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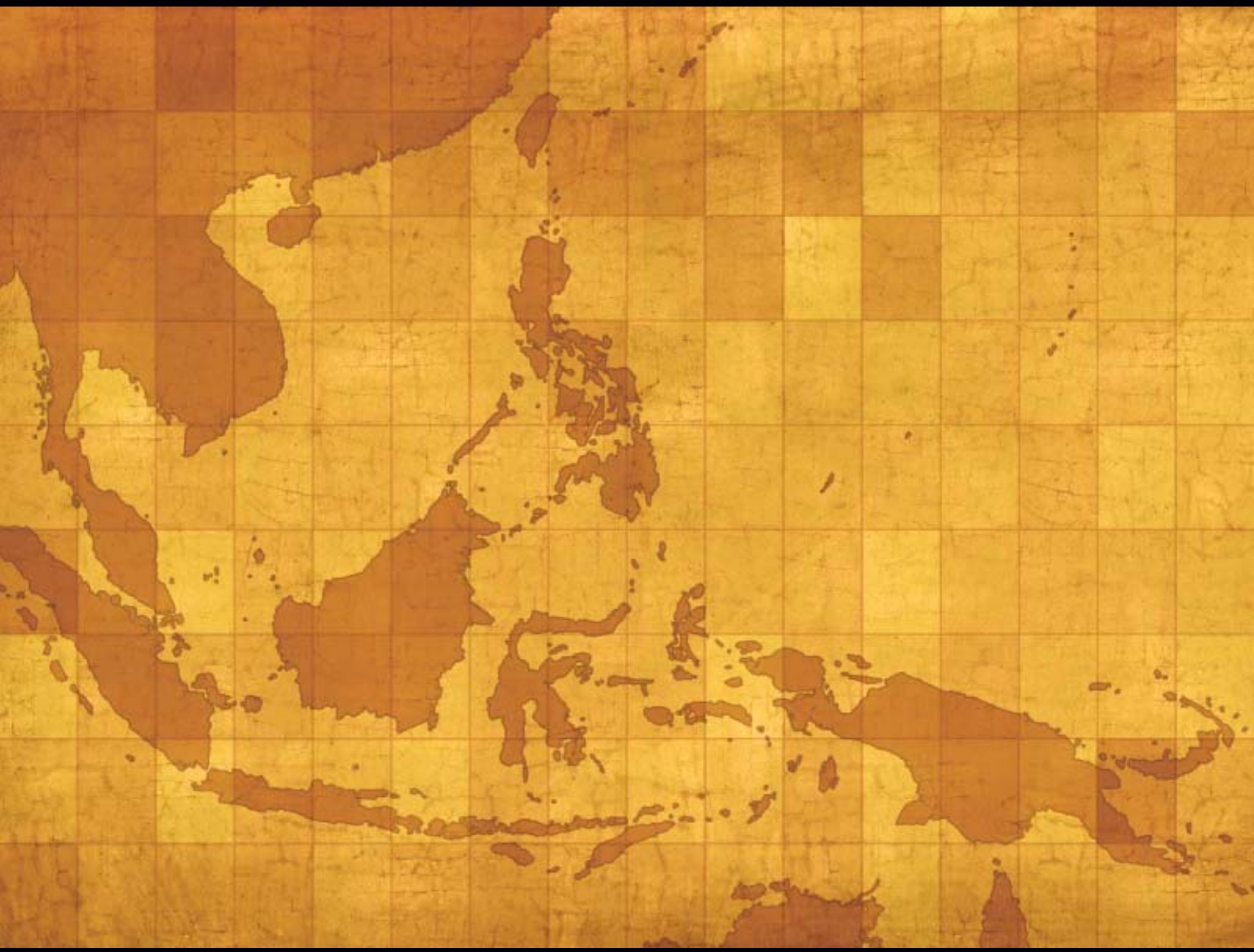

Activity Report: Southeast Asia

Seismic used to directly map reservoir permeability fields
Canadian Superior looks at size of prize in Trinidad, Nova Scotia
Egyptian gas plant employs absorbents for Hg removal
Programmed pipeline route markers increase efficiency, safety

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Dec. 11, 2006
Volume 104.46

ACTIVITY REPORT: SOUTHEAST ASIA

REGULAR FEATURES

COVER

Aggressive licensing and strong cash flows have boosted drilling in Southeast Asia through this year and will keep activity strong next year if operators can find rigs. The work has yielded a number of oil and gas discoveries, especially in Indonesia and Malaysia. In the special report beginning on p. 18, Wood Mackenzie analysts review the action.

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General Interest — Quick Takes

WoodMac: Output boost forecast for Venezuela

Production from Venezuela's marginal fields will surge within 3 years, predicts Wood Mackenzie Ltd., Edinburgh.

That conclusion came in a report entitled "Venezuela's new empresas mixtas set to boost output." Venezuela formed new joint venture companies (empresas mixtas, or mixed companies) with international oil companies after renegotiating contracts under which the companies were working (OGJ, Apr. 25, 2005, p. 48).

The mixed companies operate the assets, and state company Petroleos de Venezuela SA (PDVSA) takes a majority stake in each, typically 60% or larger.

After 2 years of reduced investment and production declines during "the painful process of rewriting the marginal-field contracts," a production boost is in prospect, WoodMac said.

"By 2009, oil production from the former marginal fields could have risen by 125,000 b/d or more, a 34% increase on today's levels," said Matthew Shaw, WoodMac Latin America senior analyst.

He noted these figures exclude production from seven marginal fields that were relinquished to PDVSA by participants choosing not to convert their contracts.

"In some cases, the return on investment arising from the contract conversion will actually increase—especially for the second-round marginal fields which had particularly tough fiscal terms—but the drop in working interest has seriously reduced the net present value of the assets for the third parties," Shaw said. "The overall decrease in their portfolio value is approximately $2.5 billion, a 43% drop."

The report also predicted long-term potential for many fields.

"The new contracts have extended the previous license terms by as much as 14 years, which should allow previously untapped oil reserves to be exploited, for instance by implementing water injection," Shaw said.

US House passes bill on produced-water use

The US government would study expanded uses for water produced with oil and gas under legislation passed Dec. 5 by the House of Representatives (OGJ, Oct. 16, 2006, p. 30).

HR 5110 would direct the US Interior secretary to identify obstacles to using produced water. It also would authorize funding for three pilot plants in Colorado, California, and Arizona or Nevada to demonstrate ways produced water can be made suitable for other uses.

The bill moves to the Senate, which would have to pass it before adjourning for the year. If the Senate doesn't act, the bill will be reintroduced early in 2007, according to a spokesman for its sponsor, Rep. Mark Udall (D-Colo.). ✦

Exploration & Development — Quick Takes

Iran plans Azadegan tenders, Pars Phases 6-8

Tender documents for Iran's Azadegan development were expected to be ready by Dec. 15, said Gholamhoseyn Nowzari, National Iranian Oil Co. (NIOC) managing director, at an NIOC seminar in Tehran last month.

In October, Japan's Inpex Corp. agreed to reduce to 10% its concession in Iran's Azadegan oil field from the current 75%, with the outstanding 65% stake to be transferred to NIOC (OGJ Online, Oct. 6, 2006).

Nozari also announced that NIOC expects to finish the preparation of a directive on modifications to buy-back deals by next week.

Meanwhile, Nowzari said, NIOC held discussions Oct. 31 with Total SA concerning a project to develop South Pars gas field and the Pars LNG project.

Nowzari expressed hope that South Pars Phases 6-8 would be commissioned by Mar. 20, 2007, the end of the current Iranian year.

Petrobras, Ecopetrol plan joint projects

The national oil companies of Brazil and Colombia plan jointly to explore the Tucano Block in Bahia, Brazil, and to expand production in Tibu oil field in Colombia.

Brazil's Petroleo Brasileiro SA (Petrobras) will sign an agreement with Colombia's Ecopetrol to further develop Tibu, 500 km north of Bogota near the Venezuelan border. The Ecopetrol-operated field began production in 1944, reached its production peak in 1955 at 26,000 b/d of 32-50° gravity oil, and has produced a total of 247 million bbl. It has 129 active wells.

Petrobras will manage the advanced development program and fund 55% of it. The program is designed to extend production by as much as 100 million bbl. Production is expected to increase to more than 15,000 b/d from 1,800 b/d, and Petrobras will retain 40% of the field's total production.

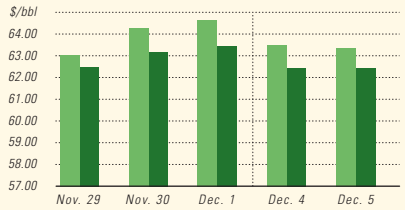
The 2½-year Phase I will begin in January. Petrobras will invest $40 million for studies to determine the field's potential and for technology.

Ecopetrol will work in partnership with Petrobras in the exploration of the 170 sq km Tucano 156 Block in Bahia. The block, in the Tucano Sul basin, 90 km from the Bahia coast, was purchased at a recent National Petroleum Agency auction.

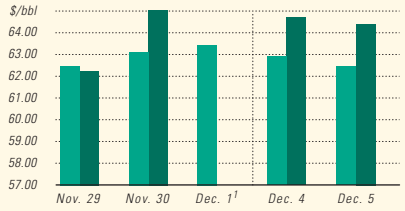
Ecopetrol, with a 30% share, will be the project's operator, and Petrobras holds 70%.

Industry Scoreboard

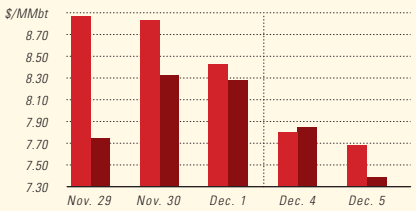
IPE BRENT / NYMEX LIGHT SWEET CRUDE



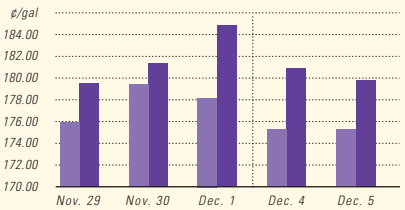
WTI CUSHING / BRENT SPOT



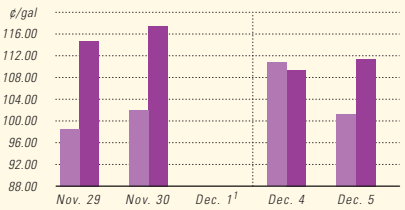
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



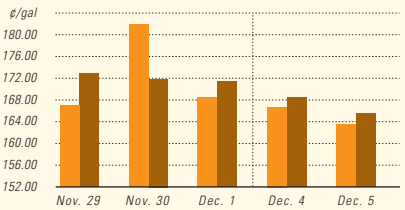
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



NYMEX GASOLINE / NY SPOT GASOLINE[2]



[1]Not available.
[2]Nonoxygenated regular unleaded.

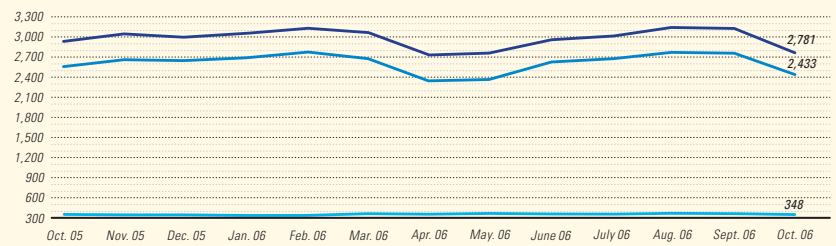
US INDUSTRY SCOREBOARD — 12/11

Latest week 12/1	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	9,782	9,085	7.7	9,827	9,123	7.7
Distillate	4,286	4,054	5.7	4,157	4,111	1.1
Jet fuel	1,635	1,603	2.0	1,607	1,627	–1.2
Residual	452	975	–53.6	715	914	–21.7
Other products	5,046	4,845	4.2	4,956	4,880	1.6
TOTAL DEMAND	21,201	20,562	3.1	21,261	20,654	2.9
Supply, 1,000 b/d						
Crude production	5,262	4,745	10.9	5,128	5,112	0.1
NGL production	2,293	1,612	42.2	2,237	1,709	30.8
Crude imports	9,788	10,255	–4.6	10,219	10,017	2.0
Product imports	2,881	3,761	–23.4	3,414	3,471	–1.6
Other supply[2]	1,161	1,221	–4.9	1,096	1,237	–11.3
TOTAL SUPPLY	21,385	21,594	–1.0	22,094	21,556	2.5
Refining, 1,000 b/d						
Crude runs to stills	14,972	15,024	–0.3	15,144	15,204	–0.4
Input to crude stills	15,354	15,240	0.7	15,569	15,479	0.6
% utilization	88.6	89.0	—	90.4	90.4	—

Latest week 12/1	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	334,102	338,237	–4,135	323,976	10,126	3.1
Motor gasoline	201,206	200,532	674	206,027	–4,821	–2.3
Distillate	139,309	140,762	–1,453	136,243	3,066	2.3
Jet fuel	37,900	37,462	438	41,597	–3,697	–8.9
Residual	45,015	44,688	327	39,796	5,216	13.1
Futures prices[3]						
Light sweet crude, $/bbl	62.50	59.71	2.79	57.79	4.71	8.2
Natural gas, $/MMbtu	8.49	7.91	0.58	12.49	–4.00	–32.0

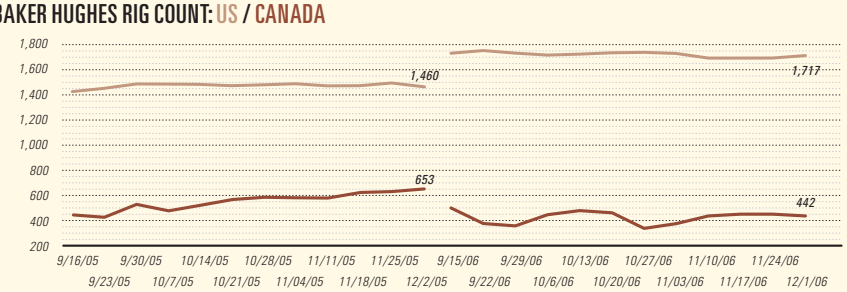
[1]Based on revised figures. [2]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil.
[3]Weekly average of daily closing futures prices.

BAKER HUGHES INTERNATIONAL RIG COUNT: TOTAL WORLD / TOTAL ONSHORE / TOTAL OFFSHORE



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

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Murphy temporarily abandons Gulf of Mexico well

Murphy Oil Corp. has temporarily plugged and abandoned its Thunder Ridge exploration well on Mississippi Canyon Block 737 in the Gulf of Mexico.

The primary objectives found wet sands, with a secondary shallower objective encountering a small oil accumulation. The exploration well and subsequent sidetrack were drilled in over 6,100 ft of water.

Postdrilling analysis will continue to determine if the resource found can be commercially viable as a tieback to another facility. Thunder Ridge lies close to the company's recently sanctioned Thunder Hawk development, which will include a stand-alone semisubmersible floating production unit that is scheduled for installation in late 2008 to accommodate the expected start of oil production in 2009.

Murphy owns a 37.5% working interest in the field and serves as operator. Partners are Dominion Exploration & Production Inc. 25%, Hydro Gulf of Mexico LLC 25%, and Marubeni Corp. subsidiary Marubeni Offshore Production (USA) Inc. 12.5%.

Talisman strikes oil off Trinidad and Tobago

Talisman Energy Inc. and its partners made an oil discovery with the Ruby-1 exploration well on Block 3(a) 30 miles off the northeast coast of Trinidad and Tobago. On test Ruby-1 produced 5,000 b/d of oil through a ⅞-in. choke from a limited interval within the pay section.

The well, which was drilled to TD 5,750 ft, found 1,200 ft of hydrocarbon-bearing sands, including more than 800 ft of net pay. Talisman said its Kingbird-1, an exploration well drilled prior to Ruby-1, found 80 ft of gross hydrocarbon pay and was abandoned without testing pending further technical studies.

Wholly owned subsidiary Talisman (Trinidad Block 3a) Ltd. holds 25.5% working interest in Block 3(a). Partners BHP Billiton (operator) and Anadarko Petroleum Corp. each hold 25.5% interest. Petrotrin has 15% interest and Total SA holds 8.5% interest.

Dana reports oil discovery off Mauritania

Dana Petroleum PLC reported an oil discovery in Cretaceous sandstones in its Aigrette-1 well on Block 7 off Mauritania (see map, OGJ, Oct. 23, 2006, p. 38).

The well was drilled to TD 5,152 m in 1,358 m of water. Dana ran wireline logs, took pressure measurements, sampled fluids, and cut sidewall cores.

"Downhole pressure measurements and fluid samples confirmed a 20-m oil column was present in good quality Cretaceous age reservoir sands," the company said.

The well was originally planned for TD 4,900 m. Dana said the deepened section encountered "significant further sands" that didn't contain oil.

Dana discovered gas in the Pelican-1 well on the same block in 2003.

"The extensive acreage of Block 7, coupled with the discovery of both oil and gas within the first two wells and the presence in Aigrette of deeper sands than those found in Pelican, all provides considerable encouragement for future drilling in this underexplored region of northern Mauritania," said Tom Cross, Dana's chief executive officer.

Dana, operator, and its partners work under a production-sharing contract on the block, which covers 10,090 sq km.

Interests are Dana 36%, Gaz de France 27.85%, Hardman Resources Ltd. 16.2%, Woodside Energy Ltd. 15%, and Roc Oil Co. Ltd. 4.95%. ✦

Drilling & Production — *Quick Takes*

Hess begins Phu Horm gas flow in Thailand

Amerada Hess (Thailand) Ltd. has begun production from Phu Horm gas field on Block E5N in Udon Thani Province of northeastern Thailand, reported Salamander Energy PLC.

Phu Horm's gas reserves are estimated at 550 bcf plus condensate capable of yielding 500 b/d of production (OGJ, Aug. 1, 2005, Newsletter).

Gross production, initially from two wells, will be about 60 MMcfd, increasing to an expected rate exceeding 100 MMcfd plus condensate. Additional wells will be brought into production in 2007, and deliveries are expected to increase to as much as 108 MMcfd.

Hess owns a 35% interest in the field and is operator. Other partners are Apico LLC 35%, PTT Exploration & Production PLC (PTTEP) 20%, and ExxonMobil Exploration & Production Khorat Inc. 10%. Salamander owns 27.2% of Apico.

A gas sales agreement with PTT Public Co. Ltd. calls for more than 500 bcf of gas from the field to be supplied to a power station at Nam Phong over 15 years.

Hydro awards contract for Brage platform

Norsk Hydro has awarded Norwegian petroleum services company Aker Kvaerner a 150 million kroner contract for the upgrade of Hydro's reinjection water system on the Brage oil and gas platform in the Norwegian North Sea. The scope of the contract includes engineering, procurement, and constructional installation and should be completed by yearend 2008.

Design and procurement will begin immediately, Aker Kvaerner said, and prefabrication will start in April 2007. The offshore installation work will take place during 2007-08.

The upgrade will give Hydro zero emissions of produced water and as much as 1.2 million bbl of extra oil from Brage plaform, Hydro said.

Brage is a mature oil field that produces 20,000 b/d of oil.

US drilling activity on the rise

US drilling activity increased by 20 rotary rigs to 1,717 working during the week ended Dec. 1, up from 1,460 in the same period a year ago, said officials at Baker Hughes Inc.

The gain primarily was in land operations, up by 21 units to 1,608 drilling. Offshore drilling increased by 1 rig to 82 in the Gulf of Mexico and 86 in US waters as a whole. Those increases were partially offset by the loss of 2 rigs to 23 drilling inland waters.

Texas registered the biggest weekly increase among the major producing states, up by 4 rigs to 771 working. Oklahoma gained 2 units to 183. Alaska increased by 1 to 7. Colorado and California were unchanged at 87 and 36, respectively. New Mexico and Wyoming lost 4 rigs each, down to 97 and 90, respectively. Louisiana was down by 2 units to 193. ✦

Processing — *Quick Takes*

Total starts up Gonfreville hydrocracker

Total SA has brought on stream a €550 million distillate hydrocracker at its 330,000-b/d Gonfreville refinery in Normandy, France.

The unit will yield 200,000 tonnes/year (tpy) of jet fuel, 400,000 tpy of naphtha for petrochemicals, 500,000 tpy of high-grade base products for lube oils, and 1.3 million tpy of diesel oil. It will raise the refinery's diesel output capacity to 5.3 million tpy.

The hydrocracker is part of the expansion and modernization of Total's 12 European refineries, spending on which this year will total about €1 billion.

Motiva lets Port Arthur refinery expansion EPC

Motiva Enterprises LLC, Houston, plans to move forward with the final design and engineering phase of a proposed 325,000 b/d expansion of its 285,000 b/cd refinery in Port Arthur, Tex.

It has selected Bechtel Jacobs Joint Venture as the engineering, procurement, and construction contractor, and it recently secured the operating air permit from the Texas Commission on Environmental Quality.

The company will use advanced technology in all new system installations and will replace existing systems to lower emissions from refinery operations on a per-barrel basis.

Motiva and Dresser-Rand Co. have been in negotiations on contracts for Dresser-Rand to supply compression equipment and start-up services. The planned project would make the refinery the largest in the US, with throughput capacity of 600,000 b/d (OGJ Online, June 19, 2006).

Motiva could make a final investment decision by around mid-year 2007. Construction is scheduled to start next year, subject to final approvals, and new production capacity is expected to come online in 2010 (OGJ Online, May 8, 2006).

Borouge lets ethylene contract for UAE plant

Borouge, a joint venture between Abu Dhabi National Oil Co. (ADNOC) and European plastics provider Borealis, let a $1.3 billion, lump-sum turnkey contract to Linde Group and Consolidated Contractors Co. for construction of an ethylene cracker in the UAE.

The steam cracker, having an ethylene capacity of 1.5 million tonnes/year, is planned as an expansion of a petrochemical complex in Ruwais, Abu Dhahi. The cracker will use ethane feedstock, producing polyethylene and polypropylene for export.

The project, scheduled to start in early December, is expected to be on stream by 2010. Borouge called the contract its first step in a major expansion project that will ultimately triple the company's production capacity.

Taiyo Oil upgrading to refine heavy oil

Japan's Taiyo Oil Co., which refines petroleum products from light crude, plans to spend ¥50 billion to install cracking equipment for heavy oil at its Ehime Prefecture refinery.

The firm wants to produce more gasoline and petrochemical products to fulfill expected demand growth. The company's total output of petrochemicals is expected to reach 1 million tonnes/year, while heavy oil production will decline by 1.2 million kl.

The new equipment, to go on stream in 2010, will increase Taiyo's production of raw materials for gasoline by 600,000 kl, kerosine and light oil by 300,000 kl, propylene by 100,000 kl, and benzene and xylene by a combined 50,000 kl.

Taiyo also will set up a 43,000-kw power generator to burn gases from production of petrochemicals and other products. The company plans to sell surplus electricity wholesale to power retailers and others.

Statoil lets Kollsnes gas plant upgrade contract

Statoil ASA, on behalf of state-owned Gassco AS, has let an engineering, installation, construction, and commissioning contract to Vetco Aibel for a gas compressor and a condensate train at the Kollsnes gas processing plant near Bergen, Norway.

The contract, valued at 790 million kroner, extends through the second half of 2008.

Building a compressor and simultaneously improving condensate capacity will ensure efficient project execution and reduce the scope of work, Statoil said. In addition, installing a new condensate train eliminates the need for an extended shutdown when the heat exchangers on the existing train need replacement in 2008.

Arnulf Østensen, vice-president for technical operation at Gassco, said the project lays the basis for future capacity expansions.

The Gassco-operated Kollsnes plant processes gas from Troll, Kvitebjørn, and Visund fields and transmits it through four pipeline systems to continental Europe. These installations, capable of handling 143 million standard cu m/day of gas, are owned by Gassled and operated by Gassco, with Statoil as the technical service provider.

Saudi Kayan lets petrochemical complex contract

Saudi Kayan, a joint venture of Saudi Basic Industries Corp. and Al-Kayan, has awarded Flour Corp. an engineering, procurement, and construction management services contract for the utilities and offsite (U&O) facilities of the joint venture's 4 million tonne/year petrochemical complex to be built in Al-Jubail, Saudi Arabia.

"This project will utilize 17 licensed technologies and will produce both specialty amine derivatives and polycarbonates for the first time in Saudi Arabia," said Jeff Faulk, Fluor's group president for energy and chemicals.

Once completed, the $2.2 billion complex will include a 2 million tonne/year ethane-butane cracker, including benzene extraction facilities; a 700,000-tonne/year polyethylene plant; a 350,000-tonne/year polypropylene plant; and a 530,000-tonne/year eth-

ylene glycol unit. Also, an integrated phenolics plant, including cumene, phenol, and Bisphenol-A units, will produce feedstock for a 260,000-tonne/year, high-value polycarbonates plant. Additional amine derivative facilities will be installed for the production of methylamines, ethanolamines, ethoxylates, and choline chloride.

Saudi Kayan said agreements with Saudi Aramco are complete for the supply of ethane and butane feedstock, and permits have been received from the Royal Commission for the commercial use of land and water.

Engineering on the U&O facilities, which Faulk said were the "heart of the complex," began in July and will continue through 2008. Construction is slated to begin in February 2007, and completion is targeted for December 2009.

Fluor also provided front-end engineering and design and project management consultancy services for the complex.

Contracts let for French biodiesel plants

Diester Industrie has let turnkey contracts to Technip for two biodiesel plants in France.

The plants, one in the Bassens port zone near Bordeaux and the other doubling the size of the Grand-Couronne plant near Rouen, will use the Axens process.

Capacities each will be 250,000 tonnes/year. The units are to start production at the end of 2007.

In addition to the existing plant near Rouen, Technip has built biodiesel plants for Diester at Sete and Compiegne and is building one for the company at Montoir-de-Bretagne.

Neste plans second biodiesel plant at Porvoo

Neste Oil plans to build a second 170,000-tonne/year biodiesel plant at its 200,000 b/cd refinery in Porvoo, Finland.

Estimated to cost €100 million, the plant will produce biodiesel from animal fats and oil. Production is scheduled for about late 2008.

The first biodiesel plant under construction is scheduled to start up around mid-2007 (OGJ, Nov. 7, 2005, Newsletter).

The plants will use Neste's proprietary process to convert biological triglycerides into a synthetic biodiesel—NExBTL—a non-oxygenate hydrocarbon biodiesel compatible with the existing vehicle fleet, the company said. The company also has biodiesel projects under way in France and Austria. ✦

Transportation — *Quick Takes*

Mississippi LNG terminal's EIS approved

Construction of a proposed LNG terminal near Pascagoula, Miss., would have minimal environmental impact, the US Federal Energy Regulatory Commission's staff said in a final environmental impact statement.

Impacts would be most significant during construction of the Gulf LNG Clean Energy Project, which also would include a new pipeline to ship as much as 1.5 bcfd of gas out to three interconnection points, FERC said.

Gulf Energy LLC, which is building the terminal, sought FERC's approval to build a berth and unloading facilities capable of accommodating one LNG tanker, LNG transfer systems, two 160,000-cu m LNG storage tanks, 10 high-pressure submerged combustion vaporizers, vapor handling systems, hazard detection and response equipment, and ancillary buildings, utilities, and service facilities.

Gulf LNG Pipeline LLC separately requested FERC approval for a 5-mile, 36-in. gas sendout pipeline and associated support facilities, including three interconnects and meter stations, one pig launcher, and one pig receiver.

Dutch-UK Balgzand-Bacton gas line starts

The new Balgzand-Bacton pipeline has begun commercial delivery of natural gas from the Netherlands to the UK.

The 235-km, 36-in. pipeline works at a pressure of 135 atm. Around 230 km of the pipeline is offshore under the North Sea. It will have a capacity of 15 billion cu m (bcm)/year when a remotely operated electrical compressor station enters service in January in Anna Paulowna, Noord Holland.

"In the Netherlands the pipeline was pulled through the dunes using a horizontal directional drilling technique to cause less damage to the environment," a BBL spokesman told OGJ.

The spokesman said BBL has received "a lot of interest" in an open season for pipeline capacity, which it will offer monthly.

BBL is a joint venture of E.ON Ruhrgas, Fluxys, and NV Nederlandse Gasunie.

The Balgzand-Bacton pipeline is the third major gas transport project serving the UK to start up this winter. The 600-km southern leg of the 1,200-km Langeled pipeline from Norway delivered first gas to the UK in October (OGJ, Oct. 23, 2006, p. 34). And an expansion of the Interconnector pipeline between the Netherlands and the UK came on stream the same month, increasing capacity by 7 bcm/year to 23.5 bcm/year.

The UK is expecting new LNG supplies to be delivered to Teesside via the Excelerate project early in 2007. The South Hook LNG and Dragon LNG terminals in south Wales are expected to become operational by late 2007.

Falcon Gas Storage to build Barnett shale pipeline

Falcon Gas Storage Co. Inc. plans to build a 63-mile, 24-in. gas pipeline to serve its expanded 16 bcf working capacity Worsham-Steed gas storage facility in the western Barnett shale gas play near Fort Worth. Pipeline capacity is expected to be 450 MMcfd, and commercial operation is scheduled to begin Sept. 1, 2007.

Falcon's Worsham-Steed pipeline will extend southward from the Worsham-Steed facility through Jack, Parker, and Hood counties in Texas. It will interconnect with two existing 36-in. gas transmission pipelines: the North Texas Pipeline, jointly owned by Enterprise Products Partners and Energy Transfer Partners, and the Atmos Energy Corp. Line X pipeline.

In addition to an existing interconnection with Energy Transfer's Old Ocean pipeline at Worsham-Steed, the new pipeline will connect to Devon Energy Corp.'s Acacia pipeline, Atmos's Line WA, and Enterprise's recently announced Sherman extension pipeline. ✦

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DECEMBER

Annual China Gas Conference, Beijing, 65 6536 8676, 65 6536 4356 (fax), e-mail: marcy.chong@abf.com.sg, website: www.abf-asia.com. 11-12.

Ethanol Summit, Houston, (207) 781-9603, (207) 781-2150 (fax), website: www.intertechusa.com/ethanol. 11-12.

2007

JANUARY

Petrotech India Conference and Exhibition, New Delhi, +44 (0) 20 8439 8890, +44 (0) 20 8439 8897 (fax), e-mail: adam.evan-cook@reedexpo.co.uk, website: www.petrotech2007.com. 15-19.

Offshore Asia Conference & Exhibition, Kuala Lumpur, (918) 831-9160, (918) 831-9161 (fax), e-mail: oaconference@pennwell.com, website: www.offshoreas-iaevent.com. 16-18.

Power-Gen Middle East Conference, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwell.com. 22-24.

API Exploration and Production Winter Standards Meeting, Scottsdale, Ariz., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 22-26.

Deepwater Operations Conference & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepwater-operations.com. 23-25.

SPE Hydraulic Fracturing Technology Conference, College Station, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 29-31.

Underwater Intervention Conference, New Orleans, (281) 893-8539, (281) 893-5118 (fax), website: www.underwaterintervention.com. Jan. 30-Feb.1.

FEBRUARY

NAPE Expo, Houston, (817) 847-7700, (817) 847-7704 (fax), e-mail: nape@landman.org, website: www.napeonline.com. 1-2.

IPAA Small Cap Conference, Boca Raton, Fla., (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org/meetings. 5-8.

IADC Health, Safety, Environment & Training Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 6-7.

Russia Offshore Oil & Gas Conference, Moscow, +44 (0) 1242 529 090, +44 (0) 1242 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 7-8.

Multiphase Pumping & Technologies Conference & Exhibition, Abu Dhabi, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.multiphasepumping.com. 11-13.

SPE Middle East Oil & Gas Show & Conference (MEOS), Bahrain, +44 20 7840 2139, +44 20 7840 2119 (fax), e-mail: meos@oesallworld.com, website: www.allworldexhibitions.com. 11-14.

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IP Week, London, +44(0)20 7467 7100, +44(0)20 7580 2230 (fax); e-mail: events@energyinst.org.uk, website: www.ipweek.co.uk. 12-15.

Pipeline Pigging & Integrity Management Conference, Houston, (713) 521-5929, (713) 521-9255 (fax), e-mail: info@clarion.org, website: www.clarion.org. 12-15.

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Pipe Line Contractors Association Annual Meeting, Aventura, Fla., (214) 969-2700, e-mail: plca@plca.org, website: www.plca.org. 21-25.

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Laurance Reid Gas Conditioning Conference, Norman, Okla., (405) 325-3136, (405) 325-7329 (fax), e-mail: bettyk@ou.edu, website: www.lrgcc.org. 25-28.

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International Symposium on Oilfield Chemistry, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. Feb. 28-Mar. 2.

MARCH

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International Pump Users Symposium, Houston, (979) 845-7417, (979) 847-9500 (fax), website: http://turbolab.tamu.edu. 5-8.

Purvin & Gertz International LPG Seminar, Houston, (713) 236-0318 x229, (713) 331 4000 (fax), website: www.purvingertz.com. 5-8.

Power-Gen Renewable Energy & Fuel Conference, Las Vegas, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwell.com. 6-8.

Annual Fuels & Lubes Asia Conference, Bangkok, +632 772 4731, +632 772 4735 (fax), e-mail: conference@flasia.info, website: www.flasia.info. 7-9.

Journally Speaking

A Malaysian perspective

Alan Petzet
Chief Editor-Exploration

Fresh from several years of exploration success in Malaysia, Arkansas-based Murphy Oil Corp. said another place it would like to be in Southeast Asia is Indonesia.

Murphy's growth in Malaysia began with discovery of West Patricia oil field in 2000 at its first well in shallow water and Kikeh oil field, the country's first deepwater discovery, in 2002.

Drilling several dozen wells off Sarawak and Sabah on northwestern Borneo has given Murphy perspective on basins of similar age in Indonesia, said David Wood, president of Murphy Exploration & Production Co.

Murphy holds acreage in Malaysia's three main producing provinces.

Sabah K fields

Murphy, with Petronas Carigali, discovered Kikeh, Kikeh Kecil, and Kakap fields on Block K in the lightly drilled Sabah Trough.

A spar has been placed in Kikeh field, in 4,400 ft of water, and a floating production, storage, and offloading vessel is to be hooked up in 2007. It is a $1.7 billion, 440 million bbl project, expected to start producing in the second half of 2007 and to deliver 30 million bbl of oil in its first 12 months.

Thirty-nine oil-producing and water-injection wells are planned. Production will rise from the initial 40,000 b/d to 120,000 b/d in 18 months.

Kakap field is smaller and in shallower water than Kikeh, but wells in both fields have oil columns more than 1,000 ft thick and test-flowed in excess of 10,000 b/d/well.

Kakap, being unitized with Shell Malaysia's 2004 Gumusut discovery on adjacent Block J, probably won't begin producing oil until 2011. Development cost is two or three times that of Kikeh.

One of Murphy's challenges is learning to make thin-bed oil pays commercial in deep water.

Wood noted that 14 of the 18 wells drilled in the Sabah Trough found hydrocarbons, but some are in high-quality sands just a few feet thick, mostly below seismic resolution.

Murphy's Jangas, Kerisi, Senangin, and Siakap finds could have a combined 1 billion bbl of oil in place. A recovery factor can't be calculated because the sands' areal extent and vertical connectivity aren't certain, Wood said.

One plan is to tie Kerisi back to Kikeh and produce it to check performance.

Sabah exploration

Elsewhere, Murphy has identified several 20-40 km-long structures, but it hasn't yet determined whether finding a small amount of hydrocarbons at a single well condemns an entire structure.

From Kikeh, Murphy found that sands, not shales, contain the organic material in the Sabah Trough.

Like Kikeh, most of the play types are toe-thrust structures. Another operator has a discovery at one of only two wells drilled to test strat traps. Of three wells drilled for intraslope structural traps, one was a success. Subthrust success is one for three.

Murphy found hydrocarbons at Kikeh 7 Deep, not part of the field development and the only well in a large area to penetrate this deep section.

A carbonate interval that works in rift plays off China and the Philippines has not been tested off Borneo, and a shallower Pliocene play is also untried, Wood said.

Meanwhile, new 3D seismic data reveal prospects in 1,200-1,500 ft of water in deepwater Block H.

Sarawak oil and gas

Murphy has had 85% success in finding movable hydrocarbons with its wells off Sarawak, Wood said.

Output averaged 13,500 b/d net to Murphy's 85% interest in 2005 from West Patricia and Congkak fields 25 miles offshore on Block SK 309. West Patricia is expected to recover 50-60 million bbl of oil.

Discoveries in 2005 at Endau and Rompin, containing oil in multiple reservoirs, are being examined for standalone development.

Meanwhile, Belum, Golok, Maharani, and Serampang found gas in multiple reservoirs in 2005. Another string of gas discoveries in 2006 on SK 309 and 311 included Pemanis, Serendah, Patricia, Wangsa, Tiram, and Sapih. Murphy plans to pipe this gas to the 23 million tonne/year Bintulu LNG facility starting in late 2008.

Golok field alone contains enough producible gas to supply the first tranche of a project agreed with Malaysia's Petronas. Golok will feed up to 300 MMcfd for 12-24 months into a pipeline to Bintulu, with other fields coming on to maintain this flow for up to 15 years.

Murphy, with undeveloped gas finds at Kenarong, Pertang, and Pergau, has been less successful off Peninsular Malaysia but still has a large area of 3D seismic coverage that it hasn't drilled. ✦

The OCS leasing struggle

Meager offshore oil and gas leasing reform tested political winds in the US House of Representatives Dec. 5 and nearly got blown away. At this writing, the effort was trying to skirt opposition in the final days of the 109th Congress as an attachment to unrelated legislation.

The bill, which would open 8.3 million acres of the Outer Continental Shelf in the eastern Gulf of Mexico, is far less aggressive than a measure the House passed in July. Still, supporters had to withdraw it when they sensed trouble winning the two-thirds majority required for passage under special rules for expeditious handling. At midweek, MSNBC reported that leasing reform was one of several bills drawn to renewal of tax cuts as a possible vehicle through the House.

Acting on supply

Trouble passing the lesser of two OCS leasing measures typifies the 109th Congress. This is the Congress that produced the sweeping Energy Policy Act of 2005, a marvel of bipartisan dealmaking notable mostly for pushing the US toward the nationalization of fuel choice. It's the Congress that chose to address outside its deliberations on "energy policy" the question of how the world's single biggest energy-consuming country can preclude leasing of 85% of its offshore territory. It's the Congress that, when it did take up leasing reform, acted with awesome timidity. It's the Congress that stayed reluctant to the bitter end to act substantially on energy supply.

Voters should remember this performance if the US winter is as cold as the last weeks of autumn. That leasing reform in any configuration survived this long is in fact a political triumph born of stressful prices for natural gas. States with industries hurt by expensive gas, some of them in the US interior, have learned that OCS access serves general interests and not just those of oil companies and coastal communities. This is ideological progress. But the legislative payoff, if any, will fall far short of what the US needs.

The bill seeking a path of least resistance through the House last week was one passed in August by the Senate, which refused to consider the broader legislation that the House passed in June. The Senate bill makes opening of the eastern gulf acreage palatable to Floridian lawmakers by precluding leasing until June 30, 2020, of acreage 125 miles off Florida's western coast and 100 miles off the panhandle. It also allows Gulf Coast states to share 37.5% of future OCS revenue up to a $500 million limit (OGJ, Aug. 7, 2006, p. 24).

The House bill would have made possible the lifting of leasing moratoriums across the whole OCS. Moratoriums would have ended automatically for federal acreage 100 miles or more offshore. Coastal states could have blocked federal leasing 50-100 miles offshore. And leasing would have been prohibited within 50 miles of shore except where affected states rescinded the ban.

Controversies

Beyond the controversial ending of moratoriums long in effect, the House bill poisoned itself in at least two other ways. To entice states to approve leasing, it would have shared federal revenue without limits. And it provided for gas-only leases. The White House Office of Management and Budget, in addition to some leasing supporters in the Senate, objected to fiscal consequences of the revenue-sharing provision and to administrative challenges of the gas-only leases (OGJ, July 10, 2006, p. 22). Senators promised not to consider the House bill if it went to a conference for reconciliation with their narrower measure. If there was to be any leasing reform, therefore, it would be the Senate bill, which the House had to pass before adjournment last week.

The something-beats-nothing argument has been made in this space before (OGJ, Aug. 7, 2006, p. 19). It's worth repeating that any bill expanding OCS acreage available for oil and gas leasing bears historic significance. But the energy significance is a direct function of the amount of acreage involved. By that test, the Senate bill didn't amount to much. It apparently requires a cold winter to underscore what still needs to be done. ✦

Interest heats up Southeast Asia discovery, production

Hazel Cameron
Thomas Young
Wood Mackenzie
Edinburgh

Exploration and appraisal drilling in Southeast Asia has continued at high levels through 2006 as oil companies, flush with cash, seek to replace reserves. The high level of license awards in 2005 sustained drilling activity through 2006, and this trend is expected to continue if operators can secure access to drilling rigs.

A number of significant discoveries were made during 2005-06, with Indonesia and Malaysia accounting for more than half of them. About 30 discoveries were made this year, adding potential reserves of 300 million bbl of oil and 10 tcf of gas.

Husky Oil China Ltd.'s deepwater gas discovery off China was the highlight of the year to date, encouraging further licensing and improving industry perceptions of the deepwater area. South Korea's Daewoo also discovered additional volumes of gas near Shwe field in Myanmar, for which cumulative reserves of 8.6 tcf was certified in 2006.

In addition to exploration success, at least 170 new field developments are expected to come on stream in Southeast Asia by 2012. They will generate about 950,000 b/d of new liquids production and more than 8 bcfd of incremental sales gas (Figs. 1 and 2).

Key developments include the Cepu Block on Java, the Kikeh and Gumusut oil fields off Sabah, supplies to the Tangguh LNG plant in Irian Jaya, and Puguang gas field in China. These five projects together should contribute 390,000 b/d and 2.1 bcfd of new production by yearend 2011.

The countries and sectors included in this review are Brunei, Cambodia, offshore China, Indonesia, Malaysia, the Malaysia-Thailand Joint Development Area (JDA), Myanmar, the Philippines, Thailand, and Vietnam.

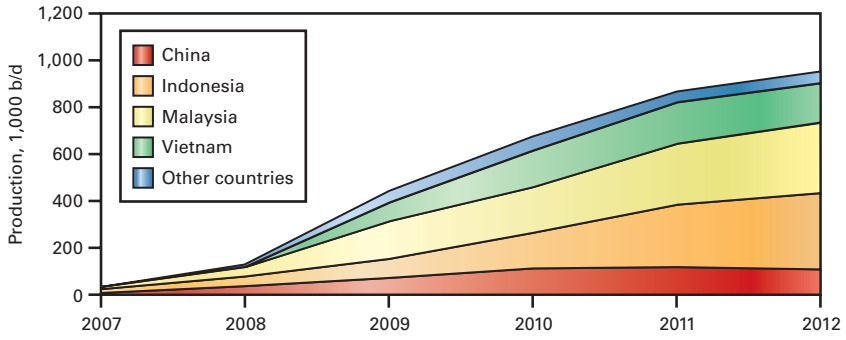
Licensing activity

Thirty-one licenses were awarded across the region in the first 10 months of this year. Although significantly lower than the 47 licenses awarded in 2005, this is not a full-year figure, and impending awards in Indonesia could boost the total. High levels of awards were seen in China and the Philippines, with lowest activity in Malaysia and Myanmar (Fig. 3). This is perhaps a reaction to preceding years of high activity, in which most of the attractive acreage was awarded. Eight areas predominated:

- *China*. Seven awards were made off China through October, continuing the trend from 2005. Six of them are in the South China Sea and followed Husky's 5 tcf Liwan discovery on its deepwater acreage (OGJ, June 26, 2006, Newsletter). Husky signed an additional deepwater block and two more in shallow water. BG Group PLC has been awarded three deepwater blocks, while Devon Energy Corp. signed the only block

NEW LIQUIDS PRODUCTION PROJECTS, 2006-11

Fig. 1



Source: Wood Mackenzie's Pathfinder

outside the South China Sea, expanding its position in the East China Sea.

In addition, Total SA, in partnership with PetroChina, gained an interest in the South Sulige Block in the Ordos basin, a rare example of an onshore China license being awarded to a foreign operator.

• *Philippines*. In the Philippines, seven service contracts (SCs) have been awarded, predominantly to international companies, including a Royal Dutch Shell unit and Nido Petroleum Ltd., Perth. Shell has expanded its Philippines portfolio by signing SC60 in the Northeast Palawan basin.

Two contracts awarded in 2006 were for Area 1 and Area 4, part of the Department of Energy's second formal licensing round in 2005. Area 1, in the Southwest Palawan basin, increased Nido Petroleum's Philippines portfolio to eight blocks, while Malaysia's Ranhill Energy, Kuala Lumpur, was awarded Area 4, in the Sulu Sea.

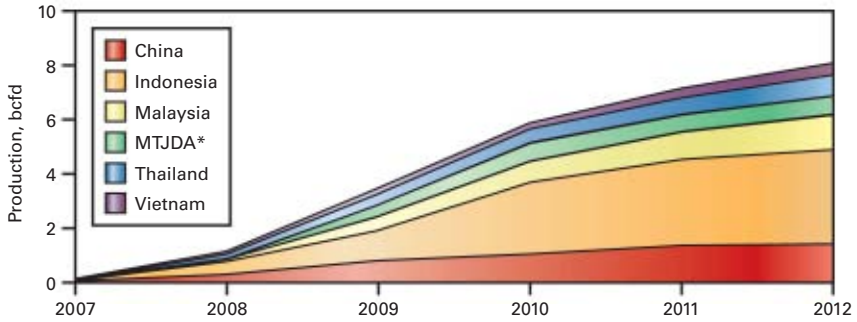
• *Indonesia*. Licensing levels have continued downward through October, with only five signings, compared with nine in 2005. However, 41 blocks have been tendered, and the number of awards could increase substantially before yearend.

The much-anticipated results of the 2005 bidding round were announced in June. Only four blocks were awarded, despite seven having attracted bids. The open acreage in the Makassar Straits was popular with international players, and Petronas Carigali, ExxonMobil Corp., Husky, and Marathon Oil Corp. were the successful operators. The blocks are characterized by high exploration risk and high costs, and seven of the 14 blocks failed to attract bids.

Of the 41 blocks offered this year, 20 are under competitive tenders that close in December. The remaining blocks were subject to direct offers and closed on Oct. 11. Only one block failed to attract a bid. ConocoPhillips, Chevron Corp., and ExxonMobil are among the international and local companies believed to have made submissions. With awards expected by yearend, this could mark a minor renaissance in Indonesia licensing activity.

New gas production projects, 2006-12

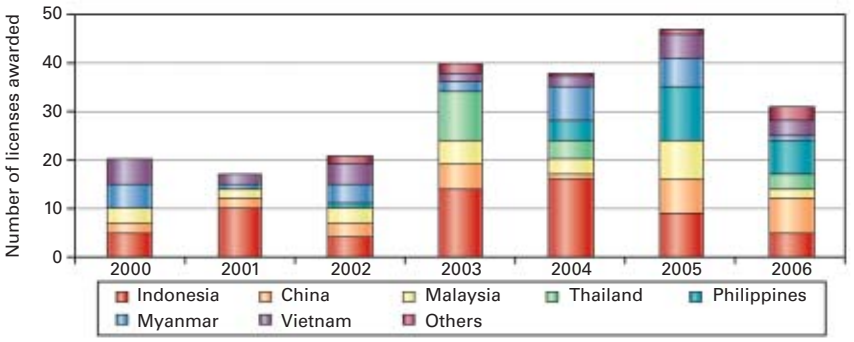
Fig. 2



*Malaysia-Thailand Joint Development Area.
Source: Wood Mackenzie's Pathfinder

Southeast Asia license awards, 2000-06

Fig. 3



Source: Wood Mackenzie's Pathfinder

• *Malaysia*. Only two blocks were awarded in Malaysia through November, marking a loss of licensing momentum from 2005, when activity was driven by exploration successes and tenders for the most prospective deepwater acreage. Despite the slowdown, the deepwater trend continued, with Murphy Sabah Oil Co. Ltd. awarded the SB P deepwater block off Sabah in January. The block includes newly demarcated acreage resulting from a partial relinquishment of Murphy's SB K block.

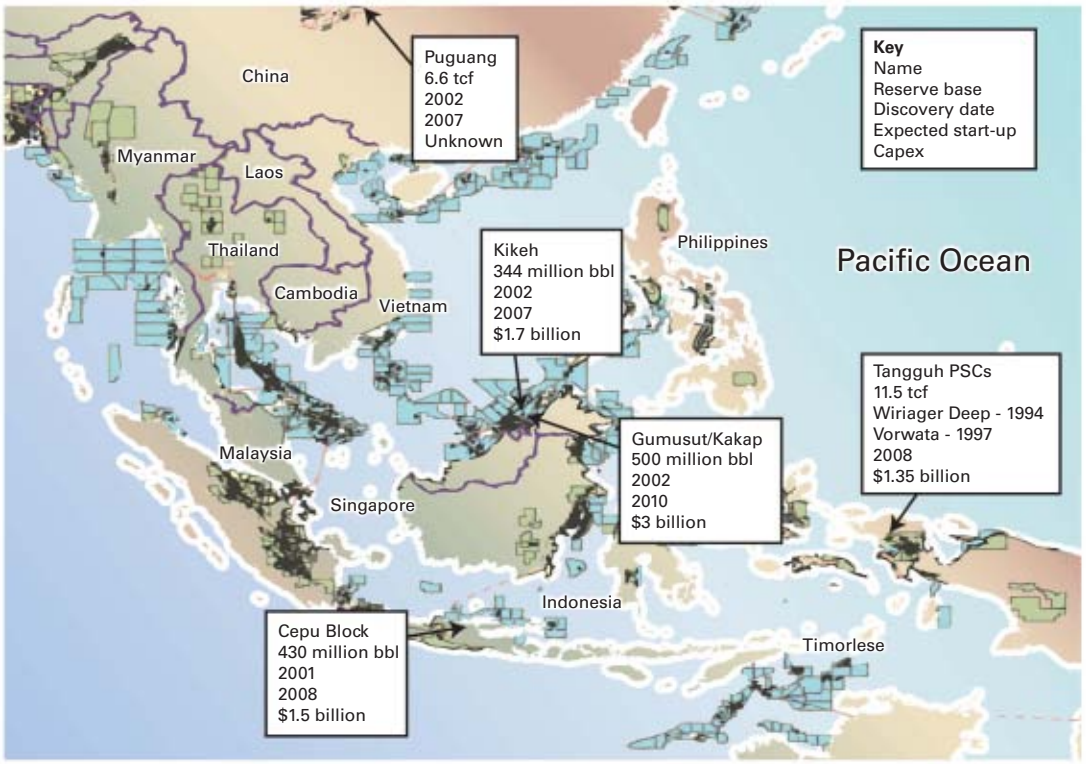
• *Thailand*. Only three blocks were officially awarded in 2006, under Thailand's 19th licensing round, which closed in June. However, at least two more are pending final approval, with authorities considering a total of 22. These awards are anticipated in early 2007.

• *Myanmar*. Most onshore and shallow-water acreage in Myanmar has been awarded following high levels of licensing activity in 2004-05. A few open blocks remain, and Block M8 was awarded to a consortium led by Zarubezhneft in September. In a bid to further boost activity, the government has offered 18 deepwater blocks, attracting interest from both existing and new players, although no awards have been announced to date. Under terms of the newly offered deepwater licenses, a 2-year technical evaluation period is offered prior to the signing of a full production-sharing contract (PSC).

• *Brunei*. Onshore Blocks L and M were awarded this year—the first since 2003. The activity planned by the new operators, Loon Energy of Canada, and China Oil, will help offset delays affecting development of Brunei's disputed offshore acreage.

• *Vietnam*. Three licenses were awarded this year: Block 122 to Chevron and

MAJOR SOUTHEAST ASIA DISCOVERIES



Source: Wood Mackenzie's Pathfinder

Petronas Carigali, Block 101-100/04 to Santos Ltd. and Singapore Petroleum Co., and Block 06/94 to Singapore's Pearl Energy Ltd. and partners in the Nam Con Son basin (OGJ Online, Aug. 1, 2006). This award remains subject to formal governmental approval. A licensing round announced in April should see a similar level of activity maintained through 2007.

Drilling

About 230 exploration and appraisal wells were drilled across the region through the end of October, maintaining activity levels from 2005. Year-on-year well counts have increased in Indonesia, Thailand, and Vietnam, with drops in Malaysia and Myanmar. Regionally, however, drilling levels are not far short of the peak levels of the late 1990s and 2001 (Fig. 4).

Drilling activity in Indonesia continues to climb steadily but has a long way to go to regain its historical peaks. Exploration activity is dominated by both local and international companies, of which Energi Mega Persada, China National Petroleum Corp., Santos, and Medco Energi are most prominent. With 20 direct offer block awards pending, drilling activity is expected to continue over the next few years.

In Vietnam, drilling activity has almost doubled from 2005. Continued appraisal efforts in the established Cuu Long and Nam Con Son basins have dominated activity, along with some successful exploration in the Gulf of Tonkin.

While overall drilling levels in Malaysia dropped this year, licensing activity in 2005 led to a high level of exploration drilling, which accounted for over 70% of the wells drilled. With several discoveries during the year, appraisal and continued exploration are likely to encourage drilling activity through 2007.

Key discoveries

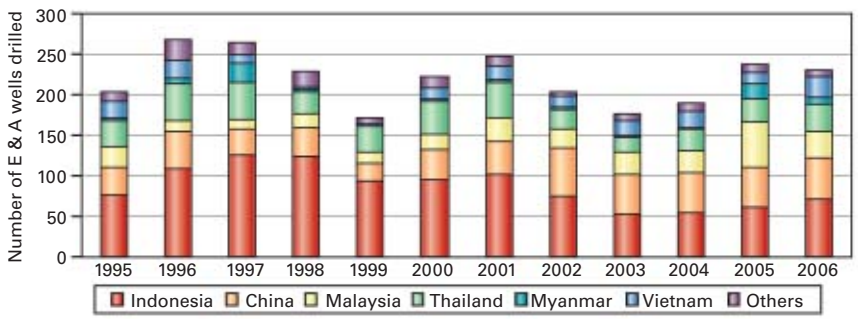
About 30 discoveries were made across Southeast Asia through October, over half of these recorded in Indonesia and Malaysia together (Fig. 5). Exploration efforts remained focused on proved provinces, including the Malay basin, the Gulf of Thailand, Sarawak, Java, Sumatra, and the Bohai Gulf.

Exploration this year has resulted in the addition of about 300 million bbl of oil and 10 tcf of gas reserves. On an oil-equivalent basis, China added the largest volumes, thanks to Husky's Liwan discovery on Block 29/26. This was the first discovery in China's deep water, and it improved the prospects in this acreage. Reserves estimates remain provisional and, in the absence of an available rig, further appraisal is unlikely until 2008-09.

Myanmar also increased its reserves significantly with the 3-tcf Mya discovery. Located on Daewoo's Block A3 off Northwest Myanmar, the field will be developed alongside Shwe and Shwe Phyu fields, with combined reserves estimated at 8.6 tcf.

Two significant discoveries were made in Malaysia in 2006. Shell Malaysia and its partners discovered Pisagan field on Block G, off Sabah, which followed successes with the Ubah, Malikai, and Gumusut discoveries in 2004-05. Petronas was also successful with the discovery of PC4 field in unlicensed acreage off Sarawak. Initial oil and gas reserves estimates for these discoveries are 100 million bbl and 1 tcf respectively.

SOUTHEAST ASIA E & A* WELLS DRILLED, 1995-2006 Fig. 4



*Exploration and appraisal.
Source: Wood Mackenzie's Pathfinder

Key developments to 2012

There are a number of key developments that will strongly influence production in the region over the next 5 years:

Cepu block

The onshore Cepu block in eastern Java is estimated to contain over 430 million bbl of oil and 3 tcf of gas, most of it in Banyu Urip field. Development has been delayed by wrangling between ExxonMobil and Pertamina over which company would operate the block. Following the intercession of the Indonesian government, a joint operating agreement (JOA) was signed in March, clearing some of the obstacles to field exploitation.

Fast-track approval of the revised plan of development (POD) had been expected from the regulating body, BP Migas, to further facilitate the development. However, a POD approved in June was returned to ExxonMobil in October for revision with queries about its gas development plans. The initial drilling program had already been delayed to early 2007 from September 2006 because of equipment shortages.

Given the history of this project and despite the JOA, the prospective lack of alignment between the partners could continue to impede progress. Despite this, production from Banyu Urip field could begin by yearend 2008, with production up to 150,000 b/d by 2011.

Tangguh (Irian Jaya)

The two-train Tangguh LNG plant in Irian Jaya, Indonesia, will process gas from three BP-operated PSCs—Wiriagar, Berau, and Muturi—which together represent over 14 tcf of sales gas. Gas sales and purchase agreements totaling 7.65 million tonnes/year have been signed. The reserves were certified in 1998, and by 2005 enough gas had been contracted to allow the project to proceed.

The LNG plant engineering, procurement, and construction contract was awarded in March, and first gas production is expected in fourth-quarter 2008. Although the way forward now appears clear, the project is not yet free of political constraints. In the light of high energy prices, and with large tranches of gas earmarked for export, Indonesia has experienced local shortfalls to domestic and industrial users. In response, the government aims to prioritize supply to domestic consumers and has proposed that a third train at Tangguh could be used to supply Java.

Kikeh (Malaysia)

Murphy-operated Kikeh field, discovered in 2002, is estimated to hold 300-700 million bbl of high-quality oil. It is one of the largest discoveries of the past decade in Southeast Asia and lies in 1,300 m of water off Sabah. Production is expected to begin in early 2008, with a plateau of 120,000 b/d of liquids and 150 MMcfd of gas by 2010.

The exploitation of Kikeh field has its share of challenges. Costs have risen to $1.7 billion, including construction of a gas pipeline to Labuan Island. Unitization issues also remain, given the field's proximity to Brunei. A fault is understood to separate the main Kikeh field from the satellite Kikeh 5 structure, which lies closer to the disputed maritime boundary with Brunei. It is likely that Kikeh 5 will require unitization before it can be integrated with the main field development.

Gumusut-Kakap (Malaysia)

Gumusut field was discovered in 2003 on Shell-operated Block J. It extends westwards into adjacent Block K and potentially over the disputed marine border with Brunei. Murphy Oil operates Block K on which Kakap field is located. Unitization issues and the ongoing territorial dispute between Brunei and Malaysia likely will complicate this development as well.

The field lies in more than 1,000 m of water. It faces engineering challenges similar to Kikeh's and could be more costly still. These challenges could slow the development of a discovery that is estimated at a cumulative 500 million bbl of oil reserves. First production could begin in 2010 and reach 83,000 b/d by 2011.

Puguang (onshore China)

The Chinese state company Sinopec discovered Puguang gas field in Sichuan Province in late 2002. Following appraisal drilling, field reserves were increased to 6.6 tcf, making it one of the largest gas fields in China. Sinopec intends to aggressively develop Puguang to produce 390 MMcfd by 2008 and more than 700 MMcfd by 2010.

Gas demand in China, concentrated in the eastern and coastal areas, is expected to rise rapidly over the next decade and accommodate the planned increase in gas production. Plans originally included construction of a pipeline to Jinan, in Shandong Province, but the Chinese government decided

in July that the pipeline would supply the Shanghai area. Such decisions illustrate the operator's inability to control key aspects of the field's development.

Production outlooks

New Southeast Asia field developments expected to come on stream by 2012 will generate a total of about 950,000 b/d of new liquids production and more than 8 bcfd of incremental sales gas. Malaysia, China, and Indonesia are positioned to lead in output.

Malaysia

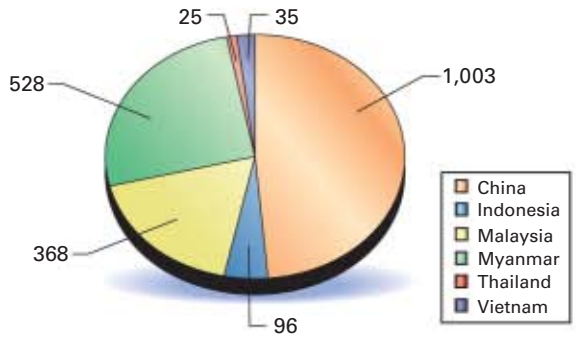
Medium-term production in Malaysia will be dominated by oil projects in deepwater Sabah. Several large oil discoveries—Kikeh, Ubah, Malikai, and Gumusut—are being developed, requiring huge investments and application of development technologies that are new to the area. WoodMac expects about 290,000 b/d of new oil production to be brought on stream by 2012, with Kikeh field accounting for almost 42% of this and Gumusut-Kakap, 36%. These additions should allow Malaysia to slow its oil production decline. Over 1.3 bcfd of new sales gas production will be on stream by 2012.

China

The installation of new infrastructure and processing capacity will facilitate a substantial increase in production from existing Chinese gas fields. This, coupled with new field start-ups, should increase output by over 3.5 bcfd by 2012. Of this, 1.4 bcfd will come from new fields, primarily newly discovered Puguang field.

While Puguang is a giant project, it will not have the singular impact of the key new fields in other countries. This is the result of a simultaneous increase in output from established fields, as well as that from other fields coming on stream.

DISCOVERED RESERVES BY COUNTRY, 2006 (BOE) Fig. 5



Source: Wood Mackenzie's Pathfinder

Indonesia

Developments in Indonesia will add up to 3.5 bcfd of gas production capacity by 2012. This will result from construction of infrastructure and commissioning of the Tangguh LNG plant. Tangguh's development will maintain Indonesia's position in the top tier of global LNG producers despite the decline in output from the Arun plant in North Sumatra.

Any spare gas production capacity is expected to supply the overstretched Java market.

Oil production from the Cepu Block will account for more than half of the 320,000 b/d of new oil capacity being brought on stream by 2012. Oil production is in decline, and Indonesia became a net importer in 2004. In these circumstances, it has become highly reliant on this single project to slow the decline.

Other areas

Elsewhere, Thailand remains dominated by gas developments, with new production adding almost 750 MMcfd by 2012.

Vietnam is forecast to see almost 170,000 b/d and 450 MMcfd of production come on stream by 2012. Other Southeast Asian countries are expected to make only a minimal impact on regional production levels.

More to come

In addition to these highlighted projects, there are several large projects waiting in the wings:

- *Vietnam*. Ca Ngu Vang, Su Tu Vang, and Te Giac Trang oil fields contain a combined 700 million bbl of oil and may all be on stream before the end of the decade. Vietnam's gas production profile also will increase once Kim Long and Ac Quy fields are brought on stream, although the timescale for their development remains uncertain.

The proposed Cuu Long gas gathering system will provide an opportunity for operators to realize value from previously stranded gas reserves.

- *Gulf of Thailand*. Development of Arthit field will provide most of this area's near-term gas production growth. Already beset by delays and cost overruns, the field is expected to come on stream in early 2008 and to supply more than 330 MMcfd to the

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gas-hungry domestic market.

• *Offshore Sabah*. Large, deepwater fields Ubah and Malikai will follow the development of Kikeh, so they are not expected to come on stream until the next decade.

First oil from Jeruk field off East Java is also not expected before 2010, although high oil prices could encourage these developments to be fast-tracked, subject to the availability of drilling rigs. In addition, the Ganal PSC gas fields, off Kalimantan, and E8 and F13 gas fields, off Sarawak, will be tied into the Bontang and MLNG plants respectively.

The development of Myanmar's large offshore gas fields awaits a decision on the destination of the gas. Memorandums of understanding have been signed with both China and India, and political machinations seem likely to continue for some time, thereby delaying a final investment decision.

Given the continued enthusiasm for exploration and the potential for new field discoveries, Southeast Asia holds strong prospects for further discoveries and major new developments through the next decade and beyond. ✦

CERA: US motor fuel market being transformed

Sam Fletcher
Senior Writer

The US motor fuel market is being transformed by higher prices, tightening environmental requirements, changing demographics, growing world demand for oil, and expanding fuel options, said analysts at Cambridge Energy Research Associates (CERA), Cambridge, Mass., a leading energy advisor.

"Americans have been driving further—40% more than 25 years ago—and using more gasoline in bigger, more-powerful cars and other light-duty vehicles. But higher gasoline prices have had a significant impact," said CERA analysts. "The rate of growth in gasoline demand slowed sharply from its 1.6%/year pace (1990-2004) to 0.3% in 2005, and continued to grow slowly in 2006, at 1%. And for the first time in 25 years, motorists' average mileage went down."

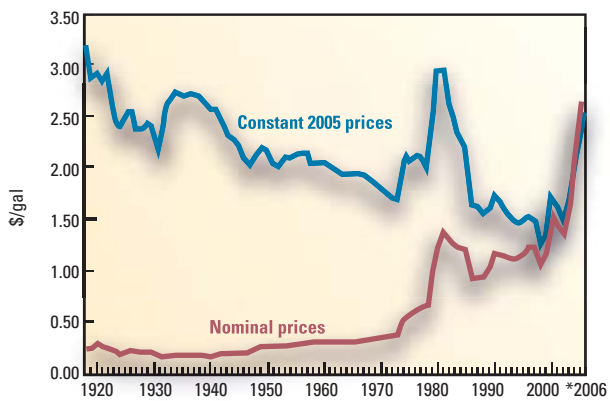
That drop in average mileage is not because of any significant reduction in the number of cars and trucks on the road, as is evident during rush hour driving in any major US city. In fact, the US is in the unusual position of having more vehicles than licensed drivers—1,148 registered personal vehicles (cars and light trucks) for every 1,000 licensed drivers, CERA acknowledged.

High fuel costs' impact

US gasoline pump prices rose from an average $1.59/gal in 2003 to $2.30/gal in 2005 and averaged $2.61/gal through mid-November 2006. "Gasoline started at $2.30 in January 2006, hit a high of $3/gal in July, and is currently averaging $2.22 in November," CERA said (Fig. 1).

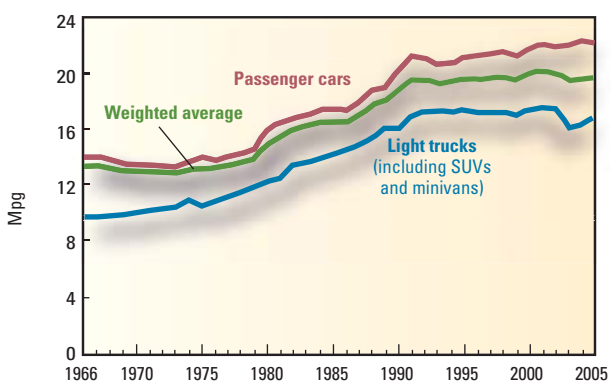
CERA claims high fuel prices have cooled US drivers' recent "passion for sport utility vehicles and minivans," since new purchases of light trucks, SUVs, and minivans declined in 2005-06 for the first time since 1990. As part of that downsizing, General Motors' new H3 Hummer, built on a midsize pickup truck platform, accounts for three-quarters of that brand's current sales. Unlike its H2 predecessor, which at more than 8,600 lb gross vehicle weight was exempt from the US Environmental Protection Agency's mileage-reporting program, the H3 has a highway rating of 19 mpg.

US AVERAGE GASOLINE PRICES, 1918-2006* Fig. 1



*Through November 2006.
Sources: Cambridge Energy Research Associates, American Petroleum Institute, US Department of Energy

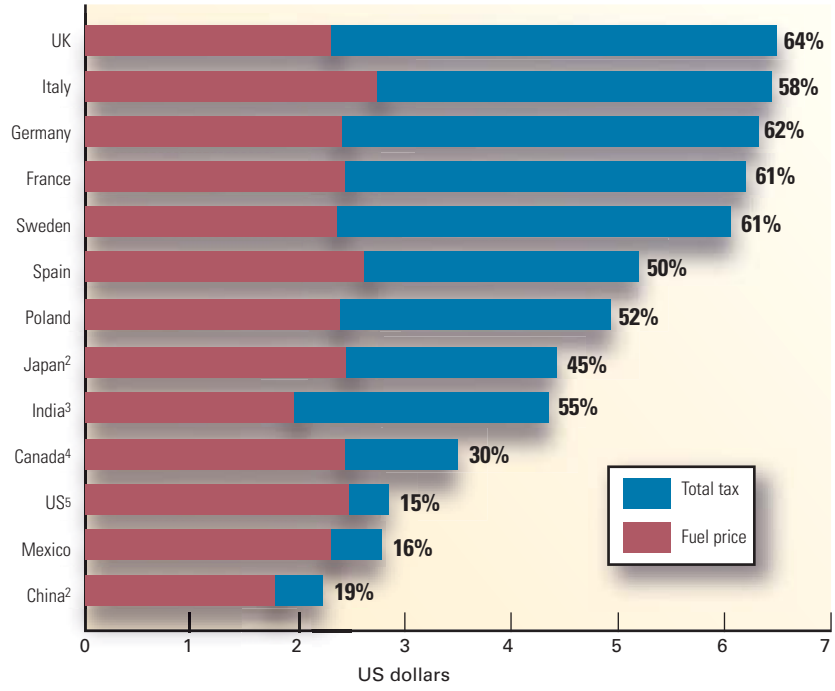
US VEHICLE ON-ROAD FUEL EFFICIENCY* Fig. 2



*Total vehicle fleet (cars and light-duty trucks).
Sources: Cambridge Energy Research Associates, Federal Highway Administration, US Department of Transportation, Highway Statistics (various years), Energy Information Administration

2006 GASOLINE PRICES,[1] TAXES IN SELECTED COUNTRIES

Fig. 3



[1]Retail premium unleaded (95 RON). Data are third quarter 2006 averages, as available. [2]Japan and China prices are for 91 RON unleaded. [3]India price is for 91 RON leaded. [4]Canada price is for 92 RON unleaded. [5]US price is for 87 octane, (R+M)/2 basis.
Sources: Cambridge Energy Research Associates, International Energy Agency, Energy Prices and Taxes

Yet there are still many H1 and H2 Hummers on the road. Those gas-guzzlers were once so popular that Hummer was the only GM division in 2003 that didn't have to resort to costly sales incentives such as 0% financing. Meanwhile, many of the 2007-model autos are being advertised for their high performance rather than their low mileage.

"Although new car buyers are once again shopping for fuel efficiency, it will take some years for the fleet fuel efficiency to change significantly since new car and light truck sales account for only about 8% of the vehicle fleet each year," CERA acknowledged.

In 1975, when corporate fuel efficiency standards were legislated, SUVs (including minivans and light trucks) accounted for just 16% of all vehicles. That market share peaked at 56% of all new vehicles sold in 2004. The SUV share of total sales slipped to under 55% in 2005 and 53% in 2006. "Buyers appear to be shifting from big SUVs to smaller, more fuel-efficient vehicles in that same class. While sales of hybrids are rapidly rising, so far in 2006 they constitute only 1.4% of new vehicles sold," said CERA analysts.

The fuel efficiency of the entire automobile fleet—new and old cars—averaged 22.1 mpg in 2001. "Since then, however, the pace of efficiency gains has slowed, flattening out at 22.2 mpg by 2005. The average for all light trucks (SUVs, minivans, and light pickup trucks) on the road was 16.9 mpg as of 2005, below the federal target for new light trucks. Since light trucks are a growing share of the vehicle fleet, they pulled down the average for all vehicles to 19.8 mpg in 2005 (the last year for which complete data are available), a drop from the peak of 20.2 mpg attained in 2001," CERA said.

Demand fluctuation

High energy prices during 1976-81 triggered rampant conservation in the 1980s, but the US economy has been slower to react to rising fuel costs this time around, partly because of greater disposable income. Gasoline and oil spending as a share of the average US household budget fluctuated at 3.4-3.6% in the 1960s, "rising to its highest level of 5% in 1981," CERA reported. "It reached its lowest level with the oil price collapse in 1998 when just 2.1% of household spending went to gasoline and oil, and increased to an estimated 3.8% in 2006. This appears remarkably stable especially compared with medical care, which grew from 11.2% of household spending in 1981 to 17.3% in 2005, and with food, which declined to 13.4% from 20% over the same period."

CERA analysts said, "The rate of growth in US gasoline demand averaged 1.6%/year over the decade and a half through 2004. But with rising gasoline prices, in 2005 US demand growth was only 0.3%, and for the first 11 months of 2006 show a reduced growth rate of just 1%. This contrasts sharply with significantly faster rates of growth from 1990 through 2005 in most emerging countries including China (6.6%), India (6.2%), and Brazil (4.5%)."

Some critics claim that US gasoline consumption is encouraged by low taxes on transportation fuels. Gasoline taxes amount to 5% of the retail price in the US, compared with 30% in Canada, 45% in Japan, 61% in France, and 64% in Britain (Fig. 2).

Demographic changes

CERA also sees demographic changes affecting the US transportation fuels market. Some 89% of the US population of driving age are licensed drivers. The average age is 40, but 29 million drivers, or 14.5%, are over the age of 65—"almost double the level of 25 years ago," analysts said.

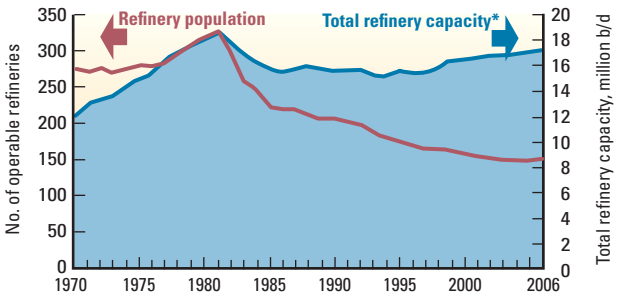
"Because people drive less as they age, and since an increasing share of the US population will enter middle age or retirement in the next 5-10 years, the growth rate of miles driven per licensed driver is likely to continue slowing, as in the recent past," CERA said.

However, other sources point out

that, thanks to modern medicine, US residents live longer and generally are healthier and more active in their later years. With more medical devices and procedures to maintain their vision and offset other handicaps that once sidelined senior citizens, the age of 60 is now considered the "new 50," and more senior citizens may remain behind the wheels of their more-comfortable and easier-to-drive automobiles instead of retiring to rocking chairs as did previous generations.

US OPERABLE REFINERIES, TOTAL CAPACITY

Fig. 4



*Capacity as of Jan. 1 of each year.
Sources: Cambridge Energy Research Associates, Oil & Gas Journal, Energy Information Administration

Impact of modified fuels

In the interim, transportation fuels are changing. "Reformulated gasoline requirements, congressional and state mandates, and significant tax incentives (currently a 51¢/gal tax credit) have driven US ethanol consumption from 11,000 b/d in 1980 to about 350,000 b/d in 2006, or about 4% of total gasoline consumption by volume (Fig. 3). These supports suggest that ethanol output will continue to grow," CERA said. However, the prevalent production of ethanol from corn in the US is not expected to exceed 10% by volume of total gasoline usage because of food-for-fuel tradeoffs and ethanol's logistical challenges. "This would still be a significant number—close to 1 million b/d. But since ethanol provides about two thirds of the energy as the same volume of gasoline, more volume of ethanol is needed for every barrel of gasoline replaced," said CERA analysts.

However, cellulose-derived ethanol made from the nonfood portions of plants expands the potential supply while reducing competition with food. A joint study by US Departments of Agriculture and Energy concluded the US has enough biomass resources to satisfy one third of US petroleum needs if cellulosic technologies and resources are employed.

"Cellulosic ethanol has the best growth potential for the biofuel market. But its current production cost of $2.25/gal ($3.38/gal of gasoline equivalent) is uneconomic," said analysts at Simmons & Co. International, Houston, in a September report.

Refinery capacity up

No new conventional refineries have been built in the US since the 1970s because of the difficulty in gaining permits and public acceptance at new sites. However, refiners have invested $5-7 billion/year to significantly increase refinery capacity at existing plants in recent years. Modernizing, debottlenecking facilities, adding capacity, and completing environmental upgrades have increased capacity to 17.4 million b/d in 2006 from 15.3 million b/d in 1996 (Fig. 4). That is "about the same effect as building 17 average-sized new refineries," CERA said. ✦

Calderon proposes opening Mexico's oil industry

Peter Howard Wertheim
OGJ Correspondent

Mexico's new President Felipe Calderon proposes opening the country's oil industry to international oil corporations to help increase crude oil exports.

Calderon, a member of the National Action Party (PAN), said foreign companies, which currently are allowed only as contractors providing oil field services such as drilling, seismic work, and infrastructure construction, should be allowed to enter into joint production agreements with Mexico's state-owned Petroleos Mexicanos.

"Pemex should be given the freedom to buy the technology or put together the contracts necessary to be able to increase reserves and produce oil," said Calderon, who was sworn in Dec. 1.

Oil accounts for 40% of Mexico's annual revenues, so the decline of oil output could leave the country with a nightmarish budget crisis, say analysts.

Yet Calderon, who realizes he would have to confront private monopolies and powerful unions, has repeatedly denied that he would privatize Pemex, as former President Vicente Fox, also of the PAN party, tried to do after taking office in December 2000.

Such a step, which would require amending the Mexican Constitution, has been repeatedly defeated in Congress by lawmakers of the Democratic Revolution (PRD) and the centrist Institutional Revolutionary Party (PRI).

Oil production declines

The nation's largest producing area, the Cantarell offshore oil field, is facing a decline similar to other fields, but on a much larger scale. Its production of 2.1 million b/d of oil is expected to fall to between 1.4 million and 520,000 b/d by 2008, according to government estimates.

If the worst-case projections materialize, Mexico's oil exports to the US

Behind Halliburton's powerful frac operations are innovations—like our ingenious, proprietary polymer technology—that ensure operators achieve higher regained conductivity.

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

The switch to biofuels

Is the day approaching when countries around the globe will switch from oil and natural gas to biofuels? Some already are touting the switch, but it could prove costlier than they think. Consider Indonesia, a member of the Organization of Petroleum Exporting Countries, where state-owned electricity company PT Perusahaan Listrik Negara (PLN) plans to operate biofuel-fired power plants next year.

With a combined capacity of 58 Mw, the plants—to be built in several regions such as Lampung, West Nusa Tenggara, East Nusa Tenggara, and South Kalimantan—would use palm oil as their main energy source.

Alhilal Hamdi, chairman of Indonesia's National Biofuel Development Team, who is also president of PT PLN's board of commissioners, said the plan was part of the company's efforts to maximize the use of alternative energy sources in its operations. "PLN will reduce its dependence on oil in stages," he said.

Exports rising

Consider Malaysia, where experts are projecting 1 million tonnes in biofuel production next year for export, more than double the production of this year's 400,000 tonnes.

Malaysian Palm Oil Association (MPOA) Chairman Sabri Ahmad explained that the demand for biofuel in Europe and the US was expanding rapidly in line with the requirement for more environmentally friendly energy.

At the launch of the International Biofuel & Alternative Energy Conference on Dec. 5, Sabri said that by 2012 Europe would require 10 million tonnes/year of biodiesel compared with 4 million tonnes/year currently. Consider the Philippines, where both chambers of the legislature have passed a bill mandating vehicles to run on environmentally friendly biofuels. The legislation mandates the use of biofuels by blending 5% bioethanol with gasoline within 2 years after the law takes effect and 1% biodiesel with diesel within 3 months after it takes effect.

Competing with food

Philippine Senate Minority Leader Aquilino Pimentel Jr. said the bill will "start the beginning of our cutting of the umbilical cord of dependence on imported fossil fuel from the Middle East, and it will start the cleansing of the environment from polluted air." It also will boost employment, he said.

While such countries are touting the new industry, biofuel still has adverse effects that are only beginning to emerge.

In China, for example, grain is getting as expensive as oil due to demand growth for corn and other crops to be used to generate biofuel instead of for food.

"We predict that agricultural products will be as hot as petroleum in the future," said one trader at the Dalian Commodity Exchange, where corn prices jumped 19.5% in October and last month to reach a 10-year high.

Of corn, Wang Jinmin, a professor at the Chinese Academy of Agricultural Sciences, said: "With its increasing role as a crude oil substitute and environmentally friendly energy, prices are unlikely to drop in the long run." ✦

could decline by as much as 1 million b/d.

Pemex predicts that the declines will be offset by new wells coming online in deepwater Gulf of Mexico and in Chicontepec field in Veracruz state. However, many experts say both areas would require at least a decade of exploration and development before significant production begins. ✦

Small producers cite struggles in UK N. Sea

Uchenna Izundu
International Editor

Small oil and gas companies are struggling to acquire and develop acreage in UK licensing rounds because of intense competition and high taxes, company executives said at a conference in London.

Speaking at the World Junior Oil and Gas Congress in London, Russell Langusch, managing director of Elixir Petroleum, said 141 companies have applied for licenses under the 24th licensing round for the UK North Sea. The UK government hasn't announced results (OGJ Online, Nov. 10, 2006).

Langusch said the introduction of promote licenses by the UK Department for Trade and Industry (DTI) to encourage exploration and production by small companies in the UK North Sea has spurred a record number of applications over the past 2 years.

However, the DTI has "unrealistic" expectations of these companies' abilities to finance drilling under promote licences, he added.

Many international oil companies are selling holdings in the mature UK North Sea to independent producers and new, small companies. Oil executives said they needed a stable and reasonable tax regime to encourage them to invest in the region, which is estimated to hold 27 billion boe.

"The UK government did not understand the impact of its tax change

in 2005 and the effect on our operations," Tom Windle, founder and chief executive officer of Wham Energy, said. In December 2005, Gordon Brown, chancellor of the exchequer, shocked the UK oil industry by doubling the supplementary corporation tax rate on oil and gas production to 20% in a move that pushed the total corporate tax on production begun after 1993 to 50% and on older production to 75%. The high taxes have hurt the economics of developing mature acreage with declining production rates.

Alex Kemp, a professor of petroleum economics at the University of Aberdeen, added that it would be challenging for the UK to meet its goal of producing 2 million b/d of oil by 2020 because companies would need to develop 20 new fields/year. Recent discoveries, he said, are smaller than their predecessors, which means that greater numbers of them are required to meet the target.

"We also need quicker decision-making and technical and managerial handling of operations to meet this goal," Kemp stressed. ✦

Tighter oil market likely in 2007, analyst says

The oil market is likely to tighten in 2007 with global demand for crude up by 1.7 million b/d, non-OPEC production growing by just 1 million b/d, and only a 1.1 million b/d increase in refining capacity, said Edward L. Morse, managing director and chief energy economist for Lehman Bros. Inc., New York.

World demand for crude rose by 5.2 million b/d from 2002 to 2005, or an average 1.7 million b/d/year. The consensus is for 2006 demand growth to be just over 1 million b/d, but Lehman Bros. puts it at 1.2 million b/d.

The reason for the 2006 demand reduction from the previous average was not the escalation of prices as some might speculate but the "incredible distortion" of supply and demand fundamentals caused by Hurricanes Katrina and Rita in 2005.

Damage inflicted by those hurricanes and the associated surge in energy prices depressed US demand until last April. But since April, US energy demand has been stronger than prehurricane 2005, Morse said Dec. 5 at an annual oil and gas conference hosted by Deloitte & Touche in Houston.

The 2006 market also was weighed down by fuel switching in electric power generation. US demand for residual fuel was reduced by 400,000 b/d as a result of lower natural gas prices. But Morse sees no room for further substitution in 2007.

Demand outlook

"Barring any unforeseen incidents, I can't see how demand can fail to grow at less than 1.7 million b/d" in 2007, Morse said. He sees US oil demand increasing by 250,000-350,000 b/d in 2007, compared with an average growth of 293,000 b/d/year in 1995-2005. US demand for gasoline, diesel, and jet fuel should grow by 300,000 b/d, even if the 2006-07 winter proves to be warmer than normal. But cold weather and fuel substitution could add another 200,000 b/d or more, said Morse.

China's demand growth is pegged at 500,000-700,000 b/d in 2007 from an average of 395,000 b/d/year in 1995-2005. Controlled product prices in China have resulted in "rationed demand," said Morse. Chinese refiners have been losing money on domestic sales of petroleum products and have restrained production availability in response. As product prices are liberalized, that pent-up demand could add 150,000 b/d to China's basic demand growth.

Other emerging Asian markets should add another 200,000 b/d of demand growth. The "torrid economic growth" in the Middle East "will likely add at least 350,000 b/d" of oil demand growth, Morse said.

Energy intensity—the measure of the energy efficiency of a nation's economy, calculated as units of energy per unit of gross domestic product—is falling, Morse said. The amount of oil necessary to produce a given level of gross domestic production is declining as a result of "economic maturing," conservation, and increased energy. In 1995-2005, global GDP growth averaged 3% vs. a 1.7% average oil demand growth.

Yet US oil intensity is almost double that of Japan and western European countries, while China and India stand at twice the world average. Oil-intensive countries, of course, run increased risks from sustained high crude prices, which have increased because of greater demand.

Morse noted the "gradual numbing" of consumers to higher oil prices, since world demand for crude increased annually September 2002-September 2005 despite rising crude prices.

Production outlook

The International Energy Agency in Paris and OPEC members expect non-OPEC supply growth to be equal to or better than demand growth. IEA is projecting non-OPEC production will grow 1.68 million b/d, while a more optimistic OPEC sees non-OPEC production growing by 1.77 million b/d. But Lehman Bros. figures non-OPEC production will grow by only 1 million b/d—"perhaps by much less, depending on disruptions in 2007." Added production by non-OPEC countries will come primarily from off West Africa, the deepwater Gulf of Mexico, and the Caspian region, Morse said.

Morse said OPEC output would need

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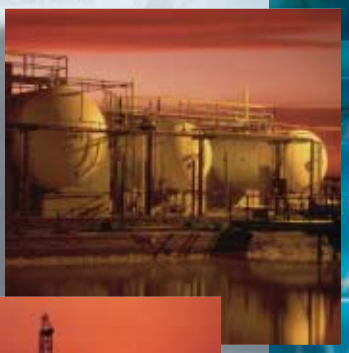

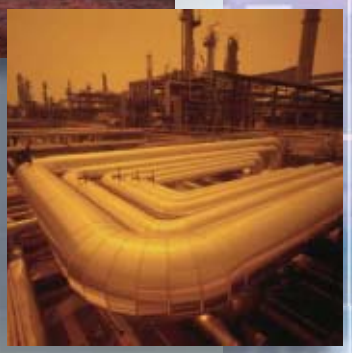

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to increase "by at least 700,000 b/d" to meeting incremental demand in 2007, but the cartel's growth capacity is limited. That means tight oil markets in 2007, "perhaps very tight," he said. At this point, crude production capacity all depends on developments within the OPEC countries, with continued political risks in Nigeria, Iran, Iraq, and Venezuela.

Lehman Bros. is projecting distillation and upgrading capacity to grow substantially by the end of this decade, with planned gross additions of 1.5 million b/d in 2008, 1.9 million in 2009, and 3.2 million b/d in 2010. ✦

OCS leasing bill pulled from House floor

US House leaders pulled the Senate's Outer Continental Shelf oil and gas leasing reform bill from the floor on Dec. 5 because there were not enough votes to pass it under special fast-track rules.

Proponents had pushed to get S. 3711 on the calendar under a rules suspension to keep it from being amended. But they apparently lacked the votes to reach the two-thirds majority required in such cases. The bill must pass the House without amendments to avoid a conference and move directly to the president for enactment.

Louisiana representatives and senators from both parties say passage of the Senate's OCS bill is vital since it contains a provision giving Gulf Coast states except Florida a portion of federal OCS oil and gas revenue.

Louisiana Reps. Bobby Jindal (R) and Charlie Melancon (D) were the two primary sponsors of HR 4761, a more aggressive OCS leasing reform bill that would have given coastal states beyond the Gulf of Mexico a means to share federal revenue in exchange for allowing leasing off their coastlines. ✦

COMPANY NEWS

Talisman sells noncore oil sands assets in two deals

Talisman Energy Inc. agreed to sell some of its noncore oil sand assets in two deals worth a total of $582.5 million (Can.).

In other recent company news:

• Surge Global Energy Inc. agreed to acquire a private Alberta oil sands company in a cash-stock transaction valued at $16 million (Can.) total. The name of the private company was not disclosed. Closing is expected Jan. 18, 2007.

• Afren PLC of London executed a heads of agreement with Gulf Energy Resources to acquire a 5% stake in Angola's Cabinda Central License Block B.

• Dan L. Duncan and three corporate entities are seeking approval from the US Federal Trade Commission to sell their interests in Mont Belvieu Storage Partners to partner Louis Dreyfus Energy Services LP.

• Mariner Energy Inc. on Nov. 1 completed the sale of its 20% working interest in the Cottonwood project in the Gulf of Mexico, to the project's operator, Petrobras America Inc., for $31.8 million. Cottonwood lies on Garden Banks Block 244 in 2,300 ft of water.

Talisman sells assets

Talisman plans to sell its 1.25% interest in Syncrude to Canadian Oil Sands Ltd. for $475 million in a cash and equity deal.

Closing is conditional upon clarification of the transaction's tax status for Canadian Oil Sands under Canada's new trust taxation rules.

Talisman said its share of Syncrude production has averaged 3,400 b/d so far this year.

In the second deal, Talisman sold its royalty on Suncor Energy Inc.'s undeveloped Lease 23, west of Suncor's Steepbank mining operations, to Suncor for $107.5 million.

Talisman said it's still in negotiations to realize value from its remaining oil sands leases.

Surge buys oil sands firm

Surge's agreement calls for it to pay owners of the private company $6.3 million in cash and $10 million worth of equity in Cold Flow Energy ULC, a wholly owned subsidiary of Surge, based in San Diego.

The oil sands company owns 30% interest in 86,400 acres in the Red Earth area of Alberta. The development involves four major contiguous blocks close to existing services and infrastructure.

Afren buys license stake

Afren PLC of London executed a heads of agreement with Gulf Energy Resources to acquire a 5% stake in Angola's Cabinda Central License Block B.

Afren's transaction is expected to close in first quarter 2007, subject to certain conditions including negotiation of a final agreement. The exploration license covers 1,125 sq km. Devon Energy Corp., Oklahoma City, is the operator and owns 30% interest. Other partners are Repsol YPF SA, Angola's state-owned Sonangol, and Petrogal.

Several prospects already have been identified and mapped on this license, Afren said, adding that 32 wells previously were drilled, several of which found light oil.

Parties sell storage

The sale would satisfy FTC's Nov. 3 final order requiring Duncan, EPCO

PERSONNEL MOVES AND PROMOTIONS

Petrobras changes international area executives

Petroleo Brasileiro SA (Petrobras) has made several changes to its international area executive staff, all effective Jan. 1.

Alberto Guimaraes, general executive director of Petrobras Energia SA since 2002, has been appointed president of Petrobras America Inc. Prior to his assignment to Argentina, he held various positions, including executive manager for new business and superintendent of the former commercial department.

Petrobras Energia Refining & Petrochemicals Director **Carlos Fontes** succeeds Guimaraes as general executive director of Petrobras Energia. Fontes, a chemical engineer, has been in Argentina since 2004. Before that, he held various positions, including products and refining processes manager, petrochemical projects manager, petrochemical executive manager, and president of Petroquisa.

Renato Tadeu Bertani, currently the managing director of Petrobras America, has been named executive manager for the Americas, Africa, and Eurasia at the international area at the company's headquarters.

Bertani joined Petrobras in 1976 and has served in several technical and managerial positions, including exploration manager and general manager of the Potiguar basin in Rio Grande do Norte, new business manager, and exploration and production director of the subsidiary Petrobras Internacional SA (Braspetro). He also has served as general manager for Petrobras UK Ltd. and from 2001 as president of Petrobras America.

Joao Carlos Araujo Figueira, executive manager for the Americas, Africa, and Eurasia at the international area since August 2004, will become E&P director of Petrobras America.

Figueira, a geophysicist, has held several technical and managerial positions in the company's international activities, including in the UK and Angola. He has served as E&P director of Braspetro, which was incorporated to Petrobras, and also as executive manager of the company's international area since its creation in 2000.

Other moves

St. Mary Land & Exploration Co. Pres. and Chief Operating Officer **Tony Best**, who joined the company in June, will transition into his new role as chief executive officer on Feb. 26, 2007. On this same date, Chief Executive **Mark Hellerstein**, who has been with the company for 15 years, will become nonexecutive chairman.

In addition, St. Mary hired **Javan Ottoson** as chief operating officer, effective Dec. 18. At that time, Best will relinquish the chief operating officer position but will continue to serve as president of the company.

Ottoson has 23 years of experience in the energy industry, most recently with Energy Partners Ltd. in New Orleans, where he served as senior vice-president, drilling and engineering. He also managed the Permian assets for Unocal Corp. subsidiary Pure Resources Inc. and its successor owner, Chevron Corp., from 2003-06.

Prior to that, Ottoson worked 20 years for ARCO in management and operational roles, including president of ARCO China, commercial director of ARCO British, and vice-president of operations and development, ARCO Permian.

Inc., Texas Eastern Products Pipeline Co. LLC, and TEPPCO Partners LP to divest their interests in land, pipelines, and other assets at the NGL storage site east of Houston by Dec. 31.

Agreements under which the partnership was formed require TE Products to offer the interests to Louis Dreyfus on the same terms proposed by any third party, the FTC said on Nov. 27. Louis Dreyfus then has 30 days to exercise the right of first refusal.

In the application, Duncan and the three firms he directly or indirectly controls ask to divest their interests in the Mont Belvieu storage partnership to Louis Dreyfus to satisfy the FTC order.

FTC will accept public comments on the application through Dec. 27.

FTC's order came from its Aug. 18 challenge of a 2005 acquisition that combined Enterprise Product Partners and TEPPCO Partners' NGL storage businesses at Mont Belvieu. It said the transaction likely would result in higher prices and degraded service by reducing the number of salt dome storage providers there to three from four.

Cottonwood sale

The sale will result in a pretax gain of $22 million to Mariner in the fourth quarter. Mariner will not be required to fund $21 million of development costs necessary to establish first production, estimated to occur in first quarter 2007.

Consequently, Mariner's 2006 capital spending forecast of $525-545 million (excluding hurricane repairs and acquisitions) is now expected to be about $504-524 million (excluding hurricane repairs, acquisitions, and dispositions).

Mariner acquired its interest in the Cottonwood project from Petrobras in April 2005 when Mariner allowed Petrobras access to Noble Drilling Inc.'s Noble Lorris Bouzigard deepwater semisubmersible, which Mariner has under long-term contract. Since acquiring its interest in 2005, Mariner participated with Petrobras in two sidetrack wells in the project. ✦

COMPANY PROFILES: CEPSA CONSOLIDATES ITS ROLE AS A LEADER IN BUNKERING WITH THE LAUNCHING OF CEPSA MARINE FUELS (CMF)

CEPSA has consolidated its position as one of Spain's leading bunker fuel suppliers since it began this activity back in 1930. Nowadays, the Company services ports in the Spanish Mainland, Canary Islands, the Strait of Gibraltar as well as in Panama and has sales offices nationwide. A recent milestone has been the start-up of CEPSA Marine Fuels (CMF), a new subsidiary aimed at bolstering the Company's international marine fuel supply business. With the creation of CMF, CEPSA aims to meet the following targets:

View of the Port of Algeciras Bay.

· Carry out and develop international trading activities, expanding sales in ports worldwide and harnessing the expertise acquired in the market and with large customers, being able to offer a variety of additional services.
· Optimize supply & trading operations, with ongoing monitoring of all purchase/sale transactions to assess their appropriateness.
· Align the business to a changing and increasingly more competitive operating environment.
· Explore and develop new projects abroad that are of economic/commercial interest.
· Optimize the use of logistical resources and fuel storage availabilities both in areas where the company currently operates as well as future ones.

This new company, with its primary focus being on delivering premium customer service, uses industry-leading technologies and offers superior quality in its products, while adhering to the most stringent international standards and guaranteeing strict compliance with safety and environmental protection mandates.

CEPSA's competitive edge relies on two main factors:

1) Geographical location: over 80,000 ships pass through the Strait of Gibraltar each year and CEPSA is firmly positioned in this area, with a world-scale refinery in Algeciras as well as storage terminals in Ceuta and ship supply facilities. Additionally, the Canary Islands, a core area for the Company's operations, also serve as a hub between the Americas and Europe and Africa.

2) A long and distinguished track record in the business, with a talented and dedicated team of people committed to providing top quality and service.

CEPSA strives to sustain outstanding safety, quality and environmental performance and supports the passage of new specifications aimed at improving environmental protection.

CEPSA is firmly convinced that its highly-qualified and committed team of people, responsiveness to customer needs, premium service and product quality, reliability and versatility are all key factors in driving the success of its business and these strengths have been the cornerstones of the Company's activity for over 75 years, as reflected in the progress achieved over time and the positive outlook for the future.

Safety continues to be a top priority and all efforts are made to ensure ongoing maintenance and enhancement of the Company's facilities. Compliance with ISO standards has enabled CEPSA to be certified by Lloyd's Register Quality Assurance, applicable to all of its product sales and distribution activities. CEPSA complies with the most strict security standards, and attends security as a must.

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SEISMIC EMISSION TOMOGRAPHY—1

Seismic used to directly map reservoir permeability fields

Peter Geiser
Jan Vermilye
STRM LLC
Boulder, Colo.

Rob Scammell
Burlington Resources Canada
Calgary

Steve Roecker
Rennselaer Polytechnic Institute
Troy, NY

This two-part article summarizes a series of tests indicating that a technology now exists for near real-time 3D mapping of the reservoir-scale permeability field using surface-based seismic acquisition networks.

Despite decades of work, hydrocarbon production, particularly that of oil, remains highly inefficient with often up to 60-70% of the known resource being left unproduced. It is generally acknowledged that the principal obstacle to more efficient production is the absence of a means of accurately mapping the reservoir "architecture" or permeability field.

Our work, combining a new geomechanical model for the behavior of fluids in the earth's brittle crust in combination with a previously unexploited seismic imaging technology, seismic emission tomography (SET), is shown to allow direct imaging and mapping of the reservoir-scale permeability field geometry.

This technique could have important implications for improved efficiencies of hydrocarbon exploration and exploitation.

Why imaging is difficult

The most ubiquitous secondary rock structure is fracture.

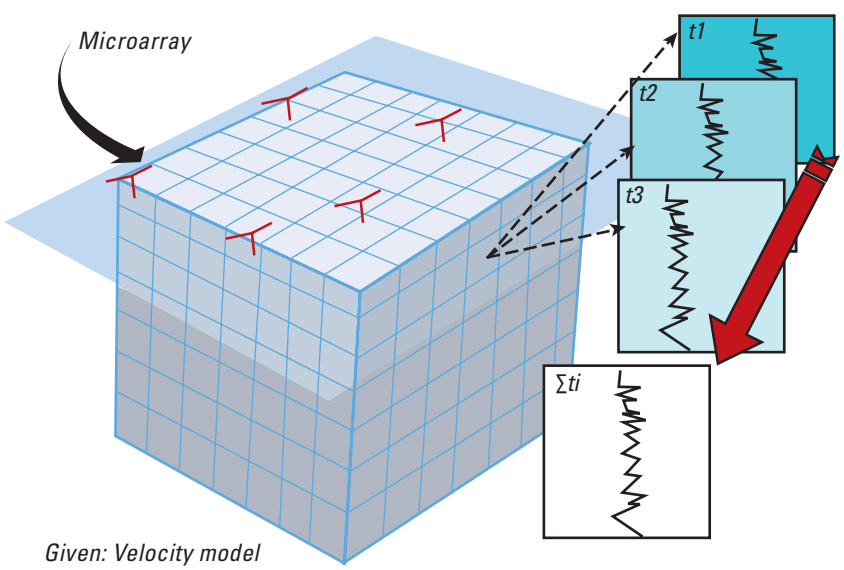
For example, no rocks are known to be totally devoid of joints. Because fractures scale like earthquakes, i.e., there is an inverse power law relationship between size and frequency, it may be said that there is no such thing as an "unfractured" rock, at least at some scale.

So to varying degrees all reservoirs are fractured reservoirs, and fractures can be said to play an important and often critical role in the architecture of all fluid reservoirs. The relationship between fracture size and frequency indicates that because there are many orders of magnitude more smaller fractures than large ones, it is highly likely that much of the permeability resides in the smaller fractures.

Thus the ability to image the full spectrum of crack sizes would seem to be a requirement for direct permeability field mapping.

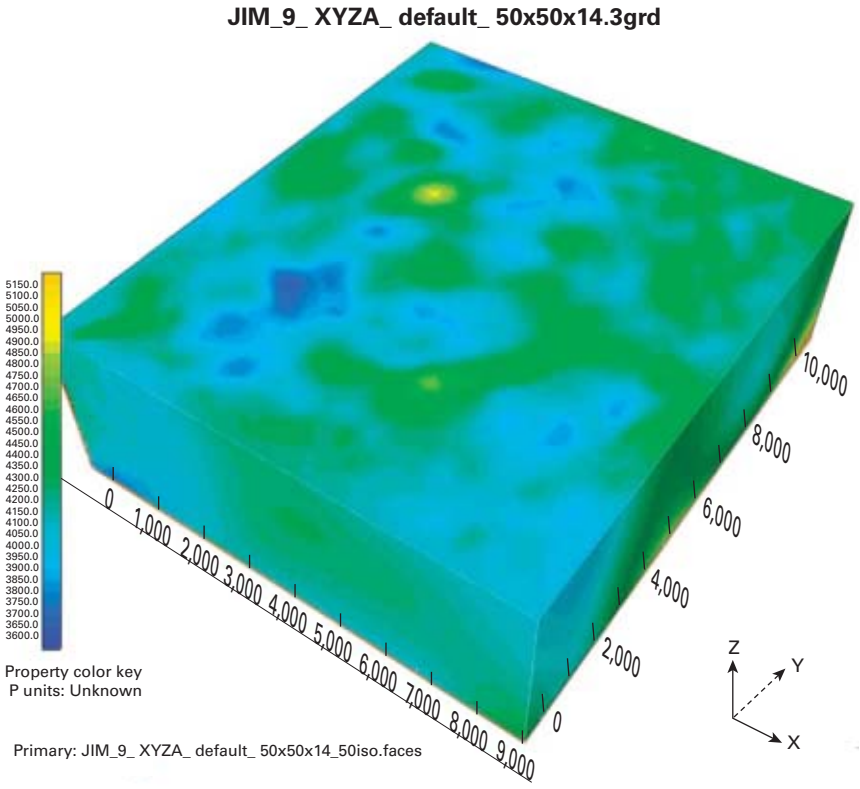
Recognizing fracture's critical role

SURFACE-BASED S-E-T NETWORK SHOWS BEAM-FORMED VOLUME WITH VOXELS Fig. 1



3D VIEW OF ACOUSTIC-ENERGY EMISSION

Fig. 2



but also recognizing that any given reservoir will have many fracture sets with a wide range of orientations for the sets, how do we identify precisely which fracture sets constitute the permeability field? A number of recent studies show that hydraulically conductive fractures are dominantly critically oriented for shear and obey Mohr Coulomb criteria suggesting that if we knew the stress field we could predict the average directions of fractures that form the permeability field.

Although statistically true at the reservoir scale, at the scale of the individual fractures there are significant exceptions to this rule thereby making it impossible to explicitly map the permeability field using only this relationship.

Another problematic aspect of reservoir permeability is that it tends to be highly heterogeneous, i.e., there are zones in which the permeability may be order of magnitudes higher than in the surrounding rocks. This phenomenon is in part responsible for the fact that in any given field a relatively small number of wells are responsible for most of the production, i.e., the ones that have hit "sweet spots."

Most important, this phenomenon creates considerable uncertainty. Further, fracture and faults themselves are typically embedded in "process" zones in which the fracture density increase with proximity to the fracture or fault and where the relation between fracture/fault length and the width of the process zone tends to increase with the length of the fault plotting as a straight line on a log/log plot. This implies that where permeability is a function of crack density and assuming that the "process zone" does not contain other permeability-reducing processes, locating the centers of such zones should provide the highest permeability.

A final complication is that the permeability field itself is dynamic. As is well known the act of producing hydrocarbons changes, sometimes disastrously, the permeability field itself. Little is understood about the causes and time scale over which these changes occur.

Behavior of fields

The following set of empirical observations, proposed a geomechanical model for the behavior of the permeability field in response to changes in fluid pressure:[1]

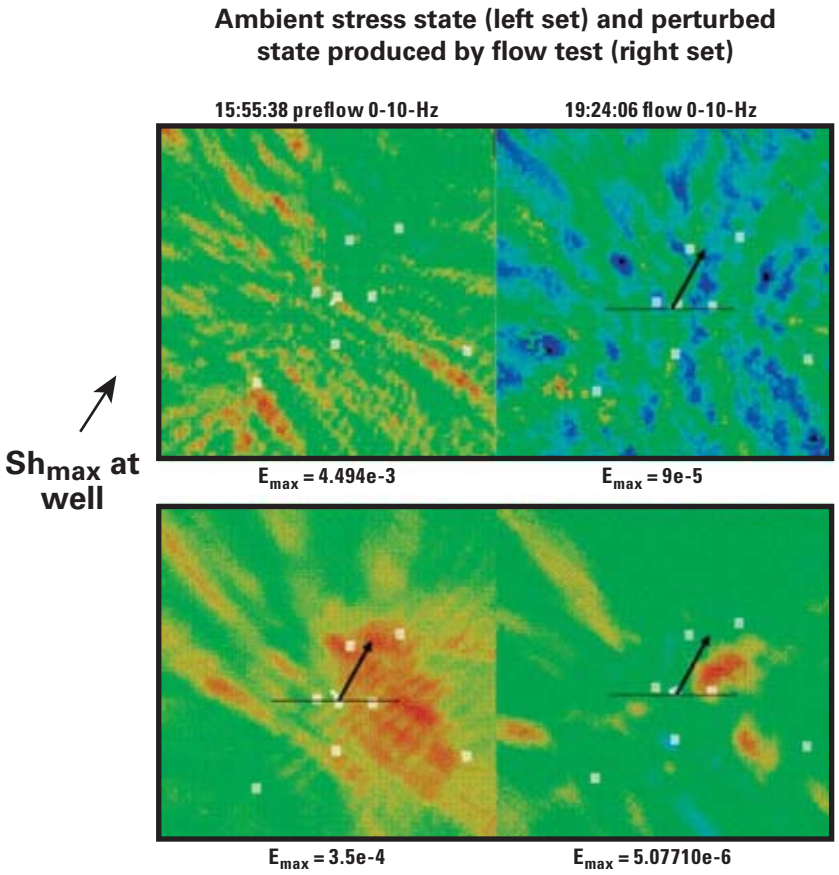
1. Rate correlation statistics: The far-field effects that production in one well may have on others, sometimes miles away, have been known for decades. These effects are known to propagate very rapidly, often within hours or even minutes. A systematic statistical analysis of these effects[2] uses rate correlation statistics to show that with respect to any given injector well, wells whose production increased (a positive rate correlation) all lay within a 70° to 80° sector of arc with respect to the injector, where the arc sector is bisected by the maximum horizontal compressive stress (Sh_{max}). Thus statistically the wells that respond positively have orientations consistent with Mohr Coulomb crack behavior. Of particular importance is that wells as much as three miles from the injector had positive correlations with essentially instantaneous response times. These observations led to an hypothesis that this behavior resulted from a wave phenomenon caused by a cascade of "inelastic failures in the fault/fracture structure of the rock propagating in 'domino fashion.'"[2] A similar analysis[2] on wells known to be in fluid communication on the basis of flood directionality studies, indicates that the results are a manifestation of the permeability field.

2. Critical orientation of hydraulically conductive fracture: Analysis of fluid flow in faulted rocks suggests that the bulk of fluid transport occurred on those fracture which are critically oriented under Mohr Coulomb conditions for shear.[3]

3. The near-critical state of the earth's crust: Over the last several decades earthquake seismologists have established that the earth's crust is in

VARIATION IN ACOUSTIC-ENERGY EMISSION

Fig. 3



The above four 8 by 8-km map slices at about 3,300 m KB through SET volume show variation in AE emission between ambient stress state (left hand set) and perturbed state produced by flow test (right hand set). Higher energies are hotter (reddish browns), and lower energies are cooler (blues and greens). Upper set of slices is horizontal seismic component and lower set is vertical seismic component. White squares are recording stations. Well is located at the intersection of the horizontal (EW) bar and the end of the arrow parallel to Sh_{max}. Voxel size is 200 m. Note that the unfavorably oriented directions for flow under Mohr Coulomb behavior (NW bands) are suppressed during the flow test and favorably oriented directions NNW and NE bands are enhanced as predicted by the geomechanical model. Note the two orders of magnitude decrease in E_{max} during flow test.

a near-critical state, i.e., it is close to brittle failure almost everywhere, where failure is manifest principally by slip on preexisting fractures. Just how close has been established by analyzing stress drop data associated with microseismic activity. Statistical analysis of the data[4] shows that small (±0.01 bar) perturbations of the ambient stress field are sufficient to cause failure of critically oriented cracks.

Because it was unclear how the crack cascade mechanism could result in the increases in fluid pressure (P_f), let alone the sustained increase in P_f required to increase production, it was suggested[1] that the phenomena was the result of a fluid pressure "P_f wave" propagating through the hydraulically linked fracture network connecting the wells.

A wave of this type has been found experimentally[5] and is referred to as a "slow wave."

Combining the P_f wave hypothesis with the foregoing empirical data forms the basis of a simple geomechanical model. The model predicts that the response of the earth's brittle crust to a change in fluid pressure should result in systematic slip and associated brittle failure of the hydraulically linked fractures connected to the point of P_f perturbation.

Acoustic energy (AE) generated by the slip events can be detected. Thus propagation of the P_f "wave" through the critically oriented fracture network forming the permeability field will produce AE emissions resulting in its "illumination." Recording the AE emissions should allow direct mapping of the fracture-related permeability field. The following outlines this model:

1. Given: The state of the earth's brittle crust is everywhere near failure.
2. A change in P_f at a well changes the stress state at the well.
3. The change in P_f propagates through the hydraulically linked fracture network connected to the perturbation point changing the stress state as it moves.
4. This fracture network consists of preexisting cracks critically oriented for slip that are also fluid filled and therefore the weakest fractures.
5. Because stress drops on the order of ±0.01 bar are sufficient to cause failure and because changes in P_f induced by production are on the order of hundreds of bars, the P_f wave will cause failure of the critically oriented cracks forming the permeability field thereby "illuminating" it.

The problem is thus reduced to one of being able to image the AE emitted by the slip on preexisting cracks across the broadest spectrum of crack sizes possible. If this can be done in near real time and at the reservoir scale then direct mapping of the permeability field is possible.

Imaging microseismicity

Because there is a continuous spectrum of crack sizes, the distinction between microseismicity and creep is arbitrary.

Creep, for instance, is defined as the processes that allow continuous deformation and so is scale dependent. Although microseismic events are considered to be larger than creep events, a rule of thumb distinguishes them on the basis of whether or not the failure

events are resolvable under ordinary field conditions.

If the event is resolvable it is considered microseismicity; if not, it is considered creep. The distinction is ambiguous as the ability to detect and resolve an individual event (microseismicity) is largely dependent on how close the event is to the receiver.

The detection of microseismic events using surface networks is severely hampered by attenuation and noise. The most robust form of microseismicity detection requires the use of downhole seismometers in the effort to place the detectors as close to the sources as possible. This is the method in general use for monitoring induced fracture stimulations. The use of downhole instruments to detect microseismicity suffers from a number of well-known drawbacks.

1. It requires a dedicated well ideally within 0.5 mile of the treatment well.
2. The ability to detect resolvable events drops off with the inverse square of the distance to the source. Thus the spectrum of events, already limited by the resolvability requirement, is further filtered by distance.
3. Because of the inverse power law relationship between the size and number of events, there are orders of magnitude more unresolvable events than resolvable. Thus only a limited part of the crack size spectrum constituting the permeability field can be seen.

This set of problems means that it is at least highly impractical if not impossible to map the reservoir scale permeability using downhole instruments. Accomplishing this task clearly requires a different technology.

The SET technique

Seismic emission tomography emerged from the technical section of the Nuclear Test Ban treaty in the late 1980s and early 1990s.

It is geared specifically toward identifying "point" sources (meaning dimensions less than a minimum processed wavelength in scale) of energy. SET can also find a sufficiently "rough" surface, meaning a surface that behaves like a bunch of individual scatters.

Identification of a scatterer as well as point sources is done by coherence (using semblance as the metric). This requires multiple channels of on-the-ground recording.

A signal will show up only if it arrives at all the channels within a certain time window. Noise will cancel out (or at least not add together as rapidly).

To first order, the signal to noise ratio behaves as the square root of the number of channels available. The best one can do with any technique in order to determine if one is looking at signal or noise is to compute the appropriate statistics. For SET these statistics are generally simple to derive.

The product of SET is a "three dimensional image of the medium where the distribution of brightness shows the distribution of active volumes...(it is) a portrait of the medium in terms of its ability to produce or scatter seismic energy."[6]

SET uses a surface-based seismic network (Fig. 1) to beam form the selected volume of the earth's crust. For any given time interval the AE emissions for each voxel are stacked to provide a value for the AE emission at each associated grid point of the volume. The values for each voxel of the volume are then normalized against all the AE values of the volume and contoured to provide an image of the AE emission field (Fig. 2).

An example of a set of map slices through two SET volumes is shown in Fig. 3. The use of SET allows 1) the entire spectrum of active crack sizes to be imaged; 2) the use of a surface network for monitoring AE emissions; 3) the area covered is limited only by the size of the network deployed.

It is clear that SET has none of the limitations that the use of downhole instruments for monitoring microseismicity has; there are, however, some tradeoffs:

1. SET cannot locate individual cracks but instead plots the distribution of AE emissions, where the primary emission sources are the product of crack failure.
2. SET cannot currently distinguish the crack sizes generating the AE. This is because the amount of AE being emitted by any given voxel is a function of the total crack area formed in the volume for the particular stack interval, i.e., the AE can result from either many small failures or from a single large failure.
3. The resolution of the AE locations is set by the voxel size, which is in turn a function of the number of receivers and the local environment. The current theoretical maximum resolution is 10 m, i.e., voxel size is 10 by 10 by 10 m, however 5-m resolution may be possible under the right set of conditions.

Next week: Results of field studies in British Columbia and the North Texas Barnett shale. ✦

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Billions of barrels in Bakken recovery seen in Williston

Alan Petzet
Chief Editor-Exploration

The Bakken formation play in the Williston basin is writing a new chapter in the oil reserves history of the US onshore Lower 48, thought by many to be a mature and fast-depleting province.

The play is spearheading production and reserves increases in Montana and North Dakota and prompting reevaluation of earlier resource assessments for the play, said the US Energy Information Administration.

EIA's report attributed to the US Geological Survey an estimate of the resource for the entire Bakken formation at 271-503 billion bbl in place, with a mean of 413 billion bbl. USGS noted that it has never published those figures, which are preliminary results from research that was never completed and therefore never technically and scientifically peer-reviewed.

The USGS's 1995 assessment stated that the Bakken might have generated billions of barrels of oil but included no specific figures. A new USGS assessment of the entire basin, due out in about a year, will contain a numerical estimate of the technically recoverable oil resource in the Bakken, the USGS said.

"If the potential bears out, this could (depending on recovery factors) increase the estimate of technically recoverable crude oil resources in the US by billions of barrels," EIA said in what it promised to be the first in a series of reports on technology-based oil and natural gas plays. By comparison, the most recent estimate of the technically recoverable crude oil resource of the entire US is 174.67 billion bbl, excluding the Bakken. US proved reserves at Dec. 31, 2005, were 21.757 billion bbl (OGJ Online, Oct. 23, 2006).

Play's largest field

Elm Coulee field, in Richland County, Mont., is at 529 sq miles the largest discovered field in the Middle Bakken formation to date.

Headington Oil Co., private Dallas operator, has estimated oil in place at 5 million bbl/sq mile in the Bakken in this field.

"With an assumed 10% average recovery factor, Headington estimates primary oil recovery could be 500 million bbl from Elm Coulee field," EIA said. The 1995 USGS assessment estimated ultimate Bakken recovery at 151 million bbl.

EIA predicted, "It is likely that other energy resources also await discovery or rebirth in the US as new technology allows us to locate, define, interpret, and extract them economically."

The continuous nature of the Bakken formation means its hydrocarbons, deposited during the Upper Devonian and Lower Mississippian periods, have not accumulated into discreet reservoirs of limited areal extent, but the Bakken remains to be penetrated across a considerable portion of the basin.

The Bakken play

Current US activity in the Bakken is taking place in the "badlands" of Richland County, Montana, and McKenzie, Golden Valley, and Billings counties, North Dakota, EIA noted.

The Bakken play started after operators analyzed geologic data on a decades-old producing area, identified an untapped resource, and applied horizontal drilling and fracturing technology to exploit it (OGJ, Dec. 10, 2001, p. 44).

Elm Coulee field, discovered in 2000, produced 15 million bbl of oil (41,000 b/d) in 2005 and is yielding nearly 50,000 b/d. This is about half Montana's crude oil production.

Current drilling is focused on the middle member of the Bakken, which is more porous and permeable than the overlying and underlying Bakken shales. The Bakken is at 11,000 ft in the basin depocenter in southwestern North Dakota and 3,100 ft in Manitoba and Saskatchewan.

As the Williston basin subsided, EIA explained, massive low-permeability carbonates above and below the Bakken acted as seals. The increased temperatures and pressures that accompanied subsidence thermally converted the kerogen content of the shales into oil.

"Sealed with no conduit or high-permeability formation adjacent to the Bakken formation to allow the petroleum to escape, the internal fluid pressure within the shales rose and eventually fractured the shales and the middle member from within," EIA explained.

Reserves, production growth

Proved reserves at the end of 2005 were 427 million bbl in Montana, 106% above the state's 1999 reserves. Operators added 63 million bbl of the increase from field extensions in 2005 alone. Proved reserves at the end of 2005 were 418 million bbl in North Dakota, up 59% since 1999, with 29 million bbl added in 2005 from field extensions.

The increases were almost exclusively from Bakken development and Ordovician Red River fields on the Cedar Creek anticline, and EIA said further gains are expected.

Early Bakken drilling targeted the shales, which swell on contact with water. The formation contains iron pyrite, which forms an iron hydroxide precipitate when exposed to the common fracturing fluid hydrochloric acid.

"There are reported cases of this phenomenon causing irreparable well damage," EIA said.

The former Lyco Energy Corp., Dallas, and Halliburton Co. frac horizontal Bakken intervals by aligning the horizontal leg so that induced fractures have longitudinal orientation to the well bore. The formation produces through an uncemented, preperforated liner. ✦

POINT OF VIEW

Canadian Superior looks at size of the prize in Trinidad, Nova Scotia

Nina M. Rach
Drilling Editor

Calgary's Canadian Superior Energy Inc., an aggressive independent, operates in Western Canada, the Maritimes, and off Trinidad and Tobago.

In April 2006, Mike Coolen was named president and chief operating officer of Canadian Superior. He had been vice-president in charge of offshore operations and a member of the company's board for several years.

At the company's Halifax offices, Coolen told OGJ that he spent 20 years at Mobil Oil Canada and saw the pace change after moving from a major to a smaller independent. "One of the differences is your ability to implement change rapidly. A large company has more structure and bureaucracy and can't operate on an ad hoc basis. At a smaller company everyone can take on a lot more initiative to make changes and add value. This is a real advantage for us. We can be very responsive to changes in oil and gas prices and tax regime."

The hurdles to fund projects can be rigorous, Coolen noted. But business fundamentals don't change, whether you're at a little company or a big company. "We must manage the portfolio within our ability to fund projects."

"It's funny—people wonder how a small Canadian company can have the technical ability to drill these offshore wells. But it's not the size of the company that matters—we're the same size as any other company's team looking after a particular basin."

Canadian Superior has about 50 employees, with more added during offshore drilling, a "great staff of day-to-day operations people," he said. They were all experienced hires, with many on the offshore team having 20-30 years in the North Sea and elsewhere, now focused on rapidly preparing and drilling prospects off Nova Scotia and Trinidad.

Trinidad

Drillers can face high pressures off Trinidad. "We can design for high temperatures, Coolen said, "but we have to watch high pressures more carefully." The rock is young, with a narrow margin between pore pressure and fracture gradient.

The physical environment off Trinidad also involves high currents, raising concerns about vortex-induced vibrations (VIV), induced fatigue damage, and straight load on the riser.

Coolen said his staff "has more experience than many other companies," noting that two engineering managers, Mark Gillis and Patrick Maris, worked in the North Sea for BPAmoco and for BG, respectively. Canadian Superior's Trinidad & Tobago country manager, Roger De Freitas, came from Global-SantaFe.

Canadian Superior holds acreage on two plays in the Columbus basin off southeast Trinidad:

"People wonder how a small Canadian company can have the technical ability to drill these offshore wells. But it's not the size of the company that matters—we're the same size as any other company's team looking after a particular basin."

—Canadian Superior Energy Inc. President, Chief Operating Officer Mike Coolen

• Mayaro-Guayaguayare "M/G" near-shore blocks, 55,000 acres, joint venture with national oil company, Petroleum Co. of Trinidad and Tobago Ltd. (Petrotrin).

• Block 5(c) "Intrepid," 80,041 acres, awarded May 2004; production-sharing contract (PSC) signed July 20, 2005.

Coolen feels positive about the company's prospects in Trinidad. He noted that 15 of BP's top 25 producing wells worldwide are located in Trinidad. Canadian Superior's Block 5(c) offsets BG and ChevronTexaco's Dolphin and Dolphin Deep gas discoveries, as well as BPTT's Chacalaca gas discovery.

Block 5(c) may contain more than 4 tcf unproven, unrisked reserves, and the company has three well locations selected based on a 3D seismic survey. "Hopefully we'll be successful in all the wells—we're not waiting for the third to hit."

Canadian Superior will use the Kan Tan IV semisubmersible to drill three back-to-back wells off Trinidad in 2007. (The company announced the third well for Block 5(c) on Nov. 14.)

The rig is a third generation, enhanced Pacesetter design, and will be delivered to Canadian Superior in early first-quarter 2007, following its current refurbishment at the AmFELS yard in Brownsville, Tex. The Kan Tan IV will have a new accommodation unit, updated BOP equipment, 1 million lb Varco top drive, and a Vetco riser.

After commissioning and field testing, the rig will be towed to Trinidad.

The Kan Tan IV is managed by A.P. Moller-Maersk AS of Copenhagen and owned by Beijing Zhiyuan Industries Co. Ltd., a Sinopec Group company.

Offshore Trinidad

Canadian Superior will spud the first well on the offshore Intrepid Block 5(c) in first-quarter 2007. Canadian exploration company Challenger Energy Corp. will pay for a third of the exploration program to obtain 25% of the prospect.

Coolen anticipates 80 days to drill the well, a straight hole to 16,000 ft proposed TD and then test for 20 days. The company is targeting 14 sands, with expected porosities of more than 20% and permaeabilities of several hundred md.

Engineering manager Mark Gillis said they have designed the well with six casing strings and plan a comprehensive suite of wireline logs. The biggest challenge is gaining a workable level of confidence in pore pressure prediction, Gillis said. Canadian Superior uses GMI software and Knowledge Systems Inc. personnel will be on site during drilling. The well design is based on activity in surrounding fields and assumes a normal compaction model.

After setting the conductor and running riser, the well will be drilled with water to about 1,000 ft. The company will switch to synthetic mud about 3,200-3,500 ft below the rotary table, and expects to reach 16.5-17 ppg at TD, assuming a pressure ramp in the lower section of the well. Without the ramp, the mud weights could stay around 13 ppg. Baroid is contracted to provide drilling fluids.

After drilling and testing the Intrepid prospect, the rig will be moved to drill the Bounty prospect, anticipated to be another 80 days plus 20 days to test.

They have "an attractive day rate" for the rig, Coolen said, because of Canadian Superior's flexibility with scheduling around the rig refurbishment. "We started conversations with Maersk in 2005, months before the market started escalating."

If they are successful, Canadian Superior expects to build a core area in Trinidad over the short and longer term. "Success in Trinidad & Tobago would have a direct and immediate affect on our offshore Nova Scotia business."

Nova Scotia

In the short term, Coolen said the company will drill another well on the Mariner block. The two main issues are the availability of a jack up rig and the details of a joint venture agreement. It's important to have a strong joint venture partner, he said.

Canadian Superior is the largest acreage holder off Nova Scotia, with 1.29 net million acres on six exploration licenses. The company has six prospects on the Sable Island Bank, along the Scotian Shelf:

• Marquis (two licenses), 111,000 acres licensed Jan. 1, 2001, drilled in 2002.

• Mayflower, 712,000 acres licensed Jan. 1, 2002.

• Mariner, 101,800 acres licensed Jan. 2, 2002, drilled 2003-04.

• Marauder and Marconi, 371,000 acres licensed Jan. 1, 2004.

There are many play types among the acreage, including deepwater turbidites at Mayflower, shallow water Abenaki reef plays at Marquis, and shallow water Cretaceous plays at Mariner, Marauder, and Marconi.

But the basin has been historically slow to develop. Coolen said that one of the reasons is the prevalence of gas and small reservoirs. The early explorationists—Shell and Mobil—were oil seekers. It took the discovery of Venture, Thebaud, North Triumph, and others, leading to the Sable development project, to get development rolling.

Now, technology is catching up, he says, and people are finding better ways to develop gas and condensate resources on the shelf. Small discoveries have more opportunity to be developed than ever before.

Deep Panuke is a good example of technology allowing companies develop plays efficiently (OGJ, Nov. 20, 2006, p. 47). Using a MOPU will be an advantage over a fixed platform, he said, and expects about 1 tcf in the deep gas reef play; the four wells tested are capable of delivering 400 Mcfd.

The Canada-Nova Scotia Offshore Petroleum Board (C-NSOPB) needs to reevaluate the taxation and royalty regime, Coolen says, and recognize the costs involved in building a multiplatform development on the shelf. Field sizes run 500 bcf-1 tcf and require a disproportionate amount of capex to produce small reserves.

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Career highlights

Michael E. Coolen is president, chief operating officer, and a director of Canadian Superior Energy Inc. Corporate offices are based in Calgary and the company is engaged in the exploration and production of oil and natural gas in Western Canada, off Trinidad and Tobago, and off Nova Scotia.

Since joining Canadian Superior in July 2001, Coolen had been responsible for the company's operations off Nova Scotia and off Trinidad, before being appointed to his current positions in April 2006.

Employment

Coolen began his career by joining what is now Martec Ltd. in Halifax, NS, as a junior ocean engineer; he rose to become the manager of ocean engineering. He joined Mobil Oil Canada and spent 20 years on numerous oil and natural gas processing and gas gathering projects, both onshore and offshore. He has held a variety of senior technical and senior management positions involving many aspects of onshore and offshore exploration and production.

Directly prior to joining Canadian Superior, Coolen served as the safety, health, and environmental manager for ExxonMobil Canada, seconded to the Sable offshore energy project off Nova Scotia, as Sable's manager of health, safety, and environment.

Education, affiliations

Coolen holds a BS from Dalhousie University, Nova Scotia, and a bachelors degree in mechanical engineering with distinction from Nova Scotia Technical College. He's also had a variety of postgraduate training, including courses at Dalhousie University, Texas A&M University, and Oklahoma State University.

Coolen is a professional engineer and a member of the Association of Professional Engineers of Nova Scotia, and the Association of Professional Engineers, Geologists, and Geophysicists of Alberta.

The government needs to look at the realities of the geology and recognize that Nova Scotia needs to offer a competitive edge to attract capital projects.

I-85 well

Canadian Superior and El Paso drilled the Mariner I-85 well from November 2003 to March 2004, using the Rowan Gorilla V jack up, about 290 km (180 miles) southeast of Halifax. They encountered gas pay in multiple zones, based on drill cuttings and fluid analyses, and also experienced high temperatures and bottom hole pressures. When the well was stopped, the costs had run to $45 million, partly due to delays from pack ice, and another $15 million was needed to test.

"It was an unusual case," Coolen said, "all the technical folks for both partners recommended testing." But El Paso's Calgary-based management decided not to proceed, perhaps due to a corporate strategy to leave the basin (OGJ, May 17, 2004, p. 43).

Canadian Superior could have assumed 100% of the expenses and risk to test the well, which included well-control and ice issues, insurance, and the need to post a $30 million letter of credit to the C-NSOPB.

The company decided to save the money for future drilling, Coolen said. They had already learned enough from the wellbore to pick the next drilling location.

In fact, later that year, in September 2004, Canadian Superior announced the purchase of El Paso Corp.'s exploration and production assets off Nova Scotia. The acquisition included El Paso's interests in the Marquis blocks (EL 2401 and 2402) and Marquis L-35/L-35A well data, the Mariner block (EL 2409) and Mariner I-85 well data, all of El Paso's seismic data, and all shared geophysical, geotechnical and environmental data.

Coolen said the acquisition gave Canadian Superior additional flexibility in exploration and development of these prospects, and the company is now focused on further drilling on Mariner.

SD licenses

On Oct. 5, Coolen participated in a panel discussion on the status of "significant discovery licenses" at the CORE.06 conference in Halifax. These licenses were issued for an indefinite length of time to a number of companies operating off Nova Scotia, predominantly ExxonMobil, Shell, Imperial Oil, and Pengrowth Corp, several of which have not drilled for more than 10 years.

"If you discover something and there's no cost to hold onto it, why would you give it back to the Crown?," he asked the audience.

Compared to licensing regimes around the world, Nova Scotia has the simplest—and most outdated—Coolen said. It puts new, smaller companies at a disadvantage.

Although it's clear that the Ministry won't do anything on a retroactive basis, he thinks there's an opportunity under existing legislation to make improvements for the future. There's lots of room to negotiate on the definition of "commerciality," for instance. And legislation can put the onus on the industry to prove up commerciality.

Coolen suggested that Nova Scotia analyze the Australian model, which includes "retention" licenses that are similar to SDLs in Atlantic Canada. Operators must demonstrate potential for commercial production within 15 years, and must reanalyze every 5 years, demonstrating that it is still not commercially viable.

However, Coolen recognized that Nova Scotia needs to offer a licensing regime that will make it attractive for operators to work in deep water, including longer-term exploration licenses and appropriate tax credits. Deep water holds the promise of larger discoveries off Nova Scotia, but the wells are likely to cost $150 million to drill.

Pure exploration licenses off Nova Scotia run 5 years, not enough time, he says, to acquire and process seismic, analyze, pick prospects, and schedule a rig in a basin so far from most of the available fleet. Environmental approval alone can take a year, he noted.

Although Coolen noted that "government has been very responsive to industry," he suggests that government

look at various additional incentives that have been offered to encourage deepwater drilling in the US Gulf of Mexico, where shallow-water licenses run 5-8 years, and deepwater licenses run 10 years.

Western Canada

Canadian Superior is growing its business in the Western Canadian Sedimentary Basin. Coolen said the company has a high success rate, drilling 60-70 wells/year, a mix of conventional and coalbed methane.

About 90% of production comes from the Drumheller area in south-central Alberta, where the company has 174,003 gross acres (112,902 net acres).

By the end of 2006, Canadian Superior will tie in more than 25 nonoperated Horseshoe Canyon CBM wells with a JV partner.

In northern Alberta and British Columbia, the company holds acreage and has seismic or drilling activity in the Windfall, Pine Creek, and Giroux Lake areas, as well as Boundary Lake, Cecil, Teepee, and East Ladyfern. The company is looking at future exploration in the Alberta foothills.

All of the company's revenue comes from western Canada production. Canadian Superior was producing about 3,330 boe/d at the end of third-quarter 2006.

Canada Southern

In June 2006, Canadian Superior began to acquire outstanding shares of Canada Southern Petroleum Ltd. with an offer of cash and stock. In August, Canadian Superior made an offer including cash, common shares of Canadian Superior and new Special Trust Units with an estimated total value of $14.97/share, in response to a parallel takeover attempt by Canadian Oil Sands Trust.

By early September, two subsidiaries of Canadian Oil Sands Trust, Canadian Oil Sands Ltd. and Alberta Ltd., had acquired 11.7 million common shares of Canada Southern, representing about 78% of outstanding shares with a totally cash offer at $13.10/share, ending Canadian Superior's takeover attempt.

New capital

As of June 30, Canadian Superior had a market capitalization of $272 million. On Nov. 13, Canadian Superior announced the completion of $15.4 million in financing through the issue of flow-through common shares. The new capital will be used to fund multiwell drilling in Trinidad and Tobago, among other projects. ✦

SARA ANALYSIS

Table 1

	Athabasca	Cold Lake	Lloydminster	Peace River
	wt %			
Saturates	16.3	19.4	23.1	20.8
Aromatics	39.8	38.1	41.7	41.1
Resins	26.4	26.7	20.4	22.1
Asphaltenes	17.5	15.8	14.8	16.0

EQUATIONS

$$P = \frac{RT}{v}\left(\frac{v + 2b}{v - b}\right) - \frac{a}{v(v + b)} \quad (1)$$

$$a = \frac{0.51301R^2T_c^2}{P_c}\{1 + c_1(1 - T_r^{0.5}) + c_2(1 - T_r^{0.5})^2 + c_3(1 - T_r^{0.5})^3\}^2 \quad (2)$$

$$b = \frac{0.058743RT_c}{P_c}\{1 + d_1(1 - T_r)\}^2 \quad (3)$$

$$c_1 = 0.4690 + 0.7096\omega - 0.2660\omega^2 \quad (4)$$

$$c_2 = -0.6548 - 1.2625\omega - 1.9727\omega^2 \quad (5)$$

$$c_3 = 0.9553 + 5.0064\omega + 0.4159\omega^2 \quad (6)$$

$$d = 0.1723 - 0.3858\omega - 0.1683\omega^2 \quad (7)$$

$$T_c(k) = 77.856M^{0.4708} \quad (8)$$

$$P_c(bar) = 189.14M^{-0.7975} \quad (9)$$

$$\omega = K(0.5837 \ln M - 2.5389) \quad (10)$$

$$\frac{1}{\rho} = \sum_{i=SARA} \frac{W_i}{\rho_i} \quad (11)$$

Cubic EOS calculates heavy oil SARA fractions

Golam Reza Pazuki
Malek Ashtar University of Technology
Tehran

Shiva Mansouri
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Tehran

A new cubic equation of state (EOS) predicts densities of Western Canadian heavy oils and their SARA (saturates, aromatics, resins, and asphaltenes) fractions. The method considers the SARA fraction of heavy oil as a pseudocomponent.

A comparison to experimental density data shows that the new EOS is more accurate than the Peng-Robinson (PR) EOS and Soave-Redlich-Kwong (SRK) EOS.

ADJUSTABLE PARAMETER K

Table 2

	K		
	New EOS	PR	SRK
Saturates	1.8055	0.7356	0.9123
Aromatics	1.7575	0.5872	0.8147
Resins	1.3391	0.6366	0.8066
Asphaltenes	0.6954	0.6684	0.8042

The new EOS is a simple and accurate correlation for modeling and simulating oil and gas processes.

SARA correlations

The industry has several correlations for estimating phase behavior of asphaltene and their SARA fractions in heavy oils.[1,2] Also, some have used cubic equations of state to predict molar volume of heavy oils and asphaltene.[3,4]

Cubic equations of state without volume translation cannot estimate molar volume of the SARA fractions.

The new method set forth in this article discusses the application of a new cubic equation of state for predicting the densities of western Canadian heavy oils and their SARA fractions.

The results are better than with the PR EOS[5] and SRK EOS.[6]

MEASURED, PREDICTED SARA FRACTIONS

Table 3

Fractions	MW, g/mol	Experimental density, kg/cu m	Calculated densities, kg/cu m at 22.5° C. and 0.101 MPa		
			New	PR	SRK
Athabasca					
Saturates	524	900	743	432	385
Aromatics	550	1,003	808	679	607
Resins	976	1,058	1,385	585	525
Asphaltenes	21,900	1,192	367	500	448
	%ADD		**34.25**	**46.76**	**52.37**
Cold Lake					
Saturates	508	882	781	441	394
Aromatics	522	995	791	689	615
Resins	930	1,019	1,165	592	531
Asphaltenes	19,200	1,190	893	498	447
	%ADD		**17.80**	**45.21**	**50.96**
Lloydminster					
Saturates	508	876	717	457	407
Aromatics	522	997	822	683	611
Resins	930	1,039	903	604	542
Asphaltenes	19,200	1,181	893	499	448
	%ADD		**18.30**	**44.73**	**50.53**
Peace River					
Saturates	508	881	742	452	403
Aromatics	522	1,004	824	681	609
Resins	930	1,051	1,052	564	506
Asphaltenes	19,200	1,182	1,415	499	448
	%ADD		**13.37**	**46.24**	**51.88**

New EOS

The new cubic equation of state is based on the authors' previous work (OGJ, Nov. 28, 2005, p. 46).

The new EOS is expressed as Equations 1-7, in which P is pressure, T is temperature, and v is molar volume.

The calculation of a and b parameters of the EOS requires critical properties and the acentric factor. These calculations use the correlation of Akbarzadeh for obtaining the critical properties and acentric factors of SARA fractions (Equations 8-10).[7]

In Equations 8-10, M is molar mass of the fractions and K is an empirically obtained adjustable parameter.

Calculations

Petroleum engineers need heavy oil density and SARA fractions for modeling the process of asphaltene precipitation. The first step, therefore, is to calculate the volumetric property of heavy oils with a cubic equations of state.

Table 1 shows the analysis of the SARA fraction for four western Canadian heavy oils. The acentric factors of SARA fractions require parameter K as a correction factor. The correction factor is an adjustable parameter.

Table 2 shows the values of K for each SARA fraction calculated with the new EOS, PR EOS, and SRK EOS. Reference 8 provided the correction factor values for the PR EOS and SRK EOS.

Table 3 presents the experimental and calculated densities of SARA fractions of the Western Canadian heavy oils and also compares the results with those from the PR EOS and SRK EOS.

The results show that the new EOS better calculates the densities of SARA fractions than the PR and SRK equations of state.

Calculating the densities of heavy oils from their SARA fractions requires a mixing rule (Equation 11, in which w_i is the mass fraction).

Table 4 shows the experimental and calculated densities of the Western Canadian heavy oil and bitumen.

The average absolute deviation (ADD) was 16.523 for the new EOS, 17.287 for the PR EOS and 32.985 for the SRK EOS. ✦

MEASURED, PREDICTED DENSITIES Table 4

Heavy oil	Experimental density, kg/cu m	Calculated densities, kg/cu m at 22.5° C. and 0.101 MPa — New	PR	SRK
Athabasca	1,026	838.0366	1,269.094	1,419.251
Cold Lake	1,001	823.9104	1,182.923	1,323.678
Lloydminster	988	830.7794	114.574	1,246.634
Peace River	1,003	860.8821	1,212.393	1,356.050
%ADD		16.523	17.287	32.985

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US MARGINAL OIL WELLS

Table 1

Year	Wells active	Oil produced Million bbl/year	Oil produced B/d/well	Wells P&A'd
1996	428,842	323.5	2.06	16,674
1997	420,674	323.5	2.11	15,172
1998	406,380	316.9	2.14	13,912
1999	410,680	315.5	2.10	11,227
2000	411,629	325.9	2.16	10,718
2001	403,459	316.1	2.15	12,234
2002	402,072	323.8	2.21	13,635
2003	393,463	313.7	2.18	14,300
2004	397,362	310.9	2.14	11,977
2005	401,072	321.8	2.20	11,058

US MARGINAL GAS WELLS

Table 2

Year	Wells active	Gas produced Bcf/year	Gas produced Mcfd/well	Wells P&A'd
1996	168,702	987	16.0	4,671
1997	189,756	1,042	15.0	4,661
1998	199,745	1,104	15.2	4,203
1999	207,766	1,139	15.3	3,546
2000	223,222	1,259	15.4	3,534
2001	234,507	1,354	15.8	3,600
2002	245,961	1,418	15.8	3,870
2003	260,563	1,478	15.5	3,883
2004	271,856	1,539	15.5	4,129
2005	288,898	1,760	16.8	4,517

Marginal wells account for much US production

Marginal wells remain an important segment of US oil and gas production operations.

In its latest report, the Interstate Oil and Gas Compact Commission (IOGCC) estimated that these wells in 2005 accounted for about 17% of oil and 9% of natural gas produced onshore US

The report "Marginal Wells: Fuel for Economic Growth," October 2006, said that these wells in 2005 produced more than 321 million bbl of crude and 1.76 tcf of natural gas, with average daily production reaching its highest in 10 years.

The report outlined also the economic benefits these wells create. It said in 2005, states collected more than $1.2 billion in taxes from marginal wells. In the US, every dollar of marginal oil and gas production created $1.01 of economic activity.

Marginal wells

IOGCC defines marginal oil wells as those producing 10 b/d or fewer. It reported that in 2005 the US had 401,072 marginal or stripper oil wells producing about 2.2 b/d on average (Table 1).

The organization defines marginal gas wells as those producing 60 Mcfd or fewer, and its report noted that during the last decade the number of marginal gas wells has steadily increased to 288,898 wells (Table 2).

Its report said that US onshore oil production in 2005 was about 5.1 million b/d with marginal wells producing about 881,000 bo/d. Marginal gas production was about 4.8 bcfd in 2005.

In its statistics on plugged and abandoned wells (Tables 1 and 2), IOGCC does not include temporarily abandoned wells but only wells permanently plugged. These in 2005 amounted to 11,058 oil wells and 4,515 gas wells. Not included in IOGCC P&A'd statistics are orphaned wells, which are wells producing 10 bo/d or fewer and have not been plugged, but whose owners are either insolvent or cannot be located.

The report noted that 11 states have about 73% of the marginal oil wells. These states, which exclude wells in the Appalachian basin, also have 44% of the marginal gas wells.

The Appalachian basin in 2005 accounted for about 50% of the marginal gas wells and almost 29% of the marginal gas production, the report found.

The statistics show that Texas has the most marginal wells, with 124,116 marginal oil and 37,396 marginal gas wells that during 2005 produced about 140 million bbl of oil and 302 bcf of gas.

IOGCC

The Interstate Oil and Gas Compact Commission is a multistate government agency whose stated goal is to promote the conservation and efficient recovery of US oil and natural gas resources while protecting health, safety, and the environment.

IOGCC members include governors from 37 states (30 members and 7 associate states) that produce most of the US oil and natural gas. The organization also has seven international affiliates.

It has monitored the status of marginal oil wells since the 1940s. ✦

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Egyptian gas plant employs absorbents for Hg removal

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Initial mercury measurements in 2000 for gas upstream of Khalda Petroleum Co.'s Salam gas plant in Egypt's Western Desert showed mercury content between 75 and 175 µg/std. cu m. Concern for the plant's downstream aluminum heat exchangers led the company to decide, therefore, to install mercury-removal equipment.

To avoid mercury condensation under pipeline conditions, mercury should be removed from sales gases to less than 20 µg/std. cu m.[1]

The company evaluated two alternatives—UOP's HgSIV adsorbents and Puraspec's 1156 absorbents—for removing mercury from natural gas.

This article will review the corrosion mechanism of mercury and aluminum, the analysis techniques for mercury in natural gas, and the mercury-removal techniques from natural gas and present the process design, field analysis procedures, and performance of Salam mercury-removal unit.

Mercury

Mercury occurs naturally in trace quantities in air and natural gas. Although difficult to generalize, mercury concentrations in air typically range between 0.001 and 10 µg/std. cu m.[2-5] Some authors report that natural gas typically contains mercury concentrations between 1-200 µg/std. cu m.[6 7] Table 1 shows that hydrocarbons from a few geographic locations contain mercury at concentrations exceeding 100 µg/std. cu m for gas and 100 µg/kg for gas condensate (C_3-C_6).[8]

Low levels of mercury are frequently found in low-sulfur-containing hydrocarbon gases and liquids such as those produced in the North Sea. In the Netherlands, the mercury content of natural gas varies from "nondemonstrable" to about 300 µg/std. cu m, where 250 µg/std. cu m is considered a high concentration.[9]

Implications of the effect of mercury in natural gas were not reported until 1973, when a catastrophic failure of aluminum heat exchangers occurred at Skikda LNG plant in Algeria (OGJ, Sept. 15, 1975, p. 192). It was found that a combination of mercury and water temperatures around 0.0° C. caused corrosion in the aluminum tubes (constructed of aluminum alloy 6061). This discovery prompted several research studies into this phenomenon.

After the Skikda failure, a study of the Groningen field in Holland revealed similar corrosion in the gas gathering system. CO_2 was initially thought to be the cause,[10] but later investigations pointed to mercury, with concentrations ranging from 0.001 to as high as 180 µg/std. cu m.[11] Although the concentration of mercury in a given natural gas may be considered extremely low, Audeh observed that its effect is "cumulative as it amalgamates."[12]

Elemental mercury forms an amalgam with the surface layer of the metal it contacts. With aluminum, the amalgam is much weaker than the metal itself.[11] The mercury-aluminum amalgam process removes the tightly adhering aluminum oxide layer, which then allows aluminum corrosion to occur.

It can be removed chemically or mechanically and is catalyzed by the presence of an aqueous electrolyte. The mercury-aluminum amalgamation generally does not occur as a direct chemical reaction because the base-metal aluminum is usually protected by the oxide film. It is formed in continuous chemical reactions.

The aqueous corrosion cell forms aluminum hydroxide and gaseous hydrogen through the following reactions:[2]

$$Al + Hg \rightarrow AlHg$$

$$2AlHg + 6H_2O \rightarrow 2\,Al(OH)_3 + 3H_e + 2Hg$$

These reactions leave the previously

HG IN NATURAL GAS, CONDENSATE*

Table 1

Location	Gas, µg/std. cu m	Liquids, µg/kg
Europe	100-150	—
South America	50-120	50-100
Gulf of Thailand	100-400	400-1,200
Africa	80-100	500-1,000
Gulf of Mexico, US	0.02 to 0.40	—
Overthrust belt, US	5-15	1-5
North Africa	50-80	20-50

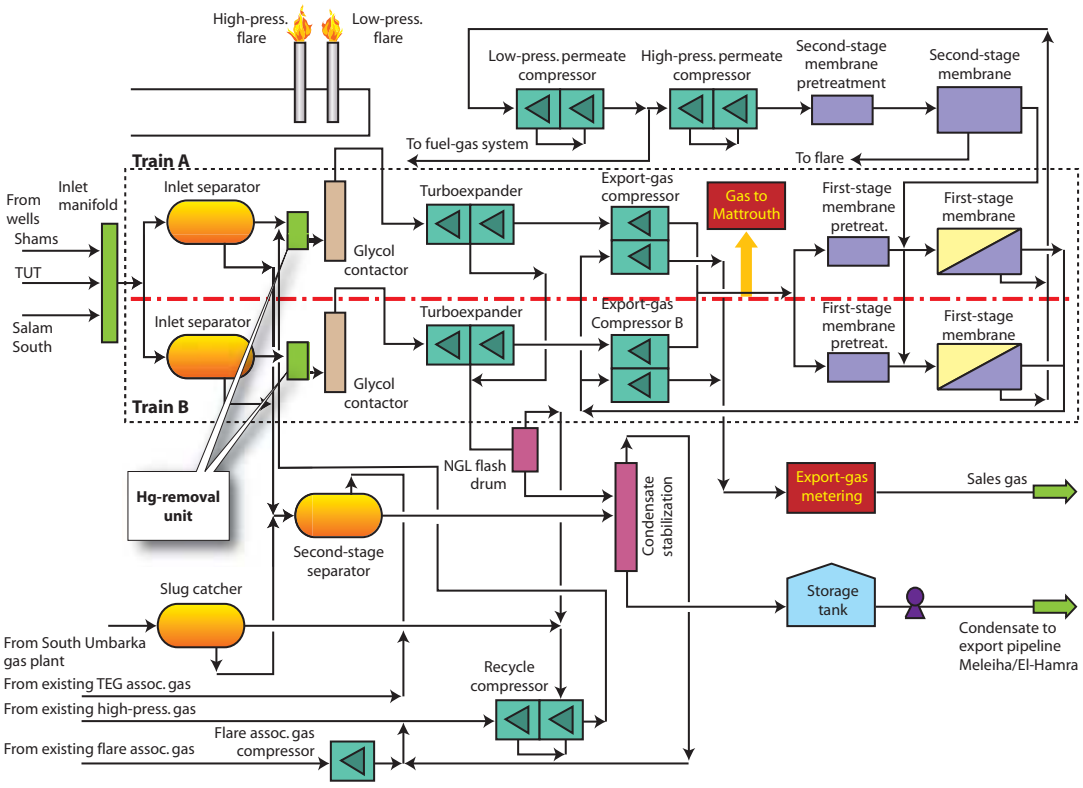
*Data report maximum wellhead concentrations at selected locations and do not represent the range for the geographic area listed.

amalgamated mercury free to form additional amalgam with the base metal in a continuous corrosion process.

In experiments on various Al-Hg systems, Phannensteil reported having ions present in the condensed water was necessary for corrosion to occur and that it was unnecessary for the protective aluminum oxide film to be removed to initiate the reaction.[11] This contradicts all other studies on this subject.

SALAM GAS PLANT

Fig. 1



Analysis, removal techniques

Keeping the sales gas and emission streams to appropriate specifications requires reliable methods of analyzing the mercury content of gas streams. Toxicology and environmental studies have been involved in development of several methods for detecting mercury in natural gas.

Table 2 summarizes the laboratory methods and depicts measurements of a finite limit of mercury mass.[2,7] Table 3 summarizes several techniques for removing mercury from the gas stream. Most of these methods have limitations that detract from their applicability to natural gas processing.

The basic requirement for successful, economical mercury removal is that the removal medium be capable of reducing mercury concentrations to extremely low levels. The medium must have a high capacity for an active bonding to mercury and must retain the mercury in a form that can be disposed of.

It must be effective at the operating pressures and temperatures of the natural gas stream, have reasonable investment and operating costs, and be readily available.

Salam gas plant

Khalda Western Desert gas development project at Salam is 70 km from Matrouh. The plant processes gas condensate from Salam field, Qasr field, South Umbarka, and an oil plant's associated gas. The project produces about 200 MMscfd of export gas at an export pressure of 101 bara and 9,000 stk. tank bbl of condensate.

The sales gas is designed to have a maximum CO_2 content of 3%, a maximum H_2S content of 4 ppm (vol), a gross heating value greater than 1,040 btu/std. cu ft, a water dewpoint of less than 0.0° C. at 71 bara, and a cricondentherm of 5° C. The condensate is designed to have a maximum of 11-psi rvp.

Fig. 1, a diagram of the Salam gas plant, shows gas from the wells flows into two parallel trains.

First it enters a three-phase separator where the main water-condensate-gas separation takes place. Gas from the three-phase separator goes to the mercury-removal unit. Then it flows to the glycol contactors to

MICROANALYTICAL TECHNIQUES FOR MERCURY DETECTION

Table 2

Technique	Absolute detection limit, µg
Calorimetric	2
Spark-source mass spectrometry	0.0001
X-ray fluorescence	0.01
Polarography	20
Differential pulse voltammetry	0.00004
Cold-vapor atomic-absorption spectrophotometry	0.0005
Zeeman spectroscopy with Cold-vapor atomic-absorption spectrophotometry	0.00007
Piezoelectric mercury sensor	0.005
Gold-film mercury detector	0.0005
Neutron-activation analysis	0.02

remove water from the gas to avoid hydrate formation and to achieve water-content specifications.

Gas is then diverted to the dewpointing package, whose function is to separate entrained traces of condensate and heavier hydrocarbons that condense as liquids from the gas at lower temperatures. This step is to achieve hydrocarbon dewpoint specifications with the turbo-expanders.

After dewpointing, the gas enters the gas-sweetening system (two-stage membrane package) to reduce CO_2 in the export gas. The final step is to export the gas via the export compressors.

Condensate collected from the various processing steps moves to stabilization before being stored in the three storage tanks. The stabilizer tower removes the light hydrocarbons to avoid release in the tanks and to achieve the rvp specification. Condensate is then shipped from the storage tanks via shipping pumps to El-Hamra.

The mercury-removal unit at the Salam gas plant is loaded with 19 tons of a catalyst that consists of a high porosity, spherical mixed-sulfide absorbent of different diameters (Fig. 2)

Removal options

Initial mercury measurements for gas upstream of the Salam gas plant 5 years ago showed that the mercury content varied between 75 and 175 µg/std. cu m. This high content of mercury and its compounds had to be removed from the gas to protect downstream aluminum heat exchangers. To avoid mercury condensation under pipeline conditions, mercury should be removed from sales gases to less than 20 µg/std. cu m.[1]

Operations at Khalda Petroleum evaluated two alternatives (UOP HgSIV adsorbents and Puraspec 1156 absorbents) for removing mercury from natural gas. Following are the characteristics of both catalysts.

HgSIV adsorbents were developed for effective mercury-removal adsorption units.

These adsorbents are molecular-sieve products that contain silver on the surface of the pellet or bead. Mercury from the process fluid (gas or liquid) amalgamates with the silver and yields a mercury-free dry process fluid. Mercury is regenerated from the HgSIV adsorbents with conventional gas dryer techniques.

Physically, HgSIV adsorbents are available as beads or pellets and are loaded into an adsorption vessel just as are conventional molecular sieves.

UOP has installed HgSIV adsorbents units in several gas processing plants in the Far East, Middle East, Africa, South America, and the US. The feed-gas mercury content for these adsorbents units ranges from 25 to 50 µg/std. cu m. The mercury level in the treated natural gas is about 0.01 µg/std. cu m.

Puraspec 1156 absorbents (pre-activated; sulfided) are by their nature active material. They consist of a high porosity, spherical mixed-sulfide absorbent of different diameters. The absorbents are loaded into a mercury-removal vessel where the mercury is irreversibly bound to them and cannot, therefore, affect downstream process equipment.

These absorbents remove small quantities of contaminants from a wide variety of liquid and gas streams, with high efficiency and effectiveness. The process is easy to operate and only requires periodic analyses to check performance. The absorbent unit is designed to remove mercury from an average inlet concentration of about 200 µg/std. cu m to about 0.1 µg/std. cu m.

The mercury-removal reaction by these absorbents appears below. Mercury vapor reacts with the metal sulfide to form a stable mercuric sulfide:

$$Hg + M_xS_y \rightarrow M_xS_{y-1} + HgS$$

The reactive metal (mercury) is incorporated in an inorganic support and the absorbent is supplied with the reactive sulfide present or formed in situ by reaction with H_2S in the hydrocarbon to be treated.

The absorbents have other advantages:

1. They can be used for wet and dry gases.
2. They retain organo-mercury compounds.
3. There is no risk of loss of sulfur by sublimation or dissolution. All sulfur

species are securely bound as inorganic sulfides.

4. The economic evaluation indicates that Puraspec 1156 is a cost-effective catalyst with a bed life of 5 years.

Technical evaluation

Operations at Khalda Petroleum evaluated UOP's HgSIV adsorbents and Puraspec's 1156 absorbents for removing mercury from the feed gas upstream of the Salam plant. Table 4 presents a summary of this evaluation.

Table 4 makes clear that UOP HgSIV adsorbents can be used to treat gas with mercury contents of 50 µg/std. cu m, which is much lower than the mercury contents of the feed gas to the Salam plant (175 µg/std. cu m).

Puraspec 1156 absorbent, however, is designed to remove mercury from gas with an average inlet concentration of about 200 µg/std. cu m, which is higher than the mercury content of gas to the Salam plant. That means Puraspec 1156 absorbent can be used to treat the feed gas, while UOP HgSIV adsorbent is not suitable for treating the gas.

Table 4 shows also that both catalysts are technologies proven in many applications: Both catalysts can be used to treat gas to levels below the acceptable limit for pipeline specifications. The economic evaluation for both technologies indicated, however, that Puraspec 1156 is a cost-effective catalyst for bed life of 5 years.

Based on the previously mentioned technical and economical evaluation, Khalda Petroleum decided to use Puraspec's absorbent for removing mercury from the feed gas upstream Salam gas plant.

Mercury removal

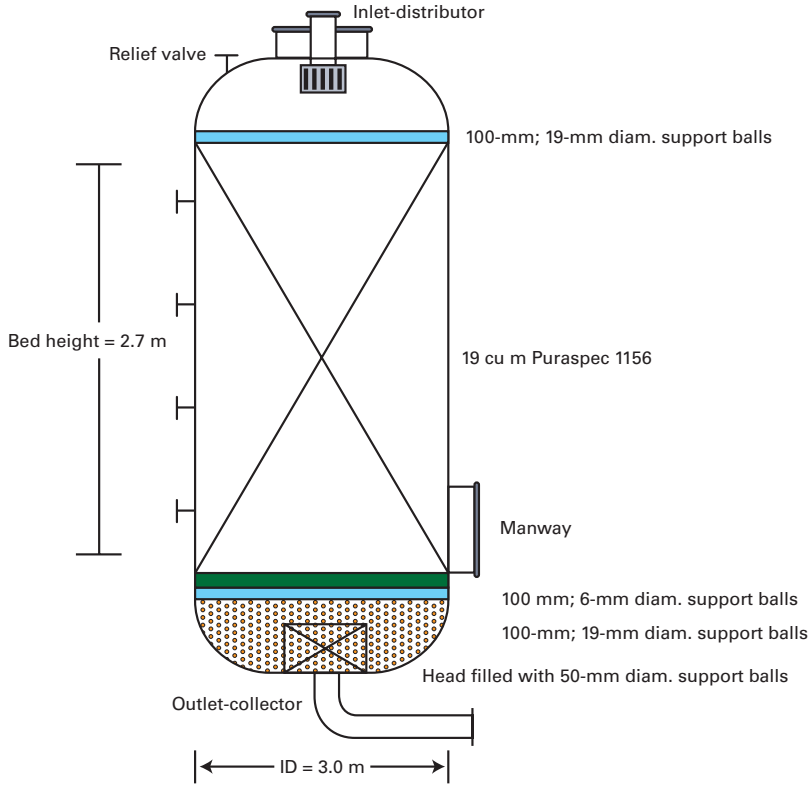
Fig. 2 shows the mercury-removal unit at the Salam gas processing plant. The mercury-removal unit is loaded with 19 tons of the catalyst Puraspec absorbent. The catalyst consists of a high porosity, spherical mixed-sulfide absorbent of different diameters as shown in Fig. 3.

Before the gas is diverted to the mercury-removal unit, it goes to filter-coalescers to remove the liquid carryover and particulates. Then the gas stream flows through the mercury-removal unit.

The mercury is irreversibly bound to the catalyst and therefore cannot affect downstream process equipment. Downstream of the mercury-removal units are cartridge filters. These protect the glycol units from any particulate carryover from the mercury-removal unit. All these units are skid mounted one skid per train.

VESSEL LOADING OF SALAM HG-REMOVAL UNIT

Fig. 3



HG-REMOVAL SYSTEMS FOR NATURAL GAS

Table 3

Method	Comments
Chemisorption: Sulfur impregnated activated carbon	Most used, cheap; disposal problems
Chemisorption: activated carbon	Low saturation loading
Chemisorption: iodine impregnated activated carbon	Good for high Hg concentrations
AmalgaDlation: silver impregnated alumina, silver zeolites, metal sulfides and oxides	High investment costs, high removal capacity
Acid adsorption in chromic acid and acidic permanganate	Increased corrosivity, through system contamination, low saturations
Oxidizing solutions—permanganates, hypochlorites, vanadates	Regeneration problems, system contamination
Chemical reaction with H_2S	Increased corrosivity, limited H_2S access
Condensation and separation	Poor removal efficiency, liquid contamination
Stripping through liquid hydrocarbons	Poor removal efficiency, liquid contamination

Field analysis

The mercury content of the feed and the exit streams from the Salam mercury-removal unit were monitored regularly to ensure the reactor was performing satisfactorily. Mercury analyses were performed at the site with the atomic fluorescence method. The analytical equipment consists of an atomic fluorescence detector for mercury measurements and an instrument for vaporizing any hydrocarbon liquid samples.

The principle of the mercury-moni-

ALTERNATIVES FOR REMOVING HG FROM NATURAL GAS

Table 4

Option	A	B
Technology General description	UOP HgSIV adsorbents Available in beaded or pelletized form	Puraspec 1156 absorbents High porosity, spherical mixed-sulfide absorbent
Hg level in feed gas	25 to 50 µg/std. cu m Much lower than Hg content of feed gas upstream Salam gas plant (175 µg/std. cu m)	200µg/std. cu m Higher than Hg content of feed gas upstream Salam gas plant (175 µg/std. cu m).
Hg level in treated gas	0.01 µg/std. cu m	0.1 µg/std. cu m
Technical advantages	Remove both water and mercury to very low limit	Remove mercury to acceptable limit for pipeline specifications
Economical advantages		Cost effective for bed life of 5 years
Commercially proven	Yes	Yes
Previous applications	Far East, Middle East, Africa, South America, US	UK, North Sea, Germany, Norway, Malaysia, Libya, Thailand, Japan, Australia, and Nigeria

toring system is the collection of mercury in a trap at process temperatures. Dual amalgamation, thermal desorption at 800° C., and analysis by atomic fluorescence spectroscopy determine the level of mercury present in a hydrocarbon feed. Samples may be either gaseous or volatile liquids.

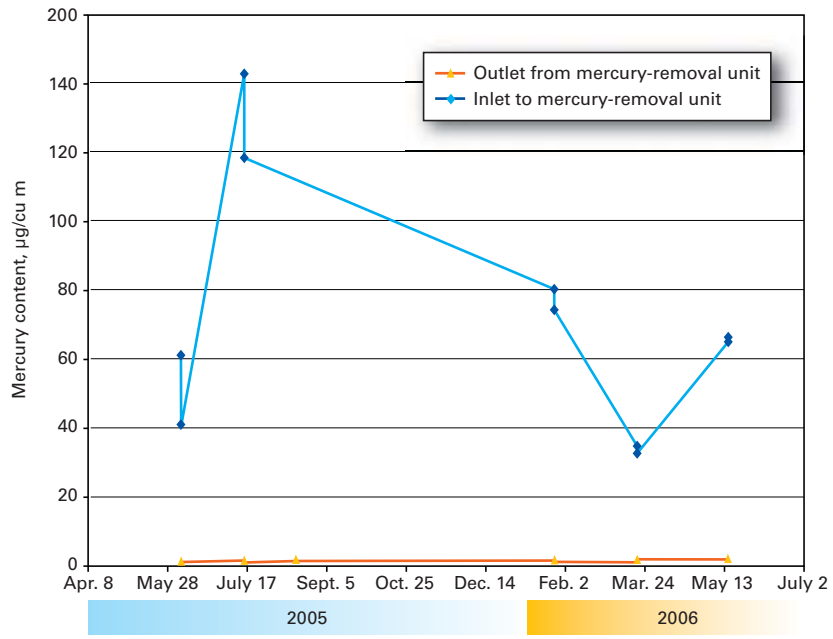
The principle of operation for gas samples is to pass a known volume of sample gas (measured by a rotary gas meter) through a trapping medium that concentrates the mercury species. The tube is then placed in the mercury analyzer, where it is heated to 800° C. in a flow of argon.

Under these conditions, the mercury on the trap is desorbed from the adsorbent as elemental mercury vapor and swept to a secondary fixed adsorber in the analyzer.

Subsequent heating of this tube to 800° C. in a flow of argon again desorbs the mercury, this time to an atomic fluorescence detector within the instrument. The response from the detector is proportional to the total mercury present in the sample in pico-grams (10^{-12} gm). The result is then reported as weight of mercury per unit volume of gas.

MERCURY AT INLET, OUTLET OF SALAM UNIT

Fig. 4



Unit performance

The mercury contents of the gas at the inlet and outlet of Salam mercury-removal unit (Trains 1 and 2) have been monitored since June 2005. Fig. 4 and Table 5 show some measurements carried out and analyzed. The mercury content of the gas at the inlet of the Salam mercury-removal unit has been fluctuating, with inconsistent values ranging between 17 and 71 µg/std. cu m. The mercury content of the gas at the outlet of the unit ranged between 0.53 and 0.92 µg/std. cu m during the sampling dates.

It is clear from these results that the mercury content of the gas at the outlet of the unit was small and almost constant (ranging between 0.53 and 0.92 µg/std. cu m), regardless of the mercury content of the gas at the inlet of the mercury-removal unit.

Results for Qasr gas

Qasr gas is produced from six wells in the Western Egyptian desert and contains some mercury. Qasr production is collected at a common manifold (Shams manifold) then diverted into three different processing plants: Salam, Obaiyed, and Tarek.

The mercury content for Qasr gas has been monitored regularly at three locations: Qasr wells, Obayed plant, and Shams manifold. Fig. 5 presents the mercury-content analysis at these sampling locations from June 2005 to May 2006. This figure shows that the mercury content of gas at Qasr wells was very high early in production, while recently it has been lower.

Fig. 5 also makes clear that mercury contents of the gas at the Obayed gas

plant and Shams manifold are lower than at Qasr wells. That may be related to the ability of the mercury to precipitate on the internal surface of the pipeline.

Bingham states that as mercury enters gathering system pipelines with gas, it is reduced because of chemisorptions onto steel pipe walls.[2] Leeper suggests the following reactions as driving this reduction:[10]

$H_2S + Fe_2O_3 \rightarrow 2FeO + S + H_2O$

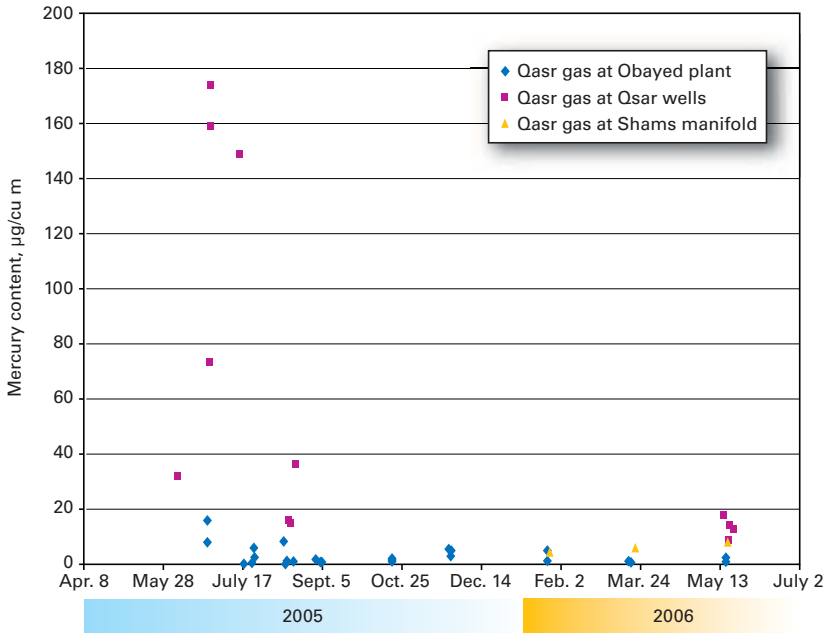
and

$Hg + S \leftrightarrow HgS$

Trace quantities of H_2S are the catalyst for the reaction of mercury with iron oxide from the pipe. The mercury-sulfide precipitates and is adsorbed onto the pipe wall. Grotewold reports that for 110-km pipeline, mercury content decreased to 20 µg/std. cu m from about 50 µg/std. cu m.[13] This reduction is influenced by pipe wall roughness and adhesive forces.

QASR GAS MERCURY CONTENT

Fig. 5



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ANALYSIS RESULTS OF SALAM HG-REMOVAL UNIT

Table 5

Date	Train	— Average, µg/std. cu m — Inlet	Outlet
June 6, 2005	One	30.3	0.55
		20.3	
	Two	—	0.43
	Export /sales	—	0.58
July 16, 2005	One	71.0	0.76
	Two	59.0	0.53
Aug.17, 2005	One	—	0.69
Jan. 27, 2006	One	39.9	0.74
	Two	37.1	0.57
Mar. 20, 2006	One	17.11	0.54
	Two	16.25	0.92
May 16, 2006	One	32.58	0.91
	Two	33.11	0.78

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Mostafa Nabawi is a general manager in the gas operation department at Khalda Petroleum. He previously worked as assistant general manager in the gas operation department at Khalda Petroleum. Nabawi holds a BSc in mechanical engineering from Assuit University, Egypt. He is a member in the Egyptian Engineers Syndicate and SPE.

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Programmed route markers increase efficiency, safety

Corey Willson
3M Track & Trace Solutions
Austin

New buried identification marker technology offers potential improvements in oil and gas pipeline-maintenance efficiency and reduction of the likelihood of accidental damage and associated safety hazards.

Electronic marking, locating, and identifying of systems used by telephone companies, power companies, water and sewer utilities, and cable companies can also protect underground gas and oil pipelines in urban and rural settings by marking road crossings and important buried features such as valves, stubs, and turn points.

The US natural gas infrastructure includes about 1.4 million miles of underground pipeline. US Office of Pipeline Safety records show that during the first 6 months of 2006 there were 16 incidents of third-party excavation damage to natural gas distribution pipelines at a cost of $1.22 million, one related death, and two serious injuries.

Four incidents of third-party excavation damage to transmission pipelines during this same 6-month period totaled $173,000 in damages. During all of 2005, there were 19 such natural gas transmission line damage accidents (costing $2.48 million) and 67 distribution line incidents (with $8.5 million in damages).[1]

Unintended contact during excavation or trenching commonly causes gas-pipeline accidents, which occur when construction companies and grading crews perform work without proper one-call notification or fail to follow common-sense digging practices.

Locating, marking

Traditional utility-locating equipment injects an RF signal into a conductive object in the ground, such as a pipe or cable, to indicate the presence and path of a buried utility. This technology only approximates utility depth and location and works only with metallic objects. Passive markers buried adjacent to utility components respond to signals from a locator device and can be pinpointed precisely as to location and subsurface depth.

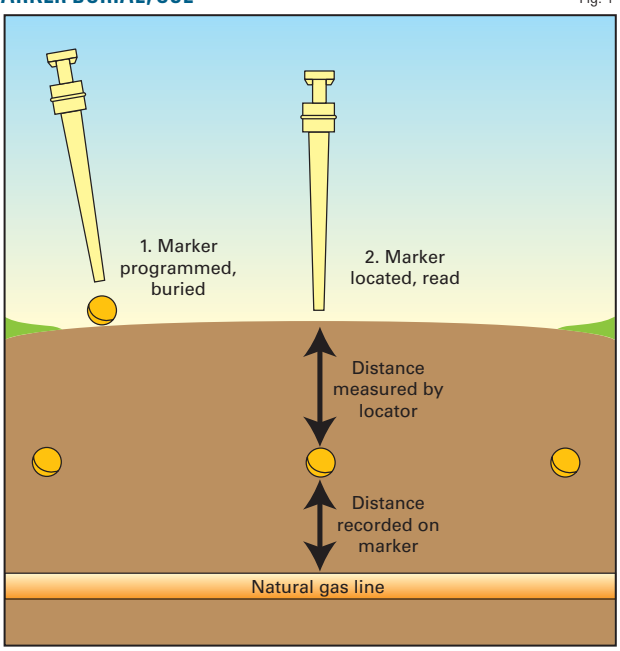
Electronic underground markers require no external power source, and are not disturbed by surface grading or construction. Their usefulness, however, is limited as they indicate simply that some utility is buried at the marked point. The effective message of an electronic marker is: "dig here to learn more."

A new buried identification marker system incorporates preprogrammed marker identification, making it possible to locate and identify quickly the depth and exact properties of the marked object without excavation.

The electronic system uses 4-in. diameter plastic balls that are located and read with hand-held locators by means of utility-specific radio-frequency signals. Individual colors and interrogation frequencies distinguish between gas, waste water, potable water, CATV, telephone, electrical power, and general

MARKER BURIAL, USE

Fig. 1



BP excavated each rural road crossing in its New Mexico region to expose buried pipeline (Fig. 2).

purpose underground marking applications. The ID markers require no external or internal source of power and are energized solely by electromagnetic energy received from the interrogating marker locator.

ID markers use application-specific integrated circuit (ASIC) chips to store static information, and each marker has a unique factory-assigned serial number for association with a specific location and for printing on as-built buried-facility drawings. The markers also have a memory capacity for storing custom labels and descriptions. The user can write these data to the chip anytime before placement in the ground.

Ball markers are programmed, located, and read by means of a multi-function locator. This unit uses an RS232 communications port to interface with an external computer to download and upload marker information for record management and mapping.

Unlike roadside signs or surface markers, buried ID markers are not subject to random damage. They resist moisture and varying temperatures, require no electrical power, and are designed to last for the life of the buried facility. The internal antenna component is self-leveling and automatically orients in a horizontal position for maximum signal strength when the ball marker is placed in the ground.

As ID markers are placed, removing an adhesive label with a unique serial

Once the pipeline was exposed, workers measured the depth from grade to pipeline (Fig. 3)

number and associated bar code from the ball and placing it on a field map provides an initial record of the marked location. The same details are temporarily stored in the marker locator device for downloading to a computer. Stored data update the utility mapping and infrastructure database.

An accessory device for the marker locator measures and records global positioning satellite (GPS) coordinates for each marked location. This GPS information is also stored in the unit during each shift for downloading in support of GIS mapping.

Application example

BP Gas has adopted ID markers for protection of rural road pipeline crossings as part of its San Juan operations center in northwest New Mexico. This center oversees 5,500 sq miles in three counties, which include several thousand natural gas wells and nearly 500 rural road pipeline crossings. Because a substantial portion of BP gas lines in this operating region is made of fiberglass, they cannot be located with traditional equipment.

Crews typically grade the gravel or dirt roads in the area at least twice a year. Because grade levels may change depending on soil conditions, rain, winter runoff, and grading activity, road crews need accurate and dependable information on the depth of every pipeline before they can safely grade a road. BP's ground-disturbance policy mandates that no mechanical equipment be permitted within 24 in. of buried facilities to safeguard against injury, shield the underground infrastructure from damage, and protect the environment.

After a preliminary field test of ID markers, BP instituted a program of marking every road crossing in the region, generally using three programmed ball markers per crossing: one over the pipe on each side of the road and one in the center of the road.

The marking program performed vacuum excavation of pipelines at each road crossing, followed by backfilling to a measured depth (typically 3-4 ft below the surface). The on site team would then program an identification marker ball with the measured distance from the pipe to the electronic marker and place it in the partially backfilled hole.

The locator accurately measures the distance from the surface to the marker

Backfilling the exposed pipes to a measured level allows placement of the ball marker at a known distance from the pipe (Fig. 4).

Marker read-write units load the ball location relative to the pipe, ID number, GPS coordinates, and any other identifying information onto the ball before burial. The same units will later use this information to confirm the precise location and depth of each marked crossing (Fig. 5).

(which varies with grading) and reads the fixed marker-to-pipe distance recorded on the marker, making calculation of the total surface-to-pipe distance for each marker easy (Figs. 1-5).

Details programmed on each marker include company name, measured depth from marker to pipeline, and pipe size and type.

County road-grading contractors in this New Mexico region can now access maps that show the location and depth of each buried gas line crossing, each of which is also registered with the New Mexico one-call system. BP will periodically monitor gas line depths in the region, using marker locaters to find and read the buried marker balls and updating published records appropriately.

High-risk areas where erosion is likely to lead to grade shifts or where soil conditions could cause line movement are monitored most closely.

BP is now installing ID markers at rural locations in Colorado. This technology may eventually be used in other BP operating areas having numerous rural road crossings, including Wyoming, Kansas, Oklahoma, Texas, and Louisiana. The company anticipates that ID marking will result in measurable cost savings because it eliminates the need to periodically pothole each road crossing to maintain ongoing accuracy of pipe depth records. ✦

Reference

1. http://ops.dot.gov/stats/LQ_SUM.HTM.

The author

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Equipment/Software/Literature

New gas sensor has 6 month calibration cycle

This new 5100-02-IT catalytic bead combustible gas sensor comes with a 6 month calibration cycle.

The firm says users can have long term calibration of an infrared sensor and cost effectiveness and the broad detection range of the proven catalytic bead sensor. This long term calibration cycle has been performance tested and approved by Factory Mutual, the firm notes.

The sensor provides interface via 4-20 ma, Modbus RS-485, or this firm's proprietary Sentry bus. The unit is a stand alone module equipped with the features required to provide the due diligence expected in hazardous areas including:

- FM approved for performance and area safety requirements including Group B.
- Fast response time and high accuracy.
- Integral scrolling LED with magnet operated menu and easy, nonintrusive calibration.
- Isolated 4-20 ma, Modbus RTU.
- Integral alarm relays.

Source: **Sierra Monitor Corp.**, 1991 Tarob Court, Milpitas, CA 95035.

New visual computing system aids exploration

The Quadro Plex 1000 dedicated visual computing system (VCS), available in three models, is designed to interface with standard work stations and servers to deliver advanced scalability for oil and gas exploration.

Available in a desktop or 3U rack mount configuration, utilizing SLI multi-GPU technology, the VCS provides:

- Density improvement of as much as 20x more than traditional GPU solutions, the firm says.
- Performance of as much as 80 billion pixels/sec and 7 billion vertices/sec.
- Resolutions as high as 148 megapixels on 16 synchronized digital-output channels and eight HD SDI channels.
- Advanced scalability that offers multiple configurations—from single system to clustered solutions.

The unit is compatible with an officially certified set of x86 32 and 64-bit Intel and AMD processors running Windows and Linux operating systems.

Source: **NVIDIA Corp.**, 2701 San Tomas Expressway, Santa Clara, CA 95050.

Services/Suppliers

EN Engineering

Woodbridge, Ill., has announced several promotions and a new appointment. David Schramm has been promoted to vice-president and senior project manager. Schramm is a graduate of Iowa State University with a BS degree related to renewable resources management. He has 26 years of experience in pipeline integrity and assessment, corrosion control methods, and cathodic protection design and operation.

Frank Andrejasich, previously director of business development, has been promoted to vice-president and business unit leader of technology. He has 25 years of natural gas industry experience. Andrejasich earned a BS degree in mechanical engineering from Bradley University, and an MBA from the Keller Graduate School of Management.

David Klimas has been promoted to director of business development and senior project manager. Klimas received a BS degree in mechanical engineering from the Illinois Institute of Chicago, and an MBA from the University of Chicago. He has over 13 years of experience in the energy industry.

John Mallinckrodt has joined EN Engineering as a senior project manager. He has been in the natural gas industry for over 35 years. Mallinckrodt holds a BS degree in agricultural engineering from the University of Missouri, and an MBA from the University of Chicago.

EN Engineering is a 50-50 joint venture between A. Epstein & Sons International Inc. and Nicor Inc. Its principal business is professional engineering design and consulting for the oil and gas industry.

C.K. Cooper & Co.

Irvine, Calif., has appointed Mary Safrai as associate director of its oil & gas group, where she assumes responsibility for four companies within Cooper's peer group and will help grow the company's research franchise in small and emerging growth E&P companies.

Safrai previously was with Carl H. Pforzheimer & Co. as a security analyst covering E&P and oil service companies. She holds an MBA in finance and economics from New York University, an MA from Boston College, and a BA from Syracuse University. She is a chartered financial analyst.

C.K. Cooper & Co. is a full service investment bank and brokerage firm, specializing in small cap and emerging growth oil and gas E&P companies.

Petris Technology Inc. and Production Access Inc.

Houston, have announced a joint cooperation for the integration of Production Access' Operations Center system and Petris' PetrisWinds DrillNet. The combined capabilities will couple Petris' strengths in engineering and wellbore analysis and data management with Production Access' understanding of financial and operational data management. The combined products will increase data access and reuse while improving overall quality and operational safety.

Petris Technology Inc. offers leading edge, energy centric software solutions combined with focused consulting and technology services.

Production Access Inc. is a leading provider of integrated data management solutions for oil and gas production operations.

Statistics

API IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4		District 5		Total US		
	12-1 2006	[1]11-24 2006	12-1 2006	[1]11-24 2006	12-1 2006	[1]11-24 2006	12-2 2005
	1,000 b/d						
Total motor gasoline	354	332	6	11	380	343	427
Mo. gas. blending comp.	427	492	6	41	433	533	547
Distillate[2]	264	322	23	12	287	334	446
Residual	226	127	58	17	284	144	647
Jet fuel-kerosine	66	53	173	81	239	134	108
LPG	370	314	—	—	370	314	304
Unfinished oils	529	547	21	76	550	623	399
Other	396	462	13	11	409	473	396
Total products	**2,632**	**2,649**	**300**	**249**	**2,932**	**2,898**	**3,274**
Canadian crude	1,738	1,942	154	286	1,892	2,228	1,593
Other foreign	7,921	5,679	787	732	8,708	6,411	8,681
Total crude	**9,659**	**7,821**	**941**	**1,018**	**10,600**	**8,639**	**10,214**
Total imports	**12,291**	**10,270**	**1,241**	**1,267**	**13,532**	**11,537**	**13,448**

[1]Revised. [2]Includes No. 4 fuel oil.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

Additional analysis of market trends is available through **OGJ Online**, *Oil & Gas Journal's* electronic information source, at http://www.ogjonline.com.

OIL&GAS JOURNAL online research center

OGJ CRACK SPREAD

	*12-1-06	*12-2-05	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	71.70	65.87	5.83	8.9
Brent crude	62.15	53.62	8.53	15.9
Crack spread	9.55	12.25	–2.70	–22.1
FUTURES MARKET PRICES				
One month				
Product value	71.94	65.49	6.45	9.9
Light sweet crude	62.07	57.79	4.28	7.4
Crack spread	9.88	7.69	2.18	28.3
Six month				
Product value	79.39	71.13	8.26	11.6
Light sweet crude	66.86	59.84	7.01	11.7
Crack spread	12.53	11.29	1.25	11.0

*Average for week ending
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

API CRUDE AND PRODUCT STOCKS

	Crude oil	Motor gasoline		Jet fuel	Fuel oils		Unfinished oils
		Total	Blending comp.[1]	Kerosine	Distillate	Residual	
	1,000 bbl						
PAD I	14,009	52,422	24,399	10,574	66,687	18,218	7,812
PAD II	72,561	51,854	16,318	7,211	25,718	1,9477	13,206
PAD III	179,457	63,482	26,942	11,991	33,390	18,840	43,754
PAD IV	13,973	5,983	2,063	534	2,791	403	3,682
PAD V	[1]54,102	27,465	20,810	7,590	10,723	5,607	19,836
Dec. 1, 2006	**[1]334,102**	**201,206**	**90,532**	**37,900**	**139,309**	**45,015**	**88,290**
Nov. 24, 2006[3]	**338,237**	**200,532**	**89,815**	**37,462**	**140,762**	**44,688**	**88,994**
Dec. 2, 2005	**323,976**	**206,027**	**68,067**	**41,597**	**136,243**	**39,796**	**91,065**

[1]Included in total motor gasoline. [2]Includes 6.860 million bbl of Alaskan crude in transit by water. [3]Revised.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

API REFINERY REPORT—Dec. 1, 2006

	REFINERY OPERATIONS					REFINERY OUTPUT			
District	Total refinery input	Crude runs	Input to crude stills	Operable capacity	Percent operated	Total motor gasoline	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual
	1,000 b/d					1,000 b/d			
East Coast	3,344	1,487	1,490	1,618	92.1	1,749	108	549	112
App. Dist. 1	100	95	95	95	100.0	5	—	28	1
Dist. 1 total	**3,444**	**1,582**	**1,585**	**1,713**	**92.5**	**1,754**	**108**	**577**	**113**
Ind., Ill., Ky.	2,166	2,099	2,133	2,355	90.6	1,193	121	611	57
Minn., Wis., Dak.	460	409	420	442	95.0	290	33	113	12
Okla., Kan., Mo.	902	760	772	786	98.2	451	27	276	7
Dist. 2 total	**3,528**	**3,268**	**3,325**	**3,583**	**92.8**	**1,934**	**181**	**1,000**	**76**
Inland Texas	928	557	608	647	94.0	397	41	144	7
Texas Gulf Coast	4,183	3,501	3,575	4,031	88.7	1,358	336	818	110
La. Gulf Coast	3,395	3,189	3,255	3,264	99.7	1,269	319	883	142
N. La. and Ark.	228	192	204	215	94.9	82	8	48	5
New Mexico	145	101	102	113	90.3	94	1	28	—
Dist. 3 total	**8,879**	**7,540**	**7,744**	**8,270**	**93.6**	**3,200**	**705**	**1,921**	**264**
Dist. 4 total	**711**	**550**	**574**	**596**	**96.3**	**310**	**23**	**158**	**16**
Dist. 5 total	**2,642**	**2,416**	**2,521**	**3,173**	**79.5**	**1.727**	**450**	**548**	**103**
Dec. 1, 2006	**19,204**	**15,356**	**15,749**	**17,335**	**90.9**	**8,925**	**1,467**	**4,204**	**572**
Nov. 24, 2006*	**18,390**	**14,855**	**15,151**	**17,335**	**87.4**	**8,741**	**1,420**	**4,168**	**590**
Dec. 2, 2005	**17,258**	**15,130**	**15,451**	**17,115**	**90.3**	**9,075**	**1,531**	**4,119**	**676**

*Revised.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

OGJ GASOLINE PRICES

	Price ex tax 11-29-06	Pump price* 11-29-06	Pump price 11-30-05
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	177.0	216.7	225.4
Baltimore	174.9	216.8	212.8
Boston	176.1	218.0	205.4
Buffalo	182.3	242.4	222.5
Miami	189.4	239.7	215.6
Newark	175.2	208.1	222.3
New York	171.9	232.0	222.2
Norfolk	173.3	210.9	224.0
Philadelphia	184.1	234.8	221.6
Pittsburgh	172.6	223.3	217.9
Wash., DC	188.9	227.3	221.7
PAD I avg.	178.7	224.5	219.2
Chicago	212.0	262.9	219.5
Cleveland	175.4	221.8	204.6
Des Moines	169.4	209.8	202.5
Detroit	178.7	227.9	206.6
Indianapolis	180.1	225.1	204.3
Kansas City	175.2	211.2	204.1
Louisville	182.9	219.8	205.3
Memphis	171.5	211.3	214.2
Milwaukee	184.4	235.7	217.2
Minn.-St. Paul	181.2	221.6	210.3
Oklahoma City	171.2	206.6	199.5
Omaha	177.5	223.9	209.1
St. Louis	179.9	215.9	213.7
Tulsa	171.1	206.5	200.1
Wichita	174.5	217.9	199.6
PAD II avg.	179.0	221.2	207.4
Albuquerque	183.2	219.6	209.9
Birmingham	179.5	218.2	208.7
Dallas-Fort Worth	177.1	215.5	209.6
Houston	169.9	208.3	207.4
Little Rock	172.7	212.9	208.8
New Orleans	175.5	213.9	248.1
San Antonio	171.5	209.9	213.4
PAD III avg.	175.6	214.1	215.1
Cheyenne	183.7	216.1	209.5
Denver	170.8	211.2	219.4
Salt Lake City	183.8	226.7	215.6
PAD IV avg.	179.4	218.0	214.8
Los Angeles	185.8	244.3	247.4
Phoenix	186.0	223.4	235.2
Portland	199.9	243.2	227.2
San Diego	190.7	249.2	244.4
San Francisco	208.1	266.6	249.4
Seattle	208.4	260.8	238.4
PAD V avg.	196.5	247.9	240.3
Week's avg.	**180.9**	**224.5**	**217.0**
Nov. avg.	**180.1**	**223.7**	**229.9**
Oct. avg.	**183.8**	**228.0**	**263.9**
2006 to date	**214.5**	**258.1**	—
2005 to date	**182.3**	**224.2**	—

*Includes state and federal motor fuel taxes and state sales tax. Local governments may impose additional taxes.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

REFINED PRODUCT PRICES

	11-24-06 ¢/gal		11-24-06 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	162.65	New York Harbor	162.95
Gulf Coast	156.15	Gulf Coast	159.95
Los Angeles	166.50	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	144.19	ARA	168.73
Singapore	153.33	Singapore	171.17
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	161.90	New York Harbor	97.93
Gulf Coast	156.15	Gulf Coast	106.26
Los Angeles	174.50	Los Angeles	111.19
		ARA	95.36
		Singapore	99.75

Source: DOE Weekly Petroleum Status Report.
Data available in OGJ Online Research Center.

BAKER HUGHES RIG COUNT

	12-1-06	12-2-05
Alabama	4	6
Alaska	7	10
Arkansas	34	15
California	36	30
Land	32	26
Offshore	4	4
Colorado	87	83
Florida	0	2
Illinois	0	0
Indiana	0	0
Kansas	11	6
Kentucky	8	5
Louisiana	193	171
N. Land	60	50
S. Inland waters	19	20
S. Land	43	36
Offshore	71	65
Maryland	0	0
Michigan	3	1
Mississippi	17	11
Montana	18	27
Nebraska	0	0
New Mexico	97	87
New York	10	4
North Dakota	33	23
Ohio	10	9
Oklahoma	183	147
Pennsylvania	17	14
South Dakota	1	2
Texas	771	658
Offshore	10	7
Inland waters	4	2
Dist. 1	13	21
Dist. 2	20	28
Dist. 3	62	64
Dist. 4	89	74
Dist. 5	144	106
Dist. 6	123	98
Dist. 7B	36	27
Dist. 7C	41	35
Dist. 8	108	75
Dist. 8A	27	27
Dist. 9	35	28
Dist. 10	59	66
Utah	44	31
West Virginia	33	25
Wyoming	90	88
Others—HI-1; ID-1; NV-1; OR-1; TN-3; VA-2, WA-1	10	5
Total US	**1,171**	**1,460**
Total Canada	**442**	**653**
Grand total	**2,159**	**2,113**
Oil rigs	289	264
Gas rigs	1,423	1,192
Total offshore	86	78
Total cum. avg. YTD	**1,643**	**1,376**

Rotary rigs from spudding in to total depth.
Definitions, see OGJ Sept. 18, 2006, p. 42.

Source: Baker Hughes Inc.
Data available in OGJ Online Research Center.

SMITH RIG COUNT

Proposed depth, ft	Rig count	12-1-06 Percent footage*	Rig count	12-2-05 Percent footage*
0-2,500	58	—	24	—
2,501-5,000	109	43.1	94	45.7
5,001-7,500	235	19.5	186	20.9
7,501-10,000	429	3.2	324	5.5
10,001-12,500	429	2.5	332	1.8
12,501-15,000	255	—	289	0.3
15,001-17,500	112	—	106	—
17,501-20,000	76	—	51	—
20,001-over	34	—	25	—
Total	**1,737**	**6.7**	**1,431**	**7.4**
INLAND	36		31	
LAND	1,640		1,351	
OFFSHORE	61		49	

*Rigs employed under footage contracts.
Definitions, see OGJ, Sept. 18, 2006, p. 42.

Source: Smith International Inc.
Data available in OGJ Online Research Center.

OGJ PRODUCTION REPORT

	[1]12-1-06	[2]12-2-05
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	18	22
Alaska	754	864
California	689	698
Colorado	58	61
Florida	6	6
Illinois	28	27
Kansas	94	93
Louisiana	1,342	975
Michigan	14	15
Mississippi	53	49
Montana	92	97
New Mexico	161	163
North Dakota	102	105
Oklahoma	169	168
Texas	1,341	1,266
Utah	44	48
Wyoming	141	143
All others	65	75
Total	**5,171**	**4,875**

[1]OGJ estimate. [2]Revised.

Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

US CRUDE PRICES

$/bbl*	12-1-06
Alaska-North Slope 27°	56.72
South Louisiana Sweet	59.25
California-Kern River 13°	51.60
Lost Hills 30°	59.10
Southwest Wyoming Sweet	60.43
East Texas Sweet	60.66
West Texas Sour 34°	51.25
West Texas Intermediate	60.00
Oklahoma Sweet	60.00
Texas Upper Gulf Coast	56.75
Michigan Sour	53.00
Kansas Common	59.00
North Dakota Sweet	50.00

*Current major refiner's posted prices except North Slope lags 2 months. 40° gravity crude unless differing gravity is shown.

Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

WORLD CRUDE PRICES

$/bbl[1]	11-24-06
United Kingdom-Brent 38°	58.42
Russia-Urals 32°	56.20
Saudi Light 34°	53.95
Dubai Fateh 32°	55.50
Algeria Saharan 44°	59.10
Nigeria-Bonny Light 37°	59.84
Indonesia-Minas 34°	56.38
Venezuela-Tia Juana Light 31°	51.80
Mexico-Isthmus 33°	51.69
OPEC basket	55.47
Total OPEC[2]	54.73
Total non-OPEC[2]	52.69
Total world[2]	53.53
US imports[3]	50.42

[1]Estimated contract prices. [2]Average price (FOB) weighted by estimated export volume. [3]Average price (FOB) weighted by estimated import volume.

Source: DOE Weekly Petroleum Status Report.
Data available in OGJ Online Research Center.

US NATURAL GAS STORAGE[1]

	11-24-06	11-17-06	Change
	Bcf		
Producing region	1,010	1,015	–5
Consuming region east	1,936	1,964	–28
Consuming region west	471	470	1
Total US	**3,417**	**3,449**	**–32**
	Aug. 06	**Aug. 05**	**Change, %**
Total US[2]	**2,969**	**2,662**	**11.5**

[1]Working gas. [2]At end of period.
Source: Energy Information Administration
Data available in OGJ Online Research Center.

Statistics

WORLDWIDE CRUDE OIL AND GAS PRODUCTION

	Sept. 2006	Aug. 2006	9 month average production 2006	2005	Chg. vs prev. year Volume	%	Sept. 2006	Aug. 2006	Cum. 2006
	Crude, 1,000 b/d						Gas, bcf		
Argentina	640	638	638	653	–15	–2.3	134.0	138.3	1,197.43
Bolivia	45	45	45	40	5	11.3	38.0	40.0	351.00
Brazil	1,733	1,703	1,706	1,1618	88	5.4	29.3	30.0	262.93
Canada	2,590	2,514	2,473	2,293	181	7.9	478.5	507.5	4,507.46
Colombia	526	507	531	526	5	0.9	15.7	17.4	142.53
Ecuador	530	542	541	517	24	4.6	0.3	0.3	2.79
Mexico	3,258	3,252	3,307	3,343	–37	–1.1	167.6	171.3	1,443.49
Peru	118	122	116	112	3	2.9	6.8	7.0	44.65
Trinidad	150	150	149	148	1	0.7	106.5	110.0	936.85
United States	5,120	5,155	5,105	5,311	–206	–3.9	1,571.0	1,618.0	14,534.00
Venezuela[1]	2,550	2,520	2,583	2,723	–140	–5.1	80.0	82.0	737.00
Other Latin America	79	79	79	80	–1	–1.3	7.2	7.5	65.74
Western Hemisphere	**17,339**	**17,228**	**17,272**	**17,364**	**–92**	**–0.5**	**2,634.9**	**2,729.4**	**24,225.89**
Austria	17	17	17	17	—	2.6	4.7	4.5	46.55
Denmark	260	349	331	382	–52	–13.5	19.9	22.2	259.25
France	22	21	21	22	—	–0.4	3.3	3.4	31.54
Germany	67	68	70	69	1	0.8	45.9	50.8	487.08
Italy	113	105	111	115	–4	–3.7	31.5	32.6	292.10
Netherlands	15	21	26	34	–8	–24.6	115.0	110.0	2,080.00
Norway	2,338	2,430	2,504	2,719	–216	–7.9	220.0	243.7	2,256.82
Turkey	42	42	42	42	—	–0.8	2.4	2.4	23.53
United Kingdom	1,369	1,214	1,511	1,686	–175	–10.4	216.3	190.1	2,209.09
Other Western Europe	5	5	5	5	—	–2.9	0.1	0.2	18.11
Western Europe	**4,248**	**4,272**	**4,637**	**5,092**	**–454**	**–8.9**	**659.1**	**659.9**	**7,704.06**
Azerbaijan	660	670	611	413	198	47.8	20.0	14.0	206.00
Croatia	17	16	17	18	–1	–4.4	4.7	4.8	42.57
Hungary	16	15	17	20	–4	–17.4	8.7	8.2	79.94
Kazakhstan	1,120	1,080	1,041	980	61	6.2	72.0	70.0	638.00
Romania	97	98	99	100	–1	–1.1	17.0	18.0	154.00
Russia	9,500	9,580	9,464	9,152	312	3.4	1,790.00	1,750.0	16,855.00
Other FSU	500	500	511	411	100	24.36	385.0	380.0	3,965.00
Other Eastern Europe	48	49	45	49	–4	–7.5	46.2	51.7	384.42
Eastern Europe and FSU	**11,958**	**12,008**	**11,806**	**11,143**	**662**	**5.9**	**2,343.6**	**2.296.7**	**22.324.92**
Algeria[1]	1,350	1,330	1,349	1,346	3	0.2	277.0	286.0	2,442.00
Angola	1,376	1,451	1,398	1,184	214	18.0	2.0	2.4	20.80
Cameroon	86	82	88	81	7	8.6	—	—	—
Congo (former Zaire)	20	20	20	20	—	—	—	—	—
Congo (Brazzaville)	240	240	240	240	—	—	—	—	—
Egypt	650	650	673	696	–22	–3.2	38.0	42.0	362.00
Equatorial Guinea	320	320	320	320	—	—	0.1	0.1	0.54
Gabon	230	230	237	232	4	1.9	0.3	0.3	2.73
Libya[1]	1,750	1,750	1,699	1,637	62	3.8	0.3	0.3	12.73
Nigeria[1]	2,190	2,270	2,222	2,392	–170	–7.1	72.0	75.0	627.00
Sudan	290	290	290	290	—	—	—	—	—
Tunisia	66	66	65	72	–6	–8.9	6.8	7.30	60.58
Other Africa	266	265	270	241	29	12.0	10.0	10.2	90.48
Africa	**8,834**	**8,935**	**8,872**	**8,751**	**121**	**1.4**	**428.1**	**445.0**	**3,800.63**
Bahrain	170	170	173	174	–2	–1.1	26.0	26.6	234.25
Iran[1]	3,850	4,050	3,892	3,892	—	—	260.0	280.0	2,433.00
Iraq[1]	2,050	2,000	1,917	1,860	57	3.0	5.2	5.4	46.50
Kuwait[1,2]	2,500	2.485	2,504	2,403	101	4.2	30.0	31.0	274.50
Oman	730	730	746	756	–10	–1.3	57.0	59.0	523.00
Qatar[1]	820	840	824	788	37	4.7	115.0	120.0	1,032.00
Saudi Arabia[1,2]	9,010	9,165	9,231	9,281	–68	–0.7	165.0	175.0	1,604.00
Syria	410	410	429	463	–34	–7.4	14.9	15.4	138.30
United Arab Emirates[1]	2,650	2,650	2,634	3,423	211	8.7	130.0	134.0	1,173.00
Yemen	350	350	347	348	–1	–0.3	—	—	—
Other Middle East	—	—	—	—	—	9.1	8.8	10.1	66.05
Middle East	**22,540**	**22,850**	**22,678**	**22,389**	**289**	**1.3**	**811.9**	**856.5**	**7,524.60**
Australia	493	522	405	4477	–47	–9.2	114.8	114.0	1,023.30
Brunei	190	190	199	184	15	7.9	33.9	35.0	318.16
China	3,659	3,670	3,695	3,628	67	1.9	163.7	170.0	1,543.71
India	703	653	676	667	10	1.4	77.0	57.8	698.85
Indonesia[1]	870	860	903	946	–42	–4.5	180.0	185.0	1,705.00
Japan	14	14	15	16	—	2.1	8.4	8.7	84,59
Malaysia	740	740	740	778	–38	–4.9	140.0	145.0	1,254.00
New Zealand	13	14	15	15	—	–0.7	11.0	12.1	100.70
Pakistan	61	64	64	64	—	0.3	109.5	113.2	1,045.18
Papua New Guinea	55	55	57	46	11	23.9	0.5	0.5	4.50
Thailand	206	203	214	176	38	21.6	72.6	73.0	570.26
Vietnam	209	206	214	180	34	18.6	70.9	72.6	641.18
Other Asia-Pacific	38	35	32	35	–2	–6.6	64.3	66.5	582.85
Asia-Pacific	**7,389**	**7,363**	**7,364**	**7,344**	**20**	**0.3**	**989.0**	**995.4**	**9,137.02**
TOTAL WORLD	**72,308**	**72,656**	**72,628**	**72,083**	**545**	**0.8**	**7,866.6**	**7,982.9**	**74,717.11**
*OPEC	29,590	29,890	29,741	29,691	50	0.2	1,336.2	1,395..4	12,268.50
North Sea	3,982	4,008	4,361	4,798	–436	–9.1	490.4	488.7	5,346.86

[1]OPEC member. [2]Kuwait and Saudi Arabia production each include half of Neutral Zone. Totals may not add due to rounding.Source: Oil & Gas Journal. Data available in OGJ Online Research Center.

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An open letter to the noble Iranian people

Noble Iranians,

Because your president, Mahmoud Ahmadinejad, took the trouble to write a letter to US citizens—"noble Americans," in his words—a reciprocal gesture, albeit from a lesser office, seems appropriate.

Your president upholds unassailable values: "compassion, empathy, respect for the rights of human beings, securing justice and equity, and defending the innocent and the weak against oppressors and bullies."

Yet Americans hear of state-sponsored political murders inside and outside your country, of bullying by Basij militia and Hizbollah vigilantes, of rigged elections, and of authoritarian rule by the religious leaders to whom Mr. Ahmadinejad answers. His lectures on human rights and defense against oppressors are, therefore, perplexing.

Your president disparages America's military presence in Iraq and support for what he calls "the Zionists." Yet he doesn't mention his regime's support for insurrectionists in Iraq, vocal truculence toward Israel, and development of what most observers believe to be nuclear weapons. In fact, Mr. Ahmadinejad seems to want the US to withdraw from Iraq only so Iran can move in. You Iranians know only too well that your president, whom a majority of voters elected, takes his orders from clerics for whom you never have the chance to vote. Experience with contradictions like these might be what makes Iranians better than Americans at distinguishing politics from culture.

Some Americans recognize that those "Down with the USA" signs in Iranian hotel lobbies don't speak for all Iranians. And some try to view Iranian political emanations in the context of the autocracy that shapes them. But not many. The only image most Americans have of Iranians is of angry young men punching the air and cursing the "great Satan." That's regrettable. The image influences government behavior.

You would do well, therefore, not to expect a letter from President Bush—not that it would be a bad idea for him to send you one. He works in a frenzied media culture that tends not to differentiate a people, like you, from those who govern, like Mr. Ahmadinejad. Sorry, but that's politics.

Besides, it's football season, and most Americans already have forgotten about your president's letter.

Sincerely,
An American

(Online Dec. 1, 2006; author's e-mail: bobt@ogjonline.com)

The Editor's Perspective

by Bob Tippee, Editor

Market Journal

by Sam Fletcher, Senior Writer

Cold weather raises energy prices

Energy prices soared to the highest levels in months during the final 4 days of November as an arctic cold front moved across the Midwest US toward the East Coast, dumping several feet of snow in its wake.

Temperatures plummeted below freezing along the Texas Gulf Coast. The National Weather Service predicted below-normal temperatures in the eastern US during the first 2 weeks of December. With the spreading cold front, analysts at Enerfax Daily said, "Heating demand across the US will climb to 10% above normal by Dec. 4, from 57% below average [on Nov. 27]." During November, the first complete month of the current heating season, temperatures averaged 4.7% colder than last year but 9.1% warmer than normal, said weather forecasters. Natural gas futures jumped to $8/MMbtu, pulling crude futures above $60/bbl as post-holiday trading resumed Nov. 27 on the New York Mercantile Exchange. The January contract for benchmark sweet, light crudes gained $1.08 to $60.32/bbl Nov. 27 on the New York Mercantile Exchange. The January natural gas contract bumped up by 28¢ to $8/MMbtu. By Nov. 30, the January crude contract was trading at $63.13/bbl. The January gas contract traded as high as $9.05/MMbtu on NYMEX before closing at $8.84/MMbtu, down by 2.7¢ in that session on forecasts of moderate weather following the cold snap.

Energy prices also were buoyed as the US dollar dropped to a fresh 20-month low against the euro and a 14-year low against the British pound. The average price for the Organization of Petroleum Exporting Countries' basket of 11 benchmark crudes "has risen by just 0.13 euro over the past week compared to the $1.58/bbl rise in dollar terms," Paul Horsnell, Barclays Capital Inc. of London, reported Nov. 29.

Analysts at Raymond James & Associates Inc. explained, "Many commodities, priced in dollars, become relatively cheaper for buyers outside of the US when the dollar weakens." They also noted a new report by McKinsey & Co. that projects world energy demand to rise 2.2%/year through 2020, outpacing the 1.6% growth seen in the past decade.

Inventories

The US Energy Information Administration said commercial crude inventories in the US fell by 300,000 bbl to 340.8 million bbl during the week ended Nov. 24, ending a 4-week build. Gasoline stocks dropped 600,000 bbl to 201.1 million bbl in the same period. Distillate fuel inventories fell for the eighth consecutive week, down 1 million bbl to 132.8 million bbl in the latest period.

"In just 7 weeks, some 90% of the US oil product overhang has disappeared, and inventories have drawn relative to their 5-year average at a rate of over 1 million b/d," said Horsnell. "Seven weeks ago, the combined build above the 5-year average for just gasoline and diesel combined was 35.4 million bbl, whereas today that combined build stands at just 1.7 million bbl. Heating oil inventories have also fallen relative to the 5-year average, although in general they have spent the whole year describing a very normal pattern from a slightly higher than normal base."

He said, "Heating oil output has been slow to ramp up this year, and from this point the race is on between that ramping up of supply and the ramping up of demand as determined by weather." On Nov. 30, EIA reported the withdrawal of 32 bcf of natural gas from US underground storage in the week ended Nov. 24. That was above the consensus of Wall Street analysts and compared with withdrawals of 1 bcf the previous week and 51 bcf during the same period last year. US gas storage now stands at 3.4 tcf, up by 185 bcf from year-ago levels and 230 bcf above the 5-year average.

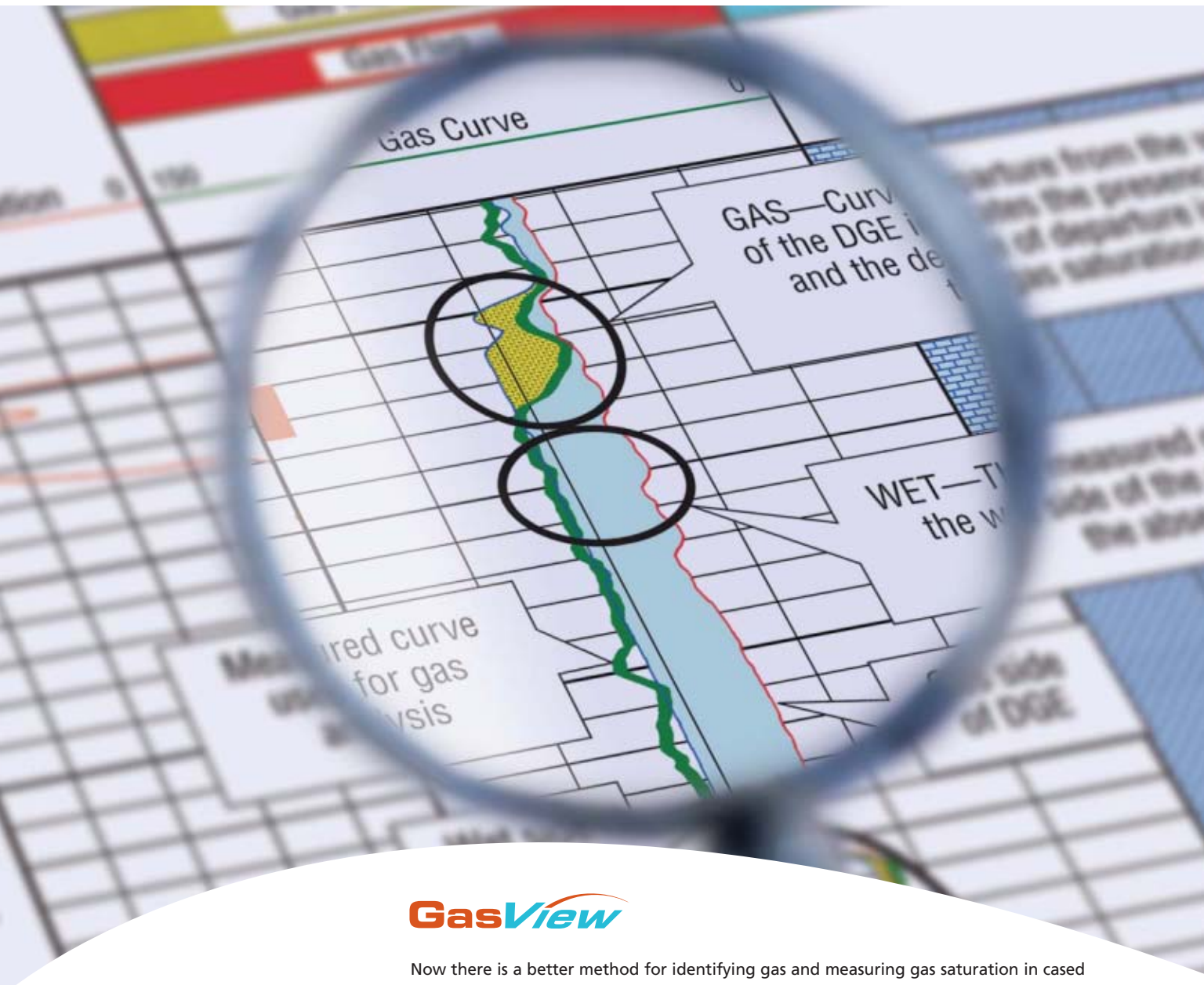
OPEC

Venezuela said it would propose another cut in production quotas by the Organization of Petroleum Exporting Countries at the group's scheduled Dec. 14 meeting in Nigeria. President Hugo Chavez wants to keep futures market prices close to $60/bbl for benchmark US crude.

Meanwhile, Ecuador announced its intention to rejoin OPEC, and Sudan and Angola also expressed interest in joining the cartel. "The sole addition of Ecuador which pumps 540,000 b/d seemed inconsequential. However, by tallying Sudan (500,000 b/d) and Angola (1.4 million b/d) the combined production of these three nations represents approximately 8% of current OPEC production," said Raymond James analysts. "The addition of new member states to the organization would allow OPEC to [wield] further influence in its ability to sway production and pricing of crude oil in world markets. No time frame has been set as to when the new members would be expected to join."

(Online Dec. 5, 2006; author's e-mail: samf@ogjonline.com)

Focusing on Gas?



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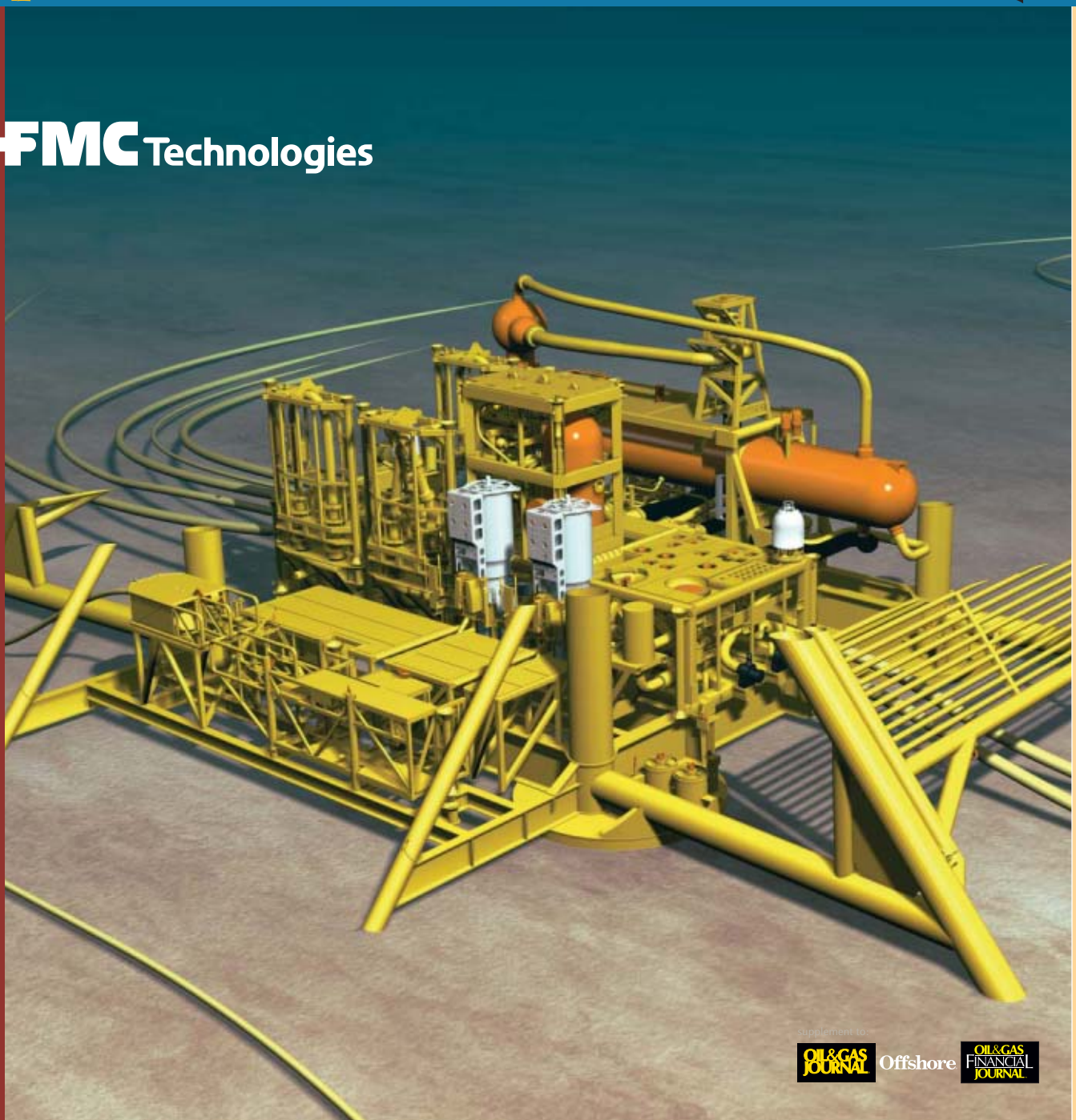

New challenges, new solutions

for subsea production systems

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"Subsea processing — a dream of offshore operators since the 1960s — is finally moving into the mainstream of our industry. FMC's goal is to make it happen; to deliver complete, integrated subsea systems with proven reliability, and to provide our clients with direct technical support for the life of the field."

— Peter Kinnear, President, FMC Technologies

FMC Technologies was expanding the frontiers of subsea production long before the introduction of its rugged and reliable UWD-15 wellhead line in 1991. Today, FMC is the world's leading provider of complete subsea systems.

We face plenty of challenges. Replacement reserves are increasingly hard to find. Explorers are working in record water depths and dealing with extreme reservoir pressure and temperature. There are shortages of every kind, from deepwater rigs to people with the skill and experience to run them. And, with heavy oil accounting for the bulk of the world's remaining reserves, even the chemistry of the crude is a challenge.

One of the industry's next frontiers is the ability to simply and reliably separate produced fluids on the seabed. The technology is emerging now to process oil, gas, water and sand without the expense of first lifting all of the produced fluids to facilities on the surface. Subsea processing also eliminates the need for offshore platforms in some new fields, and can therefore accommodate longer distance transportation of hydrocarbons. This is especially attractive in regions subject to climate extremes and seasonal storms.

The world's energy future depends on such advanced technology. Although there are still ample oil and gas reserves, they are increasingly more difficult to recover. Operators are drilling in record water depths and targeting formations they would have bypassed just five years ago.

Operators are also working hard to recover more from their existing fields. In some cases, producers are boosting recovery factors by 10 percent or more. The following pages explain some of the remarkable advances that are shaping the future of subsea production.

A History of Strategic Alliances

FMC Technologies is a global supplier of subsea production systems including subsea trees, controls, manifolds and tie-in systems. From project inception to abandonment, FMC delivers solutions that lower costs and boost performance. Since we entered the subsea market in the 1970s, our plan has been to work closely with operators to develop the technology they need.

The benefits of strategic alliances flow both ways. While our customers get exactly the tools they want, FMC Technologies gains experience on some of the most challenging oil and gas developments in the world. We are proud of these alliances, because they have led to many of the breakthrough innovations that make today's most productive subsea developments possible.

Reducing costs

In a historic 1995 contract with Shell, Statoil, Total and ExxonMobil, FMC Technologies promised to find technical solutions that would cut the high cost of subsea systems by 75 percent over 10 years, a promise that it kept.

"That is perhaps the main reason why our customers come back to us," says Tore Halvorsen, Vice President, FMC Technologies, Kongsberg, Norway. "They have a firm belief in the extra value of working with our company. Our customers see us as a solutions provider."

Global experience

At any one time, FMC is working on more than 25 subsea projects worldwide, but two of the largest have captured the attention of the petroleum industry. The first is Norsk Hydro's Ormen Lange development in the North Sea. The project was awarded in 2003 and is scheduled to come online in 2007. Ormen Lange (Long Snake) is Europe's deepest subsea development (800-1000 m water depth). It features a 120-kilometer (75-mile) pipeline from the field to onshore gas-treatment facilities off the west coast of Norway.

The second of FMC's current high-profile projects is Statoil's Tordis improved oil-recovery (IOR) project. The contract was awarded in 2005, with start-up scheduled for October 2007. Tordis will host the first commercial subsea production system, which will boost the amount of recoverable oil from the current 49 percent to 55 percent — an addition of 19 million barrels from the Tordis separators alone and 35 million barrels (including topside changes) over the life of the field.

In many ways, the experience gained through all of our alliances since the late 1990s — and everything we have learned about system reliability and quality since then — has been leading toward the Tordis development. Tordis is not just a milestone for the industry; it is a vision of the future that incorporates numerous aspects of subsea technology as we know it today.

Game-Changing Innovation

FMC Technologies manufactures much of the hardware it sells in its global network of major manufacturing sites around the world. What we don't build is purchased from other suppliers, then certified for subsea service according to our own rigorous standards. We use our experience to integrate complete subsea systems and provide technical support for the life of those fields.

Subsea trees

FMC's world-proven UWD-15 family of subsea wellheads has been meeting customer demand for weight-set installations, metal-to-metal seals, reliability and reduced cost since its introduction in 1991.

With working pressures up to 15,000 psi, the UWD-15 wellheads are available for a complete range of shallow-water and deepwater applications, including standard, shallow-water flow, large-bore and ridgidized or preloaded operations. These modular designs and multi-task running tools enable many of the same components to be used across the entire UWD-15 line.

Our UWD-15 tools also require fewer running and test tools than any competing subsea drilling system — a real advantage in crowded offshore working conditions. These multi-functional tools provide options for running and retrieving components, either individually or in combination with other equipment, enabling fast, accurate and reliable UWD-15 system installation.

More than 1,500 subsea systems worldwide are equipped with trees, controls, manifolds and tie-ins supplied by FMC Technologies.

FMC's rugged and reliable subsea trees can handle working pressures up to 15,000 psi.

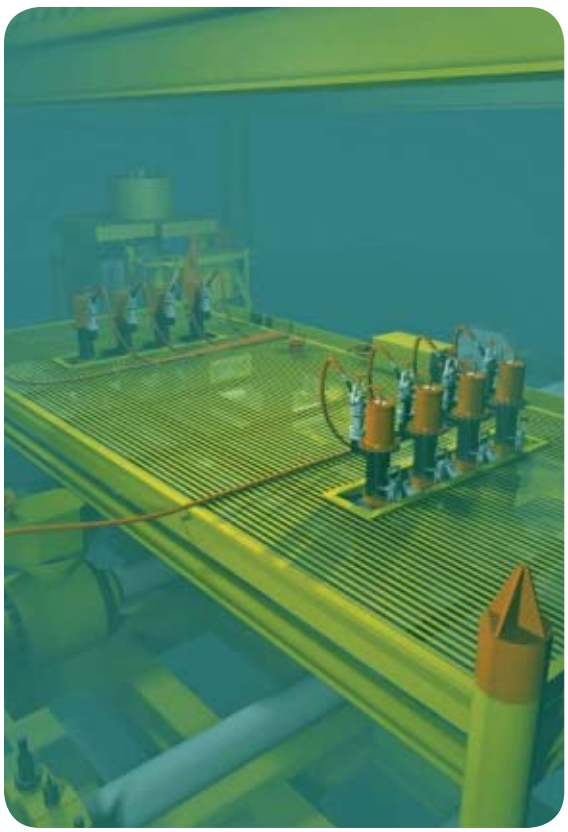
FMC is the dominant supplier of subsea HPHT systems, including the first producing system in the Shell Princess project in 2002.

FMC's high-pressure, high-temperature (HPHT) subsea tree systems, which can handle pressures up to 15,000 psi and temperatures of 350 degrees F (177 degrees C), are the most technically advanced oil and gas wellheads in the world. The trees are modular, so they can be reconfigured to meet customer needs without the expense of custom design.

Electric subsea controls

FMC Technologies began developing subsea electric controls in the 1970s and has been supplying commercial applications since 2001. Electric controls are now an alternative to traditional hydraulic controls in several subsea applications.

There are many economic, operational and environmental benefits. Electric control systems powered by rechargeable batteries eliminate the slower response time of hydraulic controls, particularly in deepwater applications. In addition, electric actuators can be operated faster and more precisely. They even allow operators to monitor the mechanical condition of the valve and actuator, based on the resistance the actuator must overcome to position them. In the future, electric controls could be one of the enabling technologies that make new developments possible, such as ultra-long tiebacks to existing platforms.



FMC Technologies is one of the world's leading providers of electro-hydraulic controls, with systems that can operate as many as 46 functions on a single tree. Now all-electric applications are extending the range of possibilities for offshore developments.

HOST system

Operating offshore, especially in deep water, is hugely expensive. Over the years, however, FMC Technologies has earned a reputation for offering simple, straightforward solutions that save time and money.

The hinged-over subsea template (HOST) system was developed as a way to standardize subsea components and reduce cost.

FMC Technologies operates major manufacturing sites for subsea systems that serve each producing basin, including this 36,000-square-meter (390,000-square-foot) facility at its corporate headquarters in Houston, Texas.

One of the most significant innovations was the hinged-over subsea template (HOST) system. The challenge was to develop a wellhead template that could be installed without the use of a barge-mounted heavy-lift crane. FMC's solution was to build a subsea template that could be installed directly from a drilling rig.

Developed as part of an alliance with Statoil, Shell, ExxonMobil and Total, the HOST system employs a hinged design that allows the template to be run in a folded-up position, which takes up much less space on the deck of a ship, barge or drilling vessel. The HOST is rugged, so it can be used at any depth. But it is still light and compact enough to lower to the seabed with a crane no larger than the ones found on most deepwater rigs. Once the HOST is positioned on the seabed, it opens like the petals of a flower to become a steady and secure base for the wellheads.

"With the HOST system and other building blocks that FMC Technologies has developed, we can provide custom solutions without the expense of having to design each new system from scratch," says FMC's Tore Halvorsen.

"The HOST system was a breakthrough in the building-block system. We were the first to come to market with such a solution. Other companies were making subsea templates, but they needed crane ships or barges to launch them."

Riserless Light Well Intervention

Subsea wells, by definition, are more difficult to service than dry trees. That means they are serviced less often. As a result, they typically achieve lower production rates over the life of the well. That could change with an emerging technology called Riserless Light Well Intervention (RLWI).

"The main driver behind RLWI is to make subsea wells easier and cheaper to access than they are now," says Harald Hansen, Well Services business manager for FMC Technologies.

Light well intervention uses equipment connected to the surface vessel only by an umbilical line, instead of through a heavy workover riser, to perform wireline operations such as logging, gauging, plugging, reperforating and other downhole operations.

The RLWI equipment to connect to and control the well can be deployed from a low-cost dynamically positioned monohull vessel. One of the enabling technologies is FMC's patented barrier and lock system, which locks onto and seals the wellhead so that a tool package can be inserted and lowered downhole with the well under full pressure.

"With this fully robotic system, we have reduced the cost of intervention by more than 60 percent," Hansen says. "We believe that it is an important tool that will increase oil recovery rates in many subsea developments."

FMC Technologies is currently using Riserless Light Well Intervention in the North Sea on wellheads as deep as 550 meters (1,815 feet). It plans to extend the range to one kilometer (more than a half mile) by 2007.

Reliability as a Discipline

Complete offshore systems, regardless of the supplier, are typically assembled from products made by companies around the world. Meters, gauges, flowlines, umbilicals, tubulars and many other components are all bought from vendors who specialize in those niche markets.

FMC Technologies has a proven track record of putting reliable equipment in the field. As the company that provides the total package, FMC takes responsibility for making sure that all the parts work as designed, regardless of the source.

"Our clients know that every component in our system has been certified by FMC to make sure that it meets our performance standards," says Brad Beitler, director of Technology and Business Development. "If there's a problem, we're the ones our clients call to make it right. That's why FMC made reliability a discipline within the company. It's one reason that over the past 20 years, simple and robust subsea systems have become one of the most reliable sets of equipment in the field."

Subsea Processing – The Next Big Step

Subsea processing

The benefits of subsea processing are obvious. If you can separate the oil and gas from the produced water and sand on the seabed, you don't have the expense of lifting them to the surface and can thereby lower the back pressure against the reservoir. Re-injecting the water into a depleted section of the reservoir can help restore reservoir pressure. The rewards are lower cost and higher production.

Subsea processing consists of treating produced fluids upstream of surface facilities at or below the seabed, including oil/gas/water separation, multi-phase pumping, gas compression and flow assurance.

Subsea separation, a technology that is available now, is particularly attractive in maturing fields, where the water cut is in danger of exceeding the capacity of the existing flowlines and process equipment.

For several years, multi-phase pumps have been available for subsea applications to maintain pressure and prevent slugging in long pipelines. By adding subsea separators, some operators see increased production rates and increased oil recovery. They will also be using their existing flowlines and surface equipment more efficiently.

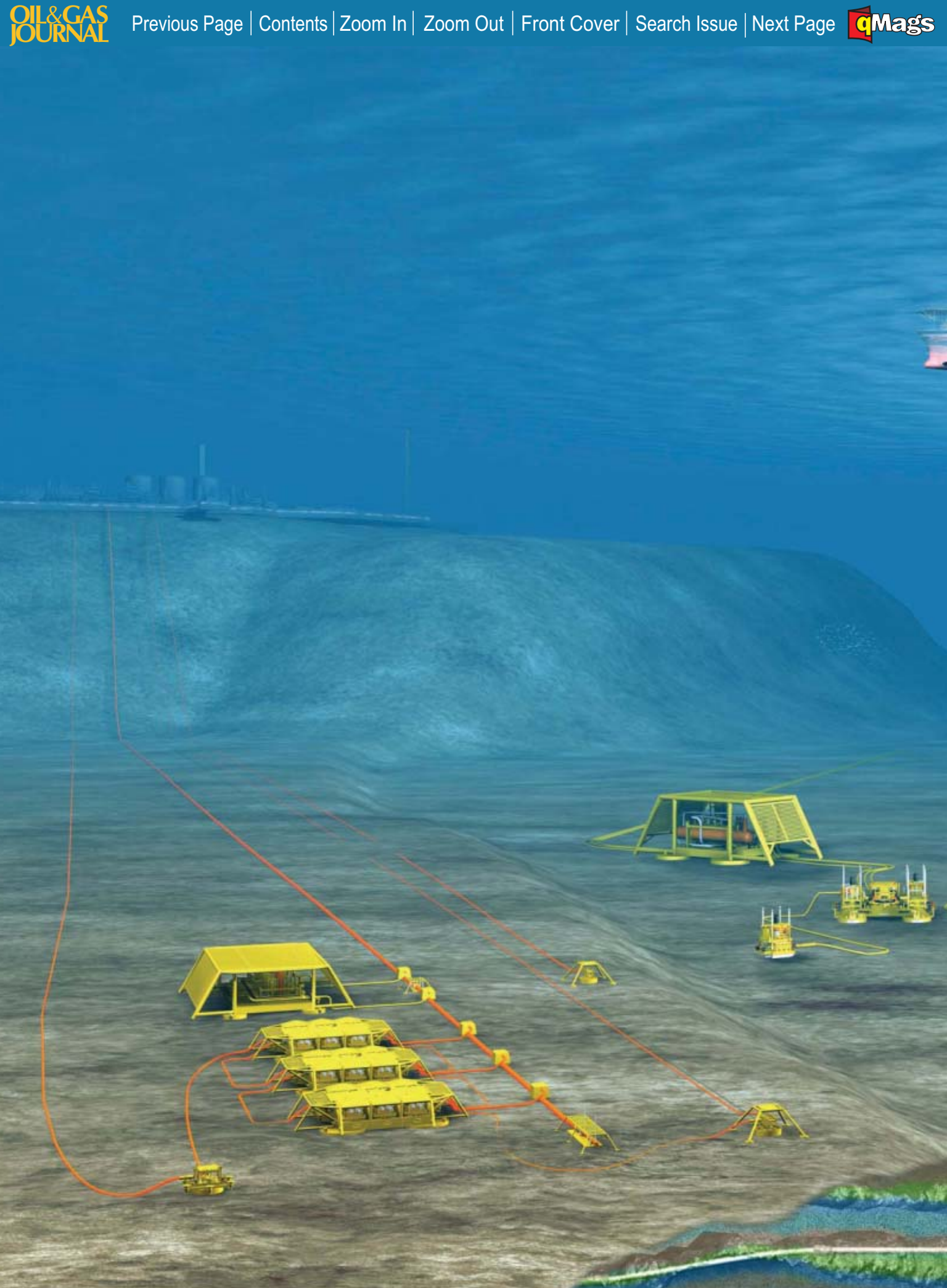
Our industry, however, is by nature very conservative. Much of the new hardware that is appearing today could have been available several years ago, but widespread acceptance takes time. FMC's approach has been to involve its clients in the design process.

"We involve our customers in the discussions and in our design thinking to show why we have done things a certain way," says Erlend Fjøsna, manager, Subsea Processing Systems. "Our designs are simple and robust, so systems should not fail. But if a primary system does go down, there is always a backup mode and the possibility of reconfiguring the flow so the facility can continue operating."

FMC Technologies believes that 2005, with the industry's first order for a full field application of subsea processing, will be remembered as a milestone for the offshore industry.

"In many ways, the interest we are seeing in subsea processing is moving faster than we thought," Fjøsna says. "But that really shouldn't be a surprise, because the value cases for subsea processing are so obvious and so strong."

With an installed base of more than 1,000 subsea trees, a global presence for life of field services and long-term relationships with our customers FMC is in a unique position to grow the FMC subsea processing business. When integrating our knowledge about subsea and processing with the CDS separation products and skills, we clearly have a competitive advantage in the market" says Tom Munkejord, Director of Process Systems.




Our technical ability to deliver
game-changing innovations is key
for future deepwater developments.

Where We Stand Today

Subsea technology is perhaps the most rapidly advancing area of the oil industry. Our ability to produce offshore oil and gas from increasingly harsh and remote locations depends on it.

"With our field development and process system skills combined with CDS's product portfolio, we can offer now is a fully integrated system," says Rombout Swanborn, managing director, CDS Separation Technology, a subsidiary of FMC Technologies. "We take a systems approach to the field, building an optimized process that starts at the subsea wellhead and ends at the sales meter."

Full-system integration is a powerful tool. In new developments, it can lower not only equipment costs but operating expenses as well over the life of the field. For existing fields, upgrading to a fully integrated subsea system can optimize the oil and gas recovery rates, in some cases adding years of production to mature reservoirs.

"The question is not about our ability to supply fully integrated subsea processing systems, but about market acceptance," Swanborn says.

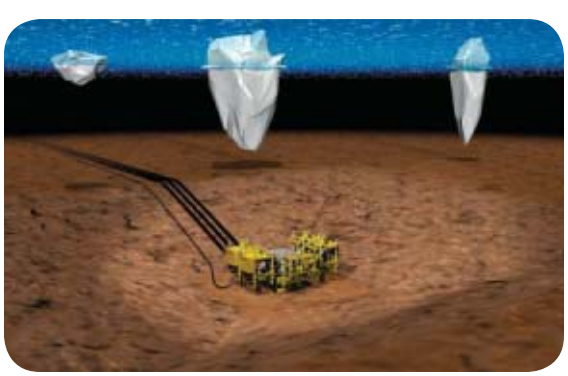
"It typically takes five to 10 years to introduce game-changing concepts to our industry, but current market pressures are shifting the rules. Producers with maturing fields are more willing than ever to try new technology. It's an exciting time now to be on the brink of widespread acceptance for a number of new technologies."

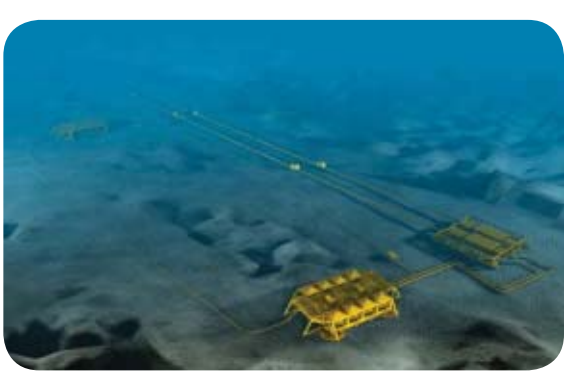
Challenges of subsea processing

Today, proven technologies are available for subsea separation and pumping at water depths of 1,000 meters (3,300 feet) with good-quality crude. Existing technology, however, is being challenged as operators go after deeper fields, more remote locations and heavier oils.

To meet these challenges, FMC and CDS are developing novel heavy-oil separation technologies that do not depend on large and heavy vessels.

In a related effort, FMC and Siemens are developing a low complexity subsea gas compression system. FMC is also working with several partners to qualify subsea power systems that will supply these new technologies with the high-voltage electricity they need, even at very long distances from the host facility.





Complete subsea systems make it possible to develop fields in areas where ice and heavy seas would threaten surface facilities.

Flow management

"With increased distances and a larger number of branches in the wells, our ability to use electric controls becomes more important. Electric controls are necessary to meet our vision of controlling all of the branches and all of the wells over long distances."

"With our separation technology and process systems, we can simulate the flow and the benefits of flow splitting," says FMC's Kjartan Berg, manager, Subsea Flow Management Systems. "We can separate water and gas and re-inject water into the reservoir. We can analyze systems, identify bottlenecks and determine the payoff if an operator is thinking about adding more equipment."

Assistance in the design stage

Ideally, FMC flow-control engineers should be involved in the design process early on. They have the tests and experience to determine the proper number and size of the flowlines and how much insulation they will need to perform in all types of weather.

If flowlines are too big, for example, operators could experience slugging problems that hold back production and damage processing equipment on the seabed and at the surface. If the flowlines are too small, they will become a bottleneck that restricts the production capacity of the field.

Without enough flowlines, operators lose some of their ability to monitor the flow from individual wells.

"Subsea systems require more attention to these details to optimize and fine-tune the flow," Berg adds. "While subsea systems can certainly simplify offshore operations, they do require more attention to flow assurance and flow optimization."

Flow metering

Accurate metering is important for maintaining the reservoir performance and assuring the accuracy of the reservoir model. How much fluid is coming from each branch of the well? How much is water, and how much is oil? Which branches may be producing too much sand? Knowing the answers to these questions can mean the difference in thousands of barrels of production every day.

"Maintaining the data quality of what comes from which branch and which well is a key to good reservoir management," Berg explains. "The information is critical for optimizing production day-to-day."

New flow-assurance center

FMC installed its first flow-assurance control center in Asker, Norway, in 2005 and will soon add others in the United States, Brazil and Australia. The plan is to offer 24-hour monitoring for wells operated by FMC clients anywhere in the world.

Increased Oil Recovery

With conventional tools, subsea operators may recover from 20 percent to 50 percent of the oil in place, and up to 70 percent of the gas. Technology has brought us to these levels, but there is still plenty of room to improve the recovery factors of existing fields and future developments.

Advanced subsea trees, electronic controls and better flow-assurance tools, plus innovations like the HOST system and Riserless Light Well Intervention, are already having an impact. The next big step is subsea separation. In that arena, one new product may change not only our ability to process oil and gas on the seabed but at the surface as well. The technology is called inline separation.

FMC Technologies' inline separation technology provides the company with a competitive advantage in subsea processing capabilities for deepwater development.

Inline separators

Inline separators are an ideal solution for subsea use for several reasons. First, they are small in diameter. The body of the separator itself is a piece of pipe with no moving parts. Supporting it are the same controls, valves and other components that have already been proven for subsea reliability on other systems.

The principle behind inline separators is relatively simple. The flow of produced fluids is set spinning at high velocities as it passes through the body of the separator. Centrifugal force pushes the heavier components toward the walls of the vessel, and gas remains closer to the center, where it can be mechanically separated from the liquid stream. Water and sand can be separated from the oil in much the same way. Not only is the small diameter an advantage in terms of surviving the pressures of deepwater environments, the design makes them super efficient.

"The efficiency of inline equipment actually drops when the diameter gets larger, because the larger radius decreases the centrifugal field," says Guy Hellinx, CDS sales director. "If you want to have high efficiency, you want to stay relatively small."

Boosting production economically

Inline separation is an option to consider each time a new production system is installed or modified. Inline separation is so versatile that it could likely be the system of choice for many new applications. However, there will still be situations where it would be better or more reliable to have a separator vessel on the surface. In some cases, a large-capacity surge tank might be needed to handle a sudden large increase in liquid volume.

One advantage of inline systems offshore is that they weigh much less than traditional separator vessels, which can save money in platform-mounted applications. Inline separators require only 20 percent of the weight and space required by most conventional separator systems. On an FPSO, for example, inline separators could save enough space and weight to give a smaller class of FPSO the same processing capacity as the largest FPSOs currently in use.

One of the best applications for inline separators is to quickly increase the capacity of onshore or offshore processing facilities. Like adding a new piece of pipe, inline separators can be installed without taking any of the existing separators and scrubbers out of service.

Additional inline separators could be added as a field matures to keep up with the increasing volume of produced water. Space for the new equipment would not be an issue, since inline separators require only a bit more room than the section of pipe they replace.

Separation at the seabed

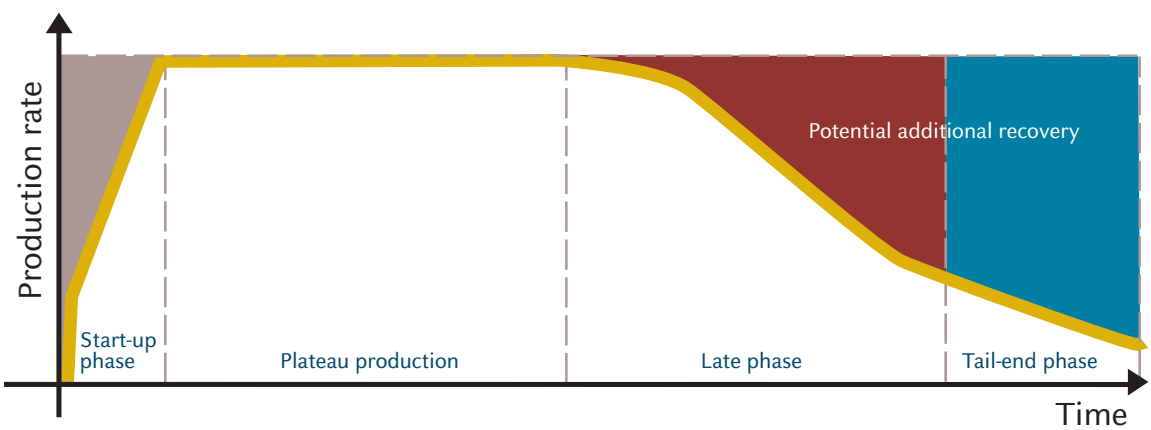
Inline separators are able to efficiently isolate most of the gas, oil, water and sand from produced fluids. The next logical step is to reinject a slurry of water and sand back into an unused portion of the reservoir, saving the expense of bringing the sand and water to the surface or shore. Statoil is planning to install a similar sand removal system in 2007 as part of the Tordis subsea separation project delivered by FMC.

Wider applications for inline processing

Inline separators were designed for subsea use, but they are just as efficient on the surface as they are on the seabed. The pipe that makes up the body of the separator is small in diameter, so inline separators are easy to install, cost effective and versatile enough to be used in most retrofit applications. They are particularly useful in debottlenecking projects. If operators need more capacity, they can simply split the stream for one separator and add a second or third.

In some cases, inline separators can boost production. Operators are beginning to see them as flow-management tools that can reduce pressure in the flowlines, which creates a greater differential between pressure in the formation and pressure at the surface.

The benefit of lighter, smaller production separators is obvious offshore, where weight and space are at a premium. Inline separators are also a good choice for remote developments onshore, where equipment is often transported thousands of miles to the field. For some new and brownfield developments, inline separators could be the difference between doing the project or not.



Subsea processing enhances economics over the life of the field.

Project Profile: Ormen Lange

Ormen Lange is Europe's deepest subsea development so far. The three-phase project is being deployed in waters ranging from 850 to 1,100 meters (2,800 to 3,600 feet), about 120 kilometers (75 miles) off the west coast of Norway.

Norsk Hydro is the operator through the planning and development phase, then Shell Norway will take over as operator when Ormen Lange comes onstream in October 2007. Shell is also responsible for drilling the production wells.

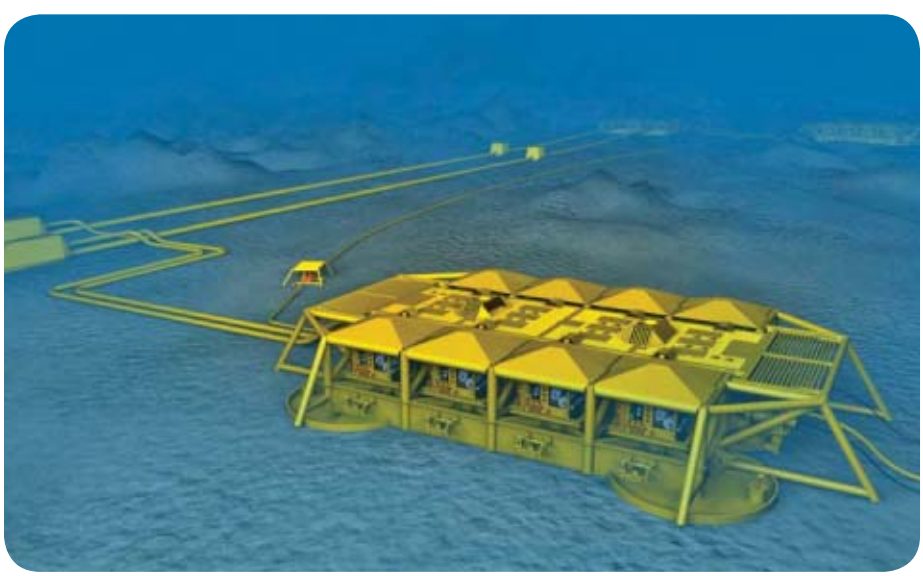
Each of Ormen Lange's three phases includes a template with eight subsea trees with a working pressure of 10,000 psi. Produced fluids will be transferred by twin 30-inch-diameter pipelines to an onshore processing plant. The processed gas will then be delivered by pipeline to Europe and the United Kingdom. Ormen Lange could eventually supply up to 20 percent of the UK's natural gas consumption.

"The operators faced a variety of challenges on this project, but their main concern was flow assurance in the long pipelines," says FMC's Kjartan Berg. They are dealing with sub-zero temperatures on the seabed, so hydrates and ice are a constant threat."

Another challenge for the Ormen Lange developers has been the seabed itself, which is an irregular and challenging mix of rocks and soft clay. Any low areas of the gas pipelines create potential traps for liquids to accumulate and freeze.

FMC Technologies responded by integrating three flow-assurance systems based on its well-established FlowManager™ real-time flow-management software. The company will also provide continuous monitoring of Ormen Lange's critical production variables. FMC qualified the flow-assurance system by conducting both computer simulations and full-scale cool-down tests of the equipment at its facilities in Asker, Norway.

"Over the next few years, formation pressure alone will be enough to push gas through the pipeline to shore," Berg says. "But the plan is to eventually install electric compressors on the seabed to compensate for the natural decline in reservoir pressure over time. This is a new step-change in subsea technology, and we are in the process of qualifying a compressor system now."



Ormen Lange's subsea kit includes three massive subsea templates, each with eight 10,000-psi trees.

Project Profile: Tordis Subsea Processing System

The world's first commercial subsea processing system will be installed in Statoil's Tordis field in the third quarter of 2007. Tordis is located in the Norwegian section of the North Sea in 200 meters (656 feet) of water. The plan is to install a full-scale separation facility and electric pumps on the seabed to reinject bulk water into a non-hydrocarbon reservoir. The oil and gas will be boosted through a multiphase pump back to the field's Gullfaks C offshore platform.

"Tordis is a perfect application of subsea separation," says FMC's Erlend Fjøsna. "The field is maturing, so its wells are producing more and more water. That is restricting production, because the flowlines and the surface facilities do not have the capacity to transport and handle all of the extra water."

It's a common problem in mature offshore fields. Operators now have three choices: they can continue to delay production and reduce ultimate recovery, they can upgrade their surface facilities and bring in additional processing equipment, or they can do some of the processing subsea. In Statoil's case, subsea processing clearly made the most economic sense.

In terms of system reliability, the subsea processing unit for Tordis will be a money-maker from day one. If it ever does need to be shut down for maintenance or repairs, the field will continue to produce at a reduced rate until the unit is returned to service.

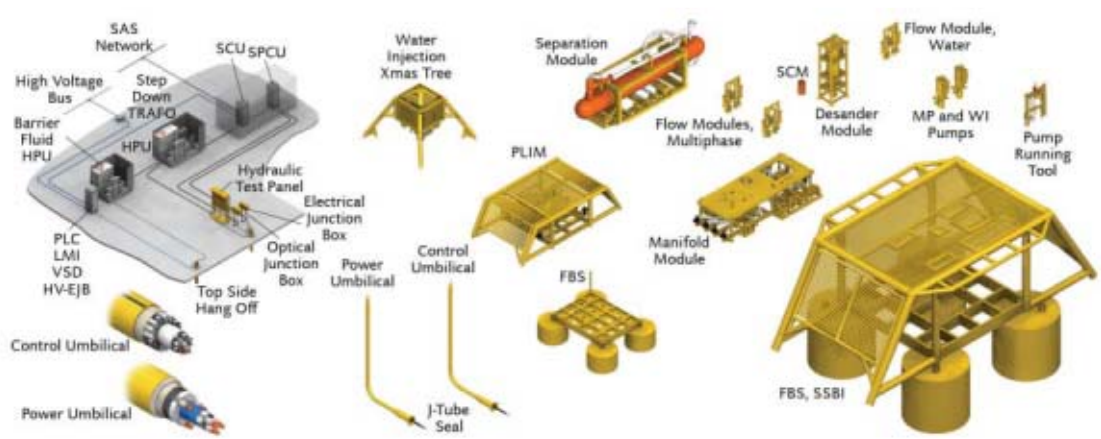
Three companies bid on the project, and FMC was awarded the contract in 2005.

"Our solution was different from the others," Fjøsna says. "By taking the gas out in the inlet section of the separator, we were able to reduce the size of the vessel by almost 50 percent. That made our vessel more compact than what our competitors proposed."

The smaller-diameter vessel is less expensive to build, but the main advantage of FMC's design is that the separator will be easy to install and easy to retrieve if it ever needs repair.

To win the contract, FMC not only came up with a more-compact design for the separator, but also performed extensive testing to demonstrate reliability of the system.

"At the beginning of the project, the operator was very concerned about the separation system's ability to remove sand," says Toine Hendriks, CDS process engineer. "So we built a full-scale test unit and demonstrated that our system would work."



Tordis scope of supply

Not *If*, But *When*

"FMC's industry-leading subsea technology is making it possible to produce subsea fields and achieve recovery factors similar to what operators expect from topside equipment," says Erlend Fjøsna, manager, Subsea Processing Systems.

In the case of the Tordis field development, production will actually increase over current levels and allow the operator to recover more of the oil in place. Elsewhere, subsea production systems will extend the lives of existing fields and make marginal developments profitable.

"Subsea separation is the key," Fjøsna says. "Without subsea processing, Tordis would have to be shut down and much of the oil left in place. This new separation technology will increase the recovery from Tordis by 35 million barrels over the life of the field, and we believe that we will see similar results in many fields over the coming years. Customers are no longer asking *if* it will happen, but *when*."

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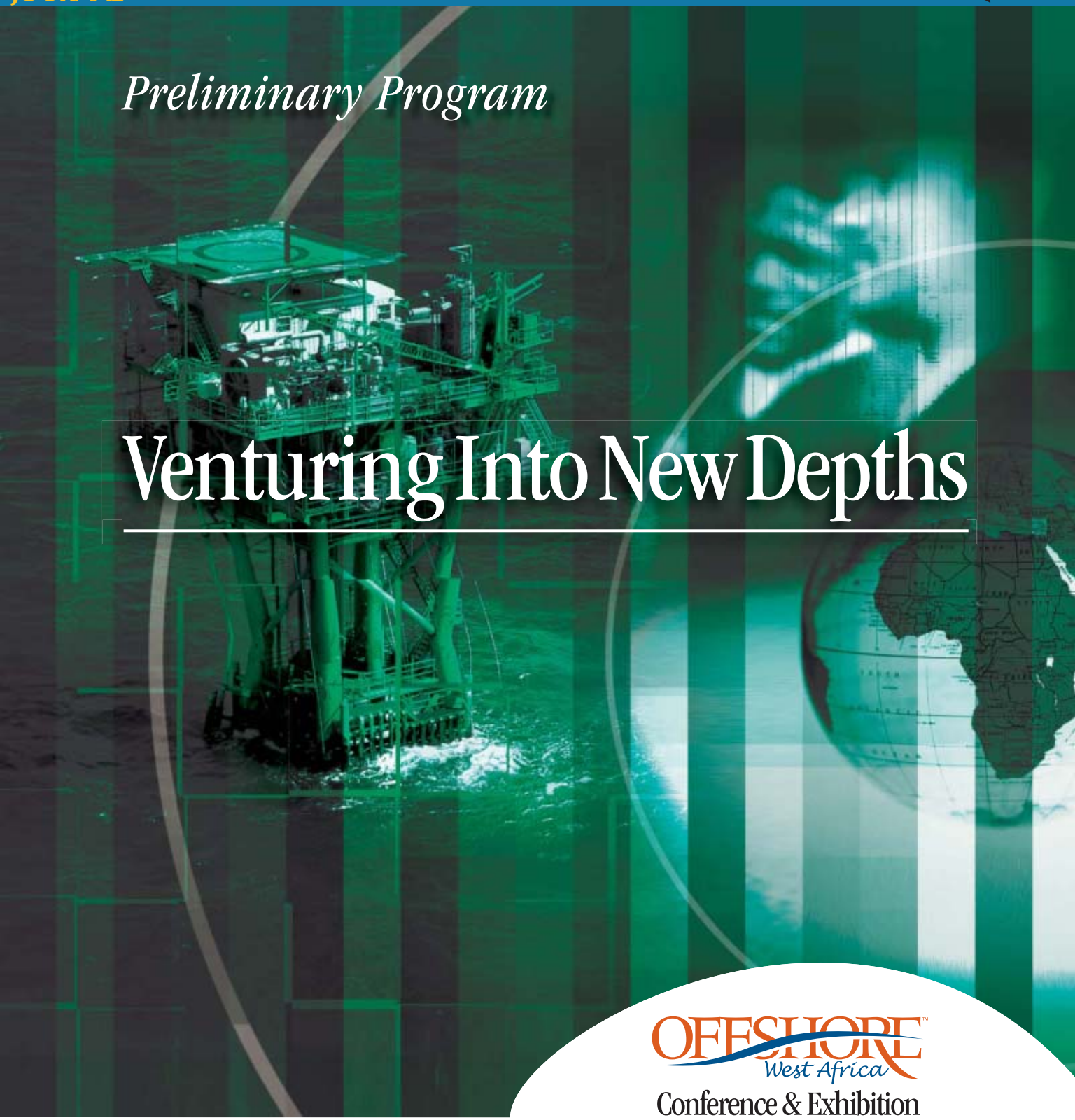

Venturing Into New Depths

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Venturing Into New Depths - More Deepwater Growth Ahead

The Offshore West Africa (OWA) Conference & Exhibition remains the leading source of information on new technology and operating expertise for this growing deepwater and subsea market. This year OWA will be held on 20 – 22 March 2007 and changes venue to the spacious International Conference Centre in Abuja, Nigeria.

Offshore West Africa is forecast to lead the world in annual spending for operations at $13 billion per year by 2010, according to energy analysts Douglas-Westwood. At the same time, the offshore industry is experiencing growth constraints because of the increasing demand for equipment and people. The experienced personnel needed to design, build, and operate drilling and production equipment are difficult to find and command a growing premium.

These offshore market forces are directing the industry toward new cost-cutting technology and other commercial innovations to overcome resource constraints. The value of the deepwater technology and expertise showcased at the Offshore West Africa conference is greater than ever.

Reflecting the increasing West Africa offshore activity, the Offshore West Africa conference has grown accordingly. OWA 2007 is expected to attract over 1,500 attendees and 100 exhibitors from the energy centers of Nigeria, Angola, Ivory Coast, Equatorial Guinea, United Kingdom, UAE, United States, France, Italy, Norway, The Netherlands, Niger, Russia, Australia, and Asia.

The Offshore West Africa technical sessions are presented in two concurrent technical tracks, with each presentation followed by a question-and-answer period.

Plan today to participate in the highest quality conference and exhibition in West Africa today!

Offshore West Africa Mission Statement

The mission of the Offshore West Africa conference is to provide an annual technical forum in the region dedicated to the advancement of oil and gas exploration and production activities offshore of Africa. This conference shall address the technical challenges to safely and cost-effectively develop both shallow-water and deepwater reserves. It shall also encourage the development of young professionals in the region.

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Event Overview:

The OWA Conference and Exhibition is the most significant offshore Africa deepwater technology event in the world. This event offers:

- A unique convocation of the world's leading executives, managers, and engineers from major and independent E&P companies focusing on West Africa's specific requirements.
- Visionary reports on the current and future state of technology in this frontier environment delivered by the key personnel involved in groundbreaking projects.
- A renewed focus on the ultra deepwater spectrum between 1,500 and 3,000 meters, viewed at the strategic level with case studies and reports on first-application technologies.
- An overview of the geopolitical and economic influences shaping the future of Africa exploration and production with input from major, independent, and state-owned operators and producers.

Technical Focus Areas: 2007

- Field Architecture & Economics
- Technology Development
- African Business Procedures and Practices
- Floating Facilities
- Lessons Learned in Deepwater Operations
- Subsea Technology
- Flow Assurance
- Gas Monetization Solutions
- Well Construction
- Sustainable Development
- Local Content
- Riser Technology
- Operations Management
- Flowlines and Pipelines
- Marginal Field Development
- Project Financing
- Geoscience/Subsurface

Conference Value:

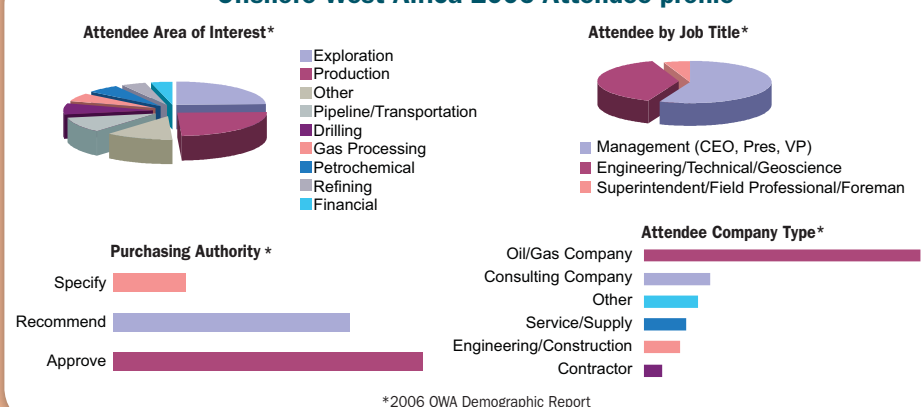
- Conference attendees include senior engineers, engineering staff and management.
- The exhibits showcase technology and capabilities to support improvement in African E&P operations.
- The conference facilitates dialogue among industry professionals and decision makers through focused presentations, extended Q&A sessions, and networking.
- The conference addresses new issues, challenges, and solutions associated with the expanding African offshore exploration and production activity.
- The exchange of knowledge represents experiences, applications, and current, real-world project examples.

Who Attends Offshore West Africa:

OWA is vital to industry leaders who seek information and emerging technology within Africa in order to plan future operations. OWA has a multi-national audience that provides a professional setting for making contacts and other business arrangements that are so vital to success within Africa.

The exhibitors at OWA have consistently recognized this conference as having the highest caliber of professionals in attendance. Exhibitors are exposed to technical specialists, key department managers, operating vice presidents, and leaders who influence purchasing decisions and bid lists.

Offshore West Africa 2006 Attendee profile



*2006 OWA Demographic Report

Why Exhibit?

As a company interested in the latest complexities of the Africa offshore market you cannot afford to miss this event. Exhibiting at this forum will provide opportunities to make instrumental connections that hold the key to successfully enter this revitalized market.

Exhibiting will provide opportunities to:

- Meet strategic decision makers face to face
- Build meaningful relationships
- Increase brand awareness and build brand value
- Source new suppliers

Exhibitor Benefits:

- Client invitations – providing your guests with free admission to the exhibit floor
- Listing on the OWA website and in the official OWA 2007 Conference Program – includes company contact information and a 30-word description of your company

Cost to Exhibit:

Space Only (US$ 530 per square meter – 9 square meters minimum)
Shell Scheme (US$ 585 per square meter – 9 square meters minimum)
Includes:

- Hard walls with 2.4 m back wall and sidewalls
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Bluewater Energy Services B.V.
Bridon International
Cameron
Cat Oil & Gas Ltd.
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ClampOn AS
Deepwater Oilbase, Nigeria
Det Norske Veritas (DNV)
Doris Engineering
Dril-Quip
E-sat
Easy Well Solutions
Energy Industries Council (EIC)
Energy Portfolios Manager Limited
ExxonMobil
Ferraz-Shawmut
FMC Technologies
Fred Olsen Production
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Furmanite Internationl Ltd.
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Global Industries Ltd.
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Hawke International
Hydratight Sweeney Ltd.
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Joe-Eboje International Limited
KM Europa Metal AG
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MTCTCL Energy Services Ltd.
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Modant Marine
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MTU Maintenance Berlin – Brandenburg GmbH
Nalco Company
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NNPC (Oil Industry Group)
Oil and Gas Free Zone Authority, ONNE
Oil States Industries, Inc.
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Weatherford Pipeline & Specialty Services
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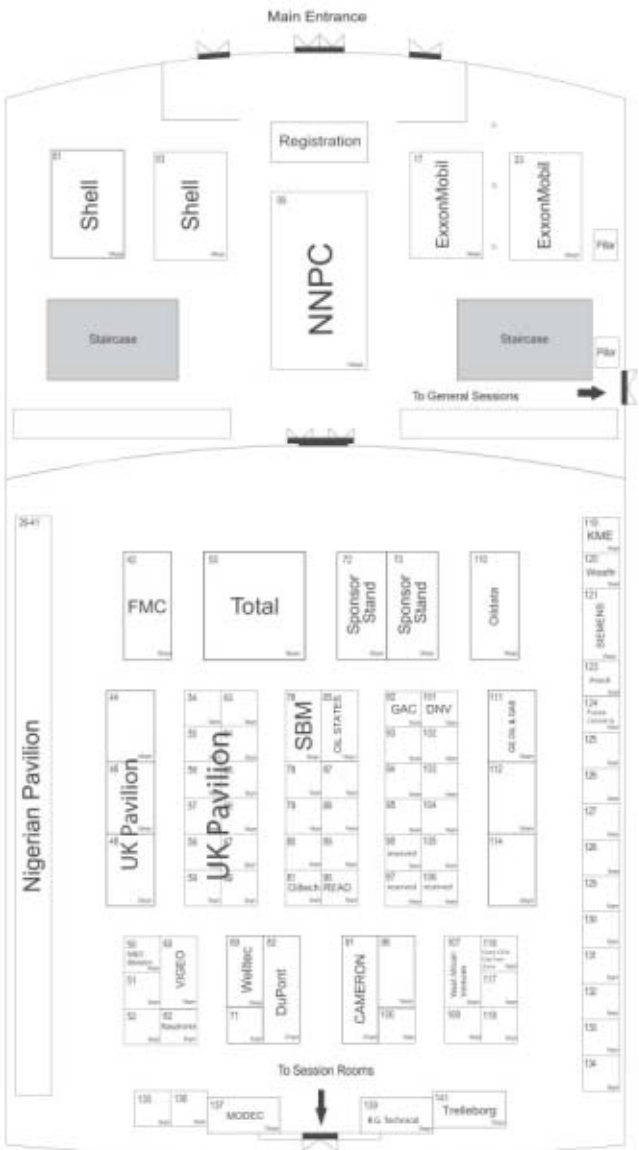
WECO Engineering & Construction Co. Limited
West African Ventures/Sea Trucks Group

Offshore West Africa

2007 Floor Plan

20 - 22 March 2007
International Conference Centre • Abuja, Nigeria

OFFSHORE West Africa CONFERENCE & EXHIBITION



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Offshore West Africa 2007 Preliminary Program

MONDAY, 19 MARCH 2007

18.00 – 20.00	**WELCOME RECEPTION** **EXHIBIT FLOOR**

TUESDAY, 20 MARCH 2007

09:00 – 11:00	**OPENING SESSION**
09:00 – 09:05	**NIGERIAN NATIONAL ANTHEM**
09:05 – 09:15	**WELCOME & INTRODUCTION** Eldon Ball – *PennWell Corporation*
09:15 – 09:20	**KEYNOTE ADDRESS** Dr. Edmund Daukoru – *Minister of State for Petroleum Resources* (Invited)
09:20 – 09:30	**INDUSTRY PERSPECTIVE** *NNPC* (invited)
09:30 – 10:00	**REGIONAL PERSPECTIVE** Desiderio da Graca Verissimo da Costa – Minister of Petroleum, Angola (Invited)
	REGIONAL PERSPECTIVE H.E Francisco Mabale, Secretary of State for Energy – *Equitorial Guinea* (Invited)
	REGIONAL PERSPECTIVE Minister of Energy & Oil, Mauritania (Invited)
10:30 – 11:00	**LOCAL CONTENT** *(speaker TBD) Dorman Long*
	MARKET FORECAST *(speaker TBD) Douglas Westwood*
11:00 – 11:15	**OFFICIAL EXHIBITION OPENING CEREMONY**
12:00 – 14:00	**LUNCH**
14:00 – 15:30	**SESSION 1A: LOCAL CONTENT & SUSTAINABLE DEVELOPMENT** Invited Chair: Joe Akande Co–Chair: Chidi Izuwah *Shell Petroleum Nigeria*
13:30 – 14:00	**Nigerian Content into Major Integrated Subsea Projects** Aloy Cheige – *Cameron*
14:00 – 14:30	**Small and Medium Scale Industries as Vehicles for Enhanced Local Content Development** Adedoyin Adeyinka – *Vigeo*
14:30 – 15:00	**Local Content Development in Nigeria: Re–engineering Supply Chain Processes for Effectiveness** Bunmi Obembe, – *Elf Petroleum*
15:30 – 16:00	**COFFEE BREAK**

Offshore West Africa 2007 Preliminary Program

16:00 – 17:30	**SESSION 2A: OFFSHORE DRILLING TECHNOLOGY & COMPLETION** Chair: Toyin Akinosho - *Chevron* Co–Chair: Mike Smart – *Cameron*
15:30 – 16:00	**Offshore Deviated Lean Profile 14"¾ Hole – 13"⅜ Casing Execution** M.Bedini, L.Pavesi and P.L. Spano, C.Okonkwo – *Nigerian Agrip Exploration*
16:00 – 16:30	**Openhole Caldding System Provides Effective, Economical and Reliable Zonal Isolation** Adedeji Oluwatosin and Vasco Felix – *Shell*
16:30 – 17:00	**Formation Pressure Testing While Drilling in the Challenging Offshore West Africa Environment** Ulrich Hahne – *Baker Hughes INTEQ*
16:00 – 17:30	**SESSION 2B: FIELD ARCHITECTURE & DEVELOPMENT** Invited Chair: Monday Otabor – *Addax Petroleum* Co–Chair: James E. Ibe – *ExxonMobil*
15:30 – 16:00	**Development of a Marginal Field** Pier Luigi Spano, Moreno De Lorenzi, Mauro Bedini, Pavesi Luca, Olaseni Okoosi and Chiedozie Okonkwo – *Nigerian Agrip Exploration*
16:00 – 16:30	**Erha North Subsea Tie–Back: Setting A Nigeria Deepwater Project Record.** Olasebikan Moses Afolabi – *Erha Nigeria Deepwater*
16:30 – 17:00	**Sharp–edge Technology in AKPO Deepwater Development Drilling** Frank Egbon and Thomas Gautherot – *TOTAL*
17:30 – 19:30	**OPENING NIGHT RECEPTION**

WEDNESDAY 21 MARCH 2007

08:30 – 10:00	**SESSION 3A: OFFSHORE PIPELINES & FLOW ASSURANCE** Chair: Claude Berbigier – *GEP* Co–Chair: Rick Hill – *EWI Microalloying*
08:30 – 09:00	**Lessen the Pressure with LiquidPower™ Flow Improvers** Tom Dujmovich and Armando Gallegos – *ConocoPhillips*; Eduardo Arevalo – *Del Rio SA*; Emmanuel Ogolo and Arthur Dede – *Nalco*
09:00 – 09:30	**Advancements in the Techniques of Connecting New Pipeline onto Existing Producing Pipeline Network without Interrupting its Production** Edgar Keijser and Jerry Woods – *Oil States Industries*
09:30 – 10:00	**Characterising Deepwater Seabed Sediments Using Pipeline Installation Records** Michael Cowie and Alan Watters – *Subsea7*
10:00 – 10:30	**COFFEE BREAK**

10:30 – 12:00	**SESSION 4A: SUBSEA TECHNOLOGY** Invited Chair: Bayo Sofidiya – *Esso E&P Lagos* Co–Chair: Philippe Bonneau - *Technip*
10:30 – 11:00	**Maximising the Availability of Subsea Production Systems through the use of Optimised Modular Architecture** Okafor Chika – *DORIS Engineering*
11:00 – 11:30	**Tordis Subsea Separation – A First Step Towards Deepwater Processing** Jens–Henrik Neuenkirchen and Rune Mode Ramberg – *Statoil*
11:30 – 12:00	**CameronDC All Electric Subsea System** Phil Jordan and Mike Smart – *Cameron*
10:30 – 12:00	**SESSION 4B: GAS MONETISATION & REGIONAL CHALLENGES 1** Invited Chair: Charles Osezua – *Addax Petroleum* Co–Chair: Adeyemi Suara – *SNEPCO*
10:30 – 11:00	**Optimized Development of an Offshore Marginal Oil Field in Nigeria** Adejumo Adebola – *IHS Energy*
11:00 – 11:30	**Strategic Management of Oil and Gas Projects** Raul Jimenez – *Global Offshore*
11:30 – 12:00	**37,000 bdp Depropanizer on New Build LPG FPSO** Shin Miura – *JGC Corporation*
12:00 – 13:30	**LUNCH** Round Table Discussion on Trends in West Africa Invited Chair: Dr. Rilwanu Lukman Invited Participants: H.E Atanasio Ela Ntugu – *Minister of Mines, Industry & Energy*; Francisco Mabale – *Secretary of State for Energy*; Alex Neyin – *Addax*; Dr. Kingsley Ojoh – *TOTAL Upstream; Shell, NNPC, Chevron (Sao Tome)*
13:30 – 15:00	**SESSION 5A: ASSET INTEGRITY (+USAN SPECIAL SESSION)** Chair: Richard Taylor – *DNV* Co–Chair: James Ibe – *ExxonMobil*
14:30 – 15:00	**Asset Integrity Management** Sture Angelsen – *DNV*
15:00 – 15:30	**Operational Experience with FPSOs Offshore West Africa** Boyd Howell and Oise Ihonde – *MODEC International Inc.*; K. Hurst and A. Duggal – *FMC Technologies*
15:30 – 16.00	**OFON Infill Completion Performance: Design and Lessons Learnt in Oil Producers and Water Injectors Wells** Jerome Profinet, Jude Atebe and Christian Terre – *Elf Petroleum Nigeria*

13:30 – 15:00	**SESSION 5B: INNOVATIVE TECHNOLOGY** Invited Chair: Todd Stevens – *Esso E&P Nigeria* Co–Chair: Nosa Omorodion – *Schlumberger Oilfield UK*
14:30 – 15:00	**Innovative Drilling Rig for Offshore and Onshore Operations** Frederik Nilsson – *Actipole*
15:00 – 15:30	**Successful Installation of Elastomeric Packers/Expandable Sand Screen in Subsea Openhole Completions Offshore Nigeria** Ezeukwu, Horace Awi, Tim Matinson, Bruno Stenger and Frederic Guinot, SPE – *Addax Petroleum Development Nigeria Limited*
15:30 – 16.00	**The "Wash Tank Process" on the Usan FPSO** Vu Van Khoi – *TOTAL*
16:00 – 16:30	**COFFEE BREAK**
16:30 – 18:00	**SESSION 6A: RESERVOIR GEOPHYSICS, ENGINEERING, FLUIDS & MONITORING** Chair: Professor K. Mosto Onuoha – *University of Nigeria* Co–Chair: John Addeh – *TOTAL*
16:30 – 17:00	**Very Fine Layers Delimitation Using the Wavelet Transform Modulus Maxima Lines (WTMM) Combined with the Discrete Wavelet Transform (DWT)** Sid Ali Ouadfeul – *University of Sciences & Technologies Algeria*
17:00 – 17:30	**AKPO Field (OML 130 Nigeria) Ocean Bottom Nodes 4D Survey** E.Ceragioli, F.Agbomedarho and A. Kabbej – *TOTAL*
17:30 – 18:00	**Complementing Formation Evaluation using Vertical Seismic Profiling** Mudi Kazeem Christopher – *University of Ibadan*
	SESSION 6B: BUSINESS ENVIRONMENT Invited Chair: *MD, Guranty Trust Bank Plc* Invited Co–Chair: Akin Osuntoki – *Vigeo*
16:30 – 17:00	**Successfully Achieving Deepwater Upstream Development Business Goals Using Project Finance** Paul Allen – *Project Executive Group*
17:00 – 17:30	**Venturing into New Depths – The Role of Contracts** Robert Omudu and Josiah Ottah – *Elf Petroleum*
17:30 – 18:00	**Doing Business in the Gulf of Guinea – A Legal Overview** Patrick Okonjo – *Okonjo, Odiawa & Ebie*
18.00 – 19:30	**NETWORKING RECEPTION** **EXHBIT FLOOR**
19:30 – 00:00	**CULTURAL EVENING AND ENTERTAINMENT**

Thursday, 22 March 2007

08:30 – 10:00	**SESSION 7A: GAS MONETISATION & REGIONAL CHALLENGES 2** Chair: Oise Ihonde – *MODEC International Inc.* Invited Co–Chair: Charles Adenji – *Chevron*
08:30 – 09:00	**Subsea Technology: Subsea Compression** Pierre Laboube – GE
09:00 – 09:30	**LNG Lite – How to Supplement LNG and Economically Transport Remote or Stranded Gas to Market** Dr.Bruce Hall – *SeaOne Maritime*
09:30 – 10:00	**GASCON Solutions** Olaberinjo Afolabi Francis – *University of Lagos*
10:00 – 10:30	**COFFEE BREAK**
10:30 – 12:00	**SESSION 8A: LOCAL CONTENT WEST AFRICA: PRACTICE & CASE STUDIES PANEL DISCUSSION** Invited Chair: Dr. Rilwan Lukman Co–Chair: Oluseyi Afolabi – *ExxonMobil*
	Panel Comprised of Representatives from: Bunmi Obembe – General Manager Nigerian Content – *TOTAL* *Invited Participants:* *Shell* *NNPC* *ExxonMobil* *Chevron* *Addax*
12:00 – 13:30	**CLOSING SESSION & LUNCH** **AWARDS CEREMONY CLOSING REMARKS**

Offshore West Africa
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20 – 22 March 2007
International Conference Centre • Abuja, Nigeria

OFFSHORE West Africa CONFERENCE & EXHIBITION

Exhibitor named below hereby applies for exhibit space at the Exhibition described above. Enclosed with this form is a deposit for 50% of the total booth/space rental. By signing below, Exhibitor agrees that this deposit is ***NON-REFUNDABLE***. If the 50% deposit did not accompany submission of this form, Exhibitor agrees to pay such deposit within 30 days of invoice. Exhibitor also agrees to pay the remaining 50% fee on invoice and not later than 18 December 2006 ***WITHOUT REFUND*** except as otherwise expressly stated in Section 9 on the back of this form.

Exhibiting company: _____

Physical address (for shipments): _____

Mailing address: _____

Address 2: _____

City/State/Zip: _____ Country: _____ Postal code: _____

Contact for exhibit arrangements: _____ Title: _____

Telephone: _____ Fax: _____

Email: _____ Website address: _____

Exhibitor's signature below signifies that Exhibitor has read, understands, and agrees to be bound by all the terms and conditions on the front and back of this form (including the EXHIBITION RULES, REGULATIONS, AND ADDITIONAL CONDITIONS, which constitute part of this Agreement). Also, by signing below, Exhibitor acknowledges that if Exhibitor has deemed it necessary or desirable, Exhibitor has raised and obtained satisfactory answers to any questions about the clarity, legibility or readability of the form.

SIGN HERE

Signer's full name: _____ Title: _____

Signature: _____ Date: _____

Exhibit Requirements:

☐ Space Only Exhibitor requires _____ square meters (minimum 9 m^2) of exhibit space. Space Only rate is US$530 per square meter.

☐ Shell Scheme Exhibitor requires _____ square meters (minimum 9 m^2) of exhibit space.
Shell Scheme space rate is US$585 per square meter. Shell scheme includes walls, fascia board with company name, 1 table, 2 chairs, electricity point, and lights.

1st Booth Choice _____ 2nd Choice _____ ☐ Best Available Total Cost $ _____

Please do not locate me near any of these exhibitors: _____ 50% Deposit Enclosed $ _____

Method of Payment:
Please check appropriate box. ☐ Check ☐ Wire Transfer **Credit Card:** ☐ VISA ☐ MasterCard ☐ AMEX ☐ Discover

Please send US wire transfer payments only to:
JPMorgan Chase Bank N.A., 300 South Riverside, 17th Floor, Chicago, IL 60606
ABA Number: 021000021 | SWIFT: CHASUS33
Account Name: PennWell Corporation | Account Number: 1009752

Please send non-US wire transfer payments only to:
JPMorgan Chase Bank N.A., P.O. Box 4972, 1 Chaseside, Bournemouth, BH7 7WH, United Kingdom | SWIFT: CHASGB2L |
Account Name: PennWell Corporation | US Dollars Account Number: 77033003
Euro Account Number: 77033001 | GBP Account Number: 77033002

Credit Card Number: | | | | | | | | | | | | | | | | | | **Expiration Date:** | | | |

Full Name (as it appears on card)**:** _____

By signing below, Card Holder acknowledges that he/she has read the front and back of this form, and agrees to be bound by all of its terms and conditions. Card Holder's signature also acknowledges that if Card Holder has felt it necessary or desirable, Card Holder has asked about anything unclear, illegible, or unreadable in this form (front and back), and has obtained answers that Card Holder regards satisfactory. Card Holder authorizes (and agrees not to dispute) charges up to the amount of this agreement at anytime from the date of submission of this form through the closing of this Show.

Card Holder Signature: _____ **Date:** _____

Return to Offshore West Africa 2007/Attn: Sue Neighbors

1700 West Loop South, Suite 1000 • Houston, Texas 77027 USA • Telephone (713) 963-6256 • Fax (713) 963-6212

For use by Show Management only:

Date Received: _____ Amount Received: $_____ Amount Due: $_____ Customer #_____

Booth Assigned: _____ Accepted For OWA 2007 By: _____ Print Name: _____

PennWell

Offshore West Africa
2007 Exhibit Space Agreement

20 – 22 March 2007
International Conference Centre • Abuja, Nigeria

OFFSHORE West Africa CONFERENCE & EXHIBITION

1. Offer and Acceptance. Exhibitor's submission of the 2007 Exhibit Space Agreement form, with or without a deposit, shall constitute an offer from Exhibitor to enter into such Agreement with PennWell Corporation, acting through its Petroleum Group ("PennWell" or "Show Management"). Such offer can only be accepted by PennWell's signing such Agreement at PennWell's place of business in Houston, Texas, USA. After signing in Houston, PennWell will send to Exhibitor a fully-signed copy of the one-page (front/back) Agreement document, which sending shall constitute PennWell's acceptance and cause the Agreement as a whole to become effective.

2. Arrangements of Exhibits. Exhibits shall be so arranged as not to obstruct the general view nor hide the exhibits of others. Plans for specially built displays not in accordance with these Exhibition Rules and the regulations set forth in the Exhibitor Service Kit must be submitted to Show Management before construction is ordered and/or begun. The Exhibitor Service Kit will be supplied to Exhibitor approximately four months before the Exhibition. With or without prior inspection, Exhibitor understands that by signing the 2007 Exhibit Space Agreement form, Exhibitor agrees to be bound by the Exhibitor Service Kit, which shall form part of the Agreement.

3. Soliciting/Photographs. Exhibitor is prohibited from distributing (i) literature, souvenirs, or other items from outside the boundaries of Exhibitor's booth, and (ii) literature, souvenirs, or other items that are other than Exhibitor's own materials; in each case, unless Exhibitor has obtained Show Management's prior written approval. These prohibitions apply before, after, or during Exhibition hours. Canvassing in exhibit halls or distribution of advertising matter, souvenirs, or any other items whatsoever by anyone who is not a paid exhibitor is strictly forbidden. Exhibitor is prohibited from taking photographs of other exhibits or other aspects of the Exhibition, without Show Management's prior written approval. Exhibitors may photograph only their own booth(s).

4. Exhibitor Personnel and Others. Technical specialists, qualified to discuss engineering details of their products, must man booths at all times during Exhibition hours. Show Management reserves the right to prohibit an exhibit or part of an exhibit that, in Show Management's sole discretion, may detract from the character or nature of the Exhibition.

5. Remedies. If Exhibitor fails to make any payment or otherwise breaches any provision of the Agreement, and fails to cure within a reasonable time (as defined in the next sentence) after Exhibitor has received written notice from Show Management specifying the breach, Show Management shall have the right to exercise (without further notice) any one or more of the following remedies at any time after such reasonable time has passed: (i) cancel the Agreement in whole or in part; (ii) evict Exhibitor from any or all of the space being rented by Exhibitor; (iii) have any of the Agreement's violated provisions specifically enforced; and/or (iv) exercise any other remedy available by rule of law. "Reasonable time" means: (i) immediately in the case of any breach occurring during the Exhibition; (ii) 24 hours, in the case of any failed payment and (iii) 5 days, in the case of any other breach. In addition, Show Management may keep any and all monies received from Exhibitor as liquidated damages, it being understood that PennWell's losses and damages from Exhibitor's breach of the Agreement as well as a precise value for services provided by PennWell prior to the conclusion of the Exhibition are difficult to ascertain and that the agreed liquidated damages are not intended and may not be construed as a penalty. Upon cancellation of the Agreement, Show Management may (without prejudice to any other available remedy) rent Exhibitor's space to any other exhibitor, or use such space in any other manner as Show Management deems necessary, in its sole discretion, without any obligation to Exhibitor.

6. Unoccupied Space. If any of Exhibitor's space remains unoccupied on opening day of the Exhibition, Exhibitor shall be deemed to have abandoned such space. Thereafter, Show Management shall have the right to rent such space to any other exhibitor, or use such space in any other manner as Show Management deems necessary, in its sole discretion, without any obligation to Exhibitor. This Section shall not be construed as affecting the obligation of Exhibitor to pay the full amount specified in the Agreement for space rental.

7. Liability. Neither Show Management nor its agents or representatives will be responsible for any injury, loss, or damage that may occur to Exhibitor or to Exhibitor's employees, invitees, licensees, or guests, or Exhibitor's property, from any cause whatsoever. Under no circumstances shall Show Management or its agents or representatives be liable for (i) any special, indirect, incidental, or consequential loss or damage whatsoever, or (ii) any loss of profit, loss of use, loss of opportunity, or any cost or damage resulting from any such loss. Exhibitor acknowledges that the risk allocations of this Section are reasonable based on the understanding that Exhibitor shall obtain, at its own expense, adequate insurance against any such injury, loss, or damage. Show Management shall not be liable for failure to perform its obligations under the Agreement as a result of strikes, riots, acts of God, or any other cause beyond its control. Anyone visiting, viewing, or otherwise participating in Exhibitor's booth or exhibit is deemed to be the invitee, licensee, or guest of Exhibitor, and not the invitee, licensee, or guest of Show Management. Exhibitor assumes full responsibility and liability for the actions of its agents, employees, independent contractors, or representatives, whether acting within or without the scope of their authority, and agrees to defend, indemnify, and hold PennWell, the exhibition hall, and their respective privies, harmless from and against claims resulting directly or indirectly from the actions or omissions of Exhibitor and/or Exhibitors agents, employees, independent contractors, or representatives, whether within or without the scope of authority. There is no other agreement or warranty between Exhibitor and Show Management except as set forth in this document and the Exhibitor Service Kit. The rights of Show Management under the Agreement shall not be deemed waived except through writing signed by an authorized officer of Show Management.

8. Insurance. For the term of the Agreement, Exhibitor shall at all times maintain insurance sufficient to cover the liabilities of Exhibitor under the Agreement. The amount and scope of such insurance shall be reasonably satisfactory to Show Management. Such insurance shall also provide coverage for Exhibitor's contractual obligations to defend, indemnify, and hold harmless, as stated in the Agreement. Show Management shall be added as an additional insured to such insurance. Exhibitor's insurer shall confirm to Show Management that such insurance cannot be cancelled or changed without thirty (30) days prior written notice to Show Management. Exhibitor agrees to provide Show Management a suitable certificate verifying that the required insurance is and will remain in force for the duration of the Exhibition.

9. Force Majeure. In case the Exhibition hall is damaged or destroyed by fire, the elements, or any other cause, or if circumstances make it unreasonably difficult for Show Management to permit Exhibitor to occupy the assigned space during any part or the whole of the Exhibition, then during such circumstances Show Management, the building management, and their respective privies will be released and discharged from the obligation to supply space, and Exhibitor will be reimbursed a proportionate share of the booth rental previously received by Show Management from Exhibitor. PennWell reserves the right to cancel, re-name, or relocate the Exhibition or change the dates on which it is held. If PennWell changes the name, relocates to another facility within the same city, or changes the dates for the Exhibition to dates that are not more than 30 days earlier or later than the dates originally scheduled, no refund will be due Exhibitor and PennWell shall assign to Exhibitor such other space as PennWell deems appropriate. In such case, Exhibitor agrees to use such space under the terms of the Agreement.

10. Jurisdiction and Attorney Fees. Should any legal action be commenced to resolve any dispute under the Agreement: (i) Exhibitor hereby consents to venue and jurisdiction in the federal or state courts located in Tulsa, Oklahoma (headquarters of PennWell), and agrees that no such action may be brought in a forum not located in Tulsa, Oklahoma; and (ii) the prevailing party shall be entitled to an award of litigation expenses, interest, and reasonable attorney fees, in addition to any other remedy obtained.

11. Taxes and Licenses. Exhibitor shall be responsible for obtaining any licenses, permits, or approvals required under local, city, state, or national law applicable to Exhibitor's activity at the Exhibition. Exhibitor shall be responsible for obtaining any tax identification numbers and paying all taxes, license fees, use fees, or other charges that may become due to any governmental authority concerning Exhibitor's activities related to the Exhibition.

12. Cancellations. In the event that Exhibitor wishes to cancel some or all of its allotted exhibit space, Exhibitor may request and Show Management may grant such cancellation, but only with the following understandings; (i) all cancellations must be requested in writing and addressed to PennWell Petroleum Group at the address below; (ii) Show Management is not required to refund any portion of moneys (the 50% deposit, full fee, or otherwise) previously paid by Exhibitor; (iii) if Exhibitor's cancellation request is received by Show Management after the Agreement has become effective, Exhibitor nevertheless agrees to pay the full fee based on the original space requirements, before such cancellation will become effective. Show Management assumes no responsibility for having included the name of Exhibitor in the Exhibition catalog, brochures, news releases, or other materials.

13. Changes. If Exhibitor requests an increase of its booth space after the Agreement has become effective, Show Management will use reasonable best efforts to accommodate such request, subject to space availability, additional fee payment, and other circumstances then prevailing. If Exhibitor requests a change that leads to a net reduction of booth space from original requirements, such request shall be covered by Section 12 above.

14. Other Matters. The Exhibition is owned and managed by PennWell Corporation, acting through its Petroleum Group whose main office is at PennWell 1700 West Loop South, Suite 1000; Houston, TX 77027 USA. All matters not expressly covered in the Agreement are subject to the reasonable decision of the Show Management, which decision shall be final.

By initialling below, Signer signifies that Exhibitor has read, understands, and agrees to be bound by all the terms and conditions set forth above.

_____ (signer's initials) for _____ (Exhibitor)

PennWell

Offshore West Africa 2007 Registration Form

20 - 22 March 2007
International Conference Centre • Abuja, Nigeria

OFFSHORE West Africa CONFERENCE & EXHIBITION

First Name: _____ Last Name: _____

Title/Position: _____

Company: _____

Address: _____

City/State/Zip: _____ Country: _____ Postal Code: _____

Telephone: _____ Fax: _____

Email: _____

Registration confirmation will be sent via-email, if a unique email address is provided above.

1. Type of Company or Organization:
- ☐ 10 Oil/Gas company
- ☐ 20 Consulting Company
- ☐ 30 Contractor
- ☐ 40 Engineering/Construction
- ☐ 50 Financial
- ☐ 60 Service/Supply
- ☐ 65 Government/Library/Education
- ☐ 70 Other _____

2. Job Function:
- ☐ 02 Management (CEO, Pres.VP)
- ☐ 05 Engineering/Technical/Geoscience
- ☐ 06 Superintendent/Field Professional/Foreman
- ☐ 10 Purchasing/Consulting
- ☐ 12 Other _____

3. Areas of Interest/Involvement:
- ☐ 10 Exploration
- ☐ 05 Drilling
- ☐ 01 Production
- ☐ 29 Gas Processing
- ☐ 23 Pipeline/Transportation
- ☐ 15 Refining
- ☐ 19 Petrochemical
- ☐ 39 Financial
- ☐ 46 Other _____

4. Purchasing Role: ☐ Specify ☐ Recommend ☐ Approve ☐ None

For Information on corporate packages, contact Carolyn Hall
Phone: +1 918 831 9160
Email: chall@pennwell.com

3 ways to register:

Pre-register on line before 14 March 2007.
Register on site after 14 March 2007.

1 Fax:
Direct: +1 918 831 9161
Toll-Free (US only): +1 888 299 8057

2 Website:
www.offshorewestafrica.com

3 Mail:
PennWell C&E Registration (OWA)
P.O. Box 973059
Dallas, TX 75397-3059 USA

For questions please call:
Phone: +1 918 831 9160
Toll Free (US only): +1 888 299 8016

PennWell®

Conference Fees:

1. Full Individual Conference Delegate*
Includes:
- Access to all Conference Sessions
- Access to the Exhibition Hall, including Opening & Networking Receptions
- Coffee Breaks in Exhibition Hall
- Delegate Lunch on Tuesday, Wednesday and Thursday (Ticketed)
- Conference Proceedings

☐ Paid By 15 December 2006.....US$ 1,310
☐ Paid After 15 December 2006.....US$ 1,525

2. Corporate Plan (10 delegates)*
Includes:
- Access to all Conference Sessions
- Access to the Exhibition Hall, including Opening & Networking Receptions
- Coffee Breaks in Exhibition Hall
- Delegate Lunch on Tuesday, Wednesday and Thursday (Ticketed)
- Conference Proceedings

☐ Paid By 15 December 2006.....US$ 9,170
☐ Paid After 15 December 2006.....US$10,675

Corporate Plan (11 to 20 delegates)*
☐ Paid By 15 December 2006.....US$13,100
☐ Paid After 15 December 2006.....US$15,250

3. Exhibit Delegate Full Conference
Includes:
- Access to all Conference Sessions
- Access to the Exhibition Hall, including move-in and move-out
- Access to Opening & Networking Receptions
- Coffee Breaks in Exhibition Hall
- Delegate Lunch on Tuesday, Wednesday and Thursday (Ticketed)
- Conference Proceedings

☐ Paid By 15 December 2006.....US$ 655
☐ Paid After 15 December 2006.....US$ 765

4. Young Engineer (35 or younger), African State Oil Companies & Other Government Agencies
Includes:
- Access to all Conference Sessions
- Access to the Exhibition Hall, including Opening & Networking Receptions
- Coffee Breaks in Exhibition Hall
- Delegate Lunch on Tuesday, Wednesday and Thursday (Ticketed)

☐ Paid By 15 December 2006.....US$ 655
☐ Paid After 15 December 2006.....US$ 765

5. Single Day Conference Delegate
Includes:
- Access to Conference Sessions on the corresponding day
- Access to the Exhibition Hall, including Opening & Networking Receptions
- Coffee Breaks in Exhibition Hall
- Luncheon on corresponding day (Ticketed)

☐ Tuesday.....US$ 615
☐ Wednesday.....US$ 615
☐ Thursday.....US$ 615

6. Exhibit Visitor.....US$ 25
Includes:
- Access to the Exhibition Hall, including Opening & Networking Receptions
- Coffee Breaks in Exhibition Hall

7. Conference Proceedings.....US$ 215

8. Additional Lunch Tickets (for non-delegates)
☐ Tuesday..... ( ) @ US$ 40/day
☐ Wednesday..... ( ) @ US$ 40/day
☐ Thursday..... ( ) @ US$ 40/day

TOTAL PAYMENT AMOUNT
(In U.S. funds only) **= US$** _____

*Your full-price registration fee includes a one-year paid subscription to *Oil & Gas Journal* (US$ 69.00 value).

Payment must be received prior to the conference. If payment is not received by the conference date, the registration fee must be guaranteed on charge card until proof of payment is provided. Make check payable to PennWell/Offshore West Africa 2007.

Cancellation: Cancellation of registration must be received in writing. Any individual, exhibitor or corporate registrations cancelled before 16 February 2007 will receive a 50% refund of registration fee. After 16 February 2007 no refunds will be permitted. Substitutions may be made at any time by contacting the registration office.

Method of Payment:
☐ Check enclosed (in U.S. funds only) ☐ Wire (Wire information will be provided on invoice)
Credit Card: ☐ Visa ☐ Mastercard ☐ AMEX ☐ Discover

Credit Card Number: _____ **Expiration Date:** _____ **CVS Code:** _____

Full Name (as it appears on card)**:** _____

Card Holder Signature: _____ **Date:** _____

(Required for credit card payment)

For more information, visit us online at www.offshorewestafrica.com or contact:

Conference Manager:
Victoria Knowles
Phone: +44 (0) 1992 656 630
Fax: +44 (0) 1992 656 735
Email: owaconference@pennwell.com

Exhibit Services Manager:
Isabelle Dessaux
Phone: +1 713 963 6236
Fax +1 713 963 6212
Email: owainfo@pennwell.com

Event Operations Manager
Paul Brown
Phone: +44 (0) 1992 656 652
Fax: +44 (0) 1992 656 704
Email: pbrown@pennwell.com

Exhibit and Sponsorship Sales:
Sue Neighbors
Phone: +1 713 963 6256
Fax: +1 713 963 6212
Email: owasales@pennwell.com

Registration Department:
Direct: +1 918 831 9160
Fax: +1 918 831 9161
Toll Free: +1 888 299 8016
Fax: +1 888 299 8057

PennWell Corporate Office
1421 S. Sheridan Road
Tulsa, OK 74112 USA
Phone: +1 918 835 3161
Toll Free: +1 800 331 4463

PennWell®