250,000 bpd, said the report issued by the National Oil and Gas Authority (Noga).

The quantity of crude oil imported from Saudi Arabia through the oleo ducts also increased by 6.1 per cent, Oil Minister and Noga chairman Dr Abdul-Hussain bin Ali Mirza has said.

Local sales soared by 9.4 per cent due to the booming urban development programme and the substantial increase in cars travelling via the King Fahad Causeway.

According to the report, Bahrain's output of gas and associated gases increased by 10.6 percent to top 258.227 billion square feet (sq ft), up by 24.766 billion sq ft compared with 233.461 billion sq ft last year.

Natural gas topped 207.06 billion sq ft (80 per cent) compared with 51.165 billion sq ft (20 per cent) for associated gases last year.

"The 10.6 per cent increase aims at meeting the soaring demand due to power plants, industrial projects and other infrastructure schemes," Dr Mirza said.

Power plants consume a major bulk of 33 per cent, followed by Alba (25 per cent).

Subsidiaries of Bahrain Oil and Gas Holding (Banagas) consortium have also reaped positive results. Thus, Banagas reported an increase by 8.6 per cent over last year.

Installing Subsea Equipment in Norwegian Sea by Acergy

Acergy S.A. was awarded a contract valued amount $60 million from BP Norge AS on behalf of the Skarv licensees.

The contract is for the installation of ten dynamic flexible risers systems, two dynamic umbilicals and a Direct Electrical Heating dynamic cable. Installation is due to commence in the second half of 2010, using the newest addition to Acergy's fleet, Skandi Acergy.

Oyvind Mikaelsen, Vice President Acergy Northern Europe and Canada, said, "We are delighted to have been awarded this contract with BP. This contract is a result of our continuing ability to deliver complex subsea projects safely and on time, within budget and to the highest standards. This, combined with our expertise as solution providers, aligns our world-class skills and technology with the needs of our clients, ensuring that Acergy delivers exactly what is required on this key field development project with BP."

China, Iraq agree $3bn oil service deal

China and Iraq have agreed the terms of a $3 billion oil service contract, Iraq's oil minister said, announcing the first major oil contract with a foreign firm since the fall of Saddam Hussein.

Energy-hungry China has beaten international oil majors to take the first opening since the US-led invasion for work on the world's third-largest reserves.

Iraqi Oil Minister Hussain Al-Shahristani warned that time was running out for big Western oil firms, which have jostled for years for Iraqi contracts, to seal even the short-term deals that were expected to mark their return to the country.Iraq and China's state-oil firm CNPC have agreed the renegotiated terms of an old deal signed in 1997 to pump oil from the Adhab oilfield, Shahristani told Reuters in an interview. CNPC is Asia's biggest oil and gas company.

"Finally we have reached an agreement," Shahristani said after clinching the deal. "The total investment of the project is expected to be about $3 billion." Iraq has toughened the terms, changing the contract to a set-fee service deal from the oil production sharing agreement signed under Saddam.

Iraq needs billions of dollars of investment in its energy sector after years of war and sanctions. But with high oil prices and strong competition for access to some of the world's cheapest oil to produce, Iraq has been negotiating from a position of strength.

Under the revised contract, Adhab will produce 110,000 barrels per day (bpd), up from the previous target of 90,000 bpd, Shahristani said.First output would come in three years, and the field should pump for 20 years, he said.

Ultra-deepwater semi ENSCO 7500 to get ready to Australia

A subsidiary of Ensco International has passed into a drilling contract with Chevron Australia PTY., Ltd for the utilization of ENSCO 7500, an ultra-deepwater semisubmersible rig now operating in the Gulf of Mexico. The rig is expected to complete its current contract with Chevron U.S.A. in September 2008 and then mobilize to west Australia to commence operations under the new contract by the end of the year. The current day rate of $365,000 will apply during the mobilization period.

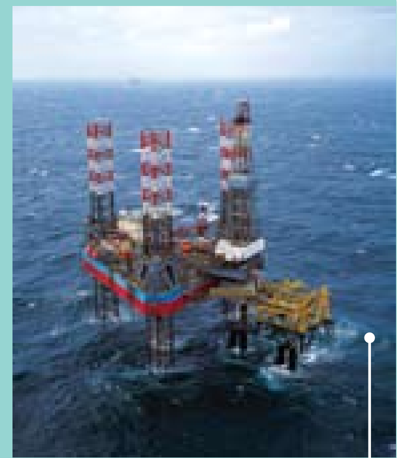
The operating rate under the new contract is $550,000 per day, and will be subject to adjustment for variances in operating costs. The initial term of the contract, which runs until August 31, 2010, can be extended by Chevron Australia for one or two additional years at the same rate if the option to extend is exercised by September 1, 2009, or at mutually agreed rates if the option is exercised thereafter.

Dan Rabun, Chairman, President and Chief Executive Officer, commented: "We are pleased that Chevron has selected the ENSCO 7500 for its deepwater drilling program in Australia. We have extensive operating experience in the region with our jackup rig fleet, and the ENSCO 7500 will add to our capabilities in this increasingly important deepwater market."

ONGC, IPR make second Gulf of Suez discovery

ONGC Videsh Ltd. and IPR Red Sea Inc. made a second oil discovery in their North Ramadan Concession in the Gulf of Suez offshore Egypt.
Oil was found in the North Ramadan-2 (NR-2) well drilled in a separate fault block north of IPR's first oil discovery, NR-1A ST1.
A total of 113 feet (34 m) over a gross interval of 286 feet (87 m) of interbedded sandstones, shales and limestones in the Asl Formation were perforated. Tests run on the latest discovery produced up to 800 b/d of oil with 34 degree of API gravity and 500 Mcf/d of natural gas flowed with no water.
The first discovery, NR-1A ST1, drilled using GlobalSantaFe jackup GSF Rig 124 encountered a hydrocarbon-bearing interval of 174 feet (53 m) and flowed 2,979 b/d of oil and 1.5 MMcf/d of gas with no water during tests run on a 133 feet (41 m) interval.
ONGC expects IPR's adjacent offshore platform and facilities infrastructure, North July, to provide an option for expedited development for the NR-1A ST1 and NR-2 discoveries. Further analysis for development of the prospect is in progress.
The North Ramadan Concession occupies 112 square miles (290 sq km) in Egypt's Gulf of Suez. ONGC Videsh holds 70 percent interest in the concession and IPR holds the remaining 30 percent interest.
ONGC Videsh and IPR are in the first phase of exploration in North Ramadan and have one remaining exploratory well to drill, North Ramadan-3, which is scheduled to spud in early November.

Maersk Honors is Satisfying to Work for Brunei Shell



Maersk Contractors has called its current newbuilding drilling rig from Jurong Shipyard Pte Ltd.
Beth Allen, accompanied by her husband, William S. Allen, Senior Vice President, A.P. Moller -- Maersk, honored Maersk Contractors and the yard by naming the rig MAERSK CONVINCER at a ceremony at the yard on August 18, 2008.
The rig is the second of two identical jackup rigs acquired by the A. P. Moller -- Maersk Group in July 2006. The rig is capable of operating in water depths up to 375 feet in most parts of the world including the harsh environment of the central and southern parts of the North Sea.
The delivery of the MAERSK CONVINCER will cement Maersk Contractors' position as a drilling contractor on the forefront of the market within high-performance drilling," said Claus V. Hemmingsen. "Our fleet's average rig-age of 9 years is amongst the lowest in the industry."
The new rig is of the Baker Marine Pacific Class 375 design and distances itself from conventional jackups in several areas, not least on the drill floor where the highly mechanised equipment leads to increased safety of the crew. The sophisticated drilling equipment will also make the rigs well qualified for drilling deep and difficult wells, including high temperature/high pressure wells.
The first assignment for the MAERSK CONVINCER is a one-year drilling contract with an option to extend the contract by two times one year, with Brunei Shell Petroleum offshore Brunei.

Drilling Start up in Salar field in Persian Gulf

National Iranian Oil Company announced the drilling operation in a new location of Salar field, 25 km off the Hendijan coast in Persain Gulf, will be commenced within a month.
The head of NIOC for exploration affairs, Mahmoud Mohaddes, also told PIN, the new location was discovered in Persian Gulf following a two-dimension seismologic operation implemented two years ago.
He added by installing Shahid Rajaei platform on the determined location during a month ahead, a well will be drilled by the depth of 4,000 meters to provide the experts with a more detailed data.
Mohaddes explained that review of the data will determine the sort of the field.He further stated that at present two platforms have been installed on exploring blocks in Kouh-Dasht region and a place between Qom and Kashan cities.

OMV starts Austrian gas production

To increase Austria's energy supplying, OMV AG has started natural gas production from Strasshof and Ebenthal fields in the Vienna basin.
The company's domestic production will increase by 20%-about 40,000 boe/d-until 2010. OMG said it cost €210 million to bring the fields on stream.
Strasshof, which holds an estimated 4 billion cu m of reserves, was discovered in 2005. OMV has since drilled four additional wells and spent €175 million to construct gas processing facilities and expand the existing sour gas treatment plant at Aderklaa. At the first expansion stage, Strasshof's maximum production will be 4,000 boe/d—20% of the company's overall production.
Ebenthal, which has gas reserves of 1.5 billion cu m, cost €35 million to develop. OMV built gas treatment facilities and revamped the Auersthal compressor station. A 16-km pipeline will link the field to the compressor station.
Ebenthal output will hit 3,000 boe/d in September, which will represent 15% of OMV's domestic gas production.
OMV will invest €250 million in 2008 and again in 2009 to boost Austrian oil and gas production for long-term supply security by optimizing production of its mature oil fields as well as exploring for new reserves.
"Environmentally sound production technologies and low emissions are particularly important for OMV," a company spokesperson said. "With Baumgarten becoming an increasingly important Central European gas hub, additional gas storage opportunities are being investigated."
At the end of 2007, OMV's Austrian reserves were 143 million boe, with natural gas reserves of 14.8 billion cu m and crude oil reserves of 56 million bbl.

Turkmenistan to Host Health, Oil and Gas Events

The Turkmen capital Ashgabat is to host two major forums in mid-November– an international fair and seminar entitled Healthcare Achievements in Turkmenistan on November 8-10, and the 13th Oil and Gas Exhibition scheduled for November 19-21, together with a conference on the energy industry.
NBCentralAsia observers say that while Turkmenistan has little to be proud of when it comes to healthcare, the gas industry is a different matter.
According to an independent audit recently produced by the British firm Gaffney, Cline & Associates, one gas field called South Yolotan-Osman could contain anything between four and 14 trillion cubic metres. The top-end estimate would place it among the top five gas fields in the world.
The last Turkmen oil and gas exhibition had close to 500 international participants, and the authorities are expecting more this year.

Asgard, North Sea Northern, Norway

Asgard lies on the Haltenbank in the Norwegian Sea, about 200km from mid-Norway and 50km south of Statoil's Heidrun field.

The field comprises the Midgard, Smorbukk and Smorbukk South deposits, which were discovered in 1981, 1984 and 1985 respectively.

Water depths are roughly 240-300m. Midgard straddles blocks 6507/11 and 6407/2, while the other two deposits lie in block 6506/11.

DEVELOPMENT

The development consists of a monohull unit (Asgard A), for oil and condensate production with the world's largest floating gas semi-submersible platform (Asgard B). The other installations for development of the fields are Asgard C (a storage ship) and the necessary subsea production installations. These subsea systems are one of the most extensive in world, embracing a total of 51 wells, grouped in 16 seabed templates, linked by 300km of flowlines. Asgard B was towed out to the field on 14 April 2000, and came on-stream in Autumn 2000.

PRODUCTION

The field will produce 12 billion m³ of gas per year (plateau), as well as 200,000 barrels of oil and 94,000 barrels of condensate per day.

RESERVES

The field has reserves of 830 million barrels of oil and condensate, and 212 billion m³ of gas.

The Asgard A oil production ship arrived in the field on 8 February 1999. This monohull is permanently moored to the seabed and provides a storage capacity on-board for roughly 907,000 barrels of oil. It is able to produce up to 200,000 barrels per day. Oil is transferred, via a loading system, to shuttle tankers for transport to customers or terminals. Oil production began on 19 May 1999.

Asgard B is a semisubmersible, floating platform with process plants for the treatment of gas and the stabilisation of oil and condensate. Developed by Kværner/GVA Consultants in Gothenburg, the semisubmersible platform has been designated a Kværner GVA70. The fabrication was carried out under a US$1 billion turnkey EPIC contract, with Kvaerner.

HULL

The Asgard B hull comprises a ring pontoon with six columns to support the topsides. It was built in Korea by Daewoo Heavy Industries, under a US$85 million contract. The hull measures 114mx96m and weighs 19,000t. The heavy-lift carrier Mighty Servant 3 transported the hull to Norway, in a 45-day journey.

TOPSIDES

Measuring 96mx114m, the platform B topside weighs 28,000t, and incorporates living quarters and processing facilities. It will also carry operative deck loads of 15,000t.

DECK

The construction of the platform deck began at Kværner Rosenberg's Stavanger yard. The two topside halves weighing a total of 33,000t were welded together, before being mated with the hull. This operation took place in the Amy Fjord, close to Stavanger in October 2001.

Asgard B has a daily export capacity of 38 million m³ of rich gas and 94,000 barrels of condensate (light oil). It incorporates facilities to produce 41,000 barrels of partially stabilised crude oil per day, for transfer to the Asgard A production ship. Around 11 million m³ of gas will be reinjected into the reservoir, daily.

The Asgard C storage unit was built in Spain's Sestao yard in Bilbao and arrived at the field in May 2000. Work then commenced pulling in and locking the condensate loading buoy. It was then connected via a flexible riser to the seabed flowline leading to the Asgard B gas and condensate production floater located 4km away. Measuring 264m long, the vessel belongs to Knutsen OAS Shipping in Haugesund north of Stavanger and has a storage capacity of 868,000 barrels.

Also part of the project is the: Asgard Transport gas trunkline, which runs for 707km to the KArstø treatment complex north of Stavanger. This line ties Asgard and other Norwegian Sea fields to markets in continental Europe and the UK.

An expansion of the facilities at KArstø separates rich gas from Asgard into lean gas (methane) for onward transmission by pipeline, and ethane, butane, propane and naphtha for export by ship

The Europipe II gas trunkline, running for 650km from KArstø to the receiving facilities at Dornum on the German coast.

WREP to be checked after bombs dropped nearby

Eric Watkins

BP PLC, which resumed shipments through the Baku-Tblisi-Ceyhan oil pipeline, said it has no start date yet for reopening the 155,000-b/d capacity Baku-Supsa pipeline, also known as the Western Route Export Pipeline (WREP).

BP briefly reopened the WREP in early August after completing repairs to damage that had kept the line closed since 2006. According to a BP spokesperson, the plan was to bring WREP back on line at around 90,000 b/d to provide some "flexibility" for the BTC pipeline.

Enough oil had been pumped through the WREP to fill four storage tanks at Supsa and load a tanker there in mid-August, according to the BP spokesperson.

But the British firm was forced to shut the line down again after the outbreak of hostilities between Russia and Georgia, especially when reports emerged that Russian warplanes had targeted the WREP and other lines.

Early reports said the physical evidence of a Russian air attack on the BTC line was "compelling" and that some 45 bomb craters were "concentrated in an area close to where BTC and the Baku-Supsa line intersect".

Journalists in Georgia reported "deep craters" alongside the WREP line, some 25 km from the border with Azerbaijan. Three of the craters, which local residents said were caused by Russian bombing raids, lay within 15 m of the pipeline.

The BP spokesperson said that the firm will be "closely following" the situation between the two countries and that it is concerned about the possible effects of alleged bombing on or near the lines.

He said that efforts to restart the WREP pipeline have been "put on hold until we can assess the impact of this conflict on the integrity of this pipeline."

Meanwhile, he said, oil flow through the BTC is nearly back to its normal daily average of 700,000-800,000 b/d after this month's closure due to an explosion in its Turkish stretch.

"It is operating—not as normal, but pretty close to it," the spokesperson said, adding: "We're ramping up towards that sort of figure."

Enviro-Political issues cloud Inpex regas plan

Inpex Holdings Inc. has begun a ¥100 billion project to build a regasification terminal in Niigata Prefecture on Japan's Honshu Island and anticipates starting regular operations in 2014.

But the Inpex plan to supplement Japan's rapidly diminishing domestic gas supply with imports is clouded by environmental issues in Australia and by resource nationalism in Indonesia, according to the Nikkei Business Daily newspaper.

Teikoku Oil Co., an Inpex group subsidiary, is supplying its natural gas customers in eastern Japan through a 1,400 km pipeline from Nagaoka in Niigata Prefecture. The company projects that the field will be depleted in 20 years.

NBD said Teikoku is planning to supplement its domestic supply with imports from a concession in Ichthys, Australia, which will produce 8 million tonnes/year, or about 10% of Japan's total gas imports.

Environmental concerns

As part of its concession, acquired in 1998, Inpex planned to build an LNG base in the Maret Islands off Western Australia, about 200 km from Ichthys gas field.

But those plans recently hit a snag, as Australia's new Labor Party administration wants all companies planning to develop gas fields in northwest Australia to centralize their LNG bases to minimize negative impacts on the environment.

That decision, the paper reported, has made Inpex unsure about the Maret LNG base.

Australia's Northern Territory government has since offered Inpex an alternate location in Darwin, promising to help it handle environmental and aboriginal concerns.

But Darwin is 900 km from Ichthys field, and no firm has ever accomplished pipeline transfers of LNG over that distance. With costs rising for steel pipe and other materials, the project would cost over $20 billion, or some ¥2.2 trillion.

Resource nationalism

Meanwhile, in Indonesia, Inpex faces different challenges. The company sees advantages in transporting gas from Indonesia's Abadi field to its LNG base in Australia when it begins producing the gas in fiscal 2015.

But the Indonesian government, which wants Japanese investment, is demanding that the firm build an offshore LNG facility.

Inpex does not have the technology to process gas into LNG offshore in the unstable ocean environment.

The Indonesian government is also putting higher priority than ever on domestic demand over exports, and if Inpex makes the wrong political move, it could jeopardize its gas field development there.

Indonesia has a general election scheduled for the spring followed by a summer presidential poll, so Inpex may have to sit and watch which way the political wind will be blowing.

Azeri-Chirag-Gunashli (ACG) Oil Field, Caspian Sea, Azerbaijan

The ACG (Azeri-Chirag-Gunashli) field lies some 120km off the coast of Azerbaijan in 120m of water and contains 5.4 billion barrels of recoverable oil. Overall investment will reach $10 billion, including $3 billion for the BTC export pipeline.

The field is operated by BP 34.1% on behalf of Socar 10.3%, Lukoil 10%, Unocal 10%, Statoil 8.6%, Exxon Mobil 8%, Turkish Petroleum 6.8%, Devon 5.6%, Itochu 3.9% and Delta Hess 2.7%. The production sharing agreement was signed in September 1994.

Production commenced in 1997 with the Chirag Early Oil Project (EOP), a single offshore platform, producing over 130,000b/d. The field will reach the end of its productive life by 2024.

Crude comes ashore by pipeline to the Sangachal terminal south of Baku. Most is carried in the 850km western export pipeline which has a daily capacity of 140,000 barrels (peak 160,000) to the Georgian port of Supsa on the Black Sea. Some of the oil from Sangachal is also exported via a northern pipeline to the Russian Black Sea port of Novorossiysk. Tankers are used to ship the crude from Supsa and Novorossiysk. Up to 2006, Chirag has produced 326 million barrels.

Central Azeri Development

Production from Central Azeri (CA) field began in February 2005 under Phase 1 of the development. This comprised two platforms built at the Amec-Tekfen-Azfen (ATA) yard, one for production and the other for compression and to provide water injection services to the Central, West and East Azeri platforms.

Output from Central Azeri totalled 93,000 barrels per day in 2005 from eight pre-drilled wells, rising to 240,000 barrels. Total capacity for the platform is 420,000b/d.

A second development phase covering the East and West Azeri involves one platform on each field.

West Azeri Development

West Azeri (WA) came on stream in 118m of water in December 2005 from three predrilled wells. The WA facilities include a 48-slot Production, Drilling and Quarters (PDQ) platform and a 30in oil pipeline connecting to the expanded onshore Sangachal terminal.

Associated gas from WA will flow via subsea pipelines to a CA compression and water injection platform for reinjection for pressure maintenance or to be used as fuel. Surplus gas will be exported to the Sangachal terminal.

East Azeri Development

East Azeri (EA) is due to start production in 2007, by which time the field will produce more than 800,000b/d. The Dada Gorgud completed the eight-well pre-drilling programme in Dec 2005. These will be tied back to the platform once it is installed offshore.

The EA Topsides construction is underway at the Baku Deepwater Jackets Factory (BDJF) yard, with all of the modules and the drilling derrick installed onto the integrated deck. The EA jacket fabrication at the BDJF yard is substantially complete and has been loaded onto the STB-1 transportation barge.

Gunashli Field Development

The third and final stage covers the deepwater section of the Gunashli field. Production is due to begin in 2008-09 with production plateauing at around one million b/d in 2010.

Work on the deepwater Gunashli Drilling, Utilities and Quarters (DUQ) platform topsides and jacket is underway, with the drilling modules being fabricated in Holland. Fabrication of the Phase 3 production, compression, water injection and utilities platform (PCWU) jacket and topsides began at the ATA yard in the third quarter of 2005.

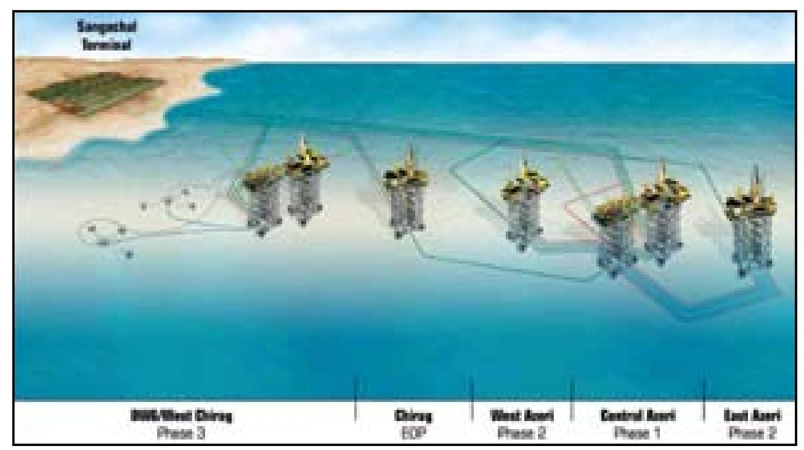
These facilities will inject over 400,000 barrels of water per day into the Gunashli reservoir through six subsea wells drilled from two subsea drilling centres approximately 5km from the Deepwater Gunashli platform.

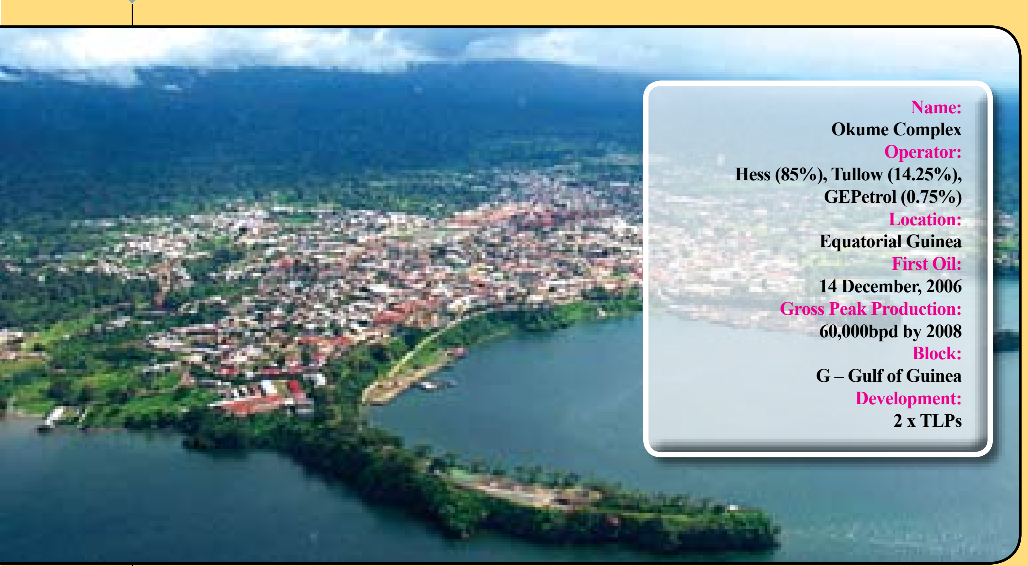
Oil And Gas Export

The new Baku-Tbilisi-Ceyhan (BTC) oil pipeline is due to come on stream in the first half of 2006, running from the Sangachal terminal via Georgia to the Mediterranean coast of Turkey. Oil from Central Azeri will travel through this system, with Chirag early production continuing to use the pipeline to Supsa.

By 2006, 18 subsea pipelines totalling over 850km (of the 21 pipelines totalling 950km)were laid using the Israfil Huseynov barge.

The SOCAR-owned dynamically positioned diving vessel Tofik Ismailov was used for installation.





Name:
Okume Complex
Operator:
Hess (85%), Tullow (14.25%), GEPetrol (0.75%)
Location:
Equatorial Guinea
First Oil:
14 December, 2006
Gross Peak Production:
60,000bpd by 2008
Block:
G – Gulf of Guinea
Development:
2 x TLPs

Okume Complex, Equatorial Guinea

The Okume development achieved first oil on December 14, 2006, when the Okume B platform came on-stream. Production will grow during 2007 as in-field drilling progresses until gross peak production of 60,000bpd is achieved during 2008.

The development is located in block G offshore Rio Muni, in the Gulf of Guinea, 55km southwest of Bata and 250km south of Malabo. The Okume complex is based on the draining of the Oveng and Okume / Ebano and Elon reservoirs.

The field is operated by Hess with an 85% working interest on behalf of its partners Tullow (14.25%) Oil and GEPetrol. Construction of the Okume complex facilities began in August 2004, following approval of the plan of development by the Republic of Equatorial Guinea.

Okume Field Development

The field is being developed by two tension-leg platforms as well as three satellite well protector platforms and a central processing platform in the Elon reservoir area. These facilities provide for full-field pressure maintenance and artificial lift capability.

The Okume complex central processing facilities are tied back to the Sendje Ceiba Floating Production Storage and Offloading (FPSO) vessel, which provides crude storage and loading capability.

Field Discovery

The field was discovered by the Okume-1 oil well, which recorded 200ft of net pay. Following this, Hess carried out an appraisal programme with Okume-2 and Okume-3, drilled and side-tracked. The wells encountered 153ft and 137ft of net pay respectively, penetrating good quality reservoirs.

Okume-2, located 1.3 miles west-southwest of Okume-1, was drilled to a total depth of 8,500ft in 1,814ft of water. Okume-3 well is located 1.7 miles north-northwest of Okume-1 and was drilled to a total depth of 9,570ft in 2,080ft of water.

The development is planned to be based on a combination of 43 oil producers with gas lift, water injection and gas injection wells. Approximately 23 of the wells will be drilled and completed from the two TLPs. The remaining 20 wells will be drilled and completed from three fixed platforms.

Okume Construction

In October 2004, MODEC was awarded the contract for the TLPs on the Oveng and Okume / Ebano Field. The Oveng TLP is installed in approximately 275m (902ft) of water while the Okume / Ebano TLP is installed in approximately 510m (1,673ft) of water. They were both built in the Samsung Heavy Industries yards in South Korea. MODEC was responsible for design, engineering, procurement and construction of the hulls, topsides, mooring, drilling riser, and production riser systems.

Both platforms are designed to support up to 18 top-tensioned production and/or water injection direct vertical access risers and a tender-assist drilling unit. The platforms provide initial processing of up to 25,000bpd of oil – 30 million cubic feet a day, water treatment and utility systems to support a ten-person operations group.

A new Self Stable Integrated Platform (SSIP) design allowed the platforms to be fully integrated (deck mated with the hull) in the shipyard, thereby providing installation and hook-up cost savings.

The trees were supplied by FMC. The surface dry trees are rated to 5,000psi with a 4-1/16in tree bore size. The field development is based on 23, 10-3/4in OD production risers systems including tieback connector, stress joint, riser joints, keel joint, tension joint and fixed tensioner system.

Each tree includes a 16-3/4in rigid lock subsea wellhead system to 10,000psi and a surface wellhead and tree systems. There is also a 18-5/8 OD surface BOP drilling riser system with tieback connector, stress joint, riser joints, keel joint, tension joint, hydropneumatic tensioner system and BOP adapter.

For the fixed platforms, there are 20 surface wellhead and tree systems including casing head, tubing head, tubing hanger and subsea tree. The pipe was supplied by Tenaris. In total, 88,087m of X65 seamless pipe was used for subsea flowlines, which were manufactured at the steel mills in Italy and Argentina. The pipelay was carried out by Acergy.

Yoho Oil Field, Nigeria

The Yoho field lies in Oil Mining Lease (OML) 104, offshore Nigeria. The completed project will cost approximately $1.2 billion and recover an estimated 0.4 billion barrels of oil from the Yoho and Awawa reservoirs. These reservoirs lie in a water depth of between 200ft and 300ft.

Yoho will serve as a hub for future development of other OML 104 petroleum resources.

ExxonMobil's subsidiary, MPN, holds a 40% interest in the joint venture. The Federal Government of Nigeria holds the remaining 60% interest through the Nigerian National Petroleum Corporation (NNPC).

ExxonMobil are employing a temporary Floating, Production, Storage and Offloading (FPSO) vessel as the basis for the initial stages of the development. This is being used as an Early Production System (EPS), ensuring that the first oil from Yoho will come onstream almost two years ahead of full-field start-up.

Production through the FPSO is currently reaching over 90,000 barrels of oil a day. This marks the first deployment using such an EPS system in West Africa. The FPSO itself is being operated by Esso Deepwater Ltd., a subsidiary of Exxon Mobil.

The full-field development will involve additional wellhead platforms, a central production platform and a living quarters platform as well as a Floating, Storage and Offloading (FSO) vessel, which will replace the EPS. Full-field start-up is scheduled for late 2004.

Once the full system comes on stream, its target peak production is 150,000 barrels of oil per day. The produced gas will be re-injected to eliminate routine flaring and maximise oil recover.

Fpso Falcon

The FPSO Falcon, formerly the Amazon Falcon VLCC, was installed over the Yoho field offshore Nigeria in a water depth of 64m.

The system was converted from the existing tanker into the FPSO in Singapore and Dubai. The FPSO Falcon registers 315,000dwt and has a storage capacity of 2,200,000bbls.

It is equipped with an external turret mooring system and production facilities capable of producing 100,000bpd of oil and 100MMscfd of gas.

The swivel stack can accommodate six 10in risers as well as three umbilicals. On Yoho, the swivel stack can contain two 12in low pressure production streams, two 12in high pressure production streams, a 10in water injection swivel (spare) and a 6in pigging swivel. It also has a low pressure utility swivel, an electric swivel and a 6in gas injection swivel.

The turret can accommodate a maximum throughput of 90,000bbls oil per day.

The system specification includes a 95MMSCFD gas injection capacity, a 20MMSCFD gas lift and export capacity while the water injection system can inject up to 90,000BWPD. These facilities have been provided by Single Buoy Moorings.

Classification And Certification

ABS was contracted by Single Buoy Mooring (SBM) to provide classification and certification services, including condition assessment of tankers, technical design review, surveys during refurbishment, conversion and hook-up and commissioning of this and two other FPSOs offshore West Africa.

Using the ABS classification society, it was assigned a new class notation +A1 Floating Offshore Installation and issued an IMO MODU Safety Certificate on behalf of the Bahamas Flag administration.

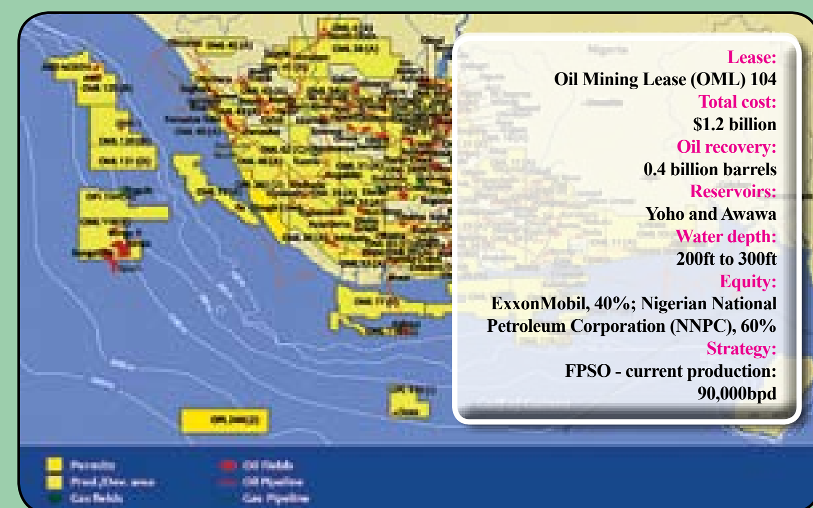
Yoho Platform Installation

The Saipem and Bouygues Offshore subsidiary, Saibos, won a contract from for production facilities to develop Yoho. The contractual scope of work includes: project management, engineering, procurement, construction, transportation and installation, hook up and commissioning of one production platform, pipeline laying and the other facility installation.

The vessel Castoro Otto will install the platform and lay the pipelines between late 2003 and early 2004, while the vessel Saipem 7000 will install the deck during the second half of 2004.

ExxonMobil is particularly active in Nigeria, with a portfolio including six deepwater blocks covering 3.2 million acres. These discoveries include Bonga and Bonga Southwest in OML 118 (20% equity), Chota in OPL 220 (47.5% equity) and Usan in OPL 222 (30% equity).

The company also has a 56.25% share in Erha located in OPL 209 and a 20% stake in Bolia in OPL 219.



Lease:
Oil Mining Lease (OML) 104
Total cost:
$1.2 billion
Oil recovery:
0.4 billion barrels
Reservoirs:
Yoho and Awawa
Water depth:
200ft to 300ft
Equity:
ExxonMobil, 40%; Nigerian National Petroleum Corporation (NNPC), 60%
Strategy:
FPSO - current production:
90,000bpd

What Aging Oil and Gas Offshore Workforce?

Research carried out by Oil & Gas UK has exploded the commonly held belief that the UK oil and gas industry is suffering from a rapidly aging, largely male offshore workforce as a result of fewer young people, especially women, taking up jobs within the sector.

Using data supplied by the Vantage POB (personnel on board) system, an Internet-based system used by the industry to keep track of people offshore, the research reveals that the average offshore worker is 41 years old, which is the expected average age for any workforce aged between 20 and 60 years.

In addition, the number of women in the industry is increasing, with over 1,800 traveling offshore in 2006. The majority are employed in the catering sector, but there are significant numbers also entering technical roles.

"Today's high activity in the UK continental shelf (UKCS) has resulted in oft-repeated concerns about the demographics of the current workforce, and the sustainability of the skills base," said Jessica Burton, a business analyst at Oil & Gas UK and author of the report. "The research gives a much more optimistic picture for industry demographics than common perception holds. For example, the age profile for female workers was weighted towards the younger age brackets, with an average age of 34.1 years, indicating an increase in the recruitment of young female graduates and other professionals into the industry."

Anecdotal evidence also suggests that the industry's efforts to attract new recruits are paying off. For example, there are 10 applicants for every place on the industry's Technician Training Scheme, while one company graduate scheme attracted 2,000 applicants for 20 places and over 7,000 people recently attended industry recruitment fairs in Newcastle and Glasgow.

However, the report highlights some areas of concern that need to be addressed. These include under-representation in the under-24 year and 30-34 year age groups and older profiles showing up in certain occupations, in particular rigging and crane operations. This emphasizes a continued need to focus recruitment in these areas to avoid potential shortages in the near future, said Oil & Gas UK.

The data recorded 117 nationalities working offshore, with workers from the UK accounting for 85.1% of all personnel. This demonstrates that the UK offshore industry is a major contributor to the UK job market, as well as an attractive global destination.

Oil & Gas UK will be reviewing the Vantage POB data on a regular basis to allow the monitoring of the age profile of the offshore workforce and permit the continued identification of potential areas of concern.

A copy of the Oil & Gas UK Workforce Demographics Report may be downloaded from http://www.oilandgas.org.uk/ukooa/newpublications/pdfs/REF19.pdf.

Oil & Gas UK is the leading representative organization for the UK offshore oil and gas industry. Its 60 members are companies licensed by the Government to explore for and produce oil and gas in UK waters and those who form any part of the industry's supply chain.

FW Consigned Contract for New Refinery in Libya

Foster Wheeler Ltd. proclaimed that its Milan-based subsidiary Foster Wheeler Italiana S.p.A., part of its Global Engineering and Construction Group, has been awarded a contract by Zwara Oil Refinery Company Limited (ZORCO) for consultancy and project management services for a planned new 200,000 barrels per stream day crude oil refinery at Mellita, near Zwara, in the Great Socialist People's Libyan Arab Jamahiriya. ZORCO is a project company in which Tamoil Africa Holdings Ltd. holds the equity.

Foster Wheeler scope under the contract includes the optimization of the refinery configuration, the selection of the licensors and the front-end engineering design (FEED), including preparation of a cost estimate. Foster Wheeler will also prepare the tender documents for the engineering, procurement, construction (EPC) phase, will assist ZORCO in selecting the EPC contractor(s) and will act as project management consultant during the EPC phase.

Foster Wheeler's contract value for the study and FEED phase will be included in the company's fourth-quarter 2008 bookings. The remainder of Foster Wheeler's project scope will not be booked until the project receives approval by ZORCO to proceed into the EPC phase. The refinery is planned to be completed in 2014.

The planned new facility, with an estimated total investment cost of about $4 billion, includes a state-of-the-art facility aimed at producing premium quality gasoline, jet fuel and diesel with minimal fuel oil production, and related utilities, offsites and marine facilities.

"We are indeed extremely pleased to be awarded this prestigious contract by ZORCO," said Marco Moresco, chief executive officer, Foster Wheeler Italiana. "We have strong roots in Libya and we look forward to leveraging our in-depth refinery expertise to build on the excellent working relationships established in the past."

"This is a flagship project in North Africa requiring deep technical knowledge, experience and flexibility," said Dr. Ali Shamekh, chairman, ZORCO Ltd. "We are very pleased to award the contract to Foster Wheeler Italiana and we will join forces for the successful implementation of the Project."

Beginning Drilling First Exploratory Well in Venezuela by Gazprom

Within the visit of Igor Sechin, Deputy Chairman of the Russian Federation Government to Venezuela, a Gazprom delegation, led by Alexander Medvedev, Deputy Chairman of the Company Management Committee took part in the activities aimed at developing the bilateral cooperation in the gas sector.

The delegation joined the meeting of the Russian-Venezuelan high-level commission, at which an agreement in principle was reached for the signing of an intergovernmental agreement. The agreement will serve as a legal framework for implementing large-scale joint investment projects in the oil and gas sectors in Venezuela and third countries.

The delegation visited the Scorpion Vigilant platform at Urumaco I Block in the Gulf of Venezuela, where drilling of the first exploratory well in the Block was launched in the presence of Hugo Chavez, President of Venezuela and Igor Sechin, Deputy Chairman of the Russian Federation Government. As part of the visit a number of meetings was held with leaders of Venezuela's Energy and Petroleum Ministry, as well as with representatives of the Venezuelan state-run oil and gas company Petroleos de Venezuela SA. The parties highly appreciated the achieved cooperation results and resumed negotiations concerning participation in new promising projects. In particular, a question was raised with regard to Gazprom's participation within a consortium of Russian oil and gas companies in the project for heavy oil production in the Carabobo area of Venezuela's Orinoco Belt area.

Background

Being the second-largest in the Western Hemisphere after the USA, Venezuela's proven natural gas reserves account for 4.1 tcm, with some 30 bcmpa of gas (mainly associated petroleum gas) produced domestically. The country's proven crude oil reserves amount to 11.2 bln t (7 per cent of the global total), with Maracaibo, Falcon, Oriental and Apure being the largest oil fields. The USA is a major importer of Venezuelan oil.

The exclusive right to produce natural gas is being held by the Venezuelan state-run oil and gas company Petroleos de Venezuela SA (PdVSA).In August 2005 Gazprom was proclaimed the winner of a tender for Phase A of the Rafael Urdaneta project and was awarded with natural gas exploration and development licenses for the Urumaco I and Urumaco II Blocks in the Gulf of Venezuela. In accordance with the bidding rules for Urumaco I and Urumaco II, Gazprom set up two joint-stock companies UrdanetaGazprom I, SA and UrdanetaGazprom II, SA. The potential natural gas reserves of Urumaco I and Urumaco II average 100 bcm.

Nigeria: Start of OML 58 Upgrade Project

Total declares that its subsidiary Total E&P Nigeria Limited (TEPNG), operator of the NNPC/TEPNG joint venture with a 40% interest, has launched the OML 58 upgrade project. Nigerian National Petroleum Corporation (NNPC) owns the remaining 60% interest of the joint venture. OML 58 is located onshore Nigeria (Rivers States), approximately 85 kilometres North West of Port Harcourt in the Niger Delta.

The OML 58 Obite gas treatment plant has been on stream since December 1999. The OML 58 upgrade is designed to increase gas production capacity from 10.6 million cubic metres per day (370 mmscfd) at present to 15.6 million cubic metres per day (550 mmscfd), and also increase oil and condensate output by around 15,000 barrels per day bringing the total output to 140,000 barrels of oil equivalent per day.

This project is expected to increase production as from 2011, and will comply with the Federal Government's "Flare Out" regulations, improve safety and extend the life of existing installations as well as enhancing oil recovery.

It will develop more than 280 million barrels of oil equivalent of proved and probable reserves. A second stage of the project is under evaluation in order to develop additional proved and probable reserves (about 230 Mboe) using these upgraded facilities.

The objective of the project is to contribute to meet the growth of domestic demand for gas in Nigeria in line with the Federal Government of Nigeria expectations, as well as to supply gas to Nigeria LNG.

In line with Total's commitments, the upgrade project will contribute significantly to Nigeria's local content policy – over 90% of the total man hours worked on the project will be performed locally.

OML58 upgrade project is situated in an area where the NNPC/TEPNG joint venture has already started using associated gas to provide continuous electricity to about 19 communities since 2005. The project will permit Total to reinforce its sustainable development policy towards local initiative programmes

REPORT

Libya's Area 47: Third Party Assessment of O&G Resources

Verenex Energy Inc. has declared the effects of a third party appraisal of oil and gas contingent and prospective resources in Area 47 in Libya.

DeGolyer and MacNaughton ("DM") has finalized an initial assessment of oil and gas resources in the Company's portfolio of discoveries and exploration prospects in Area 47 effective February 1, 2008. The assessment conforms to Canadian Securities National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities. Gross contingent (discovered) and prospective (undiscovered) oil and gas resources in Area 47 are expressed in the tables below as a range of estimates.

In summary, the aggregate of DM's best estimate of gross contingent resources and risked mean estimate of gross prospective resources is approximately 1.6 billion barrels of oil equivalent.

Area 47 Gross Contingent Resources

The DM best estimate of Area 47 gross contingent oil resources discovered in the Lower and Middle Acacus Formations is approximately 340 million barrels. This estimate is based on results from seven exploration and appraisal wells (six discoveries at A1, B1, C1, D1, E1 and F1-47/02 and one appraisal well A2-47/02) drilled by Verenex in Block 2 in the southern part of Area 47. The best estimate of gross contingent raw gas resources discovered in the Lower Acacus and Middle Acacus Formations is approximately 342 billion cubic feet. On an oil equivalent basis, the best estimate of gross contingent resources is approximately 396 million barrels.

Area 47 Gross Prospective Resources

The DM unrisked mean estimate of Area 47 gross prospective oil resources in the Lower Acacus Formation only is approximately 2.4 billion barrels associated with 34 exploration prospects and leads. The unrisked mean estimate of gross prospective raw gas resources in the Lower Acacus Formation is approximately 1.7 trillion cubic feet. On an oil equivalent basis, the mean unrisked estimate of gross prospective resources is 2.7 billion barrels.

The corresponding geologic risk-adjusted mean estimates of gross prospective resources in the Lower Acacus Formation are 1.1 billion barrels of oil and 0.8 trillion cubic feet of raw gas, or 1.2 billion barrels of oil equivalent.

Commenting on the resource assessment, Jim McFarland, President and CEO of Verenex, said, "The DM assessment confirms that Verenex has established a world class resource base in Area 47. We believe that the current discovered resources are sufficient to underpin an initial development phase of approximately 50,000 bopd (gross) and excellent potential exists to grow production above this floor. We remain tremendously excited about the future for Verenex given this resource outlook."

This initial assessment reflects information available at the end of January 2008 including drilling results from seven Verenex wells and exploration prospects and leads mapped utilizing extensive seismic coverage in Area 47 including 3D and 2D seismic shot by Verenex in 2006. As previously announced on July 23, 2008, Verenex has since drilled and cased an additional six wells (13 wells in total) and shot additional 3D and 2D seismic in late 2007 and early 2008. These more recent results have not as yet been reflected in the resource assessment.

The DM assessment excludes any resources associated with pre-existing oil discoveries at A1-NC3A and G1-NC02 located within or on the boundary of Block 2 in Area 47. The Libyan National Oil Corporation ("NOC") has advised that certain areas around these discoveries are unavailable to Verenex for exploration or exploitation under the current terms of the Area 47 Exploration and Production Sharing Agreement.

REPORT

Gas Production Starts Up at Tunisia's Chergui Field by Petrofac

Petrofac has announced that commercial production of gas and condensate has begun from the Chergui field located on Kerkennah Island in Tunisia. Petrofac Energy Developments is the operator and has a 45% interest in the field whilst its development partner, Entreprise Tunisienne D'Activitiés Pétrolières (ETAP), the Tunisian state oil company, holds the remaining 55%.

First commercial gas began flowing on August 8, 2008, and it is to be sold to Société Tunisienne de L'Electricité et du Gaz (STEG), the Tunisian state gas and electricity company under the existing gas pricing formula. The total cost of the development is approximately US$100 million.

The Chergui field central production facility will initially handle 20 million standard cubic feet per day. A 57km pipeline to shore will tie in to STEG's facilities at Ain Turkia near Sfax on its main pipeline to Tunis. Production plateau rates of 20mmscfd are expected for at least four years. Initial flow will be from two wells. Future potential gas development opportunities may extend the production plateau and the ultimate life of the field.

Bill Dunnett, Executive Vice President, Project Development commented, "Commencement of production is a major achievement following many months of hard work and dedication and I would like to thank the team for all their efforts."

Amjad Bseisu, Chief Executive of Petrofac Energy Developments, added, "Production start-up from Chergui establishes another core area for Petrofac Energy Developments and consolidates our relationship with ETAP. We look forward to future co-operation with ETAP on projects in Tunisia."

StatoilHydro finalized planed closed on Norne Ship

StatoilHydro reminded that the most exhaustive planed closed ever performed on the Norne production ship in the Norwegian Sea was concluded, August 25, 2008.

In 40 days the Company managed, with good assistance from suppliers, to replace the "heart" of the production ship, namely the swivel transferring the oil stream from the pipelines to the ship.

This is the first time an operation of this kind has been carried out at sea in any waters. Such operations have always been performed in a dock.

"After thorough testing of both old and new equipment we can conclude that everything works perfectly and the shutdown has been successful in every way. The reason for the good result is careful planning and a qualified and enthusiastic organization," said Oystein Michelsen, StatoilHydro's head of Operations North.

Strict Demands

The offshore swivel replacement operation has made strict demands on the ship's crew, StatoilHydro office in Harstad, the supplier SBM from Monaco, the operations and maintenance supplier Aker Reinertsen and the local industry of Nordland county in North Norway.

Not only did they manage to carry out the assignment without any serious incidents, they also completed the job as much as five days ahead of schedule.

"We have for a long time worked on improving the efficiency of the scheduled shutdowns. This shutdown shows that by proper planning an organisation can perform complicated jobs faster without compromising safety," said Torstein Hole, StatoilHydro's head of operational development.

This unit carries responsibility for tasks such as planning and managing scheduled shutdowns on the Norwegian continental shelf.

The swivel replacement was necessary to extend the Norne ship's lifetime from 2016 to 2021 and to prepare it for receiving gas and condensate from the Alve satellite field.

Offshore Access System Chosen by Qatar Shell for Pearl GTL Project

Offshore Solutions B.V., the joint venture between AMEC and GTI N.V, has been issued a Letter of Award, including associated services, by Qatar Shell for the provision of the "Offshore Access System", which allows the safe transfer of personnel from a vessel to an offshore installation.

The Offshore Access System (OAS) is to be used for the Pearl GTL project being built in Ras Laffan Industrial City in Qatar. Pearl GTL will be the world's largest gas-to-liquids project, converting natural gas into a range of high quality liquid hydrocarbon products. This fully integrated project is being developed under a Development Sharing Agreement with the government of the State of Qatar.

Pearl GTL will have the capacity to produce 140,000 barrels a day (b/d) of GTL products - gasoil, naphtha, kerosene, paraffin and lubricants base oils - as well as 120,000 barrels of oil equivalent a day of ethane, liquefied petroleum gas (LPG) and condensate. The project is being developed in two phases, with the first phase starting up around the end of the decade. It will help Qatar meet its aspiration of becoming the GTL capital of the world.

The Offshore Access System is due to be delivered in Qatar during the second quarter 2010.

Offshore Solutions B.V. is the world market leader in the invention, development, manufacture and safe operation of the industry's most advanced marine access systems, translating these technologies into safety and value for our customers.

The award of this contract to Offshore Solutions B.V. was a direct result of the operational success of the first Offshore Access System leased by Shell and working daily in the Southern North Sea for over two and a half years.

Addax Petroleum announces Update to Appraisal and Development Program at Taq Taq

Addax Petroleum Corp. declares the successful appraisal of the Eocene Pila Spi formation in the Taq Taq field with the TT-11 appraisal and development well. The TT-11 well was recently drilled by Taq Taq Operating Company, the joint venture company formed by Genel Enerji A.S. and Addax Petroleum to carry out petroleum operations in the Taq Taq license area.

Commenting, Jean Claude Gandur, President and Chief Executive Officer of Addax Petroleum said: "We are encouraged with the successful results from our first appraisal of the Tertiary aged Pila Spi formation in the Taq Taq field. We believe that the TT-11 well has demonstrated that the Pila Spi formation is a viable reservoir substantiating further appraisal activity. Pending additional appraisal work on the Pila Spi formation, Addax Petroleum is looking to develop this part of the Taq Taq field primarily to supply demand from the local markets in the Kurdistan Region of Iraq."

The TT-11 well was planned as a dedicated Tertiary appraisal and development well with the primary target as the Eocene Pila Spi formation at a total depth of approximately 1,000 metres. The TT-11 well encountered a gross oil column of 52 metres in the Pila Spi formation and was flow tested at 470 bbl/d of 23° API oil with no water. The flow test was restricted by a 1/2" choke size. Subsequent analysis by the Corporation has demonstrated that the TT-11 well has a high productivity index due to the fractured nature of the Pila Spi formation, which should enable flow rates to be increased substantially with artificial lift. Two secondary Tertiary targets, the Khurmala and Sinjar formations, encountered minor oil shows and were confirmed to be water bearing.

The TT-11 well is the second dedicated Pila Spi well in the Taq Taq field. The first is the TT-02 production well, which was drilled, in the late 1970's. The TT-11 well is located 1.2 kilometers north-northwest of TT-02, was spaded by the IRI-900 drilling rig in early September 2008 and reached total depth of 1,000 meters in early October 2008. The oil gravity from the TT-11 flow test is the same as is seen in the TT-02 well and the oil water contact was the same as had been established in the TT-02 well.

The Corporation's appraisal work at the Taq Taq field continues with current drilling of the TT-10 appraisal well, which is targeting the previously tested Cretaceous reservoirs: Shiranish, Kometan and Qamcheuqa. The TT-10 well was spaded with the Kurdistan-1 rig in late August and is expected to reach total depth of approximately 2,500 metres in November 2008. After testing the TT-10 well, the Corporation plans to move the Kurdistan-1 rig to drill the Kewa Chirmila exploration well in the Taq Taq license area.

Stuart Petroleum Hitches Operatorship of Timor Sea Permit

Stuart Petroleum Limited has become the Operator and 50% interest holder in Timor Sea permit AC/P33, host to the Oliver Oilfield development project. Permit AC/P33 is located approximately 700 kilometers west of Darwin in the Australian-administered section of the Timor Sea.

The first phase of development of the Oliver Oilfield – drilling the appraisal well, Oliver 2 and completing engineering studies – is expected cost $60 million and to be complete late in 2010.

Stuart's subsequent earn-in obligations will be satisfied by sole funding the drilling of an appraisal well on the Oliver Oilfield, completion of engineering studies up to Final Investment Decision for development of the oilfield and sole funding the first $25 million of development expenditure.

Stuart will review a range of funding options including debt and equity to fund the initial project commitments.

The Oliver field, containing a major column of oil, gas and condensate, was discovered by a BHP Petroleum operated consortium in 1988. The Oliver 1 well was drilled in 305 meters of water to a depth of 3,500 meters. The well encountered the column in the Plover Formation between 2,927 meters and 3,097 meters.

Stuart's interpretation of recently acquired 3-D seismic over the Oliver Oilfield has resulted in estimated recoverable liquids in the range of 9.9 million barrels to 33 million barrels of oil and condensate with a mean Joint Venture volume of 19.3 million barrels. These estimates have been independently reviewed and confirmed. Stuart's share of mean Joint Venture volumes is 9.6 million barrels.

The impact on Stuart of its 50% holding in the Oliver Oilfield is illustrated on the attached graph, which shows an increase in Stuart's share of liquids of approximately 370%. This graph also assumes no success from any of the Company's exploration drilling in the Gippsland Basin or the Cooper/Eromanga Basin.

Studies to identify development alternatives have commenced and will be followed by the Oliver 2 appraisal well to confirm the size of the field. The semi-submersible drilling rig, Songa Venus has been contracted to drill this well in mid-2009. Further studies will then determine how best to develop the field.

Equity participants in Timor Sea permit AC/P33 are:

- Stuart Petroleum Limited (Operator) 50%
- Natural Gas Corporation Ltd 15%
- Auralandia NL 15%
- Alpha Oil and Natural Gas Pty Ltd 7.5%
- National Gas Australia Pty Ltd 12.5%

The transaction is subject to the usual transfer procedures. Acquisition of the Timor Sea development interest establishes a balance between Stuart's exploration interests in the Gippsland Basin and its onshore exploration and production interests in the Cooper/Eromanga Basin. With the Timor Sea permit acquisition, the focus of Stuart's exploration and development activities has moved offshore and, while exploration and production will continue in the Cooper/Eromanga Basin, the relative importance of the Company's onshore activities is expected to diminish over time.

Stuart expects its Timor Sea and Gippsland Basin projects to establish it as a mid-tier oil and gas producer and explorer by providing the Company with the materiality and diversity it has been seeking.

REPORT

Yousefieh-1, Block 26, Syria Operations Update

Gulfsands Petroleum plc, the oil and gas production, exploration and development company with activities in Syria, Iraq, and the U.S.A., is pleased to provide the following update on the drilling of the Yousefieh-1 well in Block 26, Syria, where Gulfsands is operator and an update on production from the Khurbet East Field:

Yousefieh 1 Well, Block 26, Syria:

The Yousefieh-1 well has encountered the target Cretaceous formation at approximately 1940 metres vertical depth. The formation was encountered at a slightly shallower depth than was projected prior to the commencement of drilling.

Core sampling operations over this reservoir section were successfully completed and together with oil recovered during drilling operations, have indicated the presence of oil. The recovered cores will be further evaluated and analysed by the Company's consultants in Egypt.

Following completion of these activities the Company will resume drilling to the original target depth of approximately 2300 meters. The Company intends to run a complete logging programme on the well once drilled to target depth and expects drilling and testing operations will be completed within for new weeks.

The Yousefieh-1 well is targeting Cretaceous aged reservoirs identified within a structure located immediately adjacent to the Khurbet East Field and was designed to evaluate the potential of a newly identified play type within the Cretaceous reservoir system. The well is located very close to existing infrastructure, with the surface location of the well lying within 3 kilometers of the Khurbet East Early Production Facility (EPF).

Khurbet East Field, Block 26, Syria:

During October, the results of the pressure monitoring survey conducted in September on the Khurbet East field have been further evaluated. When taken in conjunction with the production performance of the Field, these suggest that the Massive reservoir parameters may be better than was estimated at the time of development approval last February. This, combined with the negligible amount of produced water in the Field thus far, indicates that the Field reserves may be understated. A re-evaluation of the Khurbet East Field reserves will be undertaken by RPS Group Plc as of year-end 2008, with results expected in Q1 2009.

During the month of October, additional pressure monitoring work was carried out to further assess the performance of the Field's reservoir which involved the shutting in of each of the producing wells. During uninterrupted production, the Field continued to average in excess of 11,000 bopd from 5 wells (2 horizontal and 3 vertical producers) with only trace amounts of water.

To 31st October 2008 over 840,000 barrels of oil have been produced from the Field. Gulfsands invoices for oil produced and delivered to the oil processing facilities of the Syrian Petroleum Company on a monthly basis and Gulfsands has received payment for all invoiced oil on a timely basis following marketing of the oil by the Government of Syria in accordance with the provisions of the contract for the Exploration and Development and Production of Petroleum (the "Contract") under which Gulfsands is operating in Syria. Oil sales have been achieved at prices in line with historic pricing of Syrian Souedieh blend, which historically has averaged a discount of approximately 11 per cent to the price of Brent crude.

Oilex Nabs More Than 15% Interest in West Kampar Area

Oilex Ltd. has entered into an agreement to acquire an additional 15% working interest in the West Kampar PSC (Production Sharing Contract onshore Sumatra, Indonesia) from PT Sumatera Persada Energi (SPE), thereby increasing Oilex's working interest from 45% to 60%.

The West Kampar PSC area contains the Pendalian oil field with emerging production in 2008 and a number of highly prospective geological trends that will be the subject of an intensive exploration drilling program.

- Pendalian Oil Field contains 13.7 million barrels of oil (Best Estimate oil-in-place resource).
- Production rate of 1,800 - 2,000 bopd (100% basis) in Phase 1 of Pendalian Field develop- ment anticipated during Q4 2008.

The consideration for the additional 15% interest includes Oilex carrying certain operational costs for SPE and a phased cash payment. The carried costs incurred by Oilex on behalf of SPE will be recovered preferentially by Oilex from production revenues.

On receipt of approvals from the Government of Indonesia and fulfilment of certain other conditions precedent, the participating interests (PI) in the West Kampar PSC will be:

- Joint Venture Party Current PI New PI
- Oilex 45% 60%
- PT Sumatera Persada Energi 55% 40% (Operator)

West Kampar PSC - The contract area is located in central Sumatra adjacent to the most prolific onshore oil producing province in Indonesia. Awarded in October 2005, the PSC work program commitment provides for the acquisition of 250 kilometers of 2D seismic and 50 square kilometers of 3D seismic along with drilling of the Pendalian-3 well and an additional 4 exploration wells by November 2008.

A Plan of Development (POD) for Pendalian Field is being reviewed by the Indonesian Government as part of the approval process that should result in production from the field, initially from two wells, later in 2008. The POD is based on a recent Best Estimate resource of 13.7 million barrels oil-in-place (mmstboip). The represents an increase of 14% on the original resource estimate which was based on a single oil reservoir. The POD is designed to bring Pendalian Field into production in two phases comprising two wells in Phase 1 and full field development of 3-4 wells in Phase 2.

The original plan was to start production at a likely rate of about 1,200 barrels of oil per day from a single well, Pendalian-3. That first phase may now be expanded to include a second well, Pendalian-4, with a corresponding increase in the likely production rate to 1,800 - 2,000 bopd (100% basis) in Phase 1 of development, anticipated during Q4 2008.

The opportunity to increase its stake in Pendalian Field and West Kampar PSC will add to Oilex's near-term potential oil production as it expands its asset portfolio of low risk exploration, appraisal and development projects around the Indian Ocean rim.

Developing Ahdab oil field in Iraq by CNPC

Iraqi Oil Minister: Hussain al-Shahristani

The Iraqi Ministry of Oil, re-negotiating an agreement first signed more than a decade ago, has approved arrangements that will allow state-owned China National Petroleum Co. to develop Ahdab oil field.

The agreement, which restores a project that was cancelled after the 2003 US-led invasion of Iraq, was signed by Chinese officials and Iraqi Oil Minister Hussain al-Shahristani.

Under the contract, which still requires approval of the Iraqi and Chinese governments, CNPC will provide technical advisers, oil workers, and equipment to increase production at the field, which is in Wasit province, about 160 km south-east of Baghdad.

Shahristani said the two sides agreed to renegotiated terms of a deal signed in 1997. He said the contract has been changed to a set-fee service deal from the oil production-sharing agreement signed earlier.

CNPC will help Ahdab produce 110,000 b/d, up from the originally agreed 90,000 b/d, with first output expected in 3 years. According to Shahristani, the field should have an active life of some 20 years.

CNPC will own 75% of the joint venture, with Iraq's state-owned Northern Oil Co. owning the remaining 25%. Shahristani said the contract, currently valued at some $3 billion, would be reviewed every quarter over its 22-year term.

Analysts saw the agreement as a breakthrough for China and CNPC over other countries and international oil companies.

Liu Youcheng, a Beijing-based analyst with Hongyuan Securities, noting that it has become more and more difficult to obtain equity and exploit rights in oil fields, said it is good for China to participate in the development through a service contract.

Alex Munton, an analyst with consultant Wood Mackenzie, said the biggest significance of the agreement is that CNPC will benefit as the first international oil company to be developing one of the giant discovered oil fields in Iraq in the new era.

According to Munton, CNPC will be the first with people on the ground and the first to develop a working relationship with Iraq's Oil Ministry.

IOC deals rejected

Iraqi oil ministry officials earlier expressed hopes of signing contracts with international oil companies by the end of June. Now, according to ministry spokespersons, those talks with such firms as Royal Dutch Shell PLC, BP PLC, and Exxon Mobil Corp. are unlikely to proceed.

A top Iraqi official criticized international oil companies for trying to overcharge the war-torn nation and for ignoring what he referred to as their "humanitarian" duty to help develop Iraq's battered oil industry.

The charge came after Iraq delayed the signing of short-term oil service contracts with oil majors due to disagreements over payment terms and their duration.

"The invitations to take part in these projects have not only an economic but a humanitarian character," said Iraq's electricity minister Karim Waheed after meetings with Russian energy minister Sergei Shmatko and the heads of Russian energy service firms.

"Some companies in those cases demanded sky-high prices for their services, thinking Iraq does not have a grasp of international financial markets. They were unpleasantly surprised when they found out we fully understand global commodity markets and global stock markets," Waheed said.

ExxonMobil
begins site work at Point Thomson

ExxonMobil Production has finalized initial barging of equipment and supplies to the Point Thomson drill site. This work supports the drilling program outlined in the Point Thomson development plan submitted to the Department of Natural Resources earlier this year. ExxonMobil is operator of the Point Thomson unit.

The barges and tugs, operated by Crowley Maritime Corporation, transported ice road and drill site construction equipment and supplies to the Point Thomson site located on Alaska's North Slope. ExxonMobil has conducted field operations at Point Thomson for several weeks following issuance of permits and is awaiting additional permits from State regulatory agencies necessary to allow drilling activities to continue.

Craig Haymes, Alaska production manager for ExxonMobil, said, "Point Thomson will be the highest pressure gas cycling project in the world, employing world-class drill wells. Currently over 150 people from more than 30 companies in Alaska are working to progress drilling and development activities for the Point Thomson field. The future availability of Point Thomson gas is essential to the success of an Alaska gas pipeline project."

The Point Thomson reservoir, located 60 miles east of Prudhoe Bay, is over 12,000 feet deep. The reservoir pressure of 10,200 pounds per square inch is abnormally high for the depth, requiring specialized drilling and well-completion operations to maintain well control. The project also will require high pressure injection and fluid-handling facilities.

As part of the drilling program, a $20 million project is under way to upgrade the Nabors Rig 27E with new drilling mud and electrical systems to safely access the very high pressure Point Thomson reservoir. Casing pipe and wellhead equipment containing high-strength steel and special corrosion-resistant alloys is under manufacture, with delivery scheduled before year-end. The drilling and production facilities will be designed and installed to minimize the impact on the environment. Ice roads and existing gravel pads will be used as much as practicable, with no off-lease gravel roads planned. Road construction is planned for late 2008.

The project will cost approximately $1.3 billion, which includes a five-well delineation drilling program and a multi-year development to construct production facilities, pipelines, and support infrastructure. The upgraded Nabors rig will drill the first well during the 2008-09 winter season.

Under the initial phase, approximately 200 million cubic feet per day of Point Thomson gas is expected to be produced. Approximately 10,000 barrels per day of liquid condensate that is separated from the gas is planned to be delivered for sale through new and existing oil pipelines. The remaining gas will be injected back into the Thomson Sand reservoir to maintain pressure for continued hydrocarbon recovery and for subsequent gas sales.

ExxonMobil and the other Point Thomson working interest owners are proceeding with the project while they seek to resolve the dispute with the State over the Point Thomson Unit and leases. Other owners include BP Exploration (Alaska) Inc., Chevron U.S.A. Inc., ConocoPhillips Alaska Inc, as well as 23 additional companies.

Evacuations speed up as storm approaches Louisiana

Oil and gas operators went faster their evacuations of Gulf of Mexico facilities on Aug. 31 as Hurricane Gustav sped away from Cuba and seemed headed for landfall Sept. 1 west of New Orleans.

At midday Aug. 30, the US Minerals Management Service said operators had moved workers off 223 of the 717 production platforms in the gulf.

Workers also were removed from 45 of the 121 drilling rigs operating in the gulf.

MMS estimated that 76.8% of the gulf's recent oil production of 1.3 million b/d was shut in. Shut-in gas production represented 37.2% of recent output estimated at 7.4 bcfd.

While a complete list wasn't immediately available, several major companies had announced refinery closures as of Aug. 31.

ExxonMobil Corp. said the 192,500 b/d Chalmette Refining LLC refinery in Louisiana was being shut down.

ConocoPhillips said it was idling the 247,000 b/d Alliance Refinery in Belle Chasse, La., and the 440,000 b/d refinery at Lake Charles, La.

Industry preparations

On Apr. 28, the American Petroleum Institute issued a report on preparation adjustments the oil and gas industry has made since Hurricanes Ivan in 2004 and Katrina and Rita in 2005.

API noted that during those storms, waves were higher and winds were stronger than anticipated in deeper parts of the gulf. The industry therefore no longer views the gulf as a uniform body of water.

A central portion is now seen as more hurricane-prone because it can be a gathering spot for warm currents that can strengthen the storms.

In response to revised wind, wave, and water-current measurements (so-called metocean data), API reassessed its recommended practices (RPs) for industry operations in the region.

Operators continue to integrate the updated environmental (metocean) data on how powerful storms affect conditions in the gulf offshore structure design standards. This effort led to the publication in 2008 of a final update to RP 2SK, Design and Analysis of Stationkeeping Systems for Floating Structures, that provides guidance for design and operation of mobile offshore drilling unit (MODU) mooring systems in the gulf during the hurricane season.

This update replaces API RP 95F, Interim Guidance for Gulf of Mexico MODU Mooring Practice. API RP 95J, Gulf of Mexico Jack-up Operations for Hurricane Season, was also updated and is no longer considered an interim standard. This standard recommends locating jack-up rigs on more stable areas of the sea floor and positioning platform decks higher above the sea surface.

Downstream changes

Since the 2005 storms, API said, refiners and pipeline companies have:

- Participated in industry conferences to share best practices and improvement opportunities.
- Worked with utilities to clarify priorities for electric power restoration critical to restarting operations and to help minimize significant disruptions to fuel distribution and delivery.
- Expanded on-site backup electric power generation capability or identified and located or leased backup generation equipment that may be positioned as needed.
- Established redundant communications systems to support continuity of operations and locate employees.
- Worked with vendors to preposition food, water, and transportation equipment and plan for other emergency supplies and services.
- Provided additional training for employees, who have participated in various exercises and drills.
- Reexamined and improved emergency response and business continuity plans.
- Strengthened onshore buildings and elevated equipment where appropriate to minimize potential flood damage.
- Worked with states to provide documentation to employees who need access to disaster sites where access is restricted by state and local law enforcement.

Hunt Energy drill rig appears at Melbourne docks en route to Tasmania

Empire Energy Corp. Int. (EECI) announced that having just finalized the drilling of an oil & gas well at Sealake, Victoria, the Hunt Energy Rig Number 3 has arrived at the Melbourne docks and is being washed down prior to quarantine inspection. Assuming quarantine approval, it is expected that all 32 semi-trailer loads of equipment (including the rig) should be shipped to Tasmania. Extra equipment, such as casing and a well head, have been ordered and are believed to be on their way to Tasmania.

It is expected that Bellevue #1 will be spudded as soon as permitting is completed and approvals obtained. Empire's CEO, Malcolm Bendall reports, "Our recently expanded staff and our many consultants have been working aggressively around the clock completing the numerous reports needed to obtain government permission to start our Bellevue and Thunderbolt wells. Geophysical, geological, archeological, cultural heritage, ydrogeological, acoustic, engineering, operations, emergency response, forest practices, fire service, land owner, mud disposal, well control insurance and environmental management plans, agreements and surveys have now been completed in record time for the new site. We plan to spud the 300m Bellevue top hole in September using a dual rotary DR24 open hole exploration rig provided by local Tasmanian company Spaulding Drillers. Spaulding has previously pre-collared, cased and cemented 500psi API rated 4.5 inch pipe to which blow out preventers were attached in seven stratigraphic holes. Bellevue will be our eighth well but our first conventional petroleum well drilled on a seismically defined structure."

Empire Chief Geologist and Chairman Dr. Clive Burrett says, "Our site at Bellevue is geologically and logistically very good and is at the overlap of three of the seismic lines that define the closure of the huge Bellevue Anticline.

We will spud in the Jurassic dolerite which provides a thick and effective regional seal. Under the dolerite, it is anticipated that we will intersect eight potential reservoir formations. These include Triassic and Permian freshwater sandstones and associated coal measures which are closely analogous to producing reservoirs in the Cooper Basin (Australia) and in the South Oman Basin (Oman).

We plan to carry out flow tests on the coal and sands for oil and gas. Beneath the Permian sands we expect 150 meters of Early Permian Quamby Mudstone that is similar to the Sprayberry Formation in West Texas.

The Quamby Formation contains the Tasmanite Oil Shale, which is the world standard for Type 1 kerogen and one of the richest oil source rocks for oil in the world. Based on geochemical data, government geologists have calculated that the Tasmanite Oil Shale and the Quamby Formation could have generated 9.5 barrels per square meter of basin area or over 150 billion barrels of oil over the whole Tasmania Basin. Even if only 1% of this has been trapped and is recoverable, we still have a very significant prospective resource of over 1 billion barrels.

Unconformably beneath this Permian section, we have potential reservoirs and seals in the Siluro-Devonian Eldon Group which group is analogous to similar sequences in the Appalachians. At about 2700 meters, we expect to test the Gordon Limestone, which is analogous to producing reservoirs in the Amadeus Basin in central Australia, the Trenton and Viola Formations of the USA and the Ordovician limestones of the Tarim Basin (China). After drilling, mud logging, flow testing and wireline logging is finished, we plan a borehole seismic survey which will, for the first time, give us accurate velocity information for the Early Paleozoic sequence and provide an ideal seismic trace at the well-bore to correlate with the surface seismic. These new data will be very helpful for our ongoing seismic exploration in Tasmania. Work on permitting and engineering planning for our next well, Thunderbolt #1, which is also on a huge, independently verified, seismically defined structure, is also almost complete and will be submitted shortly."

Empire has recently received a loan of AUD$5 million from Hong Kong-based Smart Win International Limited which is guaranteed by CEO Malcolm Bendall. Empire is currently negotiating a joint venture agreement with SmartWin which could provide cancellation of the loan and a further AUD$40 million in funding relating to development of its license area.

Rosneft's Profit Goes Beyond Lukoil's as Output Expands (Update1)

Russia's biggest crude oil producer, earned more than domestic rival OAO Lukoil in the second quarter, by raising output and integrating assets bought from bankrupt OAO Yukos Oil Co.

Rosneft said net income more than doubled to $4.31 billion, beating analysts' forecasts. Lukoil, the country's second- biggest oil producer, said profit rose 64 percent to $4.13 billion, less than expected.

State-run Rosneft went from being a second-tier oil company to Russia's leading producer after buying up assets belonging to Yukos, which collapsed in 2006 under back-tax claims of more than $30 billion. Lukoil has struggled against declining crude output in western Siberia.

" Rosneft is eclipsing Lukoil," said Ronald Smith, chief strategist at Moscow-based Alfa Bank. ``It has a better long- term profile, and it has younger, more-productive fields.''

Lukoil fell 50.82 rubles, or 2.7 percent, on Moscow's Micex Stock Exchange to 1,829.81 rubles. UBS AG cut its price estimate today on the shares by 2.5 percent to $94.20 (2,315 rubles), citing ``cost inflation across the board.'' Rosneft rose 3.71 rubles, or 1.8 percent, to 209.68 rubles.

Rosneft also outpaced Lukoil in terms of earnings before interest, taxation, depreciation and amortization, or Ebitda, a measure of underlying profitability.

Rosneft's Ebitda rose 97 percent to $7.05 billion, as Lukoil's rose 59.2 percent to $6.24 billion. The results mark the first time Rosneft beat Lukoil on this basis, according to JPMorgan Chase & Co.

Lukoil Hedges

Lukoil's cost of purchased oil, gas and products jumped 77 percent in the second quarter to $12.5 billion as prices rose. That included a loss of $621 million from hedging, compared with $45 million a year earlier.

The oil producer's results would have exceeded estimates ``if not for the extraordinary large hedging loss, and would have been outstanding if Lukoil exercised better cost controls,'' Igor Kurinnyy, an oil and gas analyst at ING Groep NV, wrote in an e-mailed note to investors.

The company recovered $380 million by hedging in the third quarter as the price of oil fell from its earlier highs, Lukoil Deputy Chief Executive Officer Leonid Fedun told reporters in Moscow.

`More Efficient'

Lukoil's earnings were also hurt by operating expenses that rose by 26.2 percent in the first half as oil extraction and refining became more expensive and the ruble appreciated. Selling, general and administrative expenses increased 22 percent in the first half.

``Rosneft's management is slightly more efficient than Lukoil's,'' Kurinnyy said by phone from London.

Rosneft's crude oil production grew 8.2 percent in the second quarter to an average 2.12 million barrels a day. Lukoil's fell 3 percent in the second quarter, and in western Siberia, where the company pumped 62 percent of its oil, production dropped 5.8 percent in the first half.

Rosneft's costs and expenses advanced by 87 percent to $15.19 billion in the second quarter because of rising export duties and the costs and expenses of subsidiaries acquired from Yukos. Production and exploration expenses grew to $3.31 per barrel from $3.29 per barrel.

Higher Prices

Both companies benefited from export blend Urals crude averaging $117.64 a barrel in the period, up 80 percent from a year earlier, according to data compiled by Bloomberg.

Rosneft borrowed $22 billion to buy units and refineries at auctions after former Yukos Chief Executive Officer Mikhail Khodorkovsky was jailed for tax evasion and fraud. The company agreed to sell half of production unit Tomskneft to OAO Gazprom Neft in December.

Rosneft reported net income of $7.66 billion in the second quarter of last year after receiving one-time payments from the sale of assets by Yukos, dismantled in former President Vladimir Putin's second term after getting more than $30 billion of back- tax claims. Adjusted to exclude the Yukos payments, profit was $1.7 billion during the period, Rosneft said today. Rosneft was Yukos's second-biggest creditor.

Dearth of Ships Delays Drilling of Offshore Oil

As President Bush calls for repealing a ban on drilling off most of the coast of the United States, a shortage of ships used for deep-water offshore drilling promises to impede any rapid turnaround in oil exploration and supply.

In recent years, this global shortage of drill-ships has created a critical bottleneck, frustrating energy company executives and constraining their ability to exploit known reserves or find new ones. Slow growth in oil supplies, at a time of soaring demand, has been a major factor in the spike of oil and gasoline prices.

Mr. Bush called on Congress to end a longstanding federal ban on offshore drilling and open the Arctic National Wildlife Refuge for oil exploration, arguing that the steps were needed to lower gasoline prices and bolster national security. But even as oil trades at more than $135 a barrel - up from $68 a year ago - the world's existing drill-ships are booked solid for the next five years. Some oil companies have been forced to postpone exploration while waiting for a drilling rig, executives and analysts said.

Demand is so high that shipbuilders, the biggest of whom are in Asia, have raised prices since last year by as much as $100 million a vessel to about half a billion dollars.

"The crunch on rigs is everywhere," said Alberto Guimaraes, a senior executive at Petrobras, the Brazilian oil company that has discovered some of the most promising offshore oil but has been unable to get at it.

"Almost 100 percent of the oil companies are constrained in their investment program because there is no rig available," he said.

As a result, drilling costs for some of the newest deepwater rigs in the Gulf of Mexico - the nation's top source of domestic oil and natural gas supplies - have reached about $600,000 a day, compared with $150,000 a day in 2002.

These record prices have spurred a new wave of drill-ship construction. This boom could lead to renewed offshore oil exploration that would eventually bring more supplies to the oil market, and push down prices.

Already, 16 new drill-ships are scheduled to be delivered to oil companies this year - more than double the number delivered over the last six years combined. In fact, 75 ultra-deepwater rigs should be delivered from 2008 to 2011, according to ODS-Petrodata, a firm that tracks drilling rigs.

Shipyards from South Korea to Norway are working overtime to meet a huge influx of orders.

Robert L. Long, the chief executive office of Transocean, the world's largest drilling company, said he has nine deepwater rigs under construction, eight of which are already under contract for periods ranging from four to seven years once they leave the shipyards. He expects to receive the ships between the beginning of 2009 and the end of 2010.

Transocean believes the deepwater market will continue to be constrained until at least 2012. Over three-quarters of the drill-ships currently under construction have already been contracted to oil companies eager to benefit from triple-digit oil prices, Mr. Long said.

Petrobras, whose full name is Petróleo Brasileiro, is expected to drive much of the growth in the booming new market. The company has outlined an aggressive program to increase its drilling capacity, and plans to contract or build 69 deepwater drill-ships by 2017.

Brazil stunned the oil world when it announced the discovery of a vast oil field 200 miles south of Rio de Janeiro last November, turning the country's deep blue waters into the world's most exciting oil frontier. Energy experts said the field could turn out to be just a small part of the largest oil discovery in 30 years.

But seven months later, the problem is still how to retrieve it. Petrobras has only three rigs capable of drilling in waters that exceed 6,500 feet, like the sites of the new fields.

But drilling constraints are not the only problem facing international oil companies, which are seeking to expand at a furious pace after a decade of underinvestment in the 1990s. They have also had to contend with a doubling of development costs across the industry in the last five years, more acute competition for energy resources, shortages in steel, engineering and manufacturing capacity, and pressures posed by an aging work force.

Also, gaining access to countries that hold oil reserves is becoming tougher as many oil-rich governments see fewer incentives to raise production as they reap the benefits of higher prices.

As a result, explorers are scouring ever-more remote corners of the globe in their hunt for hydrocarbons. That quest has found petroleum reserves off the shores of Africa and Brazil, and opened up promising exploration regions in the South China Sea, off the shore of India, and around the coast of Australia. But those sites will remain largely off limits until the new drill-ships arrive.

Brazil's giant offshore oil discoveries

By Jerome R. Corsi
WorldNetDaily.com

A key argument of "Peak-Oil" and "Fossil-Fuel" theorists is no new giant oilfield discoveries have been made in recent years. Oil "experts" such as Matt Simmons and Ken Deffeyes are locked into the belief that oil is a fossil fuel, and pretty soon we are bound to have found and drilled all the oil that ever was. What about Brazil?

The experience of Brazil's offshore drilling is proving that giant new oil fields are out there, waiting to be discovered, just offshore along the continental shelf. Petrobras, Brazil's largest oil company is moving Brazil from being nearly 100 percent dependent on foreign oil imports only some 50 years ago, toward becoming a net oil exporter in the next few years. How? Brazil has realized spectacular results by developing the technology to drill ultra-deep offshore wells in Brazil's Barracuda and Caratingua oil fields, in the Campos Basin some 50 miles into the Atlantic Ocean east of Rio de Janeiro.

To develop the oil resources of the Campos Basin, Petrobras formed the Barracuda & Caratingua Leasing Company B.V. as a special purpose corporation established in the Netherlands. In December 2004, BCLC finalized an $2.5 billion agreement with Halliburton's Kellogg Brown & Root subsidiary, awarding KBR a full engineering, procurement, installation and construction contract for 55 offshore wells in the two oil fields (22 horizontal producers and two multilateral horizontal producers, as well as eight horizontal injectors and eight piggyback injectors).

The contract also specified the construction and installation of two FPSO (floating, production, storage, offloading) vessels. According to Offshore-Technology.com, the Barracuda and Caratingua fields are expected to add 30 percent to the current 1 million barrels per day of production from the Campos Basin region. The two fields cover a combined area of 230 square kilometers (approximately 145 square miles). Photographs of the massive Barracuda FPSO and the P-48 Platform Topsides are posted and technically described on Rigzone.com.

According to Rigzone.com, the Barracuda and Caratingua proven oil reserves are estimated at 1.229 billion barrels. Together they are expected to produce 773 million barrels of oil by 2025. Petrobras has taken the additional step of contracting international oil consultants DeGolyer and MacNaughton to validate proven reserve estimates.

According to Energy Information Administration estimates, Brazil in 2004 produced 1.8 million barrels of oil per day, almost all of which was from offshore drilling in the Campos Basin (which includes the giant oil fields of Barracuda, Caratingua, and Merlim Sul) and the Santos Basin. Brazil's oil production has grown at a rate of about 9 percent per year since 1980.

With the country consuming 2.2 million barrels per day, Brazil is about to become oil independent. By the end of this decade, Brazil expects to become a net oil exporter. Brazil's offshore drilling success represents a complete turnaround – in 1953, Brazil domestic oil production filled only 3 percent of domestic demand.

None of this will impress peak-oil or fossil-fuel theorists, who expectedly will argue that the Brazil's offshore oil fields, regardless how large they might be, are doomed to deplete sooner or later. Petrobras has a different vision. If giant oil fields can be found 50 miles offshore Brazil, how many more giant offshore oil fields remain to be discovered?

Today, Petrobras is one of the world's leaders in developing offshore technology capable of drilling the ocean floor under some two miles of water. Petrobras enjoys considerable international prestige with its ultra-deepwater technology. The company has expanded its offshore presence in the Gulf of Mexico and off the West Coast of Africa. Petrobras is contemplating developing new offshore projects in the Caribbean, in the waters offshore Cuba.

The geological description of the Campos Basin suggests that the rock formations in which oil is being found are in Upper Oligocene to Lower Micocene deposits – in other words, deposits from the Cenozoic Era, dating back only some 24,000 years. Dinosaurs dominated in the prior Mesozoic Era which stretches back 250 million years ago and end some 65 million years ago. The oil-rich deposits in the Campos Field stretch back at most some 20 thousands of years, not millions. This should rule out that any dead dinosaurs or decaying ancient forests formed the oil found off Brazil's shore. Dinosaurs supposed died out in the Crataceous Period at the end of the Mesozoic Era, just before the Cenozoic Era began.

Moreover, the oil-rich deposits are typically described as "turbidite," a sedimentary deposit that typically consists of material that has moved down a steep slope at the edge of the continental shelf. The oil-rich sediments are mostly sand and mud. The technical descriptions of the oil-rich rock in the Campos Basin strongly suggest that the deposits flowed from the continent and settled on the ocean floor.

The biotic content of the rock is found to contain "benthic foraminifera," little shell creatures that like to live on the ocean bottom. The rock itself is described as having been formed in "bathyal" conditions, a term typically reserved to describe the ocean floor from half a mile to about two miles down. The geological descriptions suggest no findings of animal fossils or ancient flora debris.

While the geology suggests the Campos Basin oil-rich deposits formed when the sea level was lower than today, the deposits suggest that the area was most probably still underwater when the sand and mud deposits flowed into the area.

With the geological description of the rock, "Fossil-Fuel" theorists are going to have a hard time positing that ancient dinosaurs and decaying prehistoric flora were the cause of the oil. The geological description sounds like the area was already well underwater when mud and sand run-off from the shore deposited sediment. The abiotic theory of oil seems more consistent with the geology, arguing that this type of deposit was sufficiently porous for upward-seeping hydrocarbons naturally formed in the Earth's mantle to pool in reservoirs.

What is clear from reading the technical discussions from Petrobras oil engineers is that they are far more interested in the 3D seismic studies of the Campos Field oil reservoirs and 4D seismic analyses (taking into account time period analysis) than they are in debating about whether the oil came from decaying dinosaurs and ancient trees.

When Petrobras CEO Jose Eduardo Durta presented the company's Strategic Plan out to year 2015 to a group of investors in New York on May 20, 2004, he was looking to expand the company's expertise in deep and ultra-deep waters beyond the continental shelf off Brazil. Mr. Durta looked to strong expansion for Petrobras in this oil market niche, and he said not a word about whether or not dinosaurs had ever roamed a square foot of the ocean bottoms he planned to explore.

Looking at the experience of Petrobras in Brazil, we are led to wonder why the United States is leading in ultra-deep oil operations. Few countries in the world have the extensive offshore territory enjoyed by the United States. Why aren't we resolved to become oil independent by exploring offshore oil with the aggressive resolve demonstrated by Petrobras?

Our problem seems to be that the current coalition of radical environmentalists, "Peak-Oil" and "Fossil-Fuel" pessimists, and the political Left are unwilling to step down their rhetoric long enough to look rationally at some real world empirical results.

How is Offshore Oil and Gas Different?

The offshore oil and gas industry will present many unique legal issues to government, stakeholders, businesspeople and interest groups. One of the most fundamental of these issues can be summed up by asking, "which level of government has the authority to regulate and control the exploration and development of B.C.'s offshore resources?

Control over most of B.C.'s resource based industries is quite clear. Generally speaking, forestry, mining and aquaculture are governed by the provincial government; while fisheries, with some exceptions, is governed by the Federal Government. These jurisdictions, or this splits in control, are laid out Canada's Constitution.

Offshore oil and gas is a unique industry because it combines the extraction of hydrocarbons (normally under provincial control) with the marine environment (normally under federal control). Add to this the Federal Government's control over navigation and shipping, and a joint mandate over the environment, and the stage is set for a political power struggle, as occurred in Newfoundland.

The Atlantic Experience

When Newfoundland joined Canada in 1949, it negotiated a deal that saw it losing a degree of independence in return for certain benefits. During nego-

tiations, Newfoundland failed to turn its mind to its offshore resources, and did not reserve any rights in them as against the Federal Government. However, when in the 1960's the Federal Government attempted to assert rights over the seabed minerals in contemplation of developing them, the Newfoundland government became outraged that it was being cut out. In 1969, Newfoundland took the Federal Government to the Supreme Court of Canada, seeking a declaration that the seabed resources were Newfoundland's to control. The Court found that the offshore resources belonged to the Federal Government because Newfoundland had not specifically reserved rights to the minerals when they entered into Confederation.

Newfoundland was not pleased with this decision and vowed to continue fighting.

How British Columbia is Different

In 1967, British Columbia posed much the same question to the Supreme Court of Canada. The Court found that the seabed and its resources, from the mean low water mark to the outer limit of the Territorial Sea (12 nautical miles), was within the exclusive control of the Federal Government.

However, like Newfoundland, British Columbia wasn't satisfied with this answer. In 1981, the Province declared the entire coast an "Inland Marine Zone", in an attempt to assert its jurisdiction over the area. This declaration was political at best, and had little, if any, legal significance.

In 1982, BC returned to the Supreme Court to ask the Court if the seabed resources between Vancouver Island and the mainland, particularly the seabed of Queen Charlotte Straight, Johnstone Straight, Georgia Straight and Juan de Fuca Straight, were within the jurisdiction of the Province.

In deciding for the Province, the Court looked to the unique history of British Columbia. The Court found that when the Province was originally created as a colony by the British Parliament in 1866, its borders were defined with the most western outer limit of the Province being the "Pacific Ocean". The court contemplated the meaning of "Pacific Ocean" and found that the water and seabed between Vancouver Island and the mainland were not commonly considered part of the Pacific Ocean and were therefore within the jurisdiction of the province.

Importantly, we know from the Geological Survey of 1998 that the hydrocarbon reserves under these areas of Provincial control, particularly the Georgia Basin, contain minimal oil, but do contain modest natural gas reserves (6.5 trillion cubic feet). We further know from the 1998 Survey that the majority of BC's offshore oil (9.8 billion barrels) and gas (26 trillion cubic feet) lies under the Queen Charlotte Basin in the Queen Charlotte Sound and Hecate Straight.

Unfortunately for the BC government, the question posed to the Supreme Court in 1982 did not include a question as to who controls the bulk of the resources, those being under Queen Charlotte Sound and Hecate Staight. As a result, there is no binding authority that states specifically that those areas are under the control of the Federal Government. Indeed, if the Supreme Court were to find that Hecate Straight and Queen Charlotte Sound were not part of the "Pacific Ocean" proper, than the seabed resources would fall within the boundaries and the control of the Province. However, politicians may wish to settle this question themselves.

Present Status of Jurisdictions

As it stands now, the province clearly has jurisdiction over the resources under the Queen Charlotte Straight, Johnstone Straight, Georgia Straight and Juan de Fuca Straight. The Federal Government, arguably, has jurisdiction over the vast majority resources under Queen Charlotte Sound and Hecate Straight. Whether the province will attempt to capitalize on its self-pronounced "Inland Marine Zone" and assert jurisdiction over the reserves under Hecate Straight is questionable as it would likely mean a long and drawn out legal battle. Before closing, it is interesting to note that the B.C. government could avoid a dispute over jurisdiction in Hecate Straight and still explore and develop a portion of the Queen Charlotte Basin. Maps forming part of the 1998 Geological Survey Canada show that a portion of this massive petroleum reserve lies under Graham Island. This oil can be accessed from Graham Island without the jurisdictional complications and the added complexity of drilling in the marine environment. The reserves directly under Hecate Straight might also be reached by drilling from land using directional and horizontal drilling. Although such ideas may successfully avoid a conflict of jurisdictions with the Federal Government, they still contain serious social, economic and political issues with respect to drilling on Hadaii Gwai.

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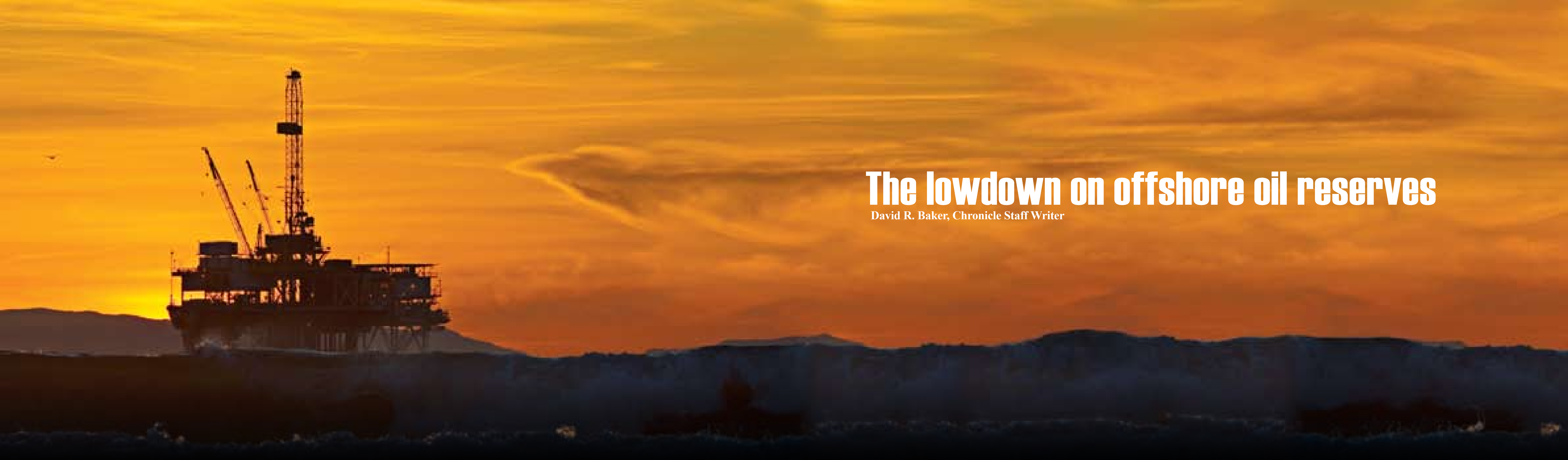


The lowdown on offshore oil reserves

David R. Baker, Chronicle Staff Writer

U.S. offshore oil fields could hold enough crude to supply all of the country's needs for more than 11 years.

Or they might not. No one knows for certain because, with new offshore oil drilling banned on the East and West coasts, no one has gone looking for oil there in years.

Now congressional Republicans are pushing hard to make offshore drilling a key issue in the presidential campaign, hoping to channel the anger Americans feel over historically high oil and gasoline prices. More oil, they argue, will bring lower prices.

The federal government estimates the nation's outer continental shelf might hold 85.9 billion barrels of crude, including 10.13 billion barrels off California. For comparison, the United States consumes about 7.56 billion barrels of oil per year. The nation's sea floor also could hold 419.9 trillion cubic feet of natural gas, equal to U.S. consumption for 14 1/2 years. But the federal estimates are just that - estimates.

"You don't really know what's there until you go out and drill a well," said Ken Medlock, an energy research fellow at Rice University's James A. Baker III Institute for Public Policy. "And even then, you're not 100 percent sure of what you're going to get."

In addition, offshore oil exploration is slow and costly.

If the federal government opened California's coast to drilling tomorrow, the first exploratory wells probably wouldn't be drilled for at least six years, Medlock said. Bringing newly discovered oil fields into full production would take longer.

That means any new oil wouldn't arrive on the market until midway through the next decade, at the earliest. The process is slow enough that the Energy Information Administration, the statistics branch of the U.S. Department of Energy, estimated last year that opening the coasts to offshore drilling would have no significant impact on oil prices before 2030.

"It's a crock to say that's any kind of near-term solution for the pain drivers are feeling at the pump," said Bill Corcoran, senior regional representative for the Sierra Club.

Drilling supporters acknowledge the long time frame but say there's no better moment to start than now. If the federal government hadn't stopped most new coastal drilling 26 years ago, some of that oil would already be on the market, they argue.

"We've had a lot of years of federal policy that has resembled a 'Just Say No' approach," said Joe Sparano, president of the Western States Petroleum Association.

He hopes changing public attitudes toward drilling will open the coasts. A Field Poll found that while a majority of Californians - 51 percent - still rejects offshore drilling, opposition within the state isn't as strong as it once was. The last time the poll asked Californians about drilling, in 2005, 56 percent opposed it.

"If the number of Californians who support new drilling offshore continues to increase, maybe the politicians who represent them will respond," Sparano said.

Not all of America's coastal waters are closed to drilling.

Most of the country's estimated offshore reserves - about 75 percent - lie in areas that have been drilled for years or are being opened for exploration. Roughly 48 percent of the nation's estimated reserves, or 41 billion barrels, lie beneath the western and central Gulf of Mexico, where oil companies armed with new drilling technology are pushing into ever deeper water. Another 27 percent of the estimated reserves, or 23.6 billion barrels, are believed to lie off the north coast of Alaska, where the federal government sold oil exploration leases this spring, despite fears that the work would hurt the polar bear population.

California has about 23 percent of the country's estimated offshore reserves, with 10.13 billion barrels in federal waters that begin 3 miles off the state's coast. An additional 1 billion barrels may lie closer to shore, in waters controlled by the state government.

California witnessed the world's first offshore oil well, drilled in 1897 at the end of a pier near Summerland (Santa Barbara County). But a 1969 accident at a well farther west in the Santa Barbara Channel, which spewed crude oil into the water and coated beaches, turned public opinion against offshore drilling.

Congress imposed a moratorium on new offshore wells along much of the country's coastline in 1982, and President George H. W. Bush added a presidential moratorium in 1990. But President George W. Bush lifted that moratorium as part of a concerted Republican push on drilling. Republican presidential candidate John McCain has called for lifting the congressional moratorium as well.

Even if that happens, it probably wouldn't create a stampede to California's coast.

Gov. Arnold Schwarzenegger remains opposed to expanded offshore drilling, saying the country should focus instead on weaning itself off oil. The state government does not have direct control over federal waters off its coast, but it could place obstacles in the way of anyone looking for oil there.

The California Coastal Commission could object to any federal lease for oil exploration off the state's coast, said Brian Baird, assistant secretary for ocean and coastal policy at the California Resources Agency. The U.S. secretary of commerce could override the commission, but the state could then take the project to court, he said.

Although victory would hardly be guaranteed, "I would say it's a pretty strong hand," Baird said.

Oil and Gas World

Brief Overview

By OilGasArticles Editor

Oil and Gas Market Introduction

The Upstream Oil and gas sector is an international market, with investment and operational decisions increasingly determined against world norms, heavily influenced by both the current world oil and gas price and anticipated price for its impact on new offshore and inshore field developments.

The volatility of the oil price has led to changes in the structure of the oil and gas sector, encompassing both the oil companies and their various suppliers and contractors. In particular there has been consolidation both horizontally and vertically in the traditional contracting oil and gas supply chain.

Every day the world consumes over 75 million barrels of oil and 6 billion cubic metres of gas. This rate of consumption further depletes the planet's finite quantity of fossil fuel.

Demand for Oil and Gas

Continued world economic growth, particularly assuming there are no major downturns in world regions (as in Russia and SE Asia in 1998 / 1999), will lead to increased demand for Oil and gas.

With limitations on the spare production capacity available world-wide at present, increased world demand will certainly require increased development activity in both OPEC and non-OPEC countries. Thus it is expected that world investment in exploration and production facilities will rise.

The level of activity in any one country is influenced generally by the expectation on oil price, and local conditions reflecting the country's competitive position with respect to others.

With limitations on the spare production capacity available world-wide at present, increased world demand will certainly require increased development activity in both OPEC and non-OPEC countries. Thus it is expected that world investment in exploration and production facilities will rise

Local conditions generally, the attractiveness of the oil province geologically (indicated perhaps by recent discovery rates and size of discovered fields), legislation affecting conditions and taxation on developments, and the confidence in political system and proximity to markets are all factors to be taken into account.

The Gas Sector

Whilst gas field exploration and developments use similar technology to Oil, the gas sector is different economically. The high cost of transporting gas (up to ten times the cost of transporting oil) means that gas field developments cannot be considered in isolation, but need to be developed in conjunction with investment in transportation infrastructure (pipelines or liquefaction systems) and the related demand markets.

Thus gas prices and contracts are often specific to a locality - country or region. The exception to this is where the gas sector - markets and infrastructure are Well developed - as in the UK, Europe and US - where, with suitable deregulation, there can be more of a genuine market-driven price.

There is increasing interest in gas world wide, with demand for gas currently growing and forecast to grow at a higher rate than oil over the next two decades. This is being driven partly by the availability of gas and its attractions on environmental grounds. It is also leading to increasing interest and development of Gas To Liquids technology in which gas is converted to a more concentrated liquid form to facilitate the exploitation of remote and smaller gas reserves.

Major oil companies such as Shell are moving into gas, seeing declining business opportunities in non-OPEC countries. Further, the importance of power generation as a market for gas is encouraging companies to become involved in both gas and power utilities.

Oil and Gas Field Development

Field developments will be matched by investment in major transportation systems, either liquefied Natural Gas(LNG) or Pipeline, in regions such as SE Asia, South America and linking Central Asia / Middle East to Europe.

There is a long term trend of refineries being built more in developing and Petroleum producing countries and away from developed, consuming, countries, as producers seek to increase their added value and developing countries seek to reduce their dependence on imports.

The developed world's refineries operated efficiently and profitably while Oil prices were low (cheap feedstock) and supply readily available. Subsequently, with tight oil supplies, higher feedstock prices and pressure from consumers on prices, they are operating less profitably. However, refineries in other parts of the world, especially SE Asia, have suffered from low demand in recent years, leading to continuing low margins. Demand for new refineries is limited, generally driven by national policies on adding value with products from Crude Oil, or meeting national demand for refined products from indigenous production capacity. However, there is an ongoing requirement for the upgrading of refineries to improve and revise the product mix and to meet more exacting environmental standards. The demands for different products in the automobile sector are an important driver in this.

Syrias Economical Overview, In view of- Depletion of oil reserves- Attempts to Reform its Economy

By Oil and Gas Author

Oil Reserves in Syria

Syrias Oil industry faces many challenges in the years to come. Oil output and production continues to decline due to technological problems and depletion of oil reserves. Since peaking at 590,000 bbl/d in 1996, Syrias oil output has fallen, to an estimated 460,000 bbl/d in 2004, as older fields, especially the large Jebisseh field discovered in 1968, have reached maturity. Syrian oil production is expected to continue its decline over the next several years, while consumption rises, leading to a reduction in Syrian net oil exports. If this trend continues, it is possible that Syria could become a net oil importer within a decade. Export levels, which had been temporarily buoyed by illegal imports from Iraq, fell sharply after the invasion of Iraq in March 2003.

Exploration and Production in Syria

Syria hopes to reverse the trend toward declining Oil exports through intensified oil exploration and production efforts, plus a switch from oil-fired to natural-gas fired electric power plants. Syria also has opened up new blocks for oil and Natural Gas exploration, with the Oil and Mineral Resources Ministry receiving bids from several international companies in December 2001 on five exploration areas.

Awards for these blocks were made in January 2003, with Shell receiving exploration rights in the Damascus-Palmyra area and Indias ONGC Videsh receiving another onshore block. Independents Ocean Energy and Stratic Energy also received awards. In 2003, three new exploration deals were announced, with companies receiving awards including Canadas Tanganyika and PetroCanada, Chinas CNPC, and Devon Energy and Gulfsands Petroleum of the United States. Another round of awards took place in January 2004, with companies involved including U.S. independent IPR Transoil, Indias ONGC, and Croatias INA Naftaplin. In May 2005, Gulfsands Petroleum purchased Devon Energys 80 percent stake in Block 26, then sold a 50 percent stake in the project to Soyuzneftegaz of Russia. Gulfsands remains as Operator of the project with a 50 percent ownership stake. INA Naftaplin reported a discovery of oil at the Jihar field in September 2004, which it expects to produce 5,000 bbl/d once it is developed.

Syrias main oil producer is al-Furat Petroleum Co. (AFPC) a joint venture established in 1985 and owned by the Syrian Petroleum Company (SPC), Shell, and PetroCanada. AFPCs fields are located in the northeastern Syria -- particularly the Deir ez-Zour region, where commercial quantities of oil were discovered in the late 1980s -- and are producing about 350,000 bbl/d of high quality light crude.

AFPCs main oil field is al-Thayyem, although production there has been declining since 1991. Another important field -- Omar/Omar North -- began production in February 1989 at 55,000 bbl/d. Shortly thereafter, operator Shell was pressed by the cash-strapped Syrian government to step up production (against Shells advice) to 100,000 bbl/d. The result was serious Reservoir damage, and in April 1989, output plummeted to 30,000 bbl/d. Currently, Omar produces about 15,000 bbl/d from natural pressure and 30,000 bbl/d from water injection. Other AFPC fields include al-Izba (light oil), Maleh (34o API Gravity oil), Sijan, and Tanak. Production from fields run by SPC peaked in the late 1970s at more than 165,000 bbl/d.

SPCs fields include:1) Karatchuk-- Syrias first discovery, located near the border with Iraq and Turkey;2) Suwaidiyah-- a giant heavy oil field located south of Karatchuk in the Hassakeh region (and extending into northwestern Iraq) which currently produces around 85,000 bbl/d; 3) Jibsah-- a major field producing both oil and gas; 4) Rumailan-- a small field near Suwaidiyah which produces heavy oil; and 5)Alian, Tishreen, and Gbebeh -- three small, depleting fields producing heavy oil.

Chinas CNPC signed a contract with SPC in March 2003 to undertake an enhanced oil recovery project for Gbebeh, which is to increase production from the current 4,500 bbl/d to 10,000 bbl/d.

Other Syrian oil fields include Maleh, Qahar, Sijan, Azraq, and Tanak. Jafra, discovered in late 1991 and located near Deir ez-Zour, is operated by TotalFinaElf and has current production of around 50,000 bbl/d. Besides conventional oil reserves, Syria also has major shale oil deposits in several locations, mainly the Yarmouk Valley stretching into Jordan.

Oil exploration activity in Syria has been slow in recent years due to unattractive contract terms by SPC, poor exploration results, and concerns about the possibility of additional U.S. sanctions. For these reasons, only a few companies out of more than a dozen operating in the country in 1991 remain in Syria at present. The recent bid rounds are an attempt to reverse this trend, but it is unclear how successful this will be. Officials of TotalFinaElf publicly expressed their intention to scale down their Syrian operations in May 2002, and ConocoPhillips announced in February 2004 that it was ending its operations in Syria.

Refineries in Syria

Syrias two refineries are located at Banias and Homs. Total current production from these refineries is 239,865 bbl/d (132,725 bbl/d and 107,140 bbl/d, respectively). Syria is planning to construct a third refinery, with an initial capacity of 60,000 bbl/d (possibly increasing to 120,000 bbl/d), at Deir ez-Zour to supply products to the eastern part of the country. A feasibility study on this project reportedly was completed in January 1998, but it has not been implemented. In addition, Syria plans to upgrade its two current refineries, both of which are in urgent need of overhauling, to replace output of fuel Oil with lighter products.

Natural Gas Reserves in Syria

Syrias proven Natural Gas reserves are estimated at 8.5 trillion cubic feet (Tcf). Most (around three quarters) of these reserves are owned by SPC, including about 3.6 Tcf in the Palmyra area, 1.6 Tcf at the al-Furat fields, 1.2 Tcf at Suwaidiyah, 0.8 Tcf at Jibsah, 0.7 Tcf at Deir ez-Zour, and the remainder at al-Hol, al-Ghona, and Marqada. About half of Syrias gas is non-associated, with the rest either associated (with Oil) or "cap" gas. In June 1999, a new natural gas field, called North al-Faydh, reportedly was discovered by SPC. The field reportedly has production potential of 35 million cubic feet per day.

Syria Pipeline Agreements

In 2003, Syria produced about 245 Bcf of Natural Gas, up sharply from 205 Bcf in 2002. Syria plans to increase this production in coming years as part of a strategy to substitute natural gas for Oil in power generation in order to free up as much oil as possible for export. A number of new gas-fired power projects are currently under construction or being planned. Another possible source of natural gas is imports. Syria signed agreements with Egypt, Jordan, and Lebanon in early 2001 for an onshore Pipeline network (the "Arab Gas Pipeline") which would link the four countries and make Syrian imports of natural gas from Egypt a possibility. The section of the pipeline running from Egypt to northern Jordan currently is in the final stages of construction. An agreement was signed in January 2004 between Egypt, Jordan, Syria, and Lebanon for the extension of the pipeline into Syria and Lebanon. Syria issued an invitation for bids for the extension project in June 2005. Meanwhile, Syria has begun exporting a small quantity of natural gas to Lebanon.

In October 1997, Syria announced discovery of a large new natural gas field in the Abi Rabah area of the Palmyra region. In addition to supplying a new (completed in 1997), 375-megawatt, power plant at Zaisoun in central Syria, the Palmyra fields have been linked with a new pipeline to Aleppo, as Well as to the Tishreen power plant in Damascus and the Mhardeh power plant in Homs. Najib, the fourth and final field to be developed in the Palmyra region, started production in 2000 at a capacity of 100 Mmcf/d. A modest-sized new discovery was reported in the Palmyra area in August 2002 by the Croatian company INA Naftaplin, which tested at about 9 Mmcf/d.

In September 2001, several months ahead of schedule, an important new, integrated natural gas project (called "Desgas") was completed in the Deir ez-Zour region, three years since a $430 million service agreement was signed between SPC on the one hand, and ConocoPhillips and TotalFinaElf on the other. The new complex utilizes approximately 175 Mmcf/d of previously-flared, "associated" (found together with oil) natural gas, in the Deir ez-Zour oil fields. TotalFinaElf and ConocoPhillips each hold 50 percent interest in the project, with ConocoPhillips as lead Operator.

ConocoPhillips announced in February 2004 that it intended to end its operations at Deir ez-Zour in the future, likely by letting the current contract lapse in 2005. The Deir ez-Zour complex now includes a natural gas gathering system and processing plant, plus a 155-mile pipeline to carry 150 Mmcf/d of natural gas to the grid serving western Syria.

Iran`s Oil Development in Offshore Area

Crude Oil Swaps by Iran

Irans desire to become a player on the Caspian Oil front has led it to push forward in the area of oil "swaps." This arrangement involves the delivery of Caspian oil to refineries, via the Caspian port town of Neka in northern Iran, for local consumption. An equivalent amount of Iranian oil is then exported through Persian Gulf terminals such as Kharg Island. Shippers normally pay a "swap fee" of $1.50-$2.00 per Barrel, with swaps handled by Naftiran Intertrade Co. (Nico), the Swiss-based trading arm of NIOC. As of August 2005, about 60,000 bbl/d of Turkmen and Kazakh oil were being shipped to Neka. From Neka, oil is then sent to Tehran by the existing 180,000-bbl/d capacity Neka-Tehran Pipeline. Eventually, Iran hopes to upgrade its facilities in order to greatly expand oil swaps, partly in order to compete with the 1-million-bbl/d Baku-Tbilisi-Ceyhan (BTC) pipeline, scheduled to open in late 2005.

Iran plans to boost capacity at its northern refineries at Arak, Tabriz, and Tehran in order to process additional Caspian oil, to boost Neka-Tehran pipeline capacity to 500,000 bbl/d, and also to increase port capacity at Neka to 500,000 bbl/d. In August 2003, a $500 million tender was issued to upgrade the Tehran and Tabriz refineries in order to handle 370,000 bbl/d of high sulfur Caspian crude. This follows a $330 million project, completed by a Sinopec-led consortium in late 2003, to expand storage at Neka and to upgrade the Tehran and Tabriz refineries.

In July 2005, Iran and Iraq signed an MOU on a swap agreement involving construction of a 24-mile, 350,000-bbl/d oil pipeline from Basra to the Abadan refinery in southwestern Iran. In exchange, Iran would ship refined products back to Iraq. In addition, Iran could allow Iraq to export crude through the Kharg Island terminal and to import refined products through the Iranian port of Bandar Mahshahr. One potential problem with this deal revolves around the ability of the Abadan refinery to process Basrah Light in significant volumes.

Another is the fact that Iran already faces a severe shortfall in its own domestic Gasoline supplies, making exports of gasoline problematic.

As of January 2005, Iran had nine aging (most built before the 1979 Iranian revolution) but operational refineries with a combined capacity of 1.47 million bbl/d.

Major refineries include: Abadan (400,000-bbl/d capacity); Isfahan (265,000 bbl/d); Bandar Abbas (232,000 bbl/d); Tehran (225,000 bbl/d); Arak (150,000 bbl/d); and Tabriz (112,000 bbl/d). In order to meet burgeoning domestic demand for middle and light Distillates (Gasoline demand is growing at around 9 percent per year), Iran plans to increase its refining capacity, possibly to 2.2 million bbl/d by 2008, although this will be extremely difficult to achieve given the security situation in the country. One goal of this expansion is to allow Irans refineries to process a heavier crude slate while decreasing the fuel Oil cut. Currently, Irans refineries produce around 30 percent heavy fuel oil and just 16 percent gasoline. In addition, diesel sulfur levels are slated for a major reduction (from 500 parts per million to 50 ppm by 2010), requiring significant additional hydrotreating capacity.

Iran has imported refined products since 1982, and these imports have been increasing rapidly. In 2005, Iran has been importing an estimated 170,000 bbl/d of gasoline at an estimated annual cost of around $3-$4 billion. According to Petroleum Argus, around 60 percent of this comes from European oil trader, Vitol, with another 15 percent coming from Indias 600,000-bbl/d Reliance refinery. For 2006, according to the FACTS consulting firm, Iran is expected to produce 266,000 bbl/d of gasoline, consume 462,000 bbl/d, and import 196,000 bbl/d.

In June 2004, Japans JGC reached an agreement with Iran to expand Arak to 250,000 bbl/d by 2009. In addition, Abadan is being expanded by 50,000 bbl/d, with completion expected by spring 2006 (in addition, a new, 180,000-bbl/d-capacity refinery is being planned for Abadan). Bandar Abbas is being expanded in several phases, adding around 250,000 bbl/d of capacity by 2010 (and significantly more after that). Two planned grassroots refineries include a 225,000-bbl/d plant at Shah Bahar and a 120,000-bbl/d unit on Qeshm Island. Under Iranian law, foreign companies are permitted to own no more than 49 percent of Iranian oil refining assets.

Iran exports Crude Oil via four main terminals - Kharg Island (by far the largest), Lavan Island, Sirri Island (reopened on April 13, 2003 for the first time since 1988, when it was damaged by an Iraqi air raid), and Ras Bahregan. Refined products are exported via the Abadan and Bandar Mahshahr terminals. Many Iranian oil export terminals were damaged during the Iran-Iraq War, but all have been rebuilt.

Jordan-Growth in Exports Offsets Drain in Current Account Balance

Major Changes in Jordans Energy Supply Situation

Jordan has no significant Oil resources of its own, and must rely on imported oil for all of its needs (around 106,000 bbl/d -- in 2004). The March 2003 invasion of Iraq has caused major changes in Jordans energy supply situation. Prior to the war, Jordan had received supplies of Crude Oil from Iraq -- half free of charge, and half at prices significantly below market levels. The country also received around 20,000 bbl/d of refined Petroleum products from Iraq. In the absence of a functioning Pipeline, all of the oil supplied to Jordan by Iraq had been transported by trucks.

In the wake of the war, Jordan has had to seek alternative sources of supply, both Kuwait and Saudi Arabia emerging as Jordans main oil suppliers since 2003. Press reports indicated that at least some of this oil was sold at discounted prices through the end of 2004, and that Jordan has been paying the full market prices in 2005. Meanwhile, Jordan has sharply raised the retail prices charged to consumers for petroleum products.

Jordans Zarqa Oil Refinery

Jordan has one refinery, at Zarqa, with a capacity of 90,400 bbl/d. The facility is in need of major upgrades, and its owner, the Jordan Petroleum Refining Corporation (JPRC), currently is studying its options. The facility was designed to produce a product mix skewed toward heavy fuel Oil, which was needed at the time it was built to run electric power plants, but the local market is now in need of additional Gasoline and diesel, while electric power generation is switching over to Natural Gas.

Oil Exploration in Jordan

Jordans state Natural Resources Authority (NRA) has been promoting Oil exploration within the country, which has been relatively unexplored until now. TransGlobal Corporation holds a concession for the Wadi Araba area in Western Jordan. Sonoran Energy of the U.S. was awarded exploration rights for an area near Amman in December 2004. Other small independent companies have conducted surveys of other areas as Well, but without yet finding commercial quantities of oil. To help attract foreign investment, the Jordanian government has plans to privatize its oil sector. In October 1995, the country set up the state-owned National Petroleum Co. (NPC) to handle Upstream oil and gas exploration and development. In mid-1999, NPC divested its oil-drilling operation, which now operates as Petra Drilling Company.

NPC is still active in the Natural Gas sector.

Natural Gas Reserves in Jordan

Jordan has modest reserves of Natural Gas, 230 billion cubic feet (Bcf), and has developed one gas field, at Risha in the eastern desert near the border with Iraq. The current output of around 30 million cubic feet per day (Mmcf/d) from the Risha field is used to fuel one nearby power plant, which generates about 10 percent of Jordans electricity.

Gas Pipelines in Jordan

In August 2003, Jordan began imports of Natural Gas from Egypt. In May 2001, a 30-year agreement had been concluded with Egypt for gas sales to begin at a rate of 100 Mmcf/d beginning in 2003. Construction of the section of the Pipeline in Egypt began in late 2001, starting from the existing pipeline terminus at El-Arish in Sinai. This section was completed in mid-2003, allowing deliveries to begin to one power plant at Aqaba. The second phase of the project, which will connect to the Rihab power plant in northern Jordan, is currently under construction and scheduled for completion by then end of 2005.

Arab governments also have been discussing the potential of extending the Egypt-Jordan pipeline and increasing its capacity - dubbed the Arab Gas Pipeline (AGP) project. The extensions under discussion include links to Syria and Lebanon and an extension to Turkey. At present, though, it seems unlikely that an extension to Turkey will be built in the near term.

South China Sea Resources and Territorial Issues

Territorial Issues - Indonesia

Indonesias ownership of the Natural Gas-rich fields offshore of the Natuna Islands was undisputed until China released an official map with unclear maritime boundaries indicating that Chinese-claimed waters in the South China Sea may extend into the waters around the Natuna Islands. Indonesia responded, in 1996, by holding large military exercises in the Natuna Islands region. Since then, Indonesia has done major natural gas production in the Natuna area and China has not voiced any objection. The three blocks in the Natuna area are estimated to contain about 5 Tcf of recoverable gas. Indonesia has been exporting Natuna gas to Singapores Jurong island via a 400-mile undersea Pipeline since 20

Territorial Issues - The Philippines and Malaysia

• The Philippines

Malampaya and Camago Natural Gas and condensate fields are in Chinese-claimed waters. The fields are estimated to contain 2.6 Tcf of natural gas. The Philippines has proceeded with development of the fields and linked the gas output to three power plants via a 312-mile Pipeline. There have been no objections from China to this development.

• Malaysia

Many of Malaysias natural gas fields located offshore Sarawak also fall under the Chinese claim, but as with the Philippine gas fields, China has not specifically objected to their development. In July 2002, a new Oil discovery by Murphy Oil (working under a contruct with state-owned Petronas) about 100 miles offshore from Sabah on island of Borneo rekindled interest in a latent dispute between Malaysia and Brunei over offshore rights. Murphy plans to begin commercial production in the area in 2007. Shell Malaysia reported a deep water oil discovery off the Sabah coast in 2004. Brunei had asserted a 200-mile exclusive economic zone (EEZ) off its coastline in 2000. Negotiations between the two governments to resolve the issue are continuing.

• Territorial Issues - Vietnam

Vietnam and China have resolved their dispute over areas in the Gulf of Tonkin to the south of Chinas Guangdong province. An agreement signed in December 2000 delineated the boundary between their EEZs, opening the way for Oil and gas exploration. Maritime boundaries in the Natural Gas-rich Gulf of Thailand portion of the South China Sea have not all been clearly defined. Several companies have signed exploration agreements but have been unable to drill in a disputed zone between Cambodia and Thailand. Overlapping claims between Thailand and Vietnam were settled on August 8, 1997, and cooperative agreements for exploration and development were signed for the Malaysia-Thai and Malaysia-Vietnam Joint Development Areas (the latter effective June 4, 1993).

Most of these claims are historical, but they are also based upon internationally accepted principles extending territorial claims offshore onto a countrys continental shelf, as Well as the 1982 United Nations Convention on the Law of the Sea.

United Nations Law of the Sea

The 1982 convention created a number of guidelines concerning the status of islands, the continental shelf, enclosed seas, and territorial limits. Among the most relevant to the South China Sea are:

1.Article 3, which establishes that "every state has the right to establish the breadth of its territorial sea up to a limit not exceeding 12 nautical miles";

2.Articles 55 - 75 define the concept of an Exclusive Economic Zone (EEZ), which is an area up to 200 nautical miles beyond and adjacent to the territorial sea. The EEZ gives coastal states "sovereign rights for the purpose of exploring and exploiting, conserving and managing the natural resources, whether living or non-living, of the waters superjacent to" (above) "the seabed and of the seabed and its subsoil...".

3.Articles 76 defines the continental shelf of a nation, which "comprises the seabed and subsoil of the submarine areas that extend beyond its territorial sea throughout the natural prolongation of its land territory to the outer edge of the continental margin, or to a distance of 200 nautical miles...". This is important because Article 77 allows every nation to exercise "over the continental shelf sovereign rights for the purpose of exploring it and exploiting its natural resources".

4.Article 121, which states that rockvvs that cannot sustain human habitation or economic life of their own shall have no exclusive economic zone or continental shelf. The establishment of the EEZ created the potential for overlapping claims in semi-enclosed seas such as the South China Sea. These claims could be extended by any nation which could establish a settlement on the islands in the region. South China Sea claimants have established outposts on the islands (mostly military) in order to conform with Article 121 in pressing their claims. The Law of the Sea Convention states that countries with overlapping claims must resolve them by good faith negotiation. The use of the Joint Development Area principle, followed in the Gulf of Thailand, is one model that has been successfully used by South China Sea claimants.

Regional Conflict and Resolution

All of the Spratly Islands claimants have occupied some of the islands, and/or stationed troops and built fortified structures on the reefs. Brunei, which does not claim any of the Spratly Islands, has not occupied any of them, but has declared an Exclusive Economic Zone that includes Louisa Reef.

Military skirmishes have occurred numerous times over the past two decades. The most serious occurred in 1974, when China invaded and captured the Paracel Islands from Vietnam, and in 1988, when the Chinese and Vietnamese navies clashed at Johnson Reef in the Spratly Islands, sinking several Vietnamese boats and killing over 70 sailors.

Indonesia has taken the leading role in diplomatic initiatives and cooperative agreements to resolve South China Sea issues, particularly through the ASEAN (Association of Southeast Asian Nations) forum, which has called for the peaceful arbitration of territorial claims. ASEAN includes all South China Sea nations except for China and Taiwan, and has held a number of working groups with China and Taiwan on related issues that have the potential to foster the cooperation and friendship needed to resolve the more contentious issues in the region. Indonesia hosted the first of these workshops in 1990. These issues have also been discussed at the larger ASEAN Regional Forum (ARF), held in conjunction with the ASEAN Post Ministerial Conference, which draws together 22 countries which are involved in the security of the Asia Pacific region, including all ASEAN members.

ASEAN ministers agreed in 1996 that there should be a regional code of conduct for the South China Sea to permit activities such as scientific research and efforts to combat piracy and drug trafficking without invoking the contentious issue of sovereignty. At the ASEAN Summit in November 1999, ASEAN members put forth a general code of conduct for resolving disputes which had been drafted by the Philippines and Vietnam.

Any such agreements would need to involve non-ASEAN members such as China and Taiwan in order to be comprehensive. China, which is a member of the ARF, has argued in the past that the resolution of territorial disputes should be a bilateral issue.

However, other ARF members, such as the United States, have argued that all ARF members had an interest in issues affecting the peace and stability of the region, and that the ARF forum was appropriate for discussing these issues. Views on this issue are varied:

China has begun a dialogue with ASEAN on the idea of a "code of conduct" governing actions by claimants, but progress has been slow. In general, ASEAN members have pushed for specific committments to refrain from additional occupation of reefs or new construction, which China has favored a more vague committment to refrain from actions which would "complicate the situation." In November 2002, China and the 10 members of ASEAN signed a Joint Declaration on the Conduct of the Parties, which pledged to "undertake to resolve their territorial and jurisdictional disputes by peaceful means" without "resorting to the threat or use of force." Malaysian Foreign Minister Syed Hamid bin Syed Jaafar Albar stated that it was his belief that ASEAN nations had agreed that the territorial disputes were an ASEAN issue, and should not be resolved in other international forums.

Vietnam has held bilateral group mettings with China to resolve disputed boundaries in the Gulf of Tonkin (referred to as the Beibu Wan by China, the Vinh Bac Bo by Vietnam) and the Spratlys, as Well as land boundaries. The Gulf of Tonkin dispute was resolved in an agreement concluded in December 2000. Vietnam has wanted to include the dispute over the Paracel Islands in any "code of conduct," but the idea is not supported by other ASEAN members because the Paracels are disputed only between Vietnam and China.

Malaysia and Brunei have held talks in 2003 on their conflicting EEZ claims, but have not yet reached an agreement. There have been incidents in 2003 in which naval vessels from Malaysia and Brunei have acted (without the actual use of force) to prevent exploration vessels from working in the disputed area.

Natural Gas Reserves in United States

EIAs latest Short-Term Energy Outlook projects that U.S. domestic dry Natural Gas production in 2005 will decline by about 4 percent, due in large part to the major disruptions to infrastructure in the Gulf of Mexico from both Hurricanes Katrina and Rita. Dry gas production is projected to increase by 4.7 percent in 2006. EIA expects net imports of natural gas (Pipeline and liquefied natural gas - LNG) to increase only slightly in 2005 (0.1 percent over 2004) but to increase by over 12 percent in 2006.

Imports of LNG appear to have exhibited little change through the first half of 2005 compared to year-ago levels. High natural gas prices in other world markets during the first three quarters of 2005 have served to attract available supplies of LNG that might otherwise have been directed to the United States, although fourth quarter imports are estimated to increase in response to high U.S. prices. Currently, total LNG imports for 2005 are projected to be approximately 650 Bcf in 2005 and just over 1,000 Bcf in 2006, compared to 650 Bcf in 2004.

In the near- to medium-term, EIA expects increases in natural gas production to come mainly from lower 48 sources. Increased use of cost-saving technologies is expected to result in continuing large natural gas finds, including in the deep waters of the Gulf of Mexico but also in onshore fields. In the longer term, Alaskas North Slope fields represent a large potential natural gas source, with an estimated 30-35 Tcf of natural gas resources. Getting the gas to market is the main challenge. One possibility is a $20 billion natural gas pipeline running 3,500 miles from the North Slope along the Alaska Highway into Alberta and on to markets in the U.S. Midwest. In October 2004, Congress promised to cover 80 percent of the projects cost if it were to go bankrupt. Still, the project is considered risky by major energy companies, and it remains uncertain whether or not the project will move ahead.

Natural Gas Storage in United States

EIA estimates that working gas in storage as of November 4, 2005 was 3,229 Bcf, which is 123 Bcf (4 percent) above the 5-year average inventory level. Although Natural Gas storage remains above the 5-year average, the double blows of Hurricanes Katrina and Rita reduced the peak storage achievable over the remainder of the injection season from what was expected previously. Expected working gas in storage at the end of the fourth quarter is expected to be about 2.5 Tcf, 200 Bcf below year-ago levels and about 50 Bcf above the 5-year average.

As of 2003, top natural-gas-producing states (in descending order) included Texas, New Mexico, Oklahoma, Wyoming, Louisiana, Colorado, Alaska, Kansas, Alabama and California.

Natural Gas Demand in United States

From 1990 through 2004, according to EIA, Natural Gas consumption in the United States increased by about 16 percent. EIAs latest Short-Term Energy Oulook projects that total natural gas demand will fall by 0.8 percent in 2005, due mainly to higher prices and Hurricanes Katrina and Rita, In 2006, natural gas consumption is expected to recover by 2.8 percent due to an assumed return to normal weather. In addition, a rebound in industrial activity is expected to increase natural gas demand in that sector by about 6 percent over 2005 levels. Natural gas is consumed in the United States mainly in the industrial (38 percent), electric power (24 percent), residential (22 percent), and commercial (13 percent) sectors.U.S. natural gas consumption and imports are expected to expand substantially in coming decades, with the fastest volumetric growth resulting from additional natural-gas-fired electric power plants. Increased U.S. natural gas consumption will require significant investments in new pipelines and other natural gas infrastructure. New LNG terminals are projected to start coming into operation in 2006, and net LNG imports are expected to increase to 6.4 trillion cubic feet in 2025. Net imports of natural gas from Canada are projected to decline from 3.0 trillion cubic feet in 2005 to 2.5 trillion cubic feet in 2009, rise again to 3.0 trillion cubic feet in 2015, and then decline to 2.5 trillion cubic feet in 2025.

Petroleum Imports/Exports in United States

Refining/Downstream in United States

The United States experienced a steep decline in refining capacity between 1981 and the mid-1990s. Between 1981 and 1989, the number of U.S. refineries fell from 324 to 204, representing a loss of 3 million bbl/d in operable capacity (from 18.6 million bbl/d to 15.7 million bbl/d), while refining capacity utilization increased from 69 percent to 87 percent. Much of the decline in U.S. refining capacity resulted from the 1981 deregulation (elimination of price controls and allocations), which effectively removed the major prop from underneath many marginally profitable, often smaller, refineries. Refinery closures have continued since 1989, bringing the total number of operable U.S. refineries to 148 as of January 1, 2005. In general, refineries that have closed were relatively small and had less favorable economics than other refineries in their market area. Also, in recent years, some smaller, less-economic refineries that needed additional investments for environmental reasons in order to stay in business found closing preferable because they predicted that they could not stay competitive in the long term.

While some refineries have closed, and no new refineries have been built in nearly 30 years, many existing refineries have expanded their capacities. As a result of capacity creep, whereby existing refineries create additional refining capacity from the same physical structure, capacity per operating refinery increased by 28 percent over the 1990 to 1998 period. Overall, since the mid-1990s, U.S. refinery capacity has increased from 15.0 million bbl/d in 1994 to 17.1 million bbl/d in September 2004. As of November 4, 2005, utilization of operating capacity at U.S. refineries was averaging around 84 percent, down from 91 percent on September 16, 2005 following Hurricanes Katrina and Rita.

United States Financial Performance, Mergers and Acquisitions

Twenty-five major U.S. energy companies reported overall net income (excluding unusual items) of $26.0 billion on revenues of $295.1 billion during the third quarter of 2005. This level of net income represented a 69 percent increase relative to the third quarter of 2004 (see EIAs "Financial News for Major Energy Companies ").

Domestic Upstream Oil and Natural Gas production operations accounted for $8.5 billion of net income, with domestic refining and marketing operations earning an additional $7.0 billion.

Foreign upstream oil and natural gas production operations accounted for $7.6 billion of net income, while foreign refining and marketing operations accounted for $2.0 billion.

Independent oil and natural gas producers, oil field companies and refiner/marketers reported a sharp increase in net income (up 139 percent) during the second quarter of 2005 compared to the second quarter of 2005 (see EIAs "Financial News for Independent Energy Companies"). This increase in net income was due primarily to large increases in the prices of natural gas and Crude Oil, and a rise in gross refining margins of 17 percent year-over-year.

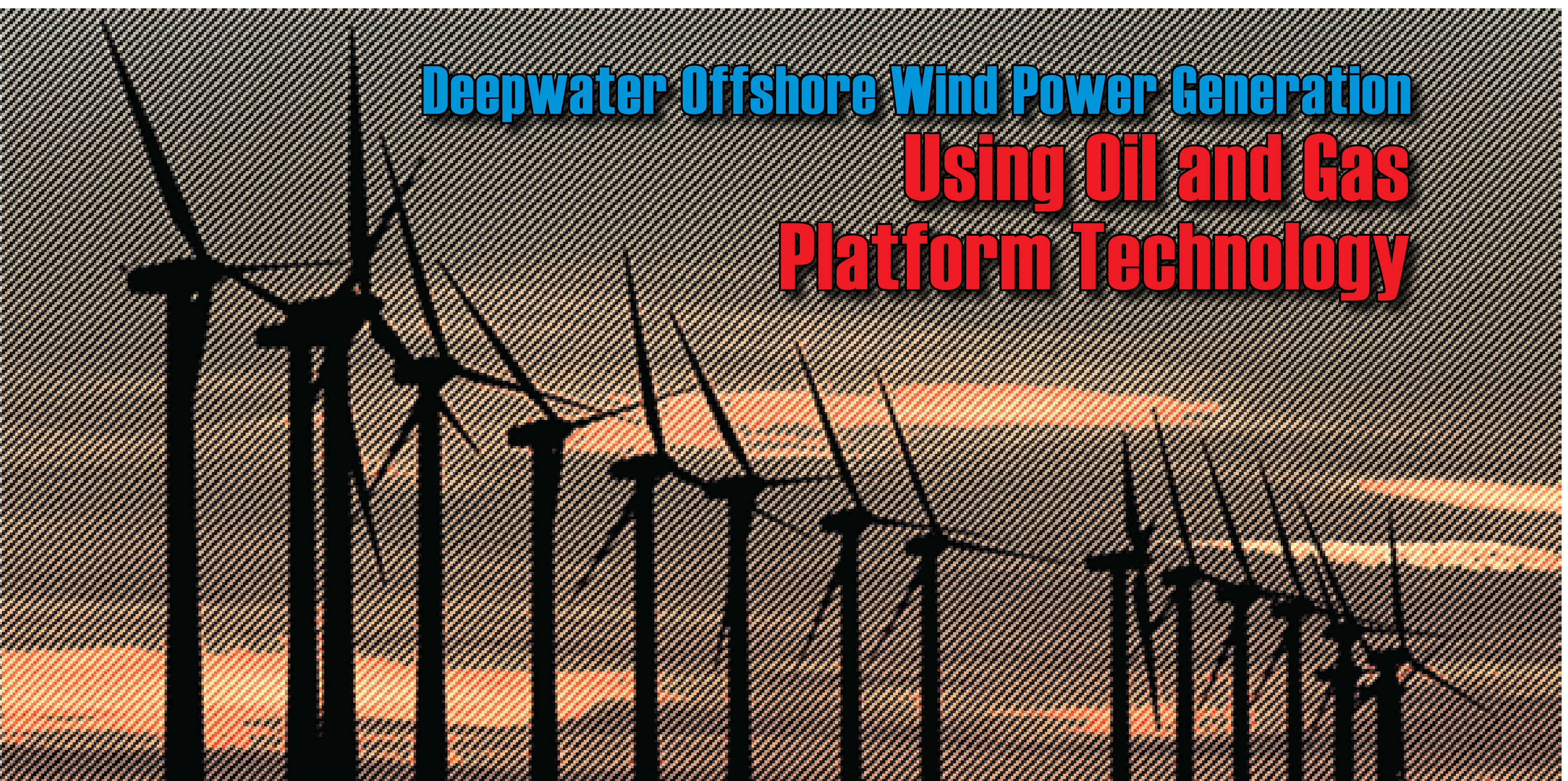
The Wall Street Journal (WSJ)

On October 13, 2005, the Wall Street Journal (WSJ) reported that Occidental Petroleum Corporation had agreed to acquire Vintage Petroleum Inc. for about $3.5 billion of cash and stock. Other recent acquisitions reported by the Wall Street Journal include: 1) Valero Energy Corp. agreed to acquire Premcor Inc. for $6.9 billion in cash and stock (reported April 25, 2005); 2) ChevronTexaco Corporation agreed to buy Unocal Corporation for about $16.8 billion of cash and stock (April 5, 2005); and 3) Marathon Oil agreed to acquire from Ashland Corporation the 38 percent of the Marathon Ashland Petroleum refining/marketing joint venture that it did not already own (March 19, 2004). Marathon reportedly paid about $3 billion (about $1.1 billion of cash and stock and the assumption of about $1.9 billion in debt) for Ashlands share in the refining/marketing joint venture. In addition to acquiring full ownership of the Marathon Ashland Petroleum assets, Marathon also acquired 61 Valvoline Instant Oil Change outlets and other related assets currently owned by Ashland.

Oil Consumption in United States

The United States consumed an average of about 20.6 million bbl/d of Oil during the first nine months of 2005, the same amount year-over-year as in 2004. Of this, motor Gasoline consumption was 9.1 million bbl/d (or 44 percent of the total), distillate fuel oil consumption was 4.1 million bbl/d (20 percent), jet fuel consumption was 1.6 million bbl/d (8 percent), and residual fuel oil consumption was 0.9 million bbl/d (4 percent). For 2005 as a whole, EIAs Short-Term Energy Outlook projects that U.S. Petroleum demand will decline by 16,000 bbl/d, to an average 20.6 million bbl/d, in response to the combined effects of the hurricanes and high Crude Oil and product prices. EIA expects motor gasoline, jet fuel, and residual demand all to remain about flat -- at 9.1 million bbl/d, 1.6 million bbl/d, and 0.9 million bbl/d, respectively. EIA expects distillate demand in 2005 to grow by about 1%, to 4.1 million bbl/d. Finally, EIA forecasts demand for "other oils" (Natural Gas liquids, liquefied refinery gas, other liquids, etc.) to decline by over 4%, to 4.9 million bbl/d, in 2005.

Deepwater Offshore Wind Power Generation Using Oil and Gas Platform Technology



Previously confined to shallow water installations or land, deep water wind power may be the next frontier for wind developers.

The key to this future source of energy may come from the technology that originated with fossil fuels. The technology that keeps deep-sea oil and gas rigs stable and running may unlock deep-sea wind power as well. Though it is far from proven or even practical testing, the idea is under hot pursuit by entrepreneurs and engineers using principles from oil and gas platform rigs. Challenges ahead lie in permitting, testing and transmission.

Principle Power, a developer of offshore wind projects, has licensed technology from Marine Innovation and Technology, a firm comprised of former oil and gas platform engineers, for development of a semi-submersible floating wind generation system. The patented WindFloat platform is a floating foundation for very large wind turbines that floats on the surface of the water, but is partially submerged.

Intended for use in waters greater than 50-meters deep and ten miles or more from shore, WindFloat's design is intended to provide physical stability for wind turbines so that existing offshore wind turbines can be used with very few modifications, according to Dominique Roddier of Marine Innovation and Technology.

"There are a lot of synergies between engineering for an oil or gas platform and engineering a platform for wind energy generation," said Roddier. Namely, deepwater installations for oil, gas, and wind should be stable, cheap and simple. However, while the oil and gas industry is established and has deep expertise in creating floating platforms for energy generation, "we're making a product in an industry that doesn't exist yet and we have to create the industry that goes along with the product," he said.

Roddier, whose background includes designing offshore oil and gas rigs, highlighted the importance of technical peer review when designing and testing new technology along with government involvement, both of which may lead to the creating of "best practices" in this emerging field.

Similarities and Differences

One major engineering difference that must be accounted for is the kind of motion these floating platforms attempt to minimize. In the oil and gas industry, minimizing vertical motion, or heave, is critical because the vertical steel tubes, called "risers" that bring the hydrocarbons from beneath the sea bed to the surface cannot be stretched. Platforms are accordingly engineered to minimize vertical motion, with less attention paid to angular motions.

With wind turbines, however, it is quite the opposite. Minimizing pitch and roll is critical in order for the turbine to function optimally.

This consideration guided Marine Innovation and Technology to create a three-columned triangular design for WindFloats. The turbine is placed on top of one of the columns, and the other two columns are given more ballast to stabilize the entire platform. The ballast from the other two columns stabilizes the weight distribution and allows the turbine to stand upright.

"The stability of the platform is achieved through the columns, which are spread out in order to increase stability and reduce motion," said Roddier. Furthermore, the WindFloat is moored with 6 lines, 4 of which are connected to the column stabilizing the turbine thus creating an asymmetric design.

Oil and gas platforms also have multiple mooring lines, but the asymmetrical design was chosen in order to support the additional forces placed on the column supporting the wind turbine.

At the base of each column, water entrapment plates resist the water around them, effectively making the platform move less in waves. A type of oil and gas platforms, called "truss spars" by contrast, stack similar water entrapment plates vertically, rather than spreading them horizontally.

The Case for Offshore Wind Development

Technical challenges aside, numerous advantages exist for large-scale deepwater offshore wind power. First, wind turbines located many miles out into the open ocean reduce the incidence of NIMBY (not in my backyard) concerns, as they cannot be seen from land.

Second, wind resources are generally higher offshore, particularly in deeper waters. "We're targeting the Great Lakes, the coast of Maine and New Hampshire and the west coast," said Alla Weinstein, CEO of Principle Power. Weinstein noted that the company has made some site selections based on an NREL (National Renewable Energy Lab) study that showed areas with significant untapped potential wind power that have previously not been explored due to the difficulty of engineering deepwater wind.

The idea is getting some traction. Oregon-based Tillamook PUD earlier this year issued a request for proposals for wave energy installations. In response, Principle Power submitted a proposal for an offshore wind installation, which resulted in a memorandum of understanding between Principle Power and Tillamook.

Principle Power is planning to launch a project off the coast of Netarts and Garibaldi, Oregon. Extensive stakeholder consultations with those communities are due to begin shortly.

Weinstein expects that Tillamook is just the first of many utilities that may be interested in Principle Power's technology. States with RPS obligations will be particularly interested, she said. "They have already identified the need and are actively looking for offshore renewable projects," Weinstein said.

Other Hurdles: Permitting, Not Transmission

Aside from proving the technology, a major hurdle awaiting Principle Power is the application process for a permit to begin the project off of the Oregon coast. The Minerals Management Service (MMS) was given the authority under the EPAct 2005 to grant licenses for deep offshore wind energy development, but will not release the rules for how to develop a project until early 2009. Principle Power's target installations all take place in federal waters, since they are miles offshore, bringing the projects under the jurisdiction of many different federal agencies.

The process to acquire an OCS Lease Nomination, the permit granting permission to pursue a deepwater wind project, can take up to two years. If there are other applicants for a specific site, MMS grants the application to the team more qualified for what is being proposed and then goes through the same environmental permitting exercise.

"Our impacts are going to be minimal," said Weinstein. She believes the project will be found to have an acceptable level of environmental impacts, because there is minimal impact to the ocean floor and therefore to wildlife. The mooring structures that tie the structure to the ocean floor are relatively thick, so that dolphins and whales can sense the structure and avoid injury, she explained.

Weinstein doesn't see transmission as an insurmountable obstacle. "Connections to the grid have been done. It's just a matter of designing it and putting it in place. This is not where the technical challenges are going to be," she said.

When the system is fully operational, she plans to bring the power from multiple WindFloats to one WindFloat location and then send one cable back to the shore. Furthermore, the transmission issue is addressed in the permitting. "The challenges are going to be in the time that it is going to take us to permit and demonstrate the operation of the WindFloat," she added.

"We aren't going to test this in the open ocean until we know that we have something that works," said Roddier. The company is currently conducting numerical model studies, with tools that have been validated in a wave tank, and will eventually re-test the final design in the lab. Each WindFloat requires site-specific engineering to address differences in water movement at various sites.

Marine Innovation and Technology and Principle Power are working together to ensure integration with the turbine and the float. Although it is still too early for Principle Power to secure deals for turbine supply, each float will is expected to be able to support a 5-MW turbine.

Once they have proven the concept, they plan to reach out to project developers, including utilities and IPPs to develop viable projects. Principle Power is also on the lookout for equity investors with 6-7 year horizons.

Hecate Straight Fish Stocks and Offshore Oil and Gas Development

by Darren Williams

You may have heard there is oil off British Columbia's coast. 9.8 billion barrels of it, yes, billion. This is three times the size of the reserves that predicated the development of Hibernian and Terra Nova, Atlantic Canada's offshore oil mega-projects which are helping to raise the East Coast out of the grave of the once great cod fishery.

You may also have heard that there is talk of lifting the current moratorium on offshore exploration and development off British Columbia's coast. The new provincial government has recently cut taxes and increased spending, forecasting multiple deficit budgets and highlighting the Province's need for new sources of revenue. The economic motive for developing the offshore is strong, as is the political will.

However, there are many obvious concerns with drilling for oil on the West Coast. In light of its awesome beauty and fragility, there is arguably, no good place to drill for oil off the BC coast. However, some places are worse than others. Take for example, Hecate Straight and western Queen Charlotte Sound. Subject to strong winter storms, Hecate Straight is a huge breeding and fishing ground for crab, halibut, sole, brill, rock fish and more. Western Queen Charlotte Sound is rich in perch, yellow tail rockfish, reed eye, and borealis, some of the oldest fish in the world.

These locations have been and continue to be some of the best fishing grounds on the coast, surpassing all other fishing grounds for value. The government has been monitoring these grounds scrupulously for several years now. The trawl industry that works this area has been said to be the most highly (successfully) monitored fishery in the world. Every trawl net that is set and hauled is done so under the watchful eye of a fisheries Observer, who records the data. Later this data becomes a tool to manage the stock by allowing more accurate modeling of the stock, and therefore more accurate total allowable catch levels.

What does this have to do with offshore oil and gas? The largest of all oil reserves on the coast lies directly under Hecate Staright and western Queen Charlotte Sound. 9.8 billion barrels of oil under the fishing area, big deal. Well, the difficulty arises even before there is any sign of oil spill. The seismic testing necessary to map subsea reserves is quite damaging to organisms in the water, including fish. The seismic testing is done with highly charged explosions of air, set off approximately every twelve seconds along a beam that is being towed under water on a grid pattern covering hundreds of square kilometers. The shock waves bounce through the water and rock, and possible oil, and come back to be analyzed by computers and used to make maps that developers will later use to determine where to drill. Marine drilling is astronomically expensive, so the seismic tests are crucial in order to save time and money when it comes time to sink a well.

Seismic testing in fishing grounds has been done all over the world, including the Grand Banks. The Living Ocean Society reports that some stocks in the North Sea had declined by 50% after seismic mapping. The Grand Banks seems to have had a depressed fishery for a decade or more now, but ask the government and they will tell you that this has nothing to do with the mapping necessary for their offshore drilling.

Will fish stocks in Hecate Staight and Queen Charlotte Sound be effected by seismic mapping? We may find out sooner than we think. The provincial government is currently reviewing bids submitted by companies to do seismic testing in order to update the seismic maps necessary for drilling.

Meanwhile, catch rates and landings of marketable fish caught in Hecate Straight and Queen Charlotte Sound are healthy. But what will happen when testing begins? Obviously, fishing stops in the area where the testing takes place, but what of the longer term effects, the effects on the stocks? Will they be damaged? License holders, vessel owners, crews and families who rely on these areas are likely not going to be very happy if their livelihoods are damaged. Vessels may be tied up. Crews may be on the dock. Mortgages foreclosed.

In the past, the law has looked at allowing a license holder to sue for economic damage that result from factors effecting his ability to earn money with the license. The law has typically found that a fishing license is simply a grant, or permission, of the Minister of Fisheries to catch fish, and does not form the basis of any right, the infringement of which can be sued over. Generally, this has meant that fishermen are without recourse for failure of their license to produce economically.

However, the situation may be different if the government does something that it knows will cause harm to the stock. The government may have created a fiduciary obligation to license holders. A fiduciary obligation is a significant relationship in which the Afiduciary, here the government, has a particularly high duty to ensure it acts with the other person's (the license holders) best interests in mind. By granting fishermen licenses yet charging as much as $10,000 yearly for them, enforcing a quota system that is market responsive and uses transferable quotas, and placing a large part of the cost of enforcement on fishermen, the government may have created a fiduciary obligation to the license holders. This obligation may be breached when the government, in an attempt to exploit another resource, such as offshore oil and gas, knowingly acts in a way that damages the fish stocks.

If indeed the courts are willing to recognize the special nature of the regulatory scheme of the West Coast trawl fishery, and the enormous financial commitment made by industry participants, the stage may be set for a change in the law. A change that would see license holders able to recoup economic damages suffered as a result of the willful acts of the government, such as the potential damage to stocks caused by seismic mapping in Hecate Straight.

Stating the law may change to recognize economic damage to license holders is a risky venture. However, British Columbia is a unique place. We give people money when their culture is damaged, we pay fishermen not to fish. The question is, when the governments knowingly damage fish stocks in order to make increase their revenue, will the law recognize the economic damage suffered by license holders and fishermen? I suggest this is an issue that the governments, federal and provincial, will likely have to address in the not so distant future.

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High Performance Corrosion Resistance Fluoropolymer/PTFE Coated Fasteners for

By Kirtan Dhami

ABSTRACT

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.

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

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)

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.
4. (Wind turbine support shafts).
5. 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 lat-

Technical Data–PTFE/Fluoropolymer Coatings

Use Temperatures:-100° C to+ 260°C **Corrosion Resistance:** Salt Spray (ASTM B117) ...up to 1,000 hrs (Nuts not frozen) **Pencil Hardness:** 5H-6H (ASTM D3363-92A) **Kinetic Friction Coefficient:**0.06-0.08 **Thickness:**nominal 0.001" (1 mil) **Impact:**160 in. lb. (ASTM D2794-93)	**Adhesion:**5B (ASTM D3359-95) **Dielectric Strength:** 500 volts per mil **Elongation:**35%-50% Tensile Strength:4,000 psi Operating Pressure:Up to 100,000 psi **Kesternich Test:**Nuts not frozen after 30+ cycles (DIN 50018) **Thread Fit:** Over tapping of nuts 0.010"

est 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.

Field Monitoring Byte by Byte

Matthew Dunbabin
Edson Nakagawa
Gerardo Sanchez

More than 80% of Australia's gas reserves exist in deep, remote offshore areas. As fields move further offshore, the distance and water depths can make these reserves difficult and uneconomical to access. Our ability to realise their full potential relies on the development of economically viable solutions to ensure reliable transportation of production to shore. A novel, platform-free fields (PF2) concept is one possible solution. An essential component for long-term operation of PF2 is the development of highly reliable, cost-effective and functional wireless, wired and mobile field monitoring technologies.

The Wealth from Oceans National Research Flagship – an initiative of the Common wealth Scientific and Industrial Research Organisation (CSIRO) – is midway through an ambitious research programme to advance innovative wireless sensor network and integrated robotic inspection technologies for remote subsea monitoring of the field to ensure safe and reliable operation and production.

Monitoring the Platform-free Gas Field

The challenges facing operators involved in remote monitoring of offshore fields include guaranteed data delivery, data throughput rates, safety, system reliability and redundancy paths, sensor power and network expandability and functionality. These are further compounded when the field is even more remote and with no surface facilities present, as in PF2.

PF2 are believed to become economically viable when the distances from shore exceed 200km and water depths exceed 1km. However, they become increasingly technologically challenging because of a reliance on remote observation and control, requiring information to be gathered at greater spatial and temporal scales. Ensuring that the operators have timely access to all of these bytes of information from across the entire field requires new and innovative methods for field and pipeline monitoring, as well as robotic inspection and maintenance systems.

Delivering the large and growing demand for cost-effective remote acquisition of quality information is the research focus of the Flagship's field monitoring project. After identifying shortcomings in existing state-of-the-art underwater wireless communications for the task of remote field monitoring, an integrated wireless monitoring system has been proposed that comprises novel distributed wireless ad hoc acoustic and radiofrequency (RF) sensor network nodes designed to be integrated into a fixed wired network.

In anticipation of greater reliance on robotic systems, these complementary networked technologies provide not only robust communication pathways for various sensors, but also data exchange and accurate localisation information, allowing robotic systems to interact with the network and perform complex monitoring, inspection and intervention tasks. These enhanced monitoring and maintenance capabilities could significantly reduce the developmental and operational costs associated with the exploitation of remote oil and gas fields.

Remote Monitoring

In the domain of field monitoring, there is currently a dependency on cabled communications. The current preference for cabled (including copper and fibre optic cables) over wireless communications arises from their speed-of-light communications (particularly in safety critical systems), data throughput and ability to supply continuous power to sensors and associated hardware. However, the spatial distribution of wired sensors is often limited because of the cost of installing new sensors. Wireless sensor and communication systems allow the number of sensors to expand, although they suffer from lower data rates and, without energy scavenging capabilities, have a limited life expectancy.

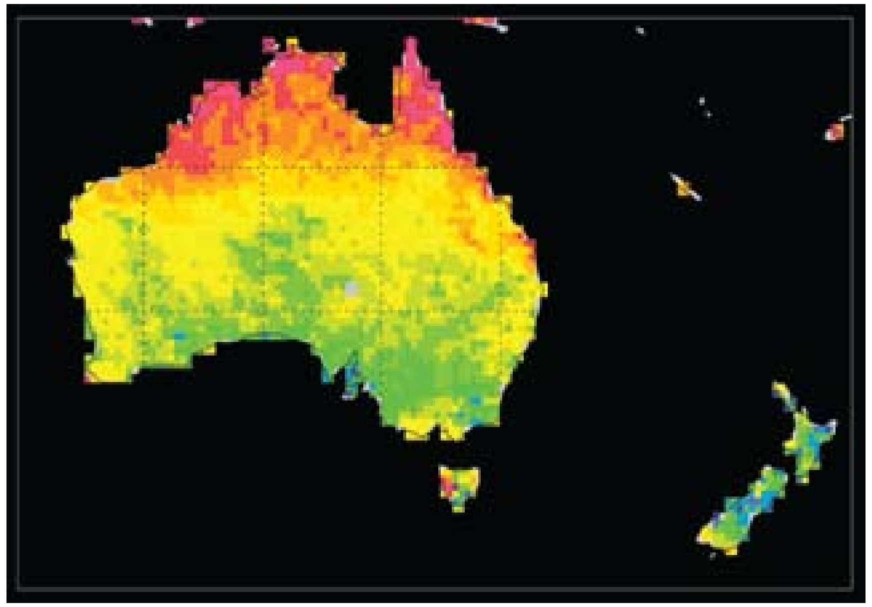
In PF2, distributed monitoring of temperature, pressure and vibration along the length of the pipeline for flow assurance and structural integrity is required. Monitoring of other production parameters is also needed. Traditionally, sensors are installed into the field at specific points, making the system relatively inflexible to changing requirements throughout the life of the field. With the need for greater remote observation of the entire field in PF2, the cost associated with a fixed wired sensor network would be prohibitive. However, an appropriate mix of new 'smarter' wireless sensor and wired communication systems could provide a suitable solution.

Distributed Wireless Monitoring

In offshore oil and gas developments, subsea communications are often limited to fibre optic and point-to-point acoustic communication systems. This does not allow for easy extension of the network into new areas, introduction of new nodes and sensors or the ability for a robotic system such as an autonomous underwater vehicle (AUV) to interact and become part of the network for intervention and inspection tasks. To allow this level of functionality and expandability in a cost-effective manner requires the use of robust distributed ad hoc wireless sensor network systems.

As wireless sensor networks become common in many terrestrial applications, they are also rapidly gaining attention for application in underwater operations. In terrestrial applications, the primary data transmission mode is via RF; however, underwater the primary transmission mode has been using acoustics.

Despite over a decade of research into underwater wireless acoustic networks, there are still many difficult problems being studied. The challenges include network protocols and architecture, data throughput, scalability, path redundancy, power consumption and increased network functionality. Today's commercial acoustic modems are designed primarily for point-to-point communication rather than ad hoc networked operation. Ad hoc network modems are increasingly desirable for tetherless communication between underwater devices such as



sensor clusters, AUVs and subsea infrastructure.

The current shortfall in existing technology has been the driving force for the Flagship's field monitoring project, with a research programme set around developing and demonstrating two wireless underwater sensor network technologies: an ad hoc acoustic network 'node controller' and a wireless RF-based sensor tag for distributed pipeline monitoring.

Ad Hoc Acoustic Networks

Reviewing the general trend in underwater sensor network protocol research highlights an emphasis on large-scale, meshed network topologies primarily conducted in simulation and often without any practicality considerations. The approach taken by CSIRO has been to focus on the development of generic solutions for ad hoc acoustic network protocols that can maximise network throughput based on available bandwidth, as well as minimising overall network energy consumption.

The novelty of this research lies in the use of a node controller to provide the networking layer that commercially available modems often lack. This allows us to take advantage of advances in commercially available link layer hardware. Therefore, if an off-theshelf modem meets a minimum set of criteria, the node controller can form an ad hoc network with this hardware. The node controller, based on the CSIRO Fleck™ wireless sensor network board, is also capable of monitoring a large number of analogue and digital sensor inputs, as well as implementing algorithms that allow the network nodes to selflocalise and power down the system for ultra-long-term operation.

This technology provides a generic solution that enables the wireless sensor node to either maximise data throughput or minimise network transmission energy, allow any number of nodes to be networked without a dependence on the network topology and automatically configure routing tables and route around failed nodes. Furthermore, it allows communication with mobile nodes such as AUVs and provides AUV ranging information for localisation within the network field. This system has been successfully demonstrated in Brisbane's Moreton Bay, proving the ability of the node controller to establish ad hoc multihop routes and transfer data within randomly distributed, 10-acoustic-node networks.

Pipeline Monitoring System

Traditionally, the use of RF communications underwater has been dismissed because the high conductivity of seawater attenuates radio communication except at very low frequencies and relatively short ranges. Despite these shortcomings, renewed interest in RF communications for various monitoring tasks has been generated, with a number of commercial companies recently developing a range of underwater RF communication devices.

In 2005, the Flagship began a feasibility study into the potential use of small RF tags attached to subsea pipelines to allow distributed monitoring of properties such as temperature, pressure and vibration along the pipeline. The resulting prototype, the LFT-PipeTag™, forms the basis of the CSIRO Pipeline Monitoring System.

This system is based on small, low-cost RF nodes that rely on low-frequency data transmission, sending data from one node to another via wireless daisy-chaining until it reaches a collector node (wired, acoustic, etc.) that can transmit the data to a shore or surface facility. The LFT-PipeTag is a self-contained surface-mounted sensor node capable of scavenging and storing energy from the environment for life-of-field operation, digitising multiple sensor inputs and minimising energy expenditure. The system is capable of data transmission rates up to 300b/s at ranges of 6–300m, depending on the installation scenario. The first Mk2 prototype of the LFT-PipeTag is currently undergoing multinode communication evaluation.

Autonomous Monitoring Systems

Many AUV and ROV operators and research organisations are functionalising their robots to perform increasingly complex tasks autonomously, such as pipeline inspection, target identification and minor maintenance tasks. An essential requirement for conducting any remote subsea operation is to accurately know the vehicle's location. The primary limitation of these systems is the requirement for external positioning infrastructure, most often provided by support vessels or specifically deployed positioning beacons. A new approach to localisation developed by CSIRO is currently being tested.

The primary research focus is on the intelligent fusion of on-board sensors with information obtained through interaction with the wireless sensor network, using both acoustic and RF nodes to achieve reliable and robust localisation for AUV navigation and control. This will allow tasks such as autonomous inspection of pipelines and other subsea structures, as well as the ability to track the position of these objects and autonomously place, collect or move sensors, in addition to being able to 'mule' data from the sensors and relay them back to shore. A further advantage of this system is that it allows the network to localise itself to identify pipeline movement as a result of 'walking' during shutdown or from changing seabed morphology.

Integrated Subsea Monitoring System

Through integration of the acoustic and RF wireless sensor network technologies, the Flagship has been investigating the feasibility of a novel idea for co-ordinating the remote collection of subsea pipeline and production sensor data. The system can best be summarised as creating a continuous integrated monitoring area. This 'integrated' approach to subsea monitoring consists of meshed wireless communication nodes (acoustic and RF) that collect data from local sensors and interfacing with a wired 'backbone' at a number of 'cluster points'. The backbone may be fibre optic or copper, with the cluster points set up at strategic locations to ensure optimal throughput of data from a series of smaller meshed networks. The data are sent from one node to another via wireless daisy-chaining until they reach a collector node (wired, acoustic, etc.) that can transmit the data to shore.

Integrating fixed-sensor networks with mobile nodes (robots) having complementary on-board sensors will greatly increase the efficiency of hardware utilisation and spatial monitoring capabilities. The resulting networked system could be capable of detecting broad-scale events and then adaptively guiding a mobile robotic survey node to perform fine-scale monitoring capabilities at sites of interest.

The potential of this system would include the provision for global information flow within the field and associated assets, increased aggregate channel capacity of data-to-shore or -surface production facilities to achieve the total daily data capacity and reduced signal propagation latency (especially for realtime control and safety critical devices). At an operational level, the system has the potential to reduce energy expenditure on high-throughput wireless nodes in large network meshes, to provide communications redundancy through the wireless network topology and to easily add sensors into the field and remotely collect data.

Research Summary

The field monitoring project at CSIRO is researching and developing next-generation underwater wireless sensor network technologies, with a specific focus on enabling integrated robust wireless sensing, control, communication and localisation systems for whole-of-life monitoring and operation of offshore oil and gas fields in Australia's deepwater frontiers.

The Flagship's integration of a diverse range of research capabilities from across many CSIRO divisions is enabling us to deliver an indepth scientific understanding of the key parameters involved in long-term operation and monitoring of offshore oil and gas fields. Existing activities in the field monitoring project are planned until 2010.

There is already commercial interest in the prototype technology, with various marine-based organisations using these preliminary technologies to enhance their monitoring capabilities.

There May Be Oil Offshore, But...

By Moira Herbst

Oil and gas firms covet US offshore reserves, but with oil prices so volatile it's unclear how much would be tapped -- or where it would end up.

Breaking with an 18-year ban imposed by his father, President George W. Bush recently lifted an executive order prohibiting oil exploration in US coastal waters. With that act, Bush said on July 15 at a Rose Garden news conference, "the only thing standing between the American people and these vast oil resources is action from the US Congress." Meanwhile, an organization led by former US House Speaker Newt Gingrich, American Solutions, is promoting a "Drill Here. Drill Now. Pay Less." campaign, collecting more than 1 million signatures to petition Congress to "act immediately to lower gasoline prices" by allowing exploration off America's coasts.

Told in political sound bites, the message is simple: Many people believe the US has walled off a vast gold mine of oil in coastal areas that could be tapped to lower prices. "We have reserves that aren't being explored or developed, and this environment of high energy prices presents a great opportunity," says Charles Davidson, CEO of Houston-based Noble Energy. He says it "would be a great win for the country" if Congress follows Bush's lead and lifts the ban.

The reality, as usual, is far more complicated. Drilling in the now-restricted areas would require years of extensive seismic research before a single rig could operate. Even then, companies would not embark on such massive projects unless the profitability were clear. What's more, the federal Energy Information Administration estimates that access to new US deposits would not significantly affect overall domestic production for 22 years.

Still, the extreme crimp of high fuel prices has mobilized efforts to expand US oil production. "If the ban is lifted, more studies can be done to find out where the best resources are," says Cathy Landry, a spokeswoman for the American Petroleum Institute. "Every day we wait is a day further from more oil production. We need to get started."

How much oil and natural gas is there offshore? No one really knows. According to estimates from the Interior Dept.'s Minerals Management Service (MMS), the US has roughly 18 billion undiscovered and technically recoverable barrels of oil and 76 trillion cubic feet of natural gas. Eric Potter, associate director of the Bureau of Economic Geology at the University of Texas at Austin, says that if these areas are opened up now, by 2025, 1 million additional bbl. per day could potentially be added to the market. Using International Energy Agency demand forecasts, by 2030 this production would equal less than 5 percent of U.S. daily consumption, and less than 1 percent of global daily consumption. "It would certainly help," says Potter. "But it won't make us energy-independent."

Still, lifting the ban is politically popular among Americans desperate for action on soaring energy costs. Almost three-quarters of American adults "strongly" or "mildly" favored increased drilling for oil and natural gas in offshore water, according to a CNN/Opinion Research poll conducted on June 26-29, higher than in previous polling.

The oil-services industry is capitalizing on the political momentum, targeting several coveted areas where it wants the freedom to explore. One is the eastern Gulf of Mexico off the coast of Florida, where the MMS says about 3 billion barrels of oil could be recovered. This area, which includes the natural gas-rich Destin Dome 30 miles from Pensacola, could prove most accessible because of existing equipment in other parts of the Gulf. In addition, there's the currently off-limits Atlantic coastline's estimated 3.8 billion recoverable barrels, and a potential 10 billion recoverable barrels lie beneath currently inaccessible Pacific waters.

The oil industry has been pressing lawmakers for access. The National Ocean Industries Assn. (NOIA), which represents 300 companies engaged in offshore oil and gas drilling, spent $200,000 (€126,000) in the first quarter, according to a disclosure form filed in the House. The group, whose members include drilling giants Diamond Offshore Drilling and Halliburton, used the money to press for lifting the offshore oil ban and on a variety of other issues. NOIA also includes companies that would more immediately benefit from more access: seismic exploration companies including CGGVeritas, WesternGeco, a subsidiary of oil-services firm Schlumberger PGS Geophysical.

Other industry groups eagerly support such a switch. "At today's [oil] price levels, there is lots of interest in offshore areas," says William Whitsitt, president of the American Exploration & Production Council, a trade group for independent oil companies including Devon Energy, Noble Energy, and Apache. The American Petroleum Institute (API) also supports lifting the ban.

But while companies and their lobbyists are gunning for access, there's no guarantee they'd ultimately produce more fossil fuels. First, seismic exploration data have not been updated for more than a quarter century, and extensive testing would be required before companies made decisions on capital allocations. And any oil that is recovered would go into the global marketplace—not directly into US consumers' cars. (The API counters that new supplies anywhere would help to lower overall consumer prices.)

Democratic lawmakers are raising such arguments to oppose new production in coastal areas. They point to MMS data showing that 83 percent of the area now leased by energy companies in the Outer Continental Shelf is not producing energy. While there are 2,200 producing leases in that space, an additional 6,300 are nonproducing. Democrats have proposed the "Drill Act," which they say would spur exploration on already available lands in Alaska, the West, and the western Gulf of Mexico. "There may be good and sufficient reasons why the companies that lease this land are not producing oil from it, but I believe we need to ensure that there is diligent development of existing leases," Jeff Bingaman, the Democratic senator of New Mexico and chair of the Senate Energy & Natural Resources Committee told the Senate on July 16.

Noble Energy's Davidson disputes the notion that companies are intentionally not drilling on leased areas, citing the complexities of obtaining the proper government permits and seismic research. Also, wells selected for drilling may come up dry because of faulty data. "Energy companies are trying to pursue every idea we can," says Davidson. "I find the idea that leases are lying fallow a real stretch."

Volatile oil prices keep

By Clifford Krauss

From the Indian Ocean to the Gulf of Mexico, giant supertankers brimming with oil are resting at anchor or slowly tracing racetrack patterns at sea, heading nowhere.

The ships are marking time, serving as floating oil-storage tanks. The companies and countries leasing them for that purpose have made a simple calculation: The price of oil has fallen so far that it is due for a rise.

Some producing countries are trying to force that rise by using the tankers to withhold oil from the market, while traders are trying to profit by buying oil now to store and sell at a higher price later. Oil storage has become so popular that onshore tank capacity is becoming scarce.

Only six months ago, companies up and down the energy pipeline were rushing oil to market, struggling to keep up with galloping demand and soaring prices. Now, with the global economy slumping and people driving less, demand for oil has plunged - and the same companies are acting in ways that would have been unimaginable until recently.

Oil producers are shutting rigs down, refiners are producing less gasoline and investment planning throughout the industry is in turmoil.

The problem for the companies is not just that prices are lower but that they have become volatile - historically, a sign of an unstable market whose direction is uncertain. Between Christmas and a week after, oil prices soared 40 percent, only to reverse course almost as sharply in recent days. The price of a barrel of crude oil dropped more than 12 percent in one day.

"The oil markets are suffering acute whiplash," said Daniel Yergin, an energy consultant and author of "The Prize," a history of world oil markets. "Price volatility is adding to the sense of shock and confusion and uncertainty."

The wild price swings are a continuation of trends from last year, when the price of a barrel of oil swelled from just below $100 in January 2008 to nearly $150 in July, before collapsing to less than $33 last month. Daily oil prices rose or dropped 5 percent or more 39 times, versus just four times in the previous two years. The only recent year that was comparably volatile was 1990, the year Iraq invaded Kuwait.

The continuing volatility is sending waves of anxiety up and down the complex production and investment chains of the oil world.

A year ago, oil producers and refiners could not move their products fast enough to meet growing world demand and chase rising prices. Now, with demand and prices slumping, they are sitting on millions of barrels at tank farms. The mounting buildup has come during the past 100 days or so, as consumption of oil has fallen.

With storage tanks filling up onshore, private and national oil companies, refiners and trading companies are storing an additional 80 million barrels aboard 35 supertankers and a handful of smaller tankers, the most in 20 years, according to Frontline, the world's largest owner of supertankers.

The various players have various reasons for storing oil, whether onshore or offshore.

National oil companies are hoping to reverse the price slide by holding oil off the market. Iran alone is reportedly using as many as 15 tankers to store crude oil in the hope that higher prices will prop up its economy, which is dependent on oil exports.

Private trading companies like Vitol and Phibro are storing oil in expectation of higher prices. They are taking their cues from markets where traders buy and sell contracts for future delivery of oil, which are signaling higher prices ahead.

Adam Sieminski, chief energy economist at Deutsche Bank, noted that a trading company could buy oil at the spot price of nearly $40 a barrel, store it and sell a contract to deliver it in a year for about $60. "You pay between $6 and $10 a barrel to store it, and you can make $10 a barrel," he said. "That's why Cushing is filling up rapidly and people are leasing tankers."

One of the big tank farms in the United States is in Cushing, Oklahoma, a major storage hub and a crossroad for pipelines.

One small example of how the price uncertainty has affected behavior is Devon Energy, an Oklahoma City company that has excited the energy world in recent years with announcements about expensive new investments in Canadian oil sands and deepwater oil exploration projects.

The company recently put off announcing details of its drilling program. Chip Minty, a Devon spokesman, said: "The volatility we have seen in the last year, and particularly the last few months, is making it more difficult to plan a drilling program that is funded through cash flow. Everybody is laying down rigs."

Devon's caution is a sign that the go-go days of investment in the oil patch are giving way to more modest expectations.

Schlumberger and Halliburton, the two top oil service companies, are cutting jobs. Many oil companies are delaying investments in their more expensive projects, like mining the Canadian oil sands. A couple of refiners face bankruptcy.

Oil volatility has complicated the efforts of automobile companies to figure out future strategies. Toyota had to suspend production at one plant that builds the Tundra pickup truck for several months when gasoline prices soared last summer. The automaker then delayed completion of a second plant that was meant to build the Prius hybrid when falling gasoline prices led to weakening demand for that fuel-efficient model.

The gyrations in prices affect shipping and other businesses around the world. Cathay Pacific, one of many airlines that use fuel price-hedging strategies, recently acknowledged that it had lost hundreds of millions of dollars because of the collapse in fuel prices.

The slowdown in oil investment is so rapid that some analysts say they believe it is only a matter of time before shortages appear that will push oil prices to new heights and damage the economy.

From day to day, the price swings reflect a push and pull among the various players in the market, and diverging geopolitical and economic trends.

After months of sharply dropping prices, the psychology on the oil markets appeared to shift strongly after Christmas - sending oil prices up as high as $50.47 in early January from as low as $32.40 a barrel on Dec. 19.

Traders were putting their investment money back into oil as OPEC appeared to be serious about cutting output. Fighting between Israel and Hamas in Gaza appeared to threaten a broader Middle East conflict that might crimp oil supplies. The conflict between Russia and Ukraine over natural gas shipments threatened European supplies, raising fears that Europeans might have to switch to oil from natural gas.

But the mood shifted just as quickly when the U.S. Energy Department reported that crude oil inventories at Cushing had climbed by four million barrels, to 32 million barrels, for the week that ended Jan. 2, the highest level since the government started tracking supplies in 2004. That number jumped again in a report, to 33 million barrels, near Cushing's operating capacity of 35 million barrels.

Gasoline, meanwhile, has become pricier at U.S. service stations because refiners have been producing less of it. Profits from refining have been so thin over the past several months that refiners have been earning little, or even losing money, on producing gasoline. So now they are storing oil or selling it to traders, or retooling their refineries to produce less gasoline and more products with better profit margins like heating oil, diesel or jet fuel.

Valero, for instance, has curtailed gasoline supplies by extending maintenance time at some refineries and cutting production at eight of its 16 refineries.

"There is not a lot of incentive right now to produce gasoline because there is lots of it," said Bill Day, a spokesman for Valero, the largest U.S. refiner. "Obviously it would be better for us if there were more stability in prices."

While Goldman Sachs has predicted the slumping global economy will soon drive the price of oil down to $30, a top Kuwaiti oil official has recently forecast that big production cuts by the Organization of Petroleum Exporting Countries will soon push oil back up.

"It's a sure bet that both will be right," Yergin said, basing his opinion on the sharp swings of recent days.

Analysts foresee prices remaining volatile for much of the year.

"Volatility is just another way of saying uncertainty," said Adam Robinson, director of commodities at Armored Wolf, a California hedge fund. "The demand outlook is very uncertain, the general outlook for prices is very uncertain, and the supply outlook is very uncertain."

ARTICLE
International Oil & Gas Magazine OFFSHORE

Muehlberg, Richard L

Long the strongest short the weakest

One trading axiom is simple: go with the winners, short the losers. Few markets have offered more opportunity in this area than the current energy complex. Here, we look at a basic concept that helps us leverage this approach.

You are watching two markets: one is rallying sharply, it is in a clear uptrend; the other is choppy, it is rallying slowly. **Which do you long: the leader or follower?**

Intellectually your answer is probably: "I would long the strongest, of course." However, for most of us, when we face real price action and the possibility of losing, our intellect may undergo a shift.

Fear often takes over, captivating you with the notion that the upside leader is poised to fall just as quickly as it has risen. The follower appears to be the safer choice. It's moving slowly and may retrace more slowly, as well. This logic often prevails, leading traders to long the follower, expecting it to catch up or not fall, and watch the leader for clues.

The opposite is true for bear markets as well. Over the summer and fall of 2008, energy futures trended lower. There were days of sharp breaks and days of sharp rallies. Trading was volatile. Nevertheless the major trend was down.

If you followed crude oil, heating oil and natural gas along with equities, currencies and gold, you had multiple choices to short. Choosing which market to short was the challenge. However, as it's easy to be tentative on the upside, when markets break, it is equally tempting to ignore the downside leader and short a follower. Again, in trying to make a safe choice, you end up with the most dangerous.

IMAGE GRAPH1

OIL SPILL

Energies peaked in July 2008 then broke sharply. A short crude position would have been profitable, but crude wasn't the weakest energy market. The 50-day moving average (green) and 20-day moving average (red) on this chart and in "Gas leak" help illustrate this.

Not surprisingly, over time the fearful response is the unprofitable one. When markets rise, you should generally long the strongest. When markets fall, you should generally short the weakest (and, maybe, both. See "Playing both sides," page 40.) This advice is easy to say but is psychologically hard to put into action.

ENERGIZED

Consider the most popular futures contracts in the energy complex: crude oil, heating oil and natural gas. If you are a trend (position) trader or a swing trader, one way to trade the complex is to look at a six-month chart and see which contract is showing the sharpest movement Sometimes one market will run sharply, while the others follow. There are times a former follower will become a leader. The idea is to constantly compare crude oil, heating oil and natural gas. Stay long the strongest in an uptrend. Stay short the weakest in a downtrend. When a new leader appears, switch to the new leader.

In "Oil spill" (left), crude oil was a good short. However, was it the best short? See "Gas leak" (right). Clearly, these two charts have the benefit of hindsight, but even taking them one day at a time you can see that natural gas was weaker from July to September, while crude oil was weaker from September through November 2008.

This helps demonstrate why, if you day-trade the energy complex, you must keep an eye on long-term direction. Trade what you see on an intraday basis, but trade in the direction of the sharpest run. Then go to cash and repeat the process the next trading day.

CAST A WIDE NET

If you are a single complex trader, you are probably aware of the other complexes and markets that can affect those you primarily trade. It's often helpful to take that awareness to the next practical step, using the guideline of long the strongest, short the weakest. When a related market runs more sharply in the same direction as your primary complex, earmark a portion of your money and take a position in the run.

During the time period covered in this article, crude oil moved in the same direction as the SSIP 500. Crude oil ran to the downside more sharply than equities and with less severe corrections (see "Weak yes, weakest no," above). As an SSd3 500 trader, you might have earmarked a portion of your money to short crude.

IMAGE GRAPH2

GAS LEAK

Comparing January crude oil to naturaL gas for the second half of 2008 shows a short natural gas trade would have worked much better through September.

WEAK YES, WEAKEST NO

Dedicated S&P traders may not have known that when stocks were falling, the energies actually were weaker. By broadening your view to include related markets, you can better appreciate what might be the best trade for your money.

If you are flexible in terms of which complex you trade, then look for a leader wherever a leader appears. When an upside or downside leader emerges, focus most of your money on the leader. Shift your money when a new leader emerges.

AGGRESSION MATTERS

Putting your money in the strongest individual market in a complex takes aggression. By going long the strongest and shorting the weakest, you are forcing yourself to be aggressive, but this will not, by itself, make you an aggressive trader.

Yes, you need to trade in a way that makes you comfortable. You also need to trade in a way that reduces your risk and increases your reward. Next time you see one market lead to the upside or one market lead to the downside, remember: long the strongest, short the weakest. You will trade more successfully. Perhaps more important to your long-term profitability, this forced aggression will ultimately become second nature.

That a market is an upside leader (or downside leader) is not changed by the analytics you use to track that market. The advice to long the strongest, short the weakest applies regardless of your analysis methods. It is a rifle-like approach to trading accuracy rather than a shotgun attempt at quick profits. It improves your aim, efficiency and success.

SIDEBAR

Playing both sides

The long the strongest, short the weakest concept not only applies to outright positions, but also can be an effective guide for spread trading. Indeed, spread trading is a relatively economical and safe way to start using this concept.

Spread trading involves going long one market and shorting a related market. That way, if an unexpected event occurs that causes both the related markets to move in one direction, your losses in one position will be dulled by gains in the other.

For this example, we'll look at two Nymex contracts: natural gas and heating oil. Both markets are widely used to heat homes and tend to move in similar fashion. The natural gas contract trades in units of 10,000 million British thermal units (mmBtu). The heating oil contract covers 42,000 U.S. gallons.

After the initial break in September, heating oil had dropped more on a percentage basis than natural gas. Heating oil slipped from roughly $3.20 per gallon to $2.90, or 9.3%. Natural gas had fallen as well, but by only 2.9%, from about $8.50 to $8.25.

IMAGE GRAPH3

FAST BREAK

Both heating oil and natural gas have fallen recently, but one market has fallen faster than the other.

SIDEBAR

By September, the energy complex looked weak and many traders were looking for ways to take advantage of the fall (see "Fast break," right).

However, the prospects of a recovery, particularly ahead of the heating season, would make any prudent trader wary. This is when a spread trade makes a lot of sense, hedging against a possible price rise.

Using the logic from the main article, we short the weakest (heating oil) and long the strongest, relatively speaking (natural gas).

After two months, the short heating oil trade had made about $50,400. The long natural gas trade had lost about $16,500. The net gain on the spread would have been about $33,900.

While gains obviously were pared by the loss on the long trade, some of that is earned back on a percentage basis. Heating oil initial margins are $11,475 per contract, while natural gas is $9,788. However, exchanges recognize the correlation of certain markets through spread margins, reductions in margins for offsetting positions in related markets. On a risk/return percentage basis, spread gains are often higher than the gains on an outright. This is one case where insurance doesn't just pay you back with peace of mind. It outright pays.

Also, the short position in heating oil went against us for a while, which may have forced us to exit the position if it weren't offset by the long position in natural gas.

Accounting For Differences In Oil And Gas Accounting

Companies involved in the exploration and development of crude oil and natural gas have the option of choosing between two accounting approaches: the "successful efforts" (SE) method and the "full cost" (FC) method. These differ in the treatment of specific operating expenses relating to the exploration of new oil and natural gas reserves.

The accounting method that a company chooses affects how its net income and cash flow numbers are reported. Therefore, when analyzing companies involved in the exploration and development of oil and natural gas, the accounting method used by such companies is an important consideration.

Two Approaches

The successful efforts (SE) method allows a company to capitalize only those expenses associated with successfully locating new oil and natural gas reserves.

For unsuccessful (or "dry hole") results, the associated operating costs are immediately charged against revenues for that period.

The alternative approach, known as the full cost (FC) method, allows all operating expenses relating to locating new oil and gas reserves - regardless of the outcome - to be capitalized.

Exploration costs capitalized under either method are recorded on the balance sheet as part of long-term assets. This is because like the lathes, presses and other machinery used by a manufacturing concern, oil and natural gas reserves are considered productive assets for an oil and gas company; Generally Accepted Accounting Principles (GAAP) require that the costs to acquire those assets be charged against revenues as the assets are used.

Why the Two Methods?

Two alternative methods for recording oil and gas exploration and development expenses is the result of two alternative views of the realities of exploring and developing oil and gas reserves. Each view insists that the associated accounting method best achieves transparency relative to an oil and gas company's accounting of its earnings and cash flows.

According to the view behind the SE method, the ultimate objective of an oil and gas company is to produce the oil or natural gas from reserves it locates and develops so that only those costs relating to successful efforts should be capitalized. Conversely, because there is no change in productive assets with unsuccessful results, costs incurred with that effort should be expensed.

On the other hand, the view represented by the FC method holds that, in general, the dominant activity of an oil and gas company is simply the exploration and development of oil and gas reserves. Therefore, all costs incurred in pursuit of that activity should first be capitalized and then written off over the course of a full operating cycle.

The choice of accounting method in effect receives regulatory approval because the Financial Accounting Standards Board (FASB), which is responsible for establishing and governing GAAP, and the Securities and Exchange Commission (SEC), which regulates the financial reporting format and content of publicly traded companies, are divided over which is the correct method. In Statement of Financial Accounting Standard (SFAS) 19, the FASB requires that oil and gas companies use the SE method, while the SEC allows companies to use the FC method. These two governing bodies have yet to find the ideological common ground needed to establish a single accounting approach.

What's the Difference?

In general, SE and FC methods differ in their approach to treating costs associated with the unsuccessful discovery of new oil or natural gas reserves. Although both methods are indifferent as to the type of reserves, oil versus natural gas, that are associated with the costs incurred, the specific treatment of those costs by each method is responsible for the difference in the resulting periodic net income and cash flows numbers.

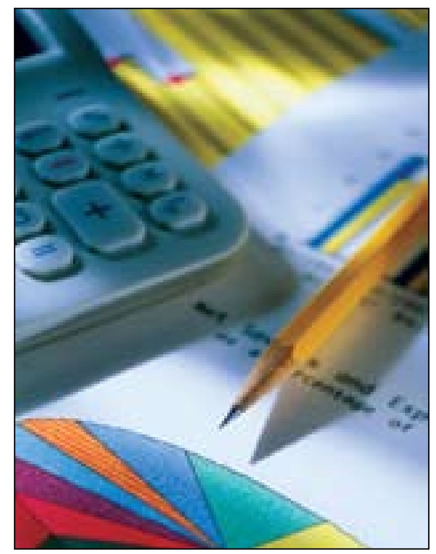
Regardless of the method it chooses to follow, an oil and gas company engaged in the exploration, development and production of new oil or natural gas reserves will incur costs that are identified as belonging to one of four categories:

Acquisition Costs

Acquisition costs are incurred in the course of acquiring the rights to explore, develop and produce oil or natural gas. They include expenses relating to either purchase or lease the right to extract the oil and gas from a property not owned by the company. Also included in acquisition costs are any lease bonus payments paid to the property owner along with legal expenses, and title search, broker and recording costs. Under both SE and FC accounting methods acquisition costs are capitalized.

Exploration Costs

Typical of exploration, costs are charges relating to the collection and analysis of geophysical and seismic data involved in the initial examination of a targeted area and later used in the decision of whether to drill at that location. Other costs include those associated with drilling a well, which are further considered as being intangible or tangible. Intangible costs in general are those incurred to ready the site prior to the installation of the drilling equipment whereas tangible drilling costs are those incurred to install and operate that equipment.All intangible costs will be charged to the income statement as part of that period's operating expenses for a company following the SE method. All tangible drilling costs associated with the successful discovery



of new reserves will be capitalized while those incurred in an unsuccessful effort are also added to operating expenses for that period.

For an oil and gas company following the FC method, all exploration costs - including both tangible and intangible drilling costs - are capitalized by being added to the balance sheet as part of long-term assets.

Development Costs

Development costs involve the preparation of discovered reserves for production such as those incurred in the construction or improvement of roads to access the well site, with additional drilling or well completion work, and with installing other needed infrastructure to extract (e.g., pumps), gather (pipelines) and store (tanks) the oil or natural gas from the reserves.

Both SE and FC methods allow for the capitalization of all development costs.

Production Costs

The costs incurred in extracting oil or natural gas from the reserves are considered production costs. Typical of these costs are wages for workers and electricity for operating well pumps.

Production costs are considered part of periodic operating expenses and are charged directly to the income statement under both accounting methods.

The Impact of Differing Levels of Capitalized Assets

The effect of choosing one accounting method over another is apparent when periodic financial results involving the income and cash flow statement are compared with the effect of highlighting the way each method treats the individual costs falling into these four categories. But such a comparison will also point out the impact to periodic results caused by differing levels of capitalized assets under the two accounting methods.

Much in the same way the financial results of a manufacturing company are impacted by depreciation expense for plant, property and equipment, those for an oil

and gas company are equally affected by periodic charges for depreciation, depletion and amortization (DD&A) of costs relating to expenditures for the acquisition, exploration and development of new oil and natural gas reserves. They include the depreciation of certain long-lived operating equipment; the depletion of costs relating to the acquisition of property or property mineral rights, and the amortization of tangible non-drilling costs incurred with developing the reserves. (For related reading, check out Appreciating Depreciation.)

The periodic depreciation, depletion and amortization expense charged to the income statement is determined by the "units-of-production" method, in which the percent of total production for the period to total proven reserves at the beginning of the period is applied to the gross total of costs capitalized on the balance sheet.

Financial Statements Impact - FC Vs. SE

Income Statement

DD&A, production expenses and exploration costs incurred from unsuccessful efforts at discovering new reserves are recorded on the income statement. Initially, net income for both an SE and FC company is impacted by the periodic charges for DD&A and production expenses, but net income for the SE company is further impacted by exploration costs that may have been incurred for that period. Thus, when identical operational results are assumed, an oil and gas company following the SE method can be expected to report lower near-term periodic net income than its FC counterpart.

However, without the subsequent discovery of new reserves, the resulting decline in periodic production rates will later begin to negatively impact revenues and the calculation of DD&A for both the SE and FC company. Due to the FC company's higher level of capitalized costs and resulting periodic DD&A expense in the face of declining revenues, the periodic net earnings of the SE company will improve relative to those for the FC company, and will eventually exceed those costs.

Statement of Cash Flows

As with the income statement, when identical operational outcomes are assumed, for a company following the FC method of accounting near-term results (shown in the cash flows from operations (CFO) portion of the statement of cash flows) will be superior to those for a company following the SE method. CFO is basically net income with non-cash charges like DD&A added back so, despite a relatively lower charge for DD&A, CFO for an SE company will reflect the net income impact from expenses relating to unsuccessful exploration efforts.

However, when there are no new reserves being added, reported net income under longer term SE and FC, each company's CFOs will be the same. This is because adding back the non-cash charge for DD&A effectively negates the relatively larger impact to net income under the FC method of accounting.)

Conclusion

When investing in companies involved in the exploration and development of oil and natural gas reserves, company analysis should include recognizing which accounting method a company follows. The differences between the two methods and their impact on near- and long-term net income and cash flow should prove helpful when comparing individual companies' past results and future expectations.

By Daniel Fineren - Analysis

Russia and Ukraine need oil-linked gas deal

Europe faces potential gas supply crises every winter unless Russia and Ukraine agree a long-term oil-linked gas contract that might require financial help from Europe, analysts said.

Russia has not offered Ukraine the kind of long-term deal enjoyed by its customers in western Europe which might settle the row for good.

Analysts said to do so would remove Moscow's favoured method of exerting political pressure on the pro-western government in Kiev.

"There has to date been little incentive to come to an amicable long-term relationship with Ukraine, so this is going to happen again and again. It suits Russia to return repeatedly to this gas relationship because it's a way of further destabilising the existing regime," Professor of Energy Policy at the University of Oxford Dieter Helm said.

"The Russians are holding them on a short-term exposure to the spot market and that's why we have this annual event," Helm added. "What is needed is a stable long-term pricing formula. That has to be pricing gas in relation to oil prices, which have fallen sharply."

Over a week after Moscow cut off Ukraine in its annual row over how much Kiev pays for its gas, the two sides have agreed an international monitoring deal that should see Russian supplies to Europe recover in a few days.

They have not agreed on how much economically-crippled Ukraine will pay for its gas this year, with Russia insisting Kiev should now pay "market prices" after decades of cheap supplies.

Ukraine's main objection to Russian gas export monopoly Gazprom's price demands is that western European buyers should see their bills halve by summer as a slump in oil prices since July feeds into oil-linked gas contracts.

Many analysts expect oil prices to remain low this year and possibly beyond as recession weighs on global demand.

This could give Ukrainian more time to recover from its worst recession in over a decade and give it a better chance of paying bills next winter.

But neither side of the bitter gas row has said publically that a long-term deal is under discussion, posing the real threat of another crisis next year.

"They may well fudge a deal again this year, like they have done for the last three or four years, but then the same problem will crop up again next year until there is probably some help," David Cox, chief consultant at Poyry Energy Consulting in London, said.

"It is in Western Europe's interest that the Ukraine does start to pay market prices and the sooner the better. But in terms of making them move to fully market related prices they can't really do that in one step, or even in a couple of years - it needs to be phased," he said.

EUROPE ROLE

"If we want the Ukraine in the EU and we want them on our side, rather than Putin's side, maybe we have got to pay a cost for that and that is partly helping them with the transition," Cox said.

Helm warned against Europe subsidising anybody's energy bills but said the European Central Bank could give additional funds to Ukraine, in addition to the $16 billion from the IMF, to help Ukraine get through its economic crisis.

"There is a good solidarity reason for the EU as a whole being in a position to help out particular countries," he said.

"So we might consider help for the Ukraine through its current financial difficulties. But it should not be tied to the gas."

Russia's price demands for this year have varied from $250 to $450 per 1,000 cubic metres of gas, with Moscow raising the price each time Kiev rejected its previous offer.

They say Ukraine should not be expected to pay the same price as buyers in Germany or Austria because Russia uses Ukraine to ship 80 percent of the gas that it supplies to Europe.

"The Russians are trying to raise the prices to the same level at which they sell to western Europe. That's always been their intention, Niall Trimble, director of the Energy Contract Company in London said.

"Obviously Ukraine does not have the wealth these countries have, so it's very hard to do that."

But some kind of oil-linked formula should ensure reliable winter warmth across Europe for years to come.

"That's what the rest of Eastern Europe's contracts are linked to as well, its not just Western Europe," Noel Tomnay, principal global gas research for Wood Mackenzie said.

"There are reasonable arguments being made here and its really up to the sides to conclude them."

Reducing offshore risk

The oil and gas industry is exposing itself to unnecessary commercial risk and financial losses because most operators do not have adequate legal measures in place when awarding offshore contracts, particularly those relating to engineering, procurement and construction (EPC).

Costly and high-profile contract disputes that have characterized the offshore oil and gas sector in the past few years could be repeated because operators and contractors have failed to adopt new practices and procedures to avoid these problems. These headline-grabbing disputes are doing little to bolster the industry's reputation or indeed help keep a healthy market for major contracts.

Curtis Davis Garrard and Douglas-Westwood Ltd. have conducted a comprehensive survey of major operators and contractors to understand attitudes to risk. The research has identified that there is an urgent need for more clarity when it comes to writing contracts, more openness from executives on both sides of the negotiating table and more involvement by lawyers who have direct experience of the industry.

The survey found that 60% of companies had no formal strategy in place to avoid litigation when contracts went wrong. In particular, there was a lack of legal control during the negotiation phase of the contract, meaning that there was a higher risk of disputes farther down the road. The majority of contractors and operators contacted for the survey said they were convinced that many contract disputes could have been avoided if more preparation work had been applied to a more detailed technical scoping of the contract. It also found that independent legal advice from specialists in offshore contracting could significantly reduce risks.

The survey showed that the balance of risk is believed to favor the operator in a lump-sum EPC contract. Some 72% of those surveyed said they strongly supported this proposition with only one respondent disagreeing and even 60% of operators admitting it was true. This has major implications for the industry as a whole because in light of recent disputes, many contractors are now reluctant to work in the sector due to what one termed the "obscene" risk they face.

In some cases, several contractors have now left the industry altogether or formed consortia, preferring to jointly bid on available projects. As a result, oil and gas companies are finding it increasingly hard to find contractors and with demand outstripping supply are also facing higher project costs, not to mention a possible lack of access to new technology.

As one contractor put it, "We have currently reached the limit of risk that we are able to absorb...it is questionable as to whether we are paid enough, especially in frontier projects." According to another, "There is an increasing reluctance to get involved in EPC contracts - we are not yet seeing people turning down work, but new jobs will have a limited number of companies interested."

Much of the reluctance on the part of the contractors is that the type of contract favored by the oil and gas companies often fails to contain sufficient checks and balances to address the issues that inevitably arise over the lifetime of a major contract. The survey found that the most important factor both for contractors and oil and gas companies when it comes to avoiding unfavorable outcomes was the use of clearer and better contracts. This was particularly true for lump-sum EPC contracts, where there was evidence of a strong need for more time to be spent on the details, especially with regard to engineering. As one operator commented, "I believe engineering to be the key risk, especially with fast-track projects where it is essentially bypassed, and it is vital that such a fundamental issue is right."

Many respondents also suggested that the UK Offshore Operators' Association (UKOOA), and the Cost Reduction In the New Era (CRINE) initiative, launched some 10 years ago, could have helped in making contracting issues clearer.

Much of the problem stems from the fact that many contracts being used today are either too generic, that is, not specific to the often complicated document that is being negotiated, or are simply dusted-off versions of contracts used in other projects. They also often fail to reflect the complexity of the contract itself. EPC contracts are traditionally some of the most complicated that the oil and gas industry deals with, yet the legal requirements are often overlooked in favor of the physical specifications of the contract.

Garrard believes this results in contracts being signed by parties that do not fully understand either the technology or the potential risks involved in the deal. Inevitably, the contract falls short of expectations when any issues arise, when instead it could be a practical, working document that can aid dispute resolution. The offshore sector needs to change the way it does business, look at the role of the contract and be more proactive not just in times of crisis. It has to become more like the onshore sector, where the contract is viewed as an aid to project management and a tool to help prevent disputes.

The survey also highlighted a tendency for both operators and contractors to focus their investment in legal resources on dispute resolution rather than dispute prevention.

Investing in legal resources from the start could prove a lot less costly than "waiting for something to go wrong." One shipyard manager contacted for the survey commented, "If more attention was paid at the start of the contract, a lot of later problems and contentious issues would not arise." With many operators and contractors still lacking an official strategy to prevent litigation, more high-profile disputes cannot be ruled out in the short term.

However, as the survey suggests, the recent spate of contract disputes means that there is a growing awareness of a need to change the way contracts are structured and managed from a legal point of view. In essence, clear, well-scoped contracts that pay greater attention to technical detail, particularly during the front-end engineering design phase, are vital if future problems are to be avoided.

The research was commissioned by Curtis Davis Garrard and undertaken by Douglas-Westwood Limited: Interviews were held with 52 companies associated with the offshore industry, including operators, contractors and brokers/intermediaries located in North America, Europe, Asia and the Middle East.

The survey also highlighted a tendency for both operators and contractors to focus their investment in legal resources on dispute resolution rather than dispute prevention

LNG
The Basics of Liquefied Natural Gas

Liquefied natural gas, or LNG

Liquefied Natural Gas, or LNG, is natural gas in its liquid form. When natural gas is cooled down to minus 259 degrees Fahrenheit (or -161 degrees Celsius), it becomes a clear, colorless, odorless liquid. Natural gas in liquid form, is only one six-hundredth of the volume of its gaseous form, which makes it easier to be stored and transport.

The natural gas is primarily Methane, with low concentrations of other Hydrocarbons, water, Carbon dioxide, nitrogen, oxygen and some sulfur compounds. During the process known as liquefaction, the natural gas is cooled down below its boiling point, and in the process removing most of these additional compounds. The remaining gas is primarily methane with only low amounts of other hydrocarbons.

Liquefied natural gas weighs less than half the weight of water so it will float if spilled on water.

LNG import and transport

A large part of the world's LNG (Liquafied Natural Gas) supply comes from countries with large natural gas reserves. These countries include Algeria, Australia, Brunei, Indonesia, Libya, Malaysia, Nigeria, Oman, Qatar, and Trinidad and Tobago.

There are more than 40 gas receiving terminals located worldwide. Japan, South Korea, the United State and a number of European Counties are importors of LNG.

LNG is normally transported in double-hulled ships specifically designed to handle the low temperature. These carriers are insulated to limit the amount of LNG that boils off or evaporates. This boil off gas is sometimes used to supplement fuel for the the carriers. LNG carriers are up to 1000 feet long, and require a minimum water depth of 40 feet when fully loaded. There are currently 136 ships which transport more than 120 million metric tons of LNG every year. (Source: University of Houston IELE, Introduction to LNG.)

Storage of LNG

When LNG is received at most terminals, it is transferred to insulated storage tanks that are built to specifically hold LNG. These tanks can be found above or below ground and keep the liquid at a low temperature to minimize the amount of evaporation. If LNG vapors are not released, the pressure and temperature within the tank will continue to rise. LNG is characterized as a cryogen, a liquefied gas kept in its liquid state at very low temperatures. The temperature within the tank will remain constant if the pressure is kept constant by allowing the boil off gas to escape from the tank. This is known as auto-refrigeration. The boil-off gas is collected and used as a fuel source in the facility or on the tanker transporting it. When Natural Gas is needed, the LNG is warmed to a point where it converts back to its gaseous state. This is accomplished using a regasification process involving heat.

Natural gas may be stored in a number of different ways. It is most commonly stored underground under pressure in three types of facilities. The most commonly used in California are depleted reservoirs in Oil and/or gas fields because they are more available. Aquifers and salt cavern formations are also used under certain conditions. The characteristics and economics of each type of storage site will dictate its suitability for use. Two of the most important characteristics of an underground storage Reservoir are its capability to hold natural gas for future use and its deliverability rate. The deliverability rate is determined by the withdrawal capacity of the associated valves and compressors and the total amount of gas in the reservoir. In other states, natural gas is also stored as LNG after the natural gas has been liquefied and placed in aboveground storage tanks. (Source: U.S. Department of Energy, Energy Information Administration.)

Use of LNG

LNG is normally warmed to make Natural Gas to be used in heating and cooking as Well as electricity generation and other industrial uses. LNG can also be kept as a liquid to be used as an alternative transportation fuel.

Natural gas is the cleanest burning fossil fuel. It produces less emissions and pollutants than either Coal or Oil. The North American supply basins are maturing and as demand for natural gas increases in California and throughout the United States, alternative sources of natural gas are being investigated. Natural gas is available outside of North America, but this gas is not accessible by pipelines. Natural gas can be imported to the United States from distant sources in the form of LNG. Since LNG occupies only a fraction (1/600) of the volume of natural gas, and takes up less space, it is more economical to transport across large distances and can be stored in larger quantities. LNG is a price-competitive source of energy that could help meet future economic needs in the United States.

LNG security

All LNG ships must comply with all pertinent local and international regulatory requirements, which include regulations and codes set forth by the International Maritime Organization (IMO), the U.S. Maritime Administration (MARAD), the U.S. Coast Guard (USCG), and the U.S. Department of Transportation (DOT), as Well as the hosting Port Authority.

DOT regulations must be followed at onshore LNG facilities and marine terminals. The Research and Special Programs Administration, DOT, regulations include 49 CFR Part 193 - Liquefied Natural Gas Facilities: Federal Safety Standards. These standards specify siting, design, construction, equipment, and fire protection requirements that apply to new LNG facilities and to existing facilities that have been replaced, relocated, or significantly altered.

Offshore marine terminals must follow regulations set by the USCG. The USCG monitors the safety of coastal waters around the U.S. and ensures the safety of ships while in U.S. waters and in port by preventing other ships from getting near LNG tankers. The USCG works with local harbor authorities and LNG facility personnel to ensure that proper procedures are followed. The USCG and MARAD are the federal agencies responsible for siting off-shore LNG facilities and are currently developing regulations.

Sources: California Energy Commision

Offshore Drilling

Drilling or digging for oil has occurred in one way or another for hundreds of years. The Chinese, for instance, invented a bamboo rig to obtain oil and gas for lighting and cooking.

But only in the last 40 years has humankind been able to efficiently extract petroleum from beneath the seas - an achievement to rank with this century's mightiest technological triumphs.

In Australia, nearly 90 per cent of our petroleum wealth is found offshore. The search is difficult, extremely expensive, and often fruitless - but critical to the nation's economic future.

Locating an oil and gas "trap" - as it is known - and extracting the oil and gas is difficult enough on land. But offshore, in deep and often stormy waters, it becomes an awesome undertaking.

Potential traps are identified by analysing seismic survey data but whether they contain oil or gas won't be known until a drill bit penetrates the structure. Directing the drill bit to a precise location - perhaps several kilometres away - requires sophisticated computer technology. A navigation device installed above the drill bit feeds back information which enables the exact position of the well to be measured and monitored. A steerable motor within the drillpipe can be remotely controlled to adjust the direction of the drill.

Environmental safeguards

What is the impact of drilling on the marine environment?

The Australian offshore petroleum industry has always contended that its activities are environmentally friendly.

The industry's case has now been given increased strength with the findings of the Independent Scientific Review Committee (ISRC) inquiry commissioned by the Australian Petroleum Exploration Association.

In Australia up to 100 offshore wells per year are drilled. About a quarter of these are development wells to produce oil or gas found by previous drilling.

Before a well can be drilled, government approval must be obtained. Drilling must then conform to statutory conditions and further operations are covered by industry Codes of Practice.

The Independent Scientific Review has found that environmental impacts from offshore exploration and production are negligible. The ISR examined the potential environmental effects of discharge of drilling fluids, drill cuttings and "produced formation water" (PFW).

Companies in Australia safeguard the environment and minimise impacts in a number of ways.

Drilling fluids used in Australia are almost exclusively water-based, not oil-based.

During production, oil is separated from the water by mechanical devices before the produced formation water is returned to sea. Australia's regulations on how much petroleum hydrocarbon is contained in PFW are among the world's strictest.

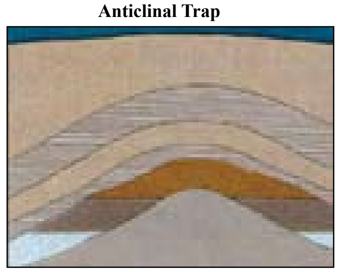
Sophisticated and reliable blowout prevention systems (BOP) are used in every production well to minimise the possibility of a blowout - where uncontrolled fluids flow from a well.

Four drilling rig types

In the early days of offshore drilling, explorers simply fitted a derrick to a barge and towed it to their site. Today, four types of offshore rigs are used to drill wildcat or exploration wells.

- **Submersibles.** These are rarely used. They can be floated to shallow water locations then ballasted to sit on the seabed.
- **Jackups.** Usually towed to a location. Their legs are then lowered to the seabed and the hull is jacked-up clear of the sea surface. Used in waters to about 160 metres deep.
- **Drill ship.** These look like ordinary ships but have a derrick on top which drills through a hole in the hull. Drill ships are either anchored or positioned with computer-controlled propellers along the hull which continually correct the ships drift. Often used to drill "wildcat" wells in deep waters.
- **Semi submersible.** Mobile structures, some with their own locomotion. Their superstructures are supported by columns sitting on hulls or pontoons which are ballasted below the water surface. They provide excellent stability in rough, deep seas.

Anticlinal Trap



Fault Trap

Production platforms

Once oil or gas is discovered, the drilling rig is generally replaced by a production platform, assembled at the site using a barge equipped with heavy lift cranes.

Platforms vary in size, shape and type depending on the size of the field, the water depth and the distance from shore. In Australia's medium to large fields, fixed production platforms are commonly used.

These are made of steel and fixed to the seabed with steel piles. These platforms house all the processing equipment and accommodate up to 80 workers who typically work a 12 hour day, one week on and one week off. There are also concrete structures which are big enough to store oil. Gravity holds them on the seabed.

The world's biggest platforms are bigger than a football field and rise above the water as high as a 25 storey office tower. They are home to 500 workers.

If the field is in shallow water and near land or another platform, small remotely controlled monopod platforms may be used. Another system is a floating structure, either anchored or tethered, called a Floating Production Storage Offloading (FPSO) vessel.

Another platform type, suitable for deep water production, is the Tension Leg platform, built of steel or concrete and anchored to the sea floor with vertical "tendons".

Drilling for oil

The first stage of drilling is called "spudding" and drilling starts when the drill bit is lowered into the seabed.

The bit can be of two types: - a roller cone or rock bit which usually has three cones armed with steel or tungsten carbide : teeth:; or buttons; or - a diamond bit, imbedded with small industrial diamonds.

The drill bit is attached to drill pipe (or a drill string) and rotated by a turntable on the platform floor. As the hole deepens, extra lengths of drill pipe are attached.

A length of drill pipe is 30 feet long, or 9.1 metres (oil workers use the old imperial measurement system). The drill bit ranges in diameter from 36 inches or approximately 91.4 centimetres (used at the start of the hole) to eight and a half inches (approximately 21.5 centimetres).

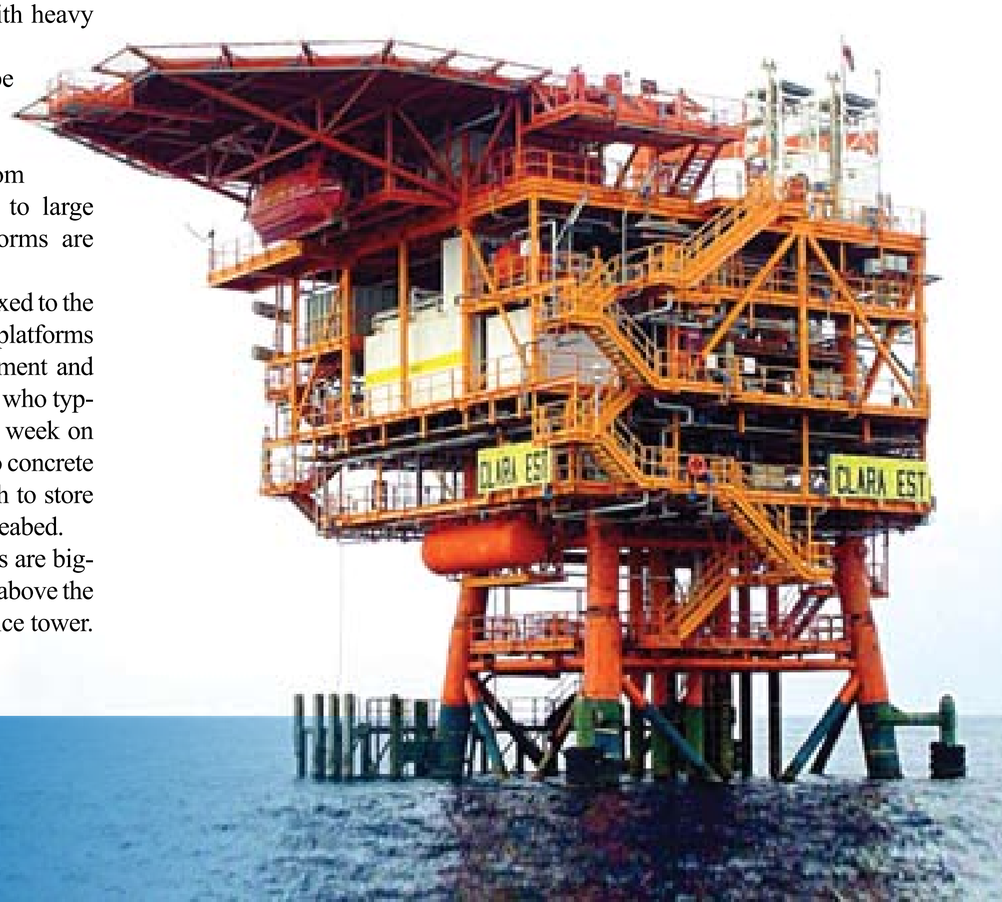
Drilling may take weeks or months before the targeted location is reached.

The major potential environmental effects from offshore drilling result from the discharge of wastes, including drilling fluids, drill cuttings and "produced formation water" (PFW).

Drilling fluid

Drilling fluid is pumped down the drill pipe and into the hole at high velocity through nozzles in the drill bit. The fluid is usually a mixture of water, clay, a weighting material (usually barite), and various chemicals.

The drilling fluid serves several purposes. It raises the drill cutting to the surface for disposal; it provides the "weight" to keep the underground pressures in check; it keeps the hold stable by caking the wall with a thin layer of clay; and it cleans and cools the bit.



The fluid is recycled through a circulation system where equipment mounted on the drilling rig separates out the drill cuttings and allows the clean fluid to be pumped back down the hole. With few exceptions, Australian wells since 1985 have been drilled using water-based drilling fluids, not oil-based.

The ISRC concluded that "drilling waste discharges have generally been shown to have only minor effects on water quality and pelagic ecosystems".

Evidence collected by the ISRC suggests that acute toxic effects of drilling fluids on marine organisms are only found at very high concentrations.

"Toxic effects on the biota in the water column from such concentrations would only be present within a few tens of metres from the point of discharge and only for short times after discharge".

As the plume of drilling fluid and cuttings falls to the seabed, it disperses, with 90 percent of it settling within 100 metres of the platform. Soluble waste concentrations will have fallen by a factor of 10,000 within 100 metres and suspended sediment concentrations by a factor of at least 50,000.

Drill cuttings

As the well is drilled, the "cuttings", consisted of crushed rock and clay, are brought to the surface by the drilling fluid and discharged overboard.

New measures to reduce discharges such as re-injecting the cuttings into the well and slim hole drilling are being examined and tested by the industry.

Produced formation water

Where you find oil, you often also find water. As oil is drawn from a reservoir, it is therefore necessary to separate the water and return it to the ocean.

This is what is known as "produced formation water" (PFW). Great emphasis is placed on ensuring that the water returned to the ocean is as free as possible from oil and chemicals. Strict regulations apply on how much petroleum hydrocarbon is contained in PFW. The Australian regulatory limit is 30 mg/litre average. Mechanical separation devices and chemical treatments are used to separate oil and water efficiently.

Preventing "blow-outs"

The weight of the drilling fluid acts as the first line of well control by keeping underground pressures in check. If an influx of pressurised oil or gas does occur during drilling, well control is maintained through the rig's blowout prevention system (BOP). This is a set of hydraulically operated valves and other closure devices (rams) which seal off the well, and route the wellbore fluids to specialised pressure controlling equipment.

Trained personnel operating this highly reliable equipment minimise the possibility of a "blowout", or an uncontrolled flow of fluids from a well.

Directional drilling

Drilling an oil well may not be a case of going straight down. Directional drilling has been developed where drill bits are steered laterally over a distance of up to several kilometres towards the petroleum reservoir.

One production platform is often used to drill a number of wells, in a variety of directions and inclinations. To steer the drill bit, a downhole motor may be used. It is turned by pumping the drilling mud through it.

Completing the well

When the well has been drilled to its target depth, production casing is set and cemented.

Tubing is lowered into the hole together with "packers" which seal the space between the tubing and the casing. Finally, at the end of the well, the casing is perforated at predetermined depths by small explosive charges detonated remotely. The small holes in the casing allow the oil or gas under its natural pressure to flow to the surface.

A dry well

If the drilled hole is considered to be "dry" or not worth developing, the decision is made to "plug and abandon" it. This involves setting several cement plugs in the well.

Classification of Oil

By OilGasArticles Editor

Brent Blend

Brent Blend, comprising 15 oils from fields in the Brent and Ninian systems in the East Shetland Basin of the North Sea. The brent crude Oil is landed at Sullom Voe in the Shetlands. Oil production from other parts of the world is often compared to the price of this brent oil, which forms a benchmark for the oil price.

Brent Crude Oil is one of the major classifications of oil consisting of Brent Crude, Brent Sweet Light Crude, Oseberg and Forties. Brent Crude oil is produced or sourced from the North Sea.

Brent blend is a fairly light crude oil, though not as light as West Texas Intermediate (WTI). It contains approx 0.37% of sulfur, classifying it as Sweet Crude, yet again not as sweet as WTI. Brent blend is ideal for production of Gasoline. It is most often refined in Northwest Europe, but when the market oil prices are favorable for export, it can also be refined also in the United States or the Mediterranean region.

West Texas Intermediate

West Texas Intermediate (WTI) is a type of crude oil used as a benchmark in estabishing oil prices and the underlying commodity of NYMEX (New York Mercantil Exchange) Crude Oil futures trading. This is normally the type of oil referenced in Western news and business reports about crude oil prices, alongside North Sea Brent Blend crude oil.

West Texas Intermediate (WTI) is a very light crude, lighter than Brent crude oil which is fairly light. It contains approx 0.24% sulfur, rating it a "sweet" crude, sweeter than Brent oil. Its properties and production site make it ideal for being refined in the USA, mostly in the Midwest and Gulf Coast regions of the country.

Current and historical oil price data for West Texas Intermediate (WTI) can be found at the Energy Infomation Administration, Department of Energy of the US government website www.eia.doe.gov

OPEC Basket

The "OPEC Basket" consisting of crude Oil from the following countries and names:

"Arab Light", which is Crude Oil from Saudi Arabia. "Bonny Light", which is crude oil from Nigeria. "Fateh", which is crude oil from Dubai, "Isthmus" from Mexico (which is non-OPEC), "Minas" Indonesia. "Saharan Blend" which is crude oil from Algeria. "Tia Juana Light" from Venezuela.

OPEC traditionally try to keep the crude oil price of the Opec Basket between upper and lower price limits, by increasing and decreasing oil production. This makes the measure important for oil market trading analysts. The "OPEC Basket", which is a a mixture of both light and heavy crudes, is heavier than both Brent and WTI crude oils.

A.Haji Ghasemi
Project Manager of phases 15&16 in IOEC

Iranian Offshore Engineering &construction Company (IOEC)

South Pars Gas Field Development Phases 15&16

South Pars Gas Field Development Phases 15&16 Project is an EPCI project which is commenced in 21.Dec.2006 by an Iranian Consortium consisting GHORB, IOEC, ISOICO and SAFF Companies. Scope of work in this project is divided in two main parts, i.e. offshore and onshore.

GHORB as leader of Consortium is responsible of onshore part and IOEC as leader of offshore Consortium is EPCI Contractor of Pipeline, Installation Contractor of platforms and supervisor of EPC Contractors of platforms i.e. ISOICO and SAFF Companies.

Now, and after two years from beginning the project in pipeline part, almost all the engineering and procurement activities have been finished, pipe Coating in Khorramshahr Coating yard is going on, and pipe laying activity according to Client agreed schedule will be started soon.

Also in platform part basic engineering is finished, detail engineering is almost finished, main jacket items are procured and under construction, and topside items are in procurement progress.

Construction of wellhead jackets are in progress and will be finished in next two months.

Contract lump sum price in offshore part is 480/000/000 USD which was fixed almost five years ago and considering world's economy change, inflation in global market and other economical factor, it is estimated that contract real price would be more than two times of this figure.

Iranian content and localization of activities is a major concern of all involved parties in this project and they did their best to follow this policy. One important sample of this effort is engineering activities which in platform part are performed by an Iranian Company and in pipeline part is also mainly done by IOEC and only endorsed by a foreign Company.

In performance of the work dependency to foreigner is less than %5 which with support of government this dependency can be also eliminated.

In new solar year (1388) IOEC's plan is pipe laying of both pipelines of project in 220 km length from shore (Asaloyeh) to platform location.

South Pars Gas Field Development Phases 15&16 Project is ministry of oil's first priority and supposed to be first project after phases 9&10 to be handed over and with exploitation of 2000 MMSCFD gas and stabilized Condensate, ethane, propane, Butane, Sulfur, and MEG not only can compensate domestic gas shortage in future, but also increase Iran's export rate in Energy section.

15 & 16

Iranian Offshore Engineering &Construction Company (IOEC)

South Pars Gas Field Development Phases 17&18

The South Pars is a gas field in the Persian Gulf. It is the world's largest gas field which along with Qatar's North Field is shared between Iran and Qatar. It covers an area of 9700 square kilometers, of which 3700 square kilometers (South Pars) is in Iranian territorial waters and 6000 square kilometers (North Field) is in Qatari territorial waters. Phases17&18 is an integral part of the 28 phases established for South Pars Gas Field that all together has an estimated 500 Trillion Cubic Feet (TCF) gas reserve.

South Pars Gas Field Phases 17 & 18 Project is among the 28 phases of South Pars gas Field. They are developed through Pars Oil & Gas Company (POGC) for National Iranian Oil Company (NIOC) in Iran. This Project includes offshore facilities fabrication and pipe-laying (Platforms and Sub-sea Pipelines) and onshore facilities for the processing of the Reservoir Fluid. IOEC is the designate contractor for the offshore part of this project.

These Phases are located in the Persian Gulf 100 km off Iranian south coast. They will be developed to produce 2,000 MMscfd Reservoir Fluid from two development Phases, 1,000 MMscfd each. These fluids will then be transported to the mainland for further treatment.

To achieve this, a project was signed for an EPC contract, which included Engineering, Procurement & Supply, Construction and Installation, Commissioning, Start-up and Performance Test. It was signed between National Iranian Oil Company (NIOC) and a Consortium consisting of Industrial Development & Renovation Organization (IDRO) as the head of the Consortium, Oil Industries Engineering & Construction (OIEC) for onshore activities and Iranian Offshore Engineering & Construction Company (IOEC) for its offshore activities.

IOEC is solely responsible for the "Offshore" portion of the project consisting of construction and installation of offshore platforms and installing undersea pipelines. The following are the activities IOEC has been involved with for the offshore section of this project.

Part - I: Offshore Platforms

Fabrication and installation of offshore platforms are one of the main activities of South Pars Gas Field Phases 17 & 18 Project. For an ease of reference, offshore platform activities can be divided into the following categories. They are engineering, procurement, construction and installation.

Engineering activities for two unmanned wellhead platforms for each phase of the project (SPD23 & SPD26 for phase 17 and SPD24 & SPD25 for phase 18), of 500 MMscfd capacity each SPD, equipped with their minimum production facilities. Two flare platforms (FSP) for each phase of the project connected by bridge to associated wellhead platform.

Procurement activities for one unmanned wellhead platform for each phase of the project and One flare platforms (FSP) for each phase of the project connected by bridge to associated wellhead platform.

Construction and Installation activities for one unmanned wellhead platform for each phase of the project flare platforms (FSP) for each phase of the project connected by bridge to associated wellhead platform

Part - II: Sub-sea Pipelines

Sub-sea pipelines are the other main activity for this project. This activity is divided to three main categories.

Engineering part includes activities for two 32" pipelines each with 4 ½"

piggy-back line of 1,000 MMscfd capacity as export line from two SPD23 & SPD24 (main wellhead platforms) to the onshore gas treatment in Assaluyeh and a 20” and a 18” pipelines each with 4 ½” piggy-back line as infield pipelines from SPD23 to SPD26 (satellite wellhead platform) and SPD24 to SPD25 (satellite wellhead platform).

Procurement activities are being carried out for one 32” export pipe-line (with 4” piggy back line) for each phase of the project and a 20” and an 18” pipelines each with 4 ½” piggy-back line as infield pipelines.

Construction and Installation activities will be performed for one 32” export pipe-line (with 4½” piggy back line) for each phase of the project.

The Present status of the Project

To provide a window to the project progress the following information is provided for the present status of the project.

For engineering activities, Basic, Detail and construction engineering for jackets and decks are being carried out and all documents are being reviewed by Third Party Agency. In procurement, all jacket materials have been provided and purchase orders are placed for Deck structural material. Presently in Fabrication, the following structures were developed: quay wall, skid way and skid beam. For jackets, the SPD23 progress stands at 98.70% and for SPD24 at 98.60%. For installation, Abouzar 110 (Launch Barge) is being mobilized and mobilization for jackets load out will be made in May 2009.

As for the sub-sea pipelines engineering for Basic, Detailed and installation engineering for main and infield pipelines are being carried out and the majority of documents has been carried out and then reviewed by Third Party Agency.

Procurement activities for 32”, 20” and 18” offshore pipelines are under process while the procurement of 4½” pipelines material has been carried out.

For installation the following has been performed:

- Shore pulling and pipelaying operation for 4.2 km (one phase)
- 32” pipeline Polyethylene coating for onshore pipe laying (820 pipe joint)
- 4½” pipeline Polyethylene coating by Ahwaz pipe mill
- Fabrication of support for crossing operation (14 concrete blocks)
- Mobilization of onshore site (Asalouyeh) for onshore pipe laying with length 10 km for each phase

As IOEC takes its responsibility to its clients very seriously, it is of outmost importance to ensure the satisfactory execution of this lump-sum project as per the client requirements.