Week of Feb. 1, 2010/US$10.00

OIL&GAS JOURNAL®

International Petroleum News and Technology / www.ogjonline.com

Practical Drilling Technology

Fitch: Credit-quality outlook mostly stable
Marcellus shale gas play entry opportunities abound
Tabulation determines cycloalkanes in crude
Subsea isolation techniques advance

OIL&GAS JOURNAL®

Feb. 1, 2010
Volume 108.4

PRACTICAL DRILLING TECHNOLOGY

REGULAR FEATURES

COVER

The drilling rig is on an unconventional gas well in the Woodford shale play of southeastern Oklahoma. Newfield Exploration Co., Houston, operator of the well, has drilled more than 300 horizontal wells in the play, with some of these wells having laterals greater than 9,000 ft. The first article in OGJ's Practical Drilling Technology special, starting on p. 42, describes rigs one drilling contractor has built for unconventional plays. A second article discusses a drilling fluid design successfully used in an exploration well in Kazakhstan with a thick salt layer. Cover photo from Newfield. Photo above from Nabors Driling USA LP.

SOMEWHERE BETWEEN THE DECK CRANES, DEEPWATER WINCHES AND MOON POOLS, YOU'LL FIND THE KITCHEN SINK.

Hornbeck Offshore's new DP-3 430 class Multi-Purpose Support Vessels (MPSVs) have it all. The HOS Achiever and HOS Iron Horse were constructed to meet the specific demands of our deepwater exploration and production customers and are well-suited to support inspection, maintenance, repair, diving and construction activities. The HOS 430 MPSVs provide large, stable, DP-3 platforms with excellent seakeeping characteristics and can be configured to provide comfortable accommodations to more than 300 offshore personnel.

HOS 430
DP-3 MPSV

Learn more about the HOS Achiever and HOS Iron Horse, as well as our new DP-2 370 class MPSVs by visiting us online at www.hornbeckoffshore.com or calling us at (985) 727-2000.

HORNBECK OFFSHORE
Service with Energy®

General Interest

Exploration & Development

Technology

 Oil & Gas Journal (ISSN 0030-1388) is published 46 times per year by PennWell Corporation, 1421 S. Sheridan Rd., Tulsa, Okla., Box 1260, 74101. Periodicals postage paid at Tulsa, Okla., and at additional mailing offices. Oil & Gas Journal and OGJ are registered trademarks of PennWell Corporation. **POSTMASTER:** send address changes, letters about subscription service, or subscription orders to P.O. Box 3497, Northbrook, IL 60065, or telephone (800) 633-1656. Change of address notices should be sent promptly with old as well as new address and with ZIP code or postal zone. Allow 30 days for change of address. Oil & Gas Journal is available for electronic retrieval on Oil & Gas Journal Online (www.ogjonline.com) or the NEXIS® Service, Box 933, Dayton, Ohio 45401, (937) 865-6800. **SUBSCRIPTION RATES** in the US: 1 yr. $89; Latin America and Canada: 1 yr. $94; Russia and republics of the former USSR, 1 yr. 2,200 rubles; all other countries: 1 yr. $129, 1 yr. premium digital $59 worldwide. These rates apply only to individuals holding responsible positions in the petroleum industry. Single copies are $10 each except for 100th Anniversary issue which is $20. Publisher reserves the right to refuse non-qualified subscriptions. Oil & Gas Journal is available on the Internet at http://www.ogjonline.com. (Vol. 108, No. 4) Printed in the US. GST No. 126813153. Publications Mail Agreement Number 602914. Return Undeliverable Canadian Addresses to: P.O. Box 1632, Windsor, ON N9A 7C9.

PennWell, Houston office
1455 West Loop South, Suite 400, Houston, TX 77027
Telephone 713.621.9720/Fax 713.963.6285/Web site www.ogjonline.com
Editor Bob Tippee, bobt@ogjonline.com
Chief Editor-Exploration Alan Petzet, alanp@ogjonline.com
Chief Technology Editor-LNG/Gas Processing Warren R. True, warrent@ogjonline.com
Production Editor Guntis Moritis, guntism@ogjonline.com
Pipeline Editor Christopher E. Smith, chriss@ogjonline.com
Senior Editor-Economics Marilyn Radler, marilynr@ogjonline.com
Senior Editor Steven Poruban, stevenp@ogjonline.com
Senior Writer Sam Fletcher, samf@ogjonline.com
Senior Staff Writer Paula Dittrick, paulad@ogjonline.com
Survey Editor/News Writer Leena Koottungal, lkoottungal@ogjonline.com

Publisher Jim Klingele, jimk@pennwell.com
Vice-President/Group Publishing Director Paul Westervelt, pwestervelt@pennwell.com
Vice-President/Custom Publishing Roy Markum, roym@pennwell.com

PennWell, Tulsa office
1421 S. Sheridan Rd., Tulsa, OK 74112
PO Box 1260, Tulsa, OK 74101
Telephone 918.835.3161 / Fax 918.832.9290
Presentation/Equipment Editor Jim Stilwell, jims@pennwell.com
Associate Presentation Editor Michelle Gourd, michelleg@pennwell.com
Statistics Editor Laura Bell, laurab@ogjonline.com
Illustrators Mike Reeder, Kay Wayne
Editorial Assistant Donna Barnett, donnab@ogjonline.com
Production Director Charlie Cole

Washington
Tel 703.533.1552
Washington Editor Nick Snow, nicks@pennwell.com

Los Angeles
Tel 310.595.5657
Oil Diplomacy Editor Eric Watkins, hippalus@yahoo.com

OGJ News
Please submit press releases via e-mail to: news@ogjonline.com

Subscriber Service
P.O. Box 2002, Tulsa OK 74101
Tel 1.800.633.1656 / 918.831.9423 / Fax 918.831.9482
E-mail ogjsub@pennwell.com
Audience Development Manager Tommie Grigg, tommieg@pennwell.com

PennWell Corporate Headquarters
1421 S. Sheridan Rd., Tulsa, OK 74112

P.C. Lauinger, 1900-1988
Chairman Frank T. Lauinger
President/Chief Executive Officer Robert F. Biolchini

Member Audit Bureau of Circulations & American Business Media

LOGGING WHILE DRILLING

The Power of now

Samples in **hours**, *not* days. And all on LWD.

Until now, retrieving formation fluid samples during the drilling operation just couldn't be done. Sperry Drilling services introduces the **GeoTap® IDS** sensor, the peerless fluid identification and sampling tool that captures truly representative fluid samples on LWD. And does it in hours, not days.

Perfect for deepwater, the **GeoTap IDS** sensor can save you millions in hidden NPT costs routinely incurred with wireline sampling. And it helps reduce reservoir uncertainty even in the most complex environments—thanks to timely downhole capture, surface recovery and identification of multiple samples of uncontaminated formation fluids.

Samples in hours, not days. To learn more, visit www.halliburton.com/geotap.

Challenge. Solved.™

HALLIBURTON | Sperry Drilling

OGJ Newsletter

Feb. 1, 2010

International news for oil and gas professionals
For up-to-the-minute news, visit www.ogjonline.com

General Interest — Quick Takes

Partners block part of Maersk's acquisition

Maersk Oil said its agreement to buy Devon Energy Production Co. LP's interests in the Gulf of Mexico Cascade and St. Malo fields is off because partners declared preferential purchase rights in those fields.

Stakes in those two fields were part of a $1.3 billion transaction involving three fields that Devon announced last year (OGJ, Nov. 23, 2009, p. 34).

When the transaction was first announced, Maersk and Devon said the deal was subject to a waiver of preferential purchase rights by other partners in the fields. Maersk might still buy a stake in Jack field from Devon.

In a news release issued late Jan. 22, Maersk said a partner exercised its preferential rights at Cascade field, where Brazil's state-run Petroleo Brasileiro SA (Petrobras) and Devon each own 50% interest. Maersk also said partners had exercised their rights in St. Malo field where Devon owns 25% interest. Petrobras operates Cascade field.

Raymond James & Associates analysts reported Chevron Corp. and Statoil ASA exercised their preferential rights in St. Malo field. Chevron operates St. Malo field.

A Devon spokesman on Jan. 26 told OGJ that talks continue with Maersk about its existing plans to buy Devon's 25% interest in Jack field. Meanwhile, Maersk is in talks with Devon about possibly buying additional gulf assets from Devon that were beyond the initial three-field transaction.

Raymond James analysts issued a Jan. 26 research note suggesting that Jack field assets "could be taken by Maersk under the original agreement but may be left at the altar."

Valero to sell Delaware City assets

Valero Energy Corp., San Antonio, said Jan. 22 that it is in advanced negotiations to sell the assets of its terminal operation and discontinued operations at its 210,000-b/d Delaware City, Del., refinery to PBF Investments LLC, Greenwich, Conn.

Valero last year announced it was permanently closing the refinery, citing financial losses caused by "very poor economic conditions, significant capital spending requirements, and high operating costs." The refinery shutdown started immediately upon the announcement (OGJ Online, Nov. 20, 2009).

Bill Klesse, Valero chairman and chief executive officer, said there is no specific timetable for when negotiations might be completed. Valero has agreed that no removal of process equipment will take place while negotiations are under way.

PBF Investments is a joint venture of European refinery Petroplus and the US private equity firms of Blackstone Group and First Reserve Corp. Reuters reported Petroplus has been interested in US refining assets since early 2008.

Klesse noted Delaware Gov. Jack Markell has been working with state economic development officials and Valero to find a buyer for the Delaware City site.

Kazakhstan asks Kashagan partners to cut costs

Kazakhstan's state-owned KazMunaiGas (KMG) has proposed to its partners in the North Caspian Operating Co., which is developing Kashagan oil field, a reduction in spending to $7.4 billion from the planned $10.4 billion.

In addition to KMG, the consortium includes Total SA, ExxonMobil Corp., ConocoPhillips, Royal Dutch Shell PLC, Eni SPA, and Inpex.

"We have suggested that this year the expenditures be optimized and, as a result, the budget be cut down by nearly $3 billion. The proposal is now being reviewed by the authorized agency," KazMunayGas Pres. Kairgeldy Kabyldin told the country's energy ministry, giving no reason for the cut.

However, analyst IHS Global Insight observed that the Kazakh government and the Kashagan consortium have a "long history" of strained relations over cost overruns and delays at the Central Asian state's flagship offshore project.

After a protracted negotiations, KazMunaiGas doubled its interest in Kashagan, a takeover that analysts said was part of a global trend by governments to reclaim control over strategic energy assets.

IHS Global Insight noted that Kazmunaigaz raised its stake to 16.81% as a result of that previous round of "sparring" between the consortium and the government, which pushed back the timetable for production and agreed on a plan for controlling costs.

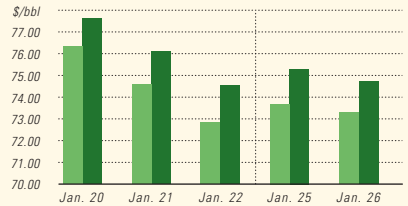
"Nevertheless, with the wild swing in oil prices over the past 18 months, expenditures in the first stage of the project have continued to be a source of friction," the analyst said, adding that Kabyldin's comments "hint that the government is keen to keep a lid on rising costs again, which are now expected to reach $38 billion by 2014."

Kabyldin's comments coincided with reports that Kazakhstan hopes to resolve a new emerged dispute with a group of foreign companies led by BG Group and Eni over the huge Karachaganak gas field this year.

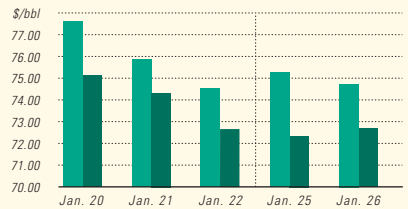
Earlier this month, Kazakhstan's Prime Minister Karim Masimov said his country was negotiating to purchase a stake in the Karachaganak gas-condensate project from Karachaganak Petroleum Operating BV (KPO), a consortium of BG, Eni, Chevron Corp., and OAO Lukoil. ✦

Industry Scoreboard

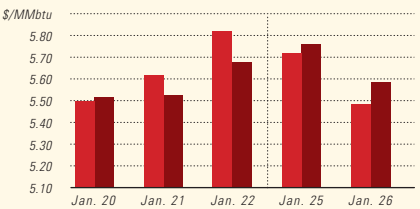
IPE BRENT / NYMEX LIGHT SWEET CRUDE



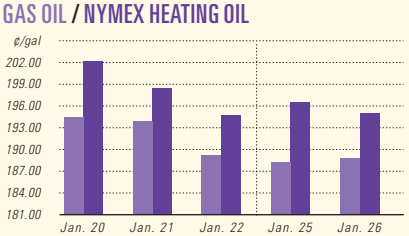
WTI CUSHING / BRENT SPOT



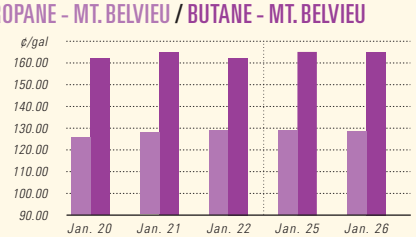
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



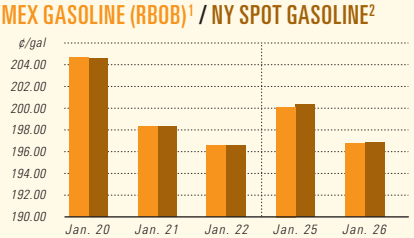
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



NYMEX GASOLINE (RBOB)[1] / NY SPOT GASOLINE[2]



[1]Reformulated gasoline blendstock for oxygen blending
[2]Nonoxygenated regular unleaded

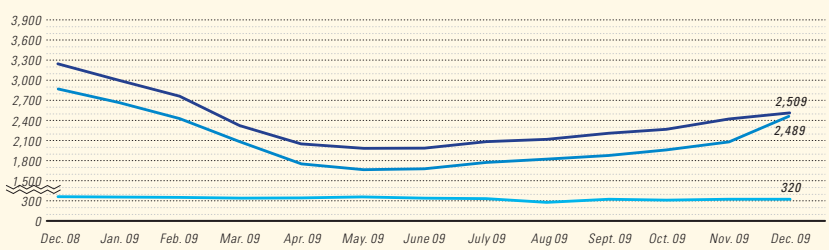
US INDUSTRY SCOREBOARD — 2/1

Latest week 1/15	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	8,789	8,809	–0.2	8,694	8,690	0.0
Distillate	3,660	3,929	–6.8	3,661	4,075	–10.2
Jet fuel	1,375	1,376	–0.1	1,373	1,357	1.2
Residual	471	727	–35.2	454	700	–35.2
Other products	4,503	4,293	4.9	4,527	4,302	5.2
TOTAL DEMAND	18,798	19,134	–1.8	18,709	19,124	–2.2
Supply, 1,000 b/d						
Crude production	5,480	5,151	6.4	5,469	5,246	4.3
NGL production[2]	2,057	1,792	14.8	2,042	1,797	13.7
Crude imports	8,454	9,636	–12.3	8,597	9,852	–12.7
Product imports	2,581	3,255	–20.7	2,646	3,321	–20.3
Other supply[3]	1,821	1,683	8.2	1,772	1,051	68.6
TOTAL SUPPLY	20,393	21,517	–5.2	20,526	21,266	–3.5
Refining, 1,000 b/d						
Crude runs to stills	13,875	14,476	–4.1	13,874	14,112	–1.7
Input to crude stills	14,136	14,635	–3.4	14,118	14,503	–2.7
% utilization	80.0	82.9	—	79.8	82.1	—

Latest week 1/15	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	330,565	331,036	–471	332,663	–2,098	–0.6
Motor gasoline	227,442	223,492	3,950	219,980	7,462	3.4
Distillate	157,138	160,401	–3,263	144,957	12,181	8.4
Jet fuel–kerosine	43,733	42,426	1,307	38,429	5,304	13.8
Residual	38,781	37,422	1,359	36,057	2,724	7.6
Stock cover (days)[4]			Change, %		Change, %	
Crude	23.8	23.9	–0.4	23.2	2.6	
Motor gasoline	25.9	25.1	3.2	24.8	4.4	
Distillate	42.9	43.3	–0.9	35.4	21.2	
Propane	25.8	29.7	–13.1	34.8	–25.9	
Futures prices[5] **1/22**			Change		Change	%
Light sweet crude ($/bbl)	76.82	80.07	–3.25	36.91	39.91	108.1
Natural gas, $/MMbtu	5.62	5.61	0.01	5.07	0.55	10.9

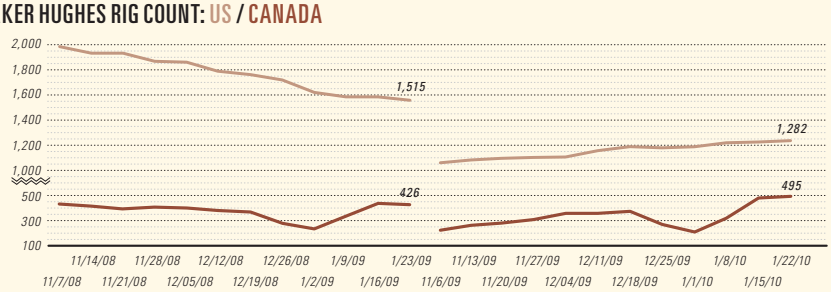
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average of daily closing futures prices.
Sources: Energy Information Administration, Wall Street Journal

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

OIL&GAS JOURNAL online research center™

OGJ Surveys in Excel!

Your Industry Analysis Made Cost Effective and Efficient

Put the *Oil & Gas Journal* staff to work for you! Employ our Surveys with accepted standards for measuring oil and gas industry activity, and do it the easy way through Excel spreadsheets.

Oil & Gas Journal Surveys are available from the OGJ Online Research Center via email, on CD, or can be downloaded directly from the online store. For more information or to order online go to www.ogjresearch.com.

FOR INFORMATION

E-mail:
orcinfo@pennwell.com

Phone:
1.918.831.9488 or 1.918.832.9267

TO ORDER

Web site:
www.ogjresearch.com

Phone:
1.800.752.9764 or 1.918.831.9421

Numbers You Can Count On Every Time!

OIL & GAS JOURNAL SURVEYS

Worldwide Refinery Survey — All refineries worldwide with detailed information.
E1080 Current E1181C Historical 1986 to current

Worldwide Refinery Survey and Complexity Analysis — Updated each January.
E1271 Refining Survey Plus Complexity Index

International Refining Catalyst Compilation — Refining catalysts with information on vendor, characteristics, application, catalyst form, active agents, etc.
CATALYST Current

OGJ guide to Export Crudes-Crude Oil Assays — Over 190 assays.
CRDASSAY Current

Worldwide Oil Field Production Survey — Field name, field type, discovery date, and depth.
E1077 Current E1077C Historical, 1980 to current

Enhanced Oil Recovery Survey — Covers active, planned and terminated projects worldwide. Updated biennially in March.
E1048 Current E1148C Historical, 1986 to current

Worldwide Gas Processing Survey — Gas processing plants worldwide with details.
E1209 Current E1219C Historical, 1985 to current

International Ethylene Survey — Information on country, company, location, capacity, etc.
E1309 Current E1309C Historical, 1994 to current

LNG Worldwide — Facilities, Construction Projects, Statistics
LNGINFO

Worldwide Construction Projects — List of planned construction products updated in May and November each year.

	Current	Historical 1996–Current
Refinery	E1340	E1340C
Pipeline	E1342	E1342C
Petrochemical	E1341	E1341C
Gas Processing	E1344	E1344C

U.S. Pipeline Study — There are 14 categories of operating and financial data on the liquids pipeline worksheet and 13 on the natural gas pipeline worksheet.
E1040

Worldwide Survey of Line Pipe Mills — Detailed data on line pipe mills throughout the world, process, capacity, dimensions, etc.
PIPEMILL

OGJ 200/100 International Company Survey — Lists valuable financial and operating data for the largest 200 publicly traded oil and gas companies.
E1345 Current E1145C Historical 1989 to current

Oil Sands Projects — Planned Canadian projects in four Excel worksheets. Includes mining, upgrading, in situ projects, and historical table with wells drilled back to 1985.
OILSANDPRJ

Production Projects Worldwide — List of planned production mega-projects.
PRODPROJ

See website for prices

www.ogjresearch.com

Exploration & Development — *Quick Takes*

Pay nearly tripled at gulf's Lucius find

An appraisal well 3,200 ft south of an Anadarko Petroleum Corp. group's December 2009 Lucius oil and gas discovery in the ultradeepwater Gulf of Mexico cut nearly three times the pay thickness of the discovery well.

The updip appraisal well, drilled to about 20,000 ft in 7,100 ft of water on Keathley Canyon Block 875 some 260 miles off Louisiana, encountered almost 600 net ft of light oil pay with additional gas-condensate pay in thick subsalt Pliocene and Miocene sands, Anadarko said. The discovery well found more than 200 ft of pay (OGJ Online, Dec. 10, 2009).

Anadarko described Lucius as a "major discovery" without giving a resource estimate. Wood Mackenzie Consultants floated an initial estimate of 150-200 million bbl of oil and natural gas liquids and around 1 tcf recoverable. Lucius is likely large enough for stand-alone development, the consultant said.

Anadarko said, "The reservoirs are characterized by excellent porosity and permeability and contain high-quality oil. We anticipate additional appraisal activity in 2010 as we continue to evaluate development options for this very large accumulation."

Lucius is 70 miles south of infrastructure at the Red Hawk spar and 7.5 miles east of Chevron's Buckskin, a 2009 Paleogene discovery (OGJ Online, Feb. 6, 2009).

Anadarko operates Lucius with 50% working interest. Plains Exploration & Production Co. has 33.33%, and Mariner Energy Inc. has 16.67%.

Multiple pays yield gas in western New York

Gastem Inc., Montreal, found gas in one sand and two shales with good thickness at its first well in a planned drilling program on 35,000 acres in western New York.

The Ross-1 vertical well in Otsego County yielded gas from Ordovician Utica shale, Silurian Oneida sand, and Devonian Marcellus shale, the company said. TD is 4,950 ft. The three zones "will be the subject of extensive programs in the coming months," the company said.

Gas flowed on penetration of the Marcellus and was flared at modest rates from natural fractures. The organic-rich Oakta Creek and Union Springs members of the Marcellus formation showed higher permeability than anticipated and were of encouraging thickness. The Marcellus shale was not stimulated because of the present regulatory situation.

Oneida flowed at the rate of 2 MMcfd of gas on a 4-hr drillstem test and has become one of Gastem's primary targets in the area.

A completion in the Utica shale was performed using the frac volume approved under current New York state regulations that authorize use of 80,000 gal of water. This modest vertical frac in one of the Utica's three members resulted in a sustained rate of more than 70 Mcfd over a 24-day test.

Final results of laboratory core analysis for all formations for the determination of original gas in place and rock properties will be completed in about a month. When review work is completed, information will include recoverable volumes across the Ross property and a resource estimate for Gastem's acreage.

ExxonMobil to expand Iraq's West Qurna 1 field

ExxonMobil Iraq Ltd. signed an agreement with the Iraq Ministry of Oil to redevelop and expand West Qurna 1 field in southern Iraq.

The agreement was signed in Baghdad in the presence of the Iraq Oil Minister Hussain al-Shahristani and Rob Franklin, president of ExxonMobil upstream ventures. The consortium members are ExxonMobil as the lead contractor with 60% interest, Oil Exploration Co. (owned by the Iraq government) with 25% interest, and Royal Dutch Shell PLC with 15% interest.

Franklin said ExxonMobil would continue discussions with the Iraqi government on other opportunities to help develop the country's resources.

As part of the agreement, ExxonMobil will focus on recruitment and development of local employees, development of qualified local vendors for the supply of goods and services, and on supporting corporate citizenship initiatives in health, education, and infrastructure.

Two competing consortia—one led by ExxonMobil and the other by OAO Lukoil—submitted bids that met Iraq's conditions for the 8.6 billion bbl West Qurna 1 field, including Iraq's price of $1.90/bbl per additional barrel. ExxonMobil proposed an additional 2.1 million b/d, while Lukoil offered 1.5 million b/d for the field, which now produces 279,000 b/d (OGJ Online, Oct. 19, 2009).

ConocoPhillips, Statoil to explore Chukchi Sea

ConocoPhillips and Statoil USA E&P have entered into a deal for Statoil to acquire 25% working interest in 50 ConocoPhillips leases acquired in the Chukchi Sea OCS lease sale in 2008.

ConocoPhillips will retain operatorship and majority working interest in these leases.

Statoil and ConocoPhillips have conducted joint operations for more than 30 years on the Norwegian continental shelf (NCS). Their NCS operating experience provided both extensive expertise in tackling harsh environments as well as developing new technology to enhance recovery from existing fields.

"By adding on these leases to the 16 we already have in Chukchi, we have now acquired a sizable acreage portfolio to explore in the coming years," said Tony Dore, heading up Statoil's exploration group in North America.

ConocoPhillips' initial drilling in the Chukchi Sea is scheduled for 2012.

In addition to undisclosed financial considerations from Statoil, ConocoPhillips will also acquire 50% working interest in 16 Statoil-operated Gulf of Mexico leases and acquire all of Statoil's 25% working interest in five additional gulf leases operated by ConocoPhillips. All of the involved gulf blocks are in the emerging Lower Tertiary play where ConocoPhillips has participated in the 2009-announced discoveries Tiber and Shenandoah.

Chevron, Woodside make finds off W. Australia

Two operators have made recent gas finds off Western Australia.

Chevron Australia's Yellowstone-1 wildcat in permit WA-268-P in the Greater Gorgon region has intersected a 137-m gas column.

The find follows last year's discoveries nearby at Satyr-1 and Achilles-1. All of them bode well in support of Chevron's plans to eventually turn the Gorgon-Jansz-Io LNG development into a five-train project.

At the moment the focus is on three trains and a total of 15 million tonnes/year of LNG. However as the gas reserves build up with new discoveries, the sights will be lifted to a plant with greater capacity output.

Separately, Woodside Petroleum Ltd. reported reaching good gas sands with its Noblige-1 wildcat, which was drilled in permit WA-404-P in the Greater Pluto field area.

Measurement-while-drilling logs at several levels in the well have indicated natural gas, one of them over a 300-m gross interval in the intra-Triassic age primary target.

The well is now drilling ahead into deeper targets and Woodside will wait until reaching total depth before undertaking a full evaluation. This will involve a full suite of wireline logs and pressure data to indicate the number of hydrocarbon zones, their size, and potential.

Nobligwe-1 is close to the previous Martell discovery, which confirmed a 110-m gas column and the presence of a gas-water contact in 2009.

The new find is welcome news for Woodside, which is attempting to secure additional gas reserves for the second train at its Pluto LNG facility proposed for the Burrup Peninsula plant.

Noblige-1 is part of the company's exploration campaign of up to 20 wells in the Greater Pluto area that began in October 2009 with the Pelion-1 and Eris-1 wells in WA-34L.

Noblige is being drilled by the Jack Bates semisubmersible rig, but the next well, Larsen-1, will be drilled with the Maersk Discoverer semisubmersible, as Jack Bates is due for release to Hess Corp. for its proposed 16-well program in the Carnarvon basin region off Western Australia. ✦

Drilling & Production — *Quick Takes*

Chevron proceeds with Papa Terra off Brazil

Chevron Overseas of Brazil Ltd. will proceed with the development of the Papa Terra project, its second deepwater field off Brazil.

Petroleo Brasileiro SA (Petrobras) is the project's operator and had announced in January 2009 the suspension of the development because of uncertain market conditions and excessive costs (OGJ, Jan 26, 2009, Newsletter).

Papa Terra will produce heavy 14-17° gravity oil from Block BC-20 in the southern Campos basin, about 70 miles off the coast in 3,900 ft of water. The production facilities will include the first tension-leg well platform off Brazil. The TLP will connect to a floating production, storage, and offloading vessel that has a 140,000 bo/d production capacity.

Chevron expects production from Papa Terra to begin in 2013.

Chevron holds a 37.5% interest in the $5.2 billion Papa Terra project and estimates that the field will recover 380 million bbl of oil. Off Brazil, Chevron started production from Frade in 2009—its first deepwater project—and also holds a 30% nonoperated interest in Maromba field, where work continues to select an optimal development plan.

In the Santos basin, Chevron holds a 20% nonoperated interest in Block BS-4, where the company continues to evaluate development plans to commercialize Atlanta and Oliva fields.

Iraq, Eni group sign Zubair field agreement

The Iraqi government has signed another technical services contract for redevelopment of a giant oil field.

Eni, Occidental Petroleum Corp., and Korea Gas Corp. agreed with state-owned South Oil Co. and Missan Oil Co. as state partner to redevelop Zubair field near Basra. The companies signed an initial agreement last November (OGJ Online, Nov. 16, 2009).

Led by Eni, the consortium plans to increase Zubair production from its current level of about 200,000 b/d to 1.2 million b/d within 6 years and to keep output at that level for 7 years.

The group will earn $2/bbl on incremental production after output has increased 10%. The agreement includes a cost-recovery mechanism. Zubair Field Operating Division will manage the rehabilitation and expansion project, staffed mainly by employees of South Oil Co. Interests are Eni 32.81%, Oxy 23.44%, Korea Gas 18.75%, and Missan Oil 25%.

The ministry describes Zubair as a series of structural traps in a northwest-southeast trending anticline about 20 km southwest of the city of Basrah. The field has four domes named Al-Hamar, Shuaiba, Rafidyah, and Safwan. Safwan extends into Kuwait, where it is known as Abdalli field.

Zubair has produced from the Upper Cretaceous Mishrif formation and upper and lower units of the Lower Cretaceous Zubair formation, all candidates for redevelopment.

The government recently has signed service contracts for similar work by a group led by ExxonMobil Iraq Ltd. at West Qurna oil field (first phase) and by Royal Dutch Shell PLC in Majnoon oil field, both giants in southern Iraq (OGJ Online, Jan. 18, 2009, and Jan. 25, 2009). ✦

Processing — *Quick Takes*

Petrotrin's cost of refinery upgrade escalates

State-owned Petroleum Co. of Trinidad & Tobago Ltd. (Petrotrin) said the cost of upgrading its 175,000-b/d Pointe-a-Pierre refinery has escalated to $1.3 billion from earlier projections of just $350 million.

Imtiaz Ali, the company's general manager of strategy and business development, said the increase was due to rising construction costs and delays in receiving certificates of environmental clearance from regulators.

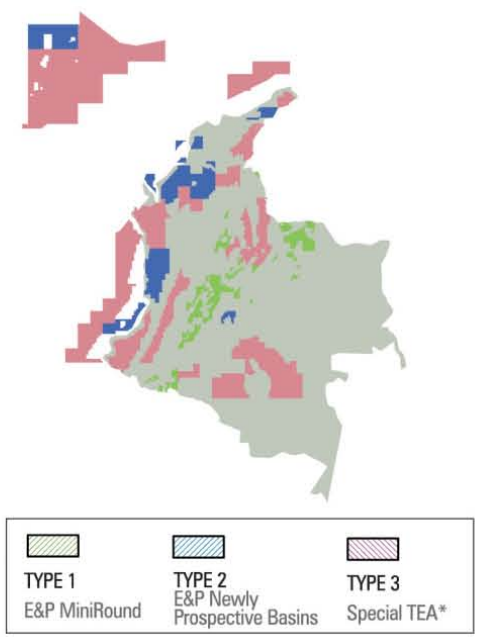
Ali said, "It is true we made mistakes in the way we estimated

COLOMBIA:
The perfect environment for Hydrocarbons

Open Round COLOMBIA 2010

START THE DECADE WITH THE BEST INVESTMENT OPPORTUNITIES

This year the best investment, exploration and production opportunities for hydrocarbons will be in Colombia. The Colombia National Hydrocarbons Agency, ANH, shall offer areas for Special TEAs*, E&P and MiniRound in 2010.



*Technical Evaluation Area

The Colombian Government and the ANH cordially invite you to the Open Round Colombia 2010 ROAD SHOW, that will be held on:

ROAD SHOW	
CITIES	DATE
TORONTO	February 2 Presentation
CALGARY	February 4 Presentation
	February 1-5 Data Room
HOUSTON	February 9 Presentation
	February 8 - 12 Data Room
DALLAS	February 11 Presentation
NEW YORK	February 25 Presentation
MADRID	March 1 Presentation
EDINBURGH	March 3 Presentation
LONDON	March 5 Presentation
	March 1-5 Data Room
RIO DE JANEIRO	March 23 Presentation
	March 23 - 24 Data Room
SIDNEY	March 30 Presentation
PERTH	April 1 Presentation
SINGAPORE Optional	April 5 Presentation
SHANGHAI	May 10 Presentation
	May 10-16 Data Room

Information subject to changes

AGENCIA NACIONAL DE HIDROCARBUROS
Calle 99 No. 9A - 54 (Piso 14)
PBX: (57+1) 593 1717 - Fax: (57+1) 593 1718
Bogotá - Colombia
www.anh.gov.co

ANH
The people to speak to

For more information register at:
rondacolombia2010@anh.gov.co
www.rondacolombia2010.com
www.colombiaround2010.com

the cost of some of these projects, but we have learned our lessons. In addition, we did not realize that the cat cracker required so much work until we pulled it down, and that also significantly added to the increase in costs."

Speaking at an energy conference in Port of Spain, Ali said the refinery upgrade—to be completed by November—was crucial because its products were increasingly uncompetitive and margins were declining. He said the upgrade will allow the refinery to produce more gasoline in its mix and a higher-quality diesel fuel.

Petrotrin also produces 74,000 boe/d, and Ali plans to drill an additional 18 developmental wells to increase production and make it more reliable.

He revealed Petrotrin will undertake 215 sq km of 3D seismic on land that could lead to additional drilling for oil.

Petrotrin has 446.7 million boe of proved reserves.

KBR to offer BP resid hydrocracking process

BP PLC has signed an agreement under which KBR will offer licensing and engineering services for a proprietary resid hydrocracking process.

KBR said it will market BP's Veba Combi-Cracker (VCC) technology globally for refining, heavy-oil upgrading, and coal-to-liquids processing.

VCC feeds vacuum resid to a slurry phase reactor at 200 bar with an antifoaming agent. Hydrogen bubbles through the slurry mixture from below. Downstream of the slurry reactor, a separator removes unconverted material and the additive, while lighter products move to a fixed-bed catalytic hydrotreatment vessel for removal of nitrogen and sulfur. Typical products are heavy gas oil, light gas oil, naphtha, and light olefins.

BP says VCC achieves a resid conversion rate of 95%, compared with slightly above 70% for delayed coking.

In addition, VCC's liquid yield exceeds 100% because of the addition of hydrogen, while liquid yields of cokers typically fall below 80%, BP says. BP acquired the technology when it absorbed Veba of Germany in 2002.

A 3,500-b/d VCC demonstration plant was built in the 1980s near what is now BP's 264,000-b/cd Gelsenkirchen refinery in Germany. Poor economic conditions forced closure of the unit in 2000. BP also has operated a 200-b/d VCC pilot plant at Gelsenkirchen able to process a wide range of feedstocks. ✦

Transportation — *Quick Takes*

Cleanup progresses in Port Arthur oil spill

The US Coast Guard said about half the 450,000 gal of crude oil spilled into the Sabine Neches Waterway at Port Arthur, Tex., on Jan. 23 had been recovered, evaporated, or dispersed by Jan. 25.

The spill occurred when the 95,660-dwt Eagle Otome tanker collided with a barge after apparently losing power.

Although the incident forced closure of the waterway, the four major refineries in the Port Arthur-Beaumont area were reported to be operating at normal rates. Owners and capacities are Total SA, 174,000 b/d; Valero Energy Corp., 250,000 b/d; ExxonMobil Corp., 345,000 b/d; and Motiva Enterprises, 285,000 b/d.

USCG said the spill affected 9 miles of shoreline. It said cleanup involved 27 skimming vessels and 36 vessels deploying and working 59,800 ft of boom. The 210-ft Texas Responder recovery vessel was on scene. Lightering was planned for the Eagle Otome and two barges involved in the collision, which were being pushed by the towing vessel Dixie Vengeance.

Indonesia targets market for LNG sales

Indonesia's state-owned PT Pertamina and state gas distributor PT Perusahaan Gas have found domestic buyers for most of the liquefied natural gas to be produced from their planned floating terminal in Teluk Jakarta Bay.

"In 2011 we require huge amounts of LNG to fuel our power generators and we will probably absorb 80% of LNG supplied through the floating terminal," said Dahlan Iskan, recently appointed as president director for state power company PT Perusahaan Listrik Negara (PLN).

"We also asked Pertamina to immediately begin the construction of the terminal because the supply gas for PLN will depend on the terminal," said Dahlan, who added that a failure to access LNG would force the firm to use gasoline, "which is more expensive."

In 2009, PLN predicted it would require 2,233 MMscfd in 2010, about 1,300 MMscfd more than the available supply of about 900 MMscfd. But the firm sees increased demand growth, saying it will need 2,474 MMscfd by 2012, while the domestic supply may only be 1,781 MMscfd.

Meanwhile, most of the remaining supply from the Teluk Jakarta site also will go to the domestic market, according to Evita H. Legowo, director general for oil and gas at the Energy and Mineral Resources Ministry. She said "state fertilizer company PT Pupuk Kujang will absorb 18% of supply from the LNG terminal."

The Teluk Jakarta LNG terminal, 70% owned by Pertamina and 30% by PGN, will eventually have a capacity of 500 MMscfd, and is expected to take $200 million of investment before going online by September 2011.

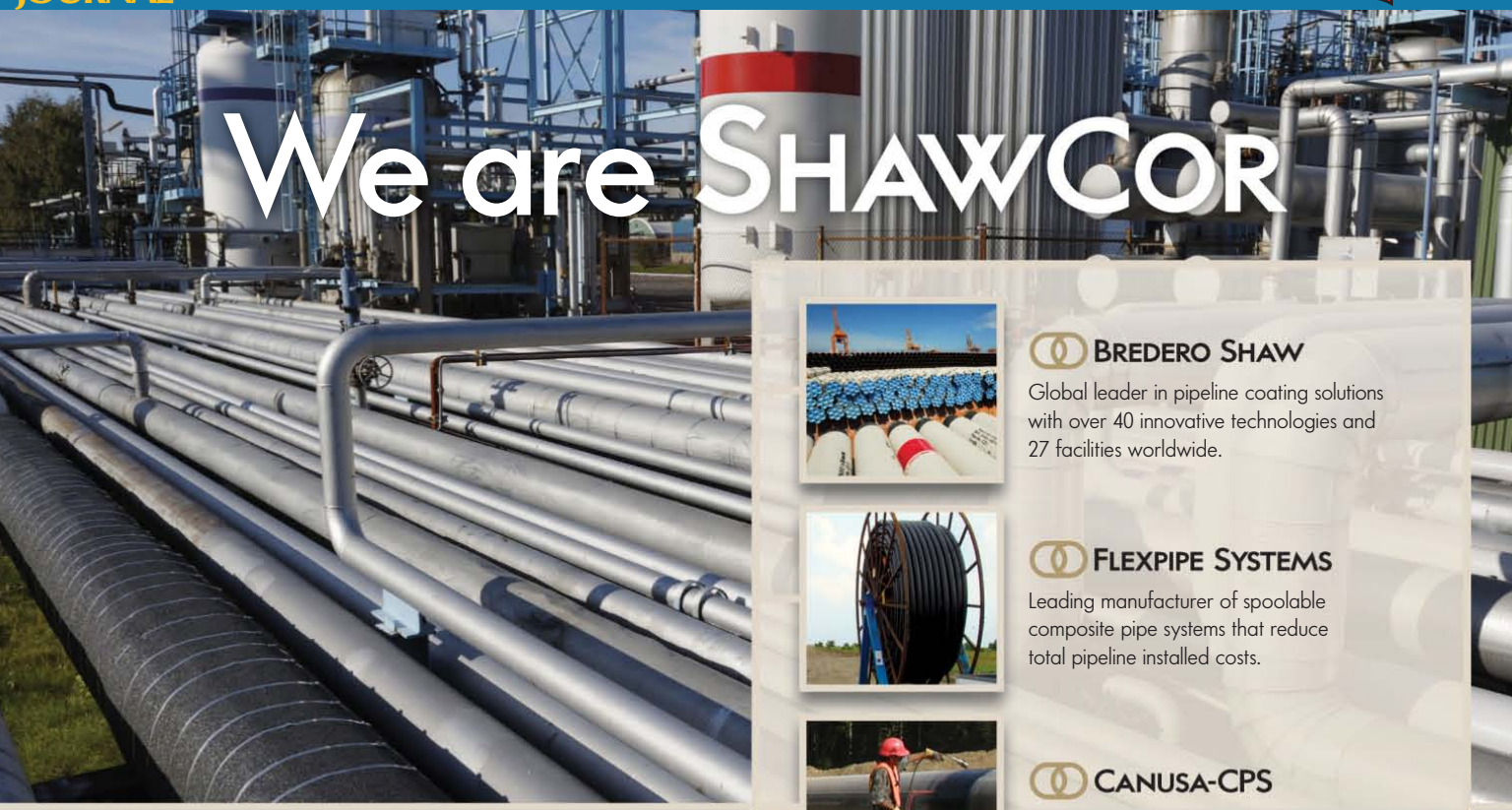
Chevron signs LNG deals with Kyushu Electric

Chevron Australia has signed multiple agreements with Japanese power utility Kyushu Electric Power Co. Inc. for delivery of LNG from Chevron's Gorgon and Wheatstone gas projects off Western Australia.

Under the heads of agreements, Kyushu will receive 300,000 tonnes/year of LNG from Gorgon for 15 years. Kyushu will also acquire 1.83% of Chevron's equity share in the Wheatstone field licenses and 1.37% interest in the proposed Wheatstone gas processing facilities to be developed onshore at Ashburton North near Onslow.

In addition Kyushu will purchase 700,000 tpy of LNG from Wheatstone for 20 years. This sales volume is over and above the LNG that Kyushu will lift as an equity partner in the project, so that Kyushu's total uplift will be 800,000 tpy from Wheatstone.

Start of gas production from Gorgon is expected in 2014. Final investment decision on Wheatstone is expected in 2011. ✦



We are SHAWCOR

The Global Leader

5,200 dedicated employees. 70 fixed and mobile facilities, strategically located in 25 countries. ShawCor is the global leader in pipeline products and services.

Reliable Execution

80 years of experience. Over 300 projects executed every year. Leadership in HSE performance. ShawCor is the industry's most reliable partner.

Innovative Solutions

240 active patents. More than 50 leading technologies. 42 researchers at 3 international R&D facilities. ShawCor works closely with its clients to develop solutions that meet their unique requirements.

Financial Strength & Stability

40 years as a publicly traded company. The strongest balance sheet in the industry. ShawCor has the strength and stability to undertake the largest projects and ensure successful completion.

www.shawcor.com

BREDERO SHAW

Global leader in pipeline coating solutions with over 40 innovative technologies and 27 facilities worldwide.

FLEXPIPE SYSTEMS

Leading manufacturer of spoolable composite pipe systems that reduce total pipeline installed costs.

CANUSA-CPS

Global leader in field-applied coating solutions and application technologies.

SHAW PIPELINE SERVICES

Total weld inspection capabilities, backed by experienced personnel and the most advanced NDT systems in the industry.

GUARDIAN

Integrated inventory, inspection and refurbishment services, providing complete OCTG management solutions.

DSG-CANUSA

Innovative heat shrink tubing and cable accessories for automotive and electrical applications.

SHAWFLEX

Quick response solutions for control, instrument and specialty cables.

SHAWCOR
ENERGY SERVICES • GLOBAL SOLUTIONS

Calendar

✦ Denotes new listing or a change in previously published information.

OIL&GAS JOURNAL online

Additional information on upcoming seminars and conferences is available through OGJ Online, Oil & Gas Journal's Internet-based electronic information source at http://www.ogjonline.com.

2010

FEBRUARY

Deep Offshore Technology International Conference & Exhibition, Houston, (713) 963-6271, (713) 963 6296 (fax), e-mail: registration@pennwell.com, website: www.dotinternational.net. 2-4.

IADC/SPE Drilling Conference and Exhibition, New Orleans, (713) 292 1945, (713) 292 1946 (fax), e-mail: info@.org, website: www.iadc.org. 2-4.

Russia Offshore Annual Meeting, Moscow, +44 (0) 20 7067 1800, +44 (0) 20 7242 2673 (fax), website: www.theenergyexchange.co.uk. 2-4.

Global Petrochemicals Conference & Annual Meeting, Vienna, Austria, +44 (0) 1242 529 090. +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 9-11.

SPE International Symposium & Exhibition of Formation Damage Control, Lafayette, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 10-12.

NAPE Expo, Houston, (817) 847-7701, (817) 847-7703 (fax), e-mail: info@napeexpo.com, website: www.napeonline.com. 11-12.

Annual Petroleum Coke Conference, Seattle, (832) 351-7828, (832) 351-7887 (fax), e-mail: petcoke.conference@jacobs.com, website: www.petcokes.com. 12-13.

SPE North Africa Technical Conference & Exhibition, Cairo, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 14-17.

IP Week, London, +44 0 20 7467 7132, +44 0 20 7255 1472 (fax), e-mail: jbia@energyinst.org.uk, website: www.energyinst.org.uk. 15-18.

Pipeline Pigging & Integrity Management Conference & Exhibition, Houston, (713) 521-5929, (713) 521-9255 (fax), e-mail: clarion@clarion.org, website: www.clarion.org. 16-18.

✦SPE European Artificial Lift Forum, Aberdeen, +44 1224 495051, Alexandra.stacey@hulse-rodger.com, website: www.spe-uk.org. 17-18.

Pipe Line Contractors Association Annual Conference (PLCA), Scottsdale, Ariz. (214) 969-2700, e-mail: plca@plca.org, website: www.plca.org. 17-21.

Laurance Reid Conditioning Conference, Norman, Okla., (512) 970-5019, (512) 233-2877 (fax), e-mail: bettyk@ou.edu, website: www.lrgcc.org. 21-24.

International Petrochemicals Technology Conference & Exhibition, Madrid, +44 (0) 20 7357 8394, +44 (0) 20 7357 8395 (fax), e-mail: enquiries@europetro.com, website: www.europetro.com. 22-23.

Photovoltaics World Conference & Exhibition, Austin, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.Photovaltaicsworldevent.com. 23-25.

Renewable Energy World North America Conference & Expo, Austin, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.renewableenergyworld-events.com. 23-25.

SPE Unconventional Gas Conference, Pittsburgh, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 23-25.

International Downstream Technology & Catalyst Conference & Exhibition, Madrid, +44 (0) 20 7357 8394, +44 (0) 20 7357 8395 (fax), e-mail: enquiries@europetro.com, website: www.europetro.com. 24-25.

SPE/IADC Managed Pressure Drilling & Underbalanced Operations Conference and Exhibition, Kuala Lumpur, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 24-25.

IPAA Private Capital Conference, Houston, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 25.

Nitrogen + Syngas International Conference and Exhibition, Manama, +44 20 7903 2058, +44 20 7903 2172 (fax), e-mail: cruevents@crugroup.com, website: www.nitrogenandsyngas2010.com. Feb. 28-Mar. 3.

MARCH

Annual Arctic Gas Symposium, Calgary, Alta., (877) 927-7936, website: www.arcticgassymposium.com. 2-3.

APPEX Conference, London, +44 0 20 74341399, +44 0 20 74341386 (fax) website: www.appexlondon.com. 2-4.

Subsea Tieback Forum & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.subseatiebackforum.com. 2-4.

Middle East Geosciences Conference and Exhibition, Manama, +973 17 550033, +973 17 553288 (fax), e-mail: fawzi@aeminfo.com.bh, website: www.geobahrain.org. 7-10.

SPE Hydrocarbon Economics and Evaluation Symposium, Dallas, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 8-9.

Purvin & Gertz LPG Seminar, The Woodlands, Tex., (713) 331-4000, (713) 236-8490 (fax), website: www.purvingertz.com. 8-11.

CERA Week, Houston, (617) 866-5992, e-mail: info@cera.com, website: www.cera.com. 8-12.

NPRA Security Conference & Exhibition, The Woodlands, Tex., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. 9-10.

Offshore West Africa Conference & Exhibition, Accra, Ghana, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.offshorewestafrica.com. 9-11.

Annual European Fuels Conference, Paris, +44 (0) 1242 529 090. +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 9-12.

✦ SPE European San Management Forum, Aberdeen, +44 1224 495051, e-mail: Alexandra.stacey@hulse-rodger.com, website: www.spe-uk.org. 10-11.

NACE International Corrosion Conference & Expo, San Antonio, (281) 228-6200, (281) 228-6300 (fax), e-mail: firstservice@nace.org, website: www.nace.org. 14-18.

International Pump Users Symposium, Houston, (979) 845-7417, (979) 845-1835 (fax), e-mail: inquiry@turbo-lab.tamu.edu, website: http://turbolab.tamu.edu. 15-18.

API Spring Committee on Petroleum Measurement Standards Meeting, Dallas, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 15-18.

Gas Asia, Kuala Lumpur, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 16-18.

Oil and Gas Africa Exhibition & Conference, Cape Town, SA, +27 21 713 3360, +27 21 713 3366 (fax), e-mail: events@fairconsultants.com, website: www.fairconsultants.com. 16-18.

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

Turkish International Oil & Gas Conference & Showcase (TUROGE), Ankara, Turkey, +44 (0) 207 596 5000, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 16-18.

Electric Light & Power Executive Conference, Tampa, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.elpconference.com. 21-22.

NPRA Annual Meeting, Phoenix, (202) 457-0480, (202) 457-0486 (fax), website: www.npra.org. 21-23.

GPA Annual Convention, Austin, Tex., (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gpaglobal.org, website: www.GPAglobal.org. 21-24.

AIChE Spring National Meeting & Global Congress on Process Safety, San Antonio, (203) 702-7660, (203) 775-5177 (fax), website: www.aiche.org. 21-25.

Howard Weil Energy Conference, New Orleans, (504) 582-2500, website: www.howardweil.com/energy-conference.aspx. 21-25.

Gas Turbine Users International (GTUI) Annual Conference, Calgary, Alta., +9714 804 7738, +9714 804 7764 (fax), e-mail: info@gtui.org, website: www.gtui.org. 21-26.

Middle East Downstream Week & Annual Meeting, Abu Dhabi, +44 (0) 1242 529 090. +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 22-25.

IADC Drilling HSE Asia Pacific Conference & Exhibition, Singapore, (713) 292 1945, (713) 292 1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 23-24.

SPE/ICoTA Coiled Tubing & Well Intervention Conference & Exhibition, The Woodlands, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 23-24.

Middle East Refining Conference & Annual Meeting, Abu Dhabi, +44 (0) 1242 529 090. +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 23-24.

Base Oils and Lubricants in Russia and CIS & Annual Meeting, Moscow, +44 (0) 1242 529 090. +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 23-25.

SPE Intelligent Energy Conference and Exhibition, Utrecht, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.intelligentenergyevent.com/conferenceOGJ. 23-25.

Utility Products Conference & Exposition, Tampa, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.utilityproductsexpo.com. 23-25.

DistribuTECH Confernece & Exhibition, Tampa, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.distributech.com. 23-25.

Gulf current under study

Sam Fletcher
Senior Writer

Benjamin Franklin was the first scientist to study and map the Gulf Stream, measuring wind speeds and current depths, speeds, and temperatures during four crossings of the Atlantic in the late 18th century. More than 300 years later, scientists are still probing the secrets of that "river" of warm water flowing north from the West Indies, along the East Coast of North America, and east across the Atlantic to Europe.

The US Minerals Management Service recently released a study of the Loop Current (LC) and Loop Current Eddies (LCEs) in the eastern gulf aimed at better forecasting the effect on hurricanes and oil and gas activity in deep waters.

The LC and hurricanes

Part of the Gulf Stream, the horseshoe-shaped LC flows clockwise, transferring warm subtropical waters from the Caribbean through the Yucatan Straits into the Gulf of Mexico. It then loops west and south before exiting to the east through the Florida Straits. The deepest levels of warm water in the gulf are associated with the LC. The current meanders in its journey, sometimes penetrating deeper into the gulf, sometimes less, and the temperature of its waters is sometimes higher than at other times.

Random eddies or LC "rings" occasionally separate from the LC and slowly drift west to splash upon the shores of Texas or Mexico. The current and its eddies can be determined by measuring the level of the sea's surface. The flow is somewhat higher than the surrounding ocean waters because of the warm water it carries. On Sept. 21, 2005, the surface level of the LC and eddies was 24 in. above surrounding waters when Hurricane Rita intensified to Category 5 strength as it passed over those warmer waters.

The LC apparently has stimulated some of the biggest storms ever to blow through the gulf. In 1969, Camille was already a Category 3 hurricane when it rounded the western tip of Cuba and charged north directly over the LC, rapidly intensifying into the top Category 5 on the Saffir-Simpson Hurricane Scale before smashing into Mississippi. Hurricane Allen ramped up to Category 5 over the current but weakened over cooler waters before it hit Texas in 1980. Hurricane Andrew crossed the LC and grew into a Category 5 storm before it smashed into Florida in 1992.

In 1995, Hurricane Opal escalated from Category 1 to Category 4 in 14 hr after encountering a warm-water eddy. That's when meteorologists first recognized the pivotal role of warm water in strengthening hurricane intensity, according to an Oct. 4, 2005, online article in Science Daily.

Hurricane Ivan—the 10th most intense Atlantic hurricane ever recorded—twice crossed the LC in 2004, growing to the size of Texas over those warm waters. In 2005 when the LC extended deep into the gulf, it boosted Hurricanes Katrina and Rita, respectively, to the sixth and fourth-strongest storms ever, and it jacked up the weaker Hurricane Wilma to a Category 3 before it blew into Florida that same year.

In 2008, Hurricane Gustav encountered the current, but the LC was shorter and cooler that year with cooler gulf waters between it and Louisiana, so the storm remained Category 3.

After Hurricane Katrina and a week before Hurricane Rita, scientists deployed various technologies in the gulf to measure salinity, currents, and water temperature to 3,300 ft in another study aimed at determining the paths and intensity changes of hurricanes in their last hours over open water.

Latest study

The latest 2-year study by MMS in conjunction with Louisiana State University's Coastal Marine Institute involved deployment in the eastern gulf of an 11,800-ft deepwater mooring cable to supplement information gathered from a previous 3-year deployment. The mooring data suggest the LC and LCEs that dominate upper-layer circulation in the eastern gulf also influence the deeper currents in those water.

Alexis Lugo-Fernandez, the MMS physical oceanographer responsible for the study, noted that a method to transmit significant energy in the form of heat to deep water in the gulf during the 2005 hurricane season was observed during this study.

As sea levels rise near the center of tropical storms, the resulting higher pressure causes a small but measurable increase in temperature at all water depths. Lugo-Fernandez said, "Simply due to the large number of storm occurrences within the [gulf], these findings represent an important process for transmitting energy to the deep water." ✦

Editorial

Another IPCC setback

A single mistake shouldn't sink a boatload of science. Bias, however, will corrode any hull.

Both interpretations have been applied to a mistake by the Intergovernmental Panel on Climate Change concerning glaciers in the Himalayas. IPCC is the volunteer scientific group set up in 1989 by the United Nations Environment Program and World Meteorological Organization to assess climate science and support policy-making. In its four-volume Fourth Assessment Report of 2007, IPCC said Himalayan glaciers faced a "very high" likelihood of disappearing by 2035—"and perhaps sooner." This month it retracted the warning.

Broader assessment

The wayward paragraph, IPCC said, contained "poorly substantiated estimates" of the melting rate and date when the glaciers would be gone. "In drafting the paragraph in question," it said, "the clear and well-established standards of evidence, required by the IPCC procedures, were not applied properly." Nevertheless, IPCC added, the general conclusion of the report is "robust, appropriate, and entirely consistent with the underlying science and the broader IPCC assessment."

The broader assessment, of course, is that most observed warming since the middle of the 20th century "very likely" results from human activity and threatens, among other things, glaciers and water supplies. "Widespread mass losses from glaciers and reductions in snow cover over recent decades are projected to accelerate throughout the 21st century, reducing water availability, hydropower potential, and changing seasonality of flows in regions supplied by meltwater from major mountain regions (e.g. Hindu-Kush, Himalaya, Andes), where more than one sixth of the world population currently lives," IPCC says.

Scary stuff, this. A sixth of the world without enough water to drink. Given the dire potential and mass of scientific arcana in the IPCC's report, how can anyone worry about a lone blooper? That, of course, is the question raised by promoters of urgent and costly precautions against the dangerous warming they believe to be looming.

Yes, the Himalayan mistake represents a solo lapse in a mammoth project. But it also fits a pattern.

In 2001, IPCC's Third Assessment Report prominently featured the infamous "hockey-stick" reconstruction of proxy temperature data from the Northern Hemisphere. The name describes the shape of a graph that seemed to show many centuries of stability in global average temperature until the time of industrialization, when temperatures began to zoom. The hockey-stick had powerful persuasive effect. It offered a simple, graphic rebuke to scientists suggesting that the uptrend in temperature over the last century resulted from natural cycles. After statistical analysis behind the graph came under challenge, though, IPCC felt obliged in its 2007 assessment report to moderate its conclusions and present a range of reconstructions of historical temperature data, many of which do indicate temperature oscillations before the Industrial Age.

More recently, scientists responsible for data central to IPCC's computer modeling have been shown to have manipulated numbers and suppressed findings of anyone resistant to their push for political warming responses. Like the hockey stick and Himalayan-glacier glitch, controversy over those apparent failures of integrity has been dismissed as a sideshow staged by unholy skeptics, a tactical distraction from a scientific consensus supporting the need for prompt action against warming, whatever the cost.

The consensus

To the extent scientific consensus does or even can exist, however, IPCC is it. And IPCC consistently errs on the frightening side in its summaries for policy-makers. Scientists involved in past assessment reports have complained about the political spin the summaries give their material. Even the way IPCC describes its initial task asserts conclusions: "Prepare a comprehensive review and recommendations with respect to the state of knowledge of the science of climate change, social and economic impact of climate change, possible response strategies, and elements for inclusion in a possible future international convention on climate."

A group with such a view of itself isn't likely to conclude that observed warming is mostly natural and that governmental restraint will remain the best policy option until more is known. The record, in fact, increasingly suggests an activist bias. Until that changes, IPCC will look like a pressure group with shrinking credibility. ✦

Fitch: Credit-quality outlook mostly stable

Sam Fletcher
Senior Writer

Barring any substantial drops in crude prices, corporate credit profiles should remain in line with 2009 levels across the oil and gas industry this year, except for the refining and service and supply businesses, reported Fitch Ratings in its 2010 oil and gas outlook.

Inflationary expectations and "significant amounts of liquidity" injected in global financial markets will likely keep crude prices above levels justified by supply and demand fundamentals, with improved cash flows and credit profiles for upstream, oil-focused companies, said Fitch analysts, who assume global economies will have weak, but positive growth this year without a "double-dip" into recession. Fitch's price forecasts for 2010 are $70/bbl for crude, up from $57.50/bbl previously, and $4/Mcf for natural gas, down from $5/Mcf.

The credit outlook is not uniform across the industry, however. Refiners run the most risk as global fuel demand and refinery utilization rates continue to slump. Offshore drillers with deepwater rigs and sizable backlogs will benefit from long-term contracts signed when business was better.

Overall, the service and supply business is suffering a major decline in credit profiles as pricing and utilization rates fall. That will continue this year, with smaller, less-diversified companies under the most stress.

On the upside, increased oil demand as the world economy returns to positive growth rates following reduced upstream investment in 2009 will likely lead to tighter market fundamentals. On the other hand, Iraq's push to increase its oil production and additional output from Brazil and Canadian oil sands will provide more supply.

Producers with large exposure to the US gas market face another year of weak commodity prices. Barring extreme weather conditions, the US gas market is not expected to improve materially for the next 2 years. However, firms that took advantage of the steep contango pricing in the gas futures market by hedging are more likely to weather 2010, Fitch analysts said.

Liquidity, upgrades

Despite increased asset sales to fill capital spending shortfalls, liquidity appears adequate for most of the upstream companies that Fitch rates. Mergers and acquisitions usually increase in weak markets, but the ability of producers to lock in cash flow from higher futures prices may limit the distress fire-sales that buyers hope for.

As in the previous up-cycle, Fitch will limit rating upgrades to companies with "sustained and substantial commitments" to conservative financial and operating profiles. Rating downgrades will be primarily company-specific unless market conditions prove so weak that "most if not all of the issuers" in a sector succumb to the same downward rating pressures.

"Many issuers are entering the current downturn from a position of strength, as they had taken advantage of the robust industry market conditions and unfettered access to banking and capital markets through midyear 2008 to protect their liquidity by extending maturities and increasing revolver availability," said Fitch analysts.

Fitch will continue to focus on cash flow, which should improve moderately because of reduced capital spending budgets, cost resets, and stable-to-higher commodities pricing. "Given the sharp premium associated with liquidity, companies are expected to continue to shift their focus away from growth-oriented objectives toward maintaining strong balance sheets during 2010," analysts said.

Among the firms rated by Fitch, 82% of the integrated companies and 77% of pure exploration and production companies have a stable outlook. By contrast, 60% of companies in the downstream refining and marketing segment "are either on rating watch negative or have a negative outlook." Fitch analysts said, "This is largely, but not entirely, due to the negative factors affecting the sector, which are considered to repre-

sent a 'supercyclical' downturn."

Fitch foresees "greater uncertainty" in 2011 when monetary and fiscal stimulus policies are expected to tighten. Interest rate policies are expected to remain "accommodative" in 2010 with attempts to rein in liquidity beginning in 2011 when global interest rates are projected to rise to 1.01%. Inflation is likely to remain muted at 0.8% in 2010 and 0.6% in 2011 as policymakers balance tradeoffs between currency stability and full employment.

Integrated companies

Credit quality remains robust for large, integrated oil companies with oil-heavy upstream portfolios, sizable cash balances, and low net debt. "Integrated oil has generally been the least impacted by volatile commodity prices, due to its high credit quality, significant headroom to absorb incremental leverage, and willingness to take a longer, 'through the cycle' view on reinvesting," said Fitch analysts.

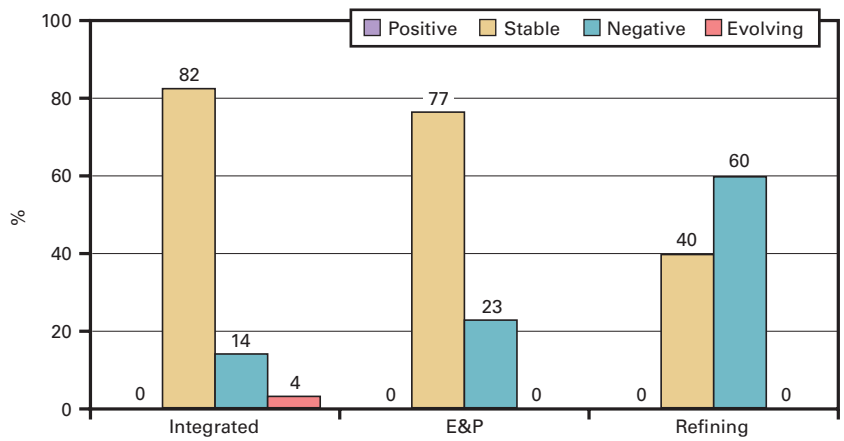
In the US, they said, "The decoupling of oil and natural gas spot pricing has strongly benefited the integrated firms in the current downturn but has also left cash flows reliant on the continued strength of oil prices," they said. While the majors have exposure to gas prices, analysts said, "Their gas portfolios are global in nature and in many cases benefit from oil-linked pricing mechanisms. Should asset sales heat up, this group is expected to be the acquirers, although past practices would indicate that equity financing is the preferred choice for sizable acquisitions or mergers, as was recently demonstrated by the share-based acquisition of XTO Energy Inc. by ExxonMobil Corp."

Unlike lower-rated independents, highly rated supermajors generally need not rely on external bank credit to fund growth since they are able to generate funds internally. Integrated companies historically have benefited from upstream, midstream, and downstream diversification, but margins and volumes for refining and chemicals have been sharply squeezed over the last several quarters. "As a result, integrateds' organic cash flows are heavily reliant on the strength of oil pricing," said Fitch analysts.

The Russian integrated oil industry remains relatively diversified with seven key producers, none of which exceed more than 25% of total daily production. Despite the recent trend of increased state ownership over the past 5 years, Russia's oil sector remains primarily private with state-owned companies accounting for 30% of total crude output. Meanwhile, Russia's oil industry faces a rapid slowdown of its production growth. In 2008, Russia's average daily oil production declined by 0.7% compared with growth of 10% just 5 years earlier. Fitch expects this to abate, with average production increasing about 1% to 10 million b/d in 2010.

Latin America is dominated by national oil companies, so higher oil prices not only increase cash generation and improve credit metrics but also decrease the political intervention risk in the region, Fisk reported. With the recovery in oil prices, companies are expected to resume aggressive capex programs, which could have a positive impact on future reserves and production prospects. However, Fitch expects production will continue to decline in Mexico and Argentina while increasing in Brazil and Colombia. Venezuelan production will depend largely on the strategy and quota restrictions of the Organization of Petroleum Exporting Countries, analysts said. Lower cost of capital and increased access to both domestic and international debt markets bode well for the business. Fitch expects refining margins to remain positive in 2010 as governments try to offset negative margins in the past.

GLOBAL CREDIT OUTLOOKS*



*As of third quarter 2009.
Source: Fitch Ratings

E&P companies

Credit quality for independent E&P companies will "remain below the highs of the recent past" and should stabilize at 2009 levels, Fisk analysts said. US independents as a group have more exposure to gas prices, which Fitch expects to remain "under considerable pressure" due to too much supply and too little demand. "That said, US E&P companies should benefit from contango market conditions for natural gas futures prices (and the resulting hedging benefits presented to them in 2009), higher oil prices, lower drilling and service costs, and a more responsive capital budget program as many of the long lead-time contracts entered into during the robust market conditions of the past expire," they said.

Improved capital market conditions

last year enabled many of these firms to increase liquidity and extend debt maturities. Moreover, many small and large independents plan asset sales. Still analysts said, "Most firms are expected to continue to live within internally generated cash flows, and as a result, reserve and production growth levels should remain well below levels seen since 2004."

Independents have better organic investment opportunities, and Fitch expects them to use cash flows for internal development and production-related projects rather than growth-oriented mergers or aggressive leasehold acquisition programs.

Downstream

The credit metrics for the refining sector "may bottom out at levels worse than those seen during the last industry downturn (2002) and could remain depressed for an extended period, given rising unemployment in many of the developed economies and the potential for a slow economic recovery," Fitch analysts reported.

Currently, 8 of the 13 Fitch-rated refiners globally have negative outlooks, including all of Fitch's North American rated refiners. High fixed costs and low utilization have sharply eroded unit economics and led to significant restructurings by individual companies. Fitch said average refinery utilization may grind lower before gradually improving.

While refiners as a group responded vigorously and early to the downturn by paring back operating costs, cutting shareholder distributions, eliminating noncritical capex, and shuttering some capacity, Fitch noted there may be relatively little left to cut if demand falls further. The shutdown of additional less-efficient refineries would further lower a company's operating structure, but it also will produce higher debt per barrel of refining capacity metrics "as we would not anticipate a proportional amount of debt being retired following further shutdowns," Fitch said.

Meanwhile, leverage to heavy and sour crude economics has been a particular weakness in the current downturn due to the compression in oil spreads, which has hurt the processing economics for cokers, analysts said. And refiners still face the expense of additional environmental and fuels regulation, including increased biofuel requirements and pending greenhouse gas regulation.

Service and supply firms

The outlook for the service and supply business remains poor. Fisk foresees "a modest increase" in drilling the onshore shale plays, but activity in conventional gas plays remains muted because of large supplies and low prices. International drilling activity could see a modest increase with higher oil prices. However, with excess rig capacity in nearly all markets, analysts said, "As older contracts expire, pricing on new contracts (excluding those signed prior to 2009) is expected to be down significantly."

Fitch expects credit quality for the service and suppliers to deteriorate in 2010 "due primarily to amortization of contract backlogs, weak natural gas prices, and the potential for weaker oil prices, weak pricing power (including expectations of falling prices for certain asset classes and geographic locales), and reduced utilization levels for fleets." There could be modest offsets from cost reductions from lower wages, cold-stacking equipment, and any restructuring to reduce overhead expenses.

Deepwater rigs will survive lower commodity prices better than other rig classes over the next 12-18 months. However, analysts said, "The longer-term outlook for these rigs could weaken due to the large number of uncontracted newbuild semis and drillships that will come to market beginning in 2011." The market for jack up rigs and midwater floating vessels has already weakened and is not expected to materially improve during 2010, they said.

The US land rig market will remain bifurcated, with newer units capable of drilling shale resources seeing modest demand increases, compared with weak utilization among older conventional rigs. Service and supply companies with diversified menus of products and services in various geographic areas will best weather the current downturn, analysts forecast. ✦

'Fracing' dominates ExxonMobil-XTO merger hearing

Nick Snow
Washington Editor

A congressional hearing that ostensibly was supposed to consider a proposed merger's market impacts quickly became a forum for debating whether to federally regulate hydraulic fracturing.

Chairman Edward J. Markey (D-Mass.) convened the Jan. 20 hearing of the House Energy and Commerce Committee's Energy and Environment Subcommittee to examine energy market impacts of ExxonMobil Corp.'s proposed $41 billion purchase of XTO Energy Corp. "This merger heralds a fundamental long-term shift in US energy markets, and one that deserves our close attention," he said in his opening statement.

But the discussion quickly turned to hydraulic fracing because the proposed combination's agreement includes a termination provision if Congress enacts legislation making hydraulic fracing too costly and uneconomic.

"This country has a propensity to regulate. We need to protect our shareholders," ExxonMobil Chief Execu-

tive Officer Rex W. Tillerson told the subcommittee.

ExxonMobil wants to acquire the Fort Worth, Tex., independent because XTO's US unconventional gas resource base and technical expertise would go well with the major's global reach, research and development capabilities, and financial capacity, Tillerson said.

"The development of our combined resources will create the opportunity for more jobs and investment in the production of natural gas across many parts of the United States," Tillerson said. "It will support our nation's economic recovery, strengthen [its] energy security, and help meet [its] environmental goals."

Focus on gas

Bob R. Simpson, XTO chairman and founder, said the company's management decided soon after it started to focus not only on gas, but also on long-lived, high-producing reserves. That led it to tight shale gas, where it eventually became an industry leader, he indicated.

"In reviewing our future path, we realized that we needed to look at options to take what we have achieved and bring it to a new level," he testified. "We recognized that the opportunities before us could best reach their potential if we could find an organization that could bring additional scale, technology, and financial capacity to the work we have been doing. We found that organization in ExxonMobil."

Markey suggested that the proposed merger has positive aspects, including the signal that another multinational oil company is willing to invest in developing unconventional US gas resources. But he also said that Congress wants to make certain those resources are developed safely, which is why it asked the US Environmental Protection Agency to study hydraulic fracing's operating record.

Republicans on the subcommittee said the technology is safe. "It is well known that gas will play a more prominent role in a carbon-restrained world," said ranking minority member Fred Upton (R-Mich.). "In fact, the success of any climate-change policy will need to rely heavily on gas. Yet some members of Congress are seeking policies that would take a majority of our domestic gas off the table."

Several Democrats said the process uses toxic substances that would create serious problems if they entered drinking water supplies. Rep. Diana DeGette (D-Colo.), who is not a member of this subcommittee, was allowed to participate because she introduced a bill last year to federally regulate hydraulic fracing under the Safe Drinking Water Act (SDWA).

"I support hydraulic fracturing," she said. "My bill would not make it illegal or impractical. It simply would require disclosure of ingredients in an emergency situation while protecting proprietary information."

Fluid confined

Tillerson and Simpson both said they would not have a problem as producers disclosing ingredients in hydraulic fracing fluid, which is primarily water. They also pointed out that the process occurs several hundred feet below drinking water supplies, and that concrete casing keeps hydrofrac fluid confined while it's pumped below the surface.

States already regulate hydraulic fracing aggressively, they continued. DeGette immediately challenged that idea, noting that only four states have regulations that specifically deal with the process. The executives responded that several others have water-management regulations that serve similar purposes.

They also contended that federally regulating hydraulic fracing simply would add another layer to a process that states already regulate well. Restricting its use would harm conventional production too, Tillerson added. "A lot of conventional wells use hydraulic fracturing to make production commercial," he said.

When DeGette asked them how much they think having to comply with SDWA regulations in using hydraulic fracing would cost their companies, the ExxonMobil and XTO executives said they did not know. "Much of it would depend on how EPA decided to implement its regulation," Tillerson told her. "I don't know what

WATCHING GOVERNMENT

Nick Snow, Washington Editor

Blog at www.ogjonline.com

Parks Service proposes changes

As US Interior Secretary Ken Salazar and the Bureau of Land Management drew fire for proposed changes in onshore oil and gas rules for public lands BLM administers, another Interior agency quietly concluded the public comment period for policy changes it has proposed.

The National Park Service (NPS) proposed revisions on Nov. 25, 2009, to regulations governing 693 nonfederal oil and gas operations within boundaries of 13 NPS units that have been in effect for more than 30 years.

"Nonfederal oil and gas rights are the result of a conveyance of an interest from a grantor other than the United States and may be held by individuals, companies, nonprofit organizations, or state and local government," the DOI agency said in the proposed rulemaking notice.

Such rights are a form of real property and are protected under the US Constitution's Fifth Amendment, it said. NPS has the authority to regulate those rights under laws passed by Congress allowing the agency to promulgate regulations necessary to manage the parks system.

Current rules

Operators must document that they are exercising a bona fide nonfederal oil and gas property right. They must identify specific steps they'll take to protect park resources and values. And they must submit a bond to assure funds will be available to reclaim a site if the operator defaults on his obligations, NPS said.

The agency proposed requiring 364 operations that are currently exempt to comply with the regulations. These include 190 wells just inside park boundaries but that are maintained without crossing park land, and 255 operations that were covered by a valid state permit when the original NPS rules took effect.

NPS also proposed possibly changing incentives for directional drilling from outside park boundaries. It said while it realizes such activity can have indirect impacts such as sight, sound, odors, or spills, effects are usually much less than from surface activity inside the parks.

Performance bonds

The agency also is considering updating performance bonds (currently capped at $200,000/operator), and replacing the limit with a variable amount of financial assurance "equal to the reasonable estimated cost of reclamation and liability today." It also proposed updating operating standards and noncompliance assessments, and changing vehicle registrations to access fees.

In its comments, Public Employees for Environmental Responsibility (PEER) lauded NPS's proposals, but added they should be extended beyond oil and gas to coal, sand, gravel, and other extraction operations. There presently are no rules governing nonfederal mineral operations within national parks other than petroleum, it said.

"The same legal authority empowering [NPS] to regulate oil and gas also empowers [it] to regulate mineral extraction," observed PEER executive director Jeff Ruch. "As long as NPS is updating one set of rules, it should also take care of the other." ✦

would be in it, and neither do you."

Markey concluded the hearing by stating, "There is no secret plot on this side of the aisle to ban hydraulic fracturing." But when he was asked by reporters afterward if he planned to schedule DeGette's bill for markup, the subcommittee chairman replied, "I'm going to have to have further discussions with her on it before I decide." ✦

API's Gerard: SOTU speech should herald improved relations

Nick Snow
Washington Editor

As OGJ went to press last week, the oil and gas industry was hoping US President Barack Obama's Jan. 27 State of the Union address would begin a shift of administration-industry relations from confrontation to cooperation, American Petroleum Institute Pres. Jack N. Gerard said.

Gerard told reporters in a Jan. 26 teleconference that he expected the president to focus on job creation and on reducing economic pressures on the middle class, and that the US oil and gas industry strongly supports both goals.

"What we seek is not an earmark or stimulus, merely an opportunity to develop the vast US oil and gas resources," Gerard continued. "We specifically do not want the pattern we've seen over the past year from the Department of the Interior when they've lessened our access to domestic resources. In the past year, since Secretary [Ken] Salazar has taken office, the total federal oil and gas leasing program has shrunk to the lowest level on record."

He noted that in New Mexico, where 8% of the total employment is tied to oil and gas and 40% of the state's revenue comes from industry and related activity, the amount of federal leas-

NPRA CONFERENCES

If You're Not Here, You're Just *Out* There.

108th NPRA Annual Meeting

March 21-23, 2010 « Sheraton and Wyndham « Phoenix, AZ

Find your way to NPRA's Annual Meeting

NPRA's Annual Meeting, the world's premier refining conference, assembles key executives and technical experts from refining and marketing organizations worldwide, as well as representatives from leading-edge technology providers.

The Annual Meeting features high-profile speakers who will address current issues of widespread importance to the refining community. Management and technical sessions provide attendees with strategic perspectives and practical technology solutions from leading industry experts on safety, energy, and environmental initiatives impacting the petroleum refining community's management and performance.

Register today at **npra.org/am** or
call us at 202.457.0480 for more information.

NPRA
NATIONAL PETROCHEMICAL
& REFINERS ASSOCIATION

Today's refining and petrochemical businesses.
The more you know about us, the better we look.

NGSA, IPAMS urge Obama not to overlook natural gas

Nick Snow
Washington Editor

As OGJ went to press last week, two oil and gas association officials said they hoped US President Barack Obama's Jan. 27 State of the Union message would reflect policies that encourage—instead of discourage—the nation's natural gas development.

"We urge the president to remember that natural gas is not only an environmental solution, it is an economic solution for our country," Natural Gas Supply Association Pres. R. Skip Horvath said in a statement.

The industry employs several million people already and is posed to add more as power plants, homes, businesses, and factories increase demand, Horvath noted, adding, "Those jobs create revenue in addition to the billions of dollars the natural gas industry already generates for state and federal government through royalties and taxes."

Marc W. Smith, executive director for the Independent Petroleum Association of Mountain States, expressed concern that the White House might respond to a $1.35 trillion deficit with the same $80 billion in tax hikes it proposed last year. "These punitive policy proposals are contrary to the president's goals of rebuilding our economy, increasing energy security, and lowering greenhouse gas emissions," Smith said.

The anticipated tax proposals would repeal expensing of intangible drilling costs and the percentage depletion deduction, and reduce expensing of geological and geophysical costs, Smith said.

G&G costs are similar to research and development costs, which are deductible for every other industry, Smith said, adding, "Because of American ingenuity and advanced technologies, the American natural gas industry has increased gas reserves by 39% in the last 3 years, catapulting the US into sixth place in world rankings. America has also surpassed Russia in terms of gas production because of superior R&D and better application of technology."

Horvath said the US should tap all energy sources, including fossil fuels, to make the domestic economy grow. "Natural gas adds to the reliability of solar and wind and, like solar and wind, it is a sustainable and responsible choice on its own," he said.

ing dropped 58% from 2008 to 2009. "We believe the best approach is to develop a sound oil and gas policy that recognizes the potential for green job creation, but also the potential for oil and gas development across the United States," he said.

Responding to reports that Salazar planned to announce on Jan. 28 that the US Minerals Management Service would begin to take public comments on a proposed Atlantic Outer Continental Shelf seismic study, Gerard said, "This has been a no-brainer. Industry has wanted to conduct these studies for some time, and we're thrilled the decision has been made. We believe it's long overdue."

'Not as constructive'

Gerard also acknowledged that relations between the secretary and some oil and gas groups have become contentious. "We would greatly appreciate the opportunity to have better communications with him," he said. "We feel at this time they're not as constructive or productive as they could be, and we hope that the president's speech tomorrow night will begin a change toward having an open and honest dialogue."

A spokeswoman for Salazar said later that day in a statement that Gerard's statements about 2009 federal oil and gas development relative to 2008 were inaccurate. "Oil and gas production on federal lands and waters is up—not down—from 2008, and under Secretary Salazar's leadership the department has offered more than 56 million additional acres for development," she said. "[DOI's] agencies will continue to promote oil and gas development in the right ways, in the right places, and with a fair return for the American taxpayer, regardless of the political spears Mr. Gerard may throw on any given day."

Gerard also said he hoped that the administration's fiscal 2011 federal budget request, when it emerges in a few more weeks, won't have the kind of onerous oil and gas taxes from a year earlier and which fortunately were not included in the final 2010 budget that emerged from Congress.

"Previous proposals have assumed we have too much energy development in the United States. Clearly, no one could believe that now," said Gerard. "We hope the dialogue over the past year will soften some of the rhetoric so we can get down to the realities of creating jobs and improving the national economy. Energy, over time, has become a partisan issue. It should not be. It is something that everyone, regardless of political persuasion, should support."

Gerard said climate-change bills that passed the full US House and the Senate Environment and Public Works Committee in 2009 were a false start. "We believe that we need to consider the reality of the energy sources we have today, and what it will take to fuel the economy today and into the future," Gerard said. "Natural gas is one example. It was not considered in the first proposals. We believe the debate has to mature, and the prospects aren't likely that there will be a climate bill this year. A comprehensive energy bill looks more likely." ✦

WORK PLANNED UNDER NORWAY'S APA 2009 ROUND (CONTINUED ON P. 30)

License number	Block(s)	Company, share[1]	Work program[2]
539	3/7	Nexen Exploration[1] 40%, RWE Dea Norge 20%, Dana Petroleum Norway 20%, Petro-Canada Norge 20%	Acquisition of 250 sq km 3D seismic; within 3 years drill exploration well and decide on continuation or drop; within 7 years submit PDO
540	3/6	Norwegian Energy Co.[1] 50%, Dong E&P Norge 50%	Reprocess 3D seismic; within 1 year decide to drill one exploration well or drop; within 3 years drill exploration well and decide on continuation or drop; within 5 years submit PDO
541	4/4	Repsol Exploration Norge[1] 50%, Skagen 44—15%, Edison International Norway Branch 35%	Reprocess 3D seismic; within 2 years decide to drill one exploration well or drop; within 4 years drill exploration well and decide on continuation or drop; within 6 years submit PDO
542	2/1	Det norske oljeselskap[1] 60%, Spring Energy Norway 40%	Acquire 3D seismic, G&G studies; within 2 years decide to drill one exploration well or drop; within 4 years drill exploration well and decide on continuation or drop; within 5 years submit PDO
331 C	2/1	ConocoPhillips Skandinavia[1] 30%, Bayerngas Norge 10%, Statoil Petroleum 40%, Petoro 20%	As for PL 331
497 B	7/8,11	Det norske oljeselskap[1] 35%, Bridge Energy 30%, Lotos Exploration & Production Norge 10%, Dana Petroleum Norway 25%	As for PL 497
543	16/7	Statoil Petroleum[1] 50%, ExxonMobil E&P Norway 50%	G&G studies; within 2 years decide to drill one exploration well into Triassic inside new acreage or inside PL 0772B or drop; within 4 years drill well and decide on continuation or drop; within 6 years submit PDO
544	16/4	Lundin Norway[1] 70%, Bayerngas Norge 30%	G&G studies and drill one firm exploration well into Triassic; within 3 years from award decide on continuation or drop; within 5 years submit PDO
545	17/2,3,5,6	Norwegian Energy Co.[1] 50%, Spring Energy Norway 30%, Petoro 20%	Drill one firm exploration well within 2 years; within 2 years decide on acquisition of 3D seismic or drop; within 5 years acquire 3D seismic and decide to drill second exploration well or drop; within 7 years drill well and decide on continuation or drop; within 9 years submit PDO
546	25/11,12	Lundin Norway[1] 60%, Bayerngas Norge 40%	Acquisition of 3D seismic, G&G studies; within 2 years decide to drill one exploration well or drop; within 4 years drill exploration well and decide on continuation or drop; within 6 years submit PDO
169 D	25/11,12	Statoil Petroleum[1] 57%, ExxonMobil E&P Norway 13%, Petoro 30%	As for PL 169
340 BS	24/9 Stratigraphically divided; applies to all levels above top Cretaceous	Marathon Petroleum Norge[1] 65%, Lundin Norway 15%, ConocoPhillips Skandinavia 20%	As for PL 340
547 S	25/7 Stratigraphically divided; applies to all levels below top Cretaceous	Marathon Petroleum Norge[1] 40%, GDF Suez E&P Norge 10%, Lundin Norway 30%, VNG Norge 20%	G&G studies, reprocess 3D seismic; within 2 years decide to drill one exploration well or drop; within 4 years drill exploration well and decide on continuation or drop, within 6 years submit PDO
504 BS	25/7 Stratigraphically divided; applies to all levels above top Cretaceous	Det norske oljeselskap[1] 58.5%, Bridge Energy 8.5%, Dana Petroleum Norway 30%, Petoro 3%	As for PL 504
548 S	24/9, 25/7 Stratigraphically divided; applies to all levels above top Cretaceous	Det norske oljeselskap[1] 40%, Bridge Energy 30%, Dana Petroleum Norway 30%	Reprocess 3D seismic; within 2 years decide to drill one exploration well or drop; within 4 years from award drill exploration well and decide on continuation or drop; within 6 years submit PDO
505 BS	25/7 Stratigraphically divided; applies to all levels below top Cretaceous	Marathon Petroleum Norge AS[1] 50%, Lundin Norway 30%, VNG Norge 20%	As for PL 505
549 S	25/1, 30/10 Stratigraphically divided; applies to all levels below top Cretaceous	Det norske oljeselskap[1] 35%, Bayerngas Norge 20%, Dana Petroleum Norway 20%, Svenska Petroleum Exploration 25%	Acquisition of 3D seismic, G&G studies; within 3 years decide to drill one exploration well or drop; within 6 years drill exploration well and decide on continuation or drop; within 8 years submit PDO
550	31/1,2	Wintershall Norge[1] 60%, Spring Energy Norway 40%	Reprocess 3D seismic, G&G studies; within 2 years decide to drill one exploration well or drop; within 4 years drill exploration well and decide on continuation or drop; within 6 years submit PDO
551	31/2,3	Wintershall Norge[1] 60%, Spring Energy Norway 40%	Reprocess 3D seismic, G&G studies; within 2 years decide to drill one exploration well or drop; within 4 years drill exploration well and decide on continuation or drop; within 6 years submit PDO
090 E	31/2	Statoil Petroleum[1] 45%, GDF Suez E&P Norge 15%, Idemitsu Petroleum Norge 15%, ExxonMobil E&P Norway 25%	As for PL 090
552	34/7	Statoil Petroleum[1] 53.896%, Idemitsu Petroleum Norge 12.468%, RWE Dea Norge 3.636%, Petoro 30%	Within 2 years drill one firm exploration well into Jurassic Brent group; within 2 years decide on continuation or drop; within 4 years submit PDO
553	34/7,8	Det norske oljeselskap[1] 40%, Svenska Petroleum Exploration 35%, Bayerngas Norge 25%	G&G studies; within 1 year decide to drill one exploration well into Brent group or drop, within 3 years drill exploration well and decide on continuation or drop; within 5 years submit PDO
554	34/6	Bridge Energy[1] 60%, Det norske oljeselskap 40%	Acquire 3D seismic, G&G studies; within 1 year decide to drill one exploration well or drop; within 3 years drill exploration well and decide on continuation or drop; within 5 years submit PDO

Norway offers 38 production licenses in mature areas

The Norwegian government has offered 38 offshore production licenses in its "awards in predefined areas" (APA 2009) round.

License interests went to 42 companies, of which 19 will be operators, with work obligations covering a range of exploration and production activity (see table).

APA 2009 was Norway's seventh licensing round focusing on mature offshore areas.

The Ministry of Petroleum and Energy offered 25 production licenses in the North Sea, 10 in the Norwegian Sea, and 3 in the Barents Sea.

It received applications for licenses from 44 companies.

WORK PLANNED UNDER NORWAY'S APA 2009 ROUND (CONTINUED FROM P. 29)

License number	Block(s)	Company, share[1]	Work program[2]
425 BS	35/1 Stratigraphically divided; applies to all levels below base Pliocene	GDF Suez E&P Norge[1] 30%, Statoil Petroleum 25%, BG Norge 25%, Petoro 20%	As for PL 423 S
555	33/2	Lundin Norway[1] 60%, Bayerngas Norge 40%	3D prestack depth migration, G&G studies; within 2 years decide to drill one exploration well or drop; within 4 years drill exploration well and decide on continuation or drop; within 6 years submit PDO
556	6407/11	Lotos E&P Norge[1] 50%, Skeie Energy 50%	G&G studies; within 1 year decide to drill one exploration well or drop; within 3 years drill exploration well and decide on continuation or drop, within 5 years submit PDO
093 B	6407/9	Norske Shell[1] 26.2%, BP Norge 18.36%, Chevron Norge 7.56%, Petoro 47.88%	As for PL 093
312 B	6407/5	Statoil Petroleum[1] 59%, Eni Norge 17%, ExxonMobil E&P Norway 24%	As for PL 312
557	6406/1, 6506/10	OMV (Norge)[1] 50%, Repsol Exploration Norge 40%, Skagen 44—10%	Acquisition of 3D seismic, G&G studies; within 3 years decide to drill one exploration well or drop; within 5 years drill exploration well and decide on continuation or drop; within 7 years submit PDO
447 B	6506/11	Centrica Resources (Norge)[1] 40%, Faroe Petroleum Norge 30%, Petro-Canada Norge 30%	As for PL 477
558	6507/5	E.On Ruhrgas Norge[1] 30%, PGNiG Norway 15%, Det norske oljeselskap 20%, Nexen Exploration Norge 15%, Petoro 20%	Reprocess 3D seismic, G&G studies; within 2 years decide to drill one exploration well or drop; within 4 years drill exploration well and decide on continuation or drop, within 6 years submit PDO
559	6608/10,11	Rocksource[1] 60%, Skagen 44—10%, VNG Norge 30%	G&G studies, reprocess 3D seismic; within 2 years decide to drill one exploration well or drop; within 4 years drill exploration well and decide on continuation or drop; within 6 years submit PDO
560	6608/7,8	Statoil Petroleum[1] 75.45455%, Petoro 24.54546%	G&G studies; within 1 year decide to drill one exploration well or drop; within 3 years drill exploration well and decide on continuation or drop; within 5 years submit PDO
561	6608/7,8	Wintershall Norge[1] 35%, Concedo 20%, Det norske oljeselskap 20%, E.On Ruhrgas Norge 25%	Reprocess 3D seismic, G&G studies; within 2 years drill one exploration well or drop; within 4 years drill exploration and decide on continuation or drop; within 6 years submit PDO
562	6609/5,6,8	Dana Petroleum Norway[1] 30%, E.On Ruhrgas Norge 20%, Norwegian Energy Co. 20%, North Energy 10%, Petoro 20%	Acquisition of 3D seismic, G&G studies; within 3 years decide to drill one exploration well or drop; within 5 years drill exploration well and decide on continuation or drop; within 7 years submit PDO
518 B	7121/7,8,10,11	DONG E&P Norge[1] 40%, North Energy 30%, Sagex Petroleum Norge 10%, Discover Petroleum 20%	As for PL 518
563	7119/6, 7120/4	Lundin Norway[1] 40%, Det norske oljeselskap 20%, Det norske oljeselskap 10%, Norwegian Energy Co. 20%, Talisman Energy Norge 10%	Acquisition of 250 sq km 3D seismic, G&G studies; within 3 years decide to drill one exploration well or drop; within 5 years drill exploration well and decide on continuation or drop; within 7 years submit PDO
564	7123/4	OMV (Norge)[1] 50%, Wintershall Norge 30%, North Energy 20%	Acquisition of 3D seismic, G&G studies; within 2 years decide to drill one exploration well or drop; within 4 years drill exploration well and decide on continuation or drop; within 6 years submit PDO

[1]Operator. [2]Timing is from award; PDO = plan for development and operation.

In a press statement, the ministry noted declining expectations for the size of discoveries in mature areas and the need for small discoveries to have access to producing facilities in existing oil and gas fields.

"It is therefore important to discover and develop resources in these areas before existing infrastructure in connection to other fields is shut down," it said.

Companies offered licenses to operate and their numbers are AS Norske Shell, one; Bridge Energy AS, one; Centrica Resources (Norge) AS, one; ConocoPhillips Skandinavia AS, one; Dana Petroleum Norway AS, one; DNO ASA, six; Dong E&P Norge AS, one; E.On Ruhrgas Norge AS, one; GDF Suez E&P Norge AS, one; Lotos Exploration & Production Norge AS, one; Lundin Norway AS, four; Marathon Petroleum Norge AS, three; Nexen Exploration Norge AS, one; Norwegian Energy Co. ASA, two; OMV (Norge) AS, two; Repsol Exploration Norge AS, one; Rocksource ASA, one; Statoil Petroleum AS, six; and Wintershall Norge AS, three. ✦

Trinidad and Tobago makes term changes to 2010 bid round

Curtis Williams
OGJ Correspondent

Trinidad and Tobago has announced major changes to its fiscal terms for energy companies operating in the country and those seeking new blocks in its 2010 bid round.

The government made the announcement at an energy conference hosted by the South Trinidad Chamber of Industry and Commerce at which it said that it will continue to use production-sharing contracts but will eliminate taxes on the PSCs. Instead, Trinidad and Tobago will collect its revenues via profit oil.

Energy Minister Conrad Enill told the conference: "Our new PSC will be similar to the 1995-96 models in which companies were allowed to evaluate their risks and offer an adequate share of profit petroleum. This is intended to reduce some of the inherent risks and encourage potential investment."

Enill admitted that the world outlook for oil and gas was not as attractive as it was 18 months ago and in the circumstances the twin-island nation had to be more competitive.

Enill said concessionary arrangements will be put in place in areas and activities where incentives for revitalization and sustainability are required, such as in the mature offshore oil acreages and on land where enhanced oil recovery projects are undertaken.

He said, "Specifically, the incentives will directly impact on the supplemental petroleum tax rates that will be payable by companies. In so doing, it will provide companies with additional financial flows to reinvest in the upstream sector. This new regime will address small, mature fields and tailend production and will allow for a situation intended to encourage new investment while allowing current production levels to be sustained." Trinidad and Tobago produces 115,000 bo/d and 4 bcfd of gas.

Under the new fiscal terms, there is a distinction between 'shallow' and what is referred to as 'average' water depths. In the shallow fields, the government has maintained its windfall taxes but it kicks in whenever crude prices are above $70/bbl and gas prices are $6/MMbtu. In average water depts., the windfall taxes kick in at $80/bbl for crude and $7/MMbtu for gas.

Director of Resource Management Helena Inniss-King revealed that there will be additional benefits for companies operating in both the shallow and average-water depths with an increase in the percentage of cost recovery companies can claim.

Inniss-King said, "We had some comments on the cost recovery, that it was too low, and we have increased the cost recovery for the shallow water to 50% and for the average water depth 55%." Average water depth are blocks in more than 400 m of water.

Trinidad and Tobago says the new fiscal regime was arrived at after consultation with the major oil and gas companies operating in the country.

BP PLC Chief Executive Officer Tony Hayward called for a new fiscal regime in Trinidad and Tobago. During a recent visit, Hayward said he was confident that BP Trinidad & Tobago (BPTT) and the Patrick Manning administration will reach agreement on the new terms.

BPTT produces 450,000 boe/d from its Trinidad and Tobago operations.

Trinidad and Tobago will offer seven blocks in shallow and average water in this year's first quarter and has announced that later this year will offer blocks in its deepwater areas—in water 1,000-3,500 m deep. ✦

WATCHING THE WORLD

Eric Watkins, Oil Diplomacy Editor

Blog at www.ogjonline.com

IOCs under attack

If anyone thought the international oil and gas industry was in for an easy time this year, they will have to revise those thoughts immediately.

Consider the Philippines where the Moro Islamic Liberation Front (MILF) said that ExxonMobil Corp. should recognize the Moros' ancestral claims and rightful share of resources extracted from Sulu Sea.

"The Moro Islamic Liberation Front has reminded ExxonMobil, which is presently engaged in oil exploration in Sulu, not to forget that it is operating within the Moro ancestral homeland," MILF said.

More ominously, MILF warned that "the rightful share" of the Bangsamoro people, which amounts to 75% of the income derived, should not be overlooked by ExxonMobil's agreement with Manila.

'Sharing scheme'

MILF's "sharing scheme" is part of the larger political autonomy that the group is pushing in its current negotiations with Manila. And, not to make too fine a point of the matter, MILF claims to have a military presence in the island provinces of Sulu, Tawi-Tawi, and Basilan.

Little wonder that ExxonMobil took preventive measures recently, entering an deal with the Western Mindanao Command—the largest military command outside Manila—for security assistance to thwart terror attacks on its drilling operations.

Even as they fend off such old-style methods of attack, however, ExxonMobil and other major oil firms are facing an altogether new kind of attack as well—one that comes from a much more formidable opponent than a band of guerillas in the Sulu Sea. According to recent media reports, at least three US oil firms were the target of a series of previously undisclosed cyber attacks that may have originated in China. Experts say the attacks highlight "a new level of sophistication in the growing global war of internet espionage."

Bid data stolen

The oil and gas industry breaches, according to a report in the Christian Science Monitor, were focused on valuable bid data detailing the quantity, value, and location of oil discoveries worldwide.

The targeted companies—Marathon Oil, ExxonMobil, and ConocoPhillips—didn't realize the full extent of the attacks, which occurred in 2008, until the FBI alerted them that year and in early 2009.

Federal officials told the companies that proprietary information had been flowing out, including to computers overseas, according to documents obtained by the Monitor and a source familiar with the attacks.

The data included e-mail passwords, messages, and other data tied to executives with access to proprietary exploration and discovery information, the source said. "What [corporate officials] don't realize, because nobody tells them, is that a major foreign intelligence agency has taken control of major portions of their network," the source said.

One oil company's security personnel referred to the breaches in one of the documents as the "China virus" and another said, "We've never seen anything this clever, this tenacious." ✦

Nord Stream consortium awards pipeline contracts

Eric Watkins
Oil Diplomacy Editor

The Nord Stream AG consortium said it will commission Sumitomo Group, Europipe GMBH, and United Metallurgical Co. (OMK) to supply 1 million tons of steel pipe for construction of the second pipeline of the Nord Stream project.

"The contract value is approximately €1 billion of which German Europipe will be awarded 65%, the Russian pipe company OMK 25%, and Japanese Sumitomo 10%," said partners OAO Gazprom, BASF SE/Wintershall Holding AG, E.On Ruhrgas, and Gasunie.

They said the tender award for the second 1,220 km gas pipeline from Vyborg in Russia to Lubmin in Germany "will ensure timely delivery of the pipes in line with the logistic requirements of the Nord Stream project."

The partners said the decision was made by the shareholder's committee following "thorough evaluation" of bids from German, Japanese, and Russian companies.

"With €1 billion, the total volume of the contracts is below the price level of the first line reflecting the current market development of increased competition and more available capacity," said Henning Kothe, project director at Nord Stream, who added, "Three times the amount of steel pipes required was quoted."

The consortium partners said the tender for the second line was completely independent of the 2007 tender of the first line and procurement of steel pipe for the second line was "the last outstanding significant decision" regarding the requirements for the project as well as for the overall budget.

With the contracts for the second

line, which are expected to be signed within weeks, Nord Stream said it has secured the pipe at the current price level. Delivery of the pipe for the second pipeline is scheduled to start in May.

First line construction

Meanwhile, the partners said construction of the first line of the Nord Stream Pipeline is scheduled to commence Apr. 1 and construction of the second line is planned to start in spring 2011.

The Nord Stream partners also said they received permits for the project from all of the states whose waters it crosses, including Russia, Finland, Sweden, Denmark, and Germany.

However, deputies of Poland's main opposition party—Law and Justice—this week called on the Donald Tusk government to appeal the decision of the German Federal Maritime and Hydrographic Agency (BSH) approving the Nord Stream gas pipeline.

According to the party, the pipeline will block big ships' access to Polish ports in Swinoujscie and Szczecin.

At yearend 2009, BSH granted a permit to Nord Stream AG to construct the 31-km section of the natural gas pipeline in Germany's Exclusive Economic Zone.

"This means the launching of the construction," said Grazyna Gesicka, who heads the Law and Justice parliamentary caucus. "From Poland's point of view this means a failure of Poland's energy policy. Poland's diplomacy was unable to stop this investment."

Gesicka has called on Poland's government to appeal the decision and to ask Germany to present full technical documentation of the construction to Poland.

According to Law and Justice Member of the European Parliament Marek Grobarczyk, the Nord Stream pipeline will endanger deliveries to a LNG terminal in Swinoujscie and will block large vessels from accessing the ports in Swinoujscie and Szczecin. ✦

EPA announces new short-term NO_2 standard

The US Environmental Protection Agency announced a new national air quality standard for short-term exposures to nitrogen dioxide. Both the American Lung Association and American Petroleum Institute responded critically.

The new 1-hr standard of 100 ppb is directed at short-term NO_2 exposures occurring mainly near major highways, EPA said. It added that it is retaining the 53 ppb average annual NO_2 standard.

EPA said it plans to establish new monitoring requirements in urban areas to measure NO_2 levels around major roads and across communities. Cities with at least 500,000 residents will be required to place monitors near roadways. Larger cities and areas with major highways will have additional monitors. Community-wide monitoring will continue in cities with at least 1 million residents.

"Working with the states, EPA will site at least 40 monitors in locations to help protect communities that are susceptible and vulnerable to elevated levels of NO_2," EPA said.

The agency expects to identify or designate areas not meeting the new standard based on existing community-wide monitors, by January 2012, and will require new monitors to begin operating by Jan. 1, 2013. It also plans to redesignate areas when 3 years of air-quality data are available from the new monitoring network.

ALA said it was pleased that EPA acted, but had "hoped for a...more-protective standard." It said, "[EPA's] decision allows areas to have NO_2 concentrations that remain hazardous to the millions of people.... [Its] final decision, unlike [its] proposal of last summer, allows twice as many days when NO_2 will spike to dangerous levels."

API issued a statement saying it was "deeply concerned" with the new standard, which it said was based on faulty science. "There is no significant evidence that the short-term NO_2 standard established today by [EPA Administrator Lisa P. Jackson] is necessary to protect public health. EPA is over-regulating this air-quality standard for political, not health, reasons," it said. ✦

Marcellus shale gas play entry opportunities abound

Stephen Bull
Statoil ASA
Houston

The US shale business has been one of the hottest E&P topics the past few years, with the Marcellus capturing most recent attention.

Many have expressed concern that they are either too late or too slow to enter the Marcellus and fear that the best opportunities have passed. However, deal flow in the Marcellus since 2008 has actually increased, while entry opportunities are still numerous and may be strategically matched through a variety of business models from existing and new players.

The main reason is that the US unconventional gas market remains distinctly unconsolidated. The sheer breadth of entry choices can be executed and measured in a number of ways from bigger corporate deals to small focused land acquisitions.

In this article, the author suggests a framework for explaining Marcellus deal activity through the concept of development phases, namely where in the operational development cycle the play is currently and where it is going.

Marcellus transactions

Despite the economic slowdown and weaker gas prices, the number and variety of entry deals in US shale plays has increased considerably.

In 2009 alone, Marcellus-related deals increased by 60% vs. 2008. Strategic entry choices companies can make to gain shale gas exposure are wide, including joint ventures, alliances, financial investments, private equity participation, land acquisitions, and all-out corporate deals.

The lack of consolidation in the US shale gas sector can be explained by low entry and exit barriers and the rapid application of transferable drilling and completion technologies.

A short history of the past 5 years' deal flow shows a variety of deals with very different strategic drivers (Table 1).

The most significant early deal in the Marcellus was in 2005, with Chesapeake Energy Corp.'s acquisition of Columbia Natural Resources Inc. for $2.95 billion. Through this acquisition, coupled with engaging a "land army" of brokers, Chesapeake built the largest acreage position in the Marcellus fairway.

Three years later, in 2008, Statoil entered into a strategic alliance with Chesapeake, acquiring 32.5% of Chesapeake's 1.8 million Marcellus acres.

Most recently, in what is the largest multiplay unconventional gas deal so far, ExxonMobil Corp. is expected to acquire XTO Energy Inc. for $41 billion in 2010. Then Chesapeake announced its fourth major JV, with Total in the Texas Barnett shale.

Private equity investments in the Marcellus have also captured headlines in the business press, including deals involving Morgan Stanley Capital Partners and KKR. Midstream deals are also apparent including Williams, MarkWest, and NGP Midstream Resources.

And most recently, large land acquisitions, including deals from Ultra Petroleum, Hess Corp., and Seneca Resources, have raised the land stakes further as companies vie for leases to build contiguous acreage and drillsites.

These reported deals fail to reflect the real underlying activity, including the under-the-radar deals covering all types of swaps, acquisitions, and divestments. Newer deals covering all these entry choices are likely to continue in 2010.

Understanding deals

To make sense of deal activity, the competitive landscape and entry choices into the Marcellus, a framework is presented in Fig. 1.

When companies want to enter US shale plays, they typically assess the relationship between the industry strategic drivers and the stage of development of the particular play. By making sense of this interaction, it helps in asking the fundamental question: In which part of the development phase can you

SELECTED MARCELLUS-RELATED DEALS SINCE 2005

Table 1

Date	Buyer	Seller	Transaction value, billion $	Details
2009-12	Ultra Petroleum	Private seller	0.400	80,000 net acres acquired in Pennsylvania, close to existing acreage.
2009-12	ExxonMobil	XTO	41.000	Biggest unconventional deal to date. XTO has 280,000 acres in Marcellus and a key growth asset.
2009-11	Lime Rock Partners	Petroleum Devel. Corp.	0.159	JV formed called PDC Mountaineer covering 115,000 net acres, of which 55,000 acres in Marcellus.
2009-10	Newfield	Hess	N/A	Joint exploration agreement covering 140,000 acres in Susquehanna and Wayne counties, Pa.
2009-09	EV Energy Partners and Enervest Ltd.	EXCO	0.145	Producing assets in Ohio and NW Pennsylvania. EVEP sees upside in the Knox formation.
2009-09	Talisman	N/A	0.529	Double shale acquisition in Marcellus and Montney shales in Canada
2009-08	Enerplus Resources Fund	Chief Oil & Gas	0.406	Cash and carry deal, Chief to drill and operate. Enerplus gets 21.9% net working interest.
2009-06	Williams Cos.	Rex Energy	N/A	Participation and exploration agreement. Williams acquiring about 50% of 44,000 net acres in Pennsylvania.
2009-06	Rex Energy	Undisclosed	0.004	Acquisition of remaining 50% of acreage held by JV partner in Pennsylvania.
2009-06	Hess/Seneca	SWOGG	N/A	Landowners group in Susquehanna and Wayne counties, Pa.
2009-06	KKR	East Resources	0.350	KKR investment structured as debt; convertible into undisclosed minority stake.
2009-05	Morgan Stanley Capital Partners	Triana Energy LLC	N/A	Morgan Stanley entered strategic partnership with Triana-Morgan Stanley's fourth Marcellus investment.
2009-04	Atlas Energy Inc.	Atlas Energy Resources LLC	1.000	Acquisition of remaining 51.7% stake in partnership.
2009-04	Williams Cos.	Atlas Pipeline Partners	0.128	Midstream JV covering 1,800 miles of intrastate gathering lines
2008-11	Avista Capital Partners LLC	Carrizo Oil & Gas	0.150	Both parties committed to $150 million each in cash and properties in a 155,000 acre JV.
2008-11	Statoil ASA	Chesapeake Energy	3.375	Strategic alliance covering 32.5% of Chesapeake's Marcellus acreage and international partnership
2008-09	ExxonMobil	Pennsylvania Dept. of Natural Resources	0.022	19,400 acres in Tioga and Lycoming counties, Pa. ExxonMobil highest bidder on 6 of 18 blocks.
2008-07	XTO	Undisclosed	1.300	Acquisition in four shale plays, including Marcellus with multiple parties
2008-06	Antero Resources	Dominion	0.347	Assigned drilling rights covering 114,000 acres.
2008-04	XTO	Linn Energy	0.600	152,000 acres of Marcellus leases
2008-02	EXCO	EOG	0.388	Shallow natural gas producing properties in central Pennsylvania
2008-01	Undisclosed	Rex Energy	N/A	4,100 net acres acquired
2007-12	UBS and Deutsche Bank	Chesapeake Energy	1.100	Volumetric production payment from Kentucky and West Virginia properties
2007-12	Rex Energy	Undisclosed	N/A	Rex acquired 50% interest in 8,000 net acres in southwest Pennsylvania.
2006-11	EOG	Seneca	N/A	Joint exploration program covering Seneca's 770,000 acres and EOG's 130,000 acres in "Devonian black shales"
2006-04	Private owner	EXCO	0.115	Properties in Pennsylvania, Ohio, West Virginia including 178,000 HBP acres and 2,000 drillsites
2005-10	Chesapeake Energy	Triana Energy Holdings	2.950	Triana Energy Holdings LLC sells Columbia Natural Resources. Properties in West Virginia, Kentucky, Ohio, Pennsylvania, New York.

Source: John S. Herold Inc.

create value and how can success be measured?

The development phase for most shale plays can be roughly broken down into four key stages: early moves and land grabs; experimentation and growth; core development; and, exploitation and optimization.

Early moves and land grabs: This can be from an existing player already exposed to the play (vertical wells or CBM); from applying technology from one shale play to another (Barnett as a laboratory); or by simply making early bets (using land as a commodity). For the Marcellus, this started with Range's first Marcellus well in 2003.

Experimentation and growth: Shale gas production growth kicked off in 2005 and within 3 years became a game changer for the US gas market. What defines this phase is the rise of US independent E&P companies, phenomenal increases in bonus payments, and the entry of the majors. The Marcellus is still in this period.

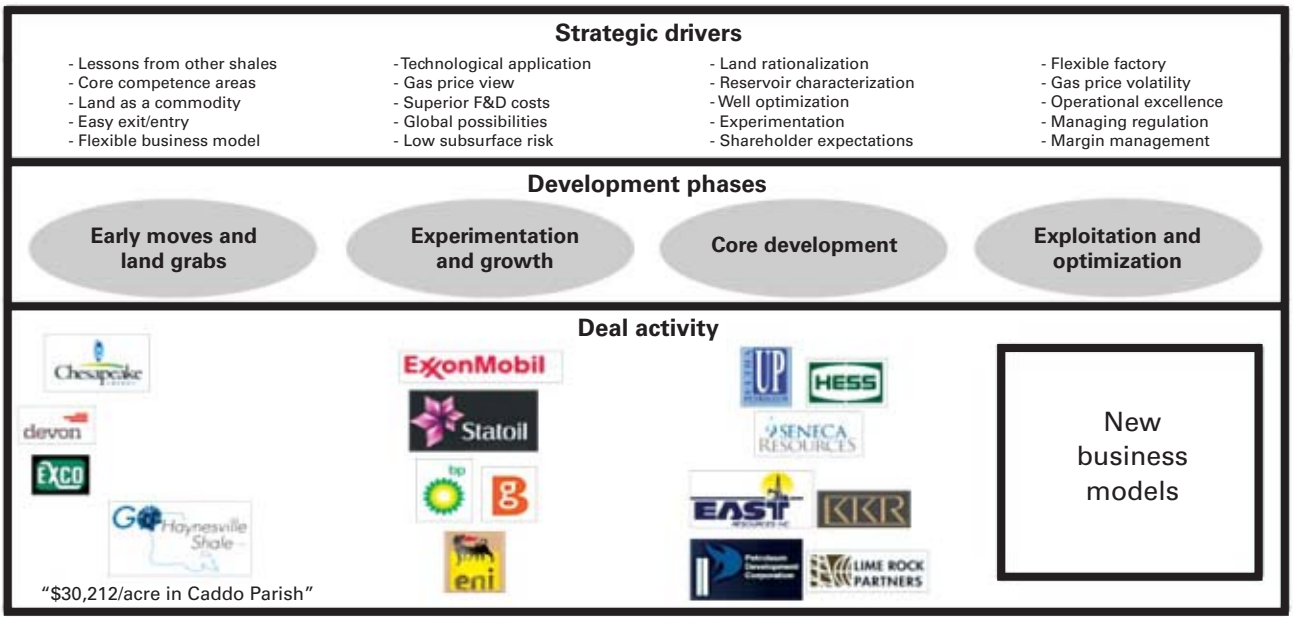
Core development: This is all about positioning and the core. Not all shales are created equal. Where drilling and completion experimentation aligns with subsurface understanding, the difference in value between core and noncore is great. Much of this is occurring in the Marcellus, but the play is too large and untested to draw conclusions on the subsurface.

Exploitation and optimization: This stage is what some consultants call factory drilling or the flexible factory. What defines this phase, which we are witnessing in the Barnett, is how to efficiently organize around the parameters of a margin business and how to squeeze the most out of existing acreage in a volatile gas price environment. The Marcellus is not at this stage yet.

Given that development phases and strategic drivers are never static entities, external drivers including changes in the competitive environment, gas price volatility, technological developments, legislation, and regulation all will influence companies' entry strategies. Using the entry choice framework a discussion of past entry deals, principally in the Marcellus, is analyzed below.

A FRAMEWORK FOR EXPLAINING ENTRY CHOICES

Fig. 1



At the heart of this concept is the relationship between the industry strategic drivers and the development stage of the play.

Early moves and land grabs

While some companies possess what may be called legacy positions in the Marcellus, including Range Resources, Atlas, and EQT, established Appalachian producers, it was Chesapeake that made the boldest move into the play through the acquisition of Columbia Natural Resources in 2005.

In the Barnett, Devon Energy employed the early move and land grab strategy through the $3.5 billion acquisition of Mitchell Energy in 2001. XTO Energy acquired much of its 280,000 acres Marcellus position from Linn Energy and private sellers in 2008. In the same year, ExxonMobil made a $22.4 million land acquisition in Pennsylvania that at the time received little attention.

Many private investors were fast at making early moves into the Marcellus. Their business model is essentially buying and selling leases as a commodity. During the high lease activity levels in 2008, thousands of leases were signed to companies with no intention of developing the resources, which will open up opportunities as the expiry horizon closes.

The strategic drivers and value propositions behind these deals vary, but the underlying assumption is that first-mover advantage in a new play will offer upsides that outweigh the underlying risk. Just 3 years ago, acreage in what are turning out to be the most prolific counties of the Marcellus went for $25/acre with a 12.5% royalty. Today the same area will bring over $5,750/acre with a 20% royalty (Fig. 2).

Comparing the NPV per well between these figures is significant. Taking a bet on gas prices also helped in this period, as US gas prices trended upwards and spiked to $13/MMbtu in both 2005 and 2008.

Transferring technology to the play was instrumental, too, during this phase, building on experiences from other shale plays.

Range Resources experimentation of drilling and hydraulic fracturing practices used in the Barnett is widely regarded as helping to unlock the Marcellus in 2003-05. The key technical and subsurface drivers during this phase included attempting to identify subsurface core areas using existing well data, identifying the "sweet spot" in the prospective zone, determining best drilling and completion practices to lower finding cost, and maximizing recovery.

In addition, educating government agencies and developing service industry capacity was essential. Smaller companies have generally shown that the advantages of speed of execution and management of risk have proven to be the most successful business model in this part of the development phase.

Measuring success in this phase is relative to the time horizon. Clearly some players are positioning to be acquired by a larger company, while smaller private actors are playing the waiting game to offload leases before expiry. What is important to consider is that as the Marcellus moved out of this phase the breadth of entry choices increased.

Experimentation and growth

The pace of unconventional drilling, the growing scale of activity, and evolving completion technologies have quite possibly created a new paradigm in the US gas market.

Where technology, positive well results, and high gas prices met, shale gas soon became perceived as a game changer in the industry. This new

OFFSHORE West Africa

9 - 11 March 2010
Ghana, Accra

Early Bird Offer

register before 12 February 2010 and save $220*

The 14th Annual Offshore West Africa (OWA) Conference & Exhibition will be held in the new location of Ghana at International Conference Center 23 – 25 March, 2010. Offshore West Africa is the premier technical forum focused exclusively on West Africa offshore exploration and production. The conference delivers the latest technological innovations, solutions and lessons learned from leading industry professionals.

Why Attend Offshore West Africa?

The annual Offshore West Africa Conference and Exhibition remains the leading source of information on new technology and operating expertise for this booming deepwater and subsea market and is the most significant offshore Africa deepwater technology event in the world.

- A unique audience of the world's leading executives, managers and engineers from major and independent E&P companies focusing on West Africa's specific requirements
- A world-class two-track technical conference program
- An exhibition showcase of technology and capabilities to support improvements in African E&P operations
- Expert opinions on the new issues, challenges and solutions associated with the expanding African exploration & production activity

BOOK SPACE NOW FOR PRIME PLACEMENT!

For Exhibit and Sponsorship Information, Please Contact:
Ana Monteiro, Phone: + 44(0) 1992 656 658 or
Email: anam@pennwell.com

Use promotion code OGJ-AD03 for an extra $50 saving & free entrance to exhibiton

Register now at :
www.offshorewestafrica.com

www.offshorewestafrica.com

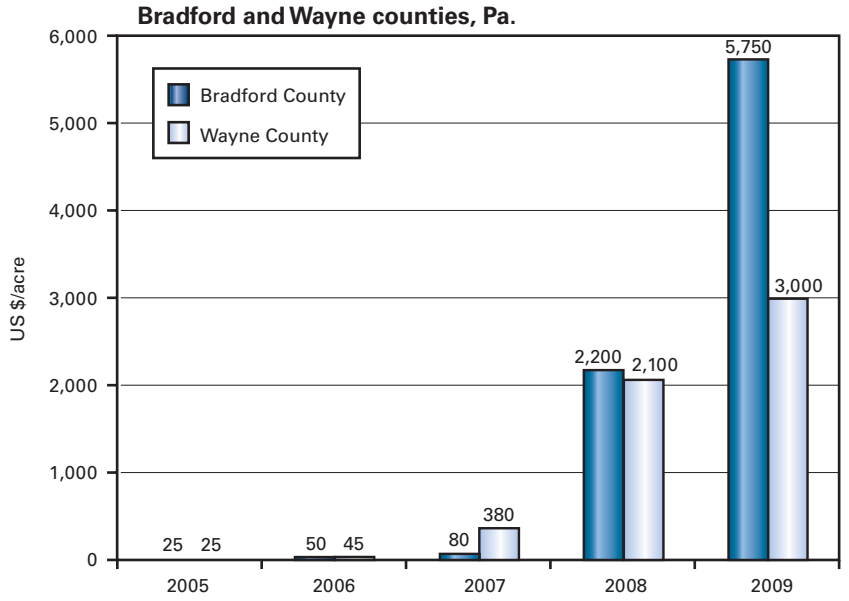
* This saving applies to Individual Delegate (Full Conference Registration)

Owned & Managed by: PennWell

Flagship Media Sponsors: Offshore OIL&GAS JOURNAL

SELECTED MARCELLUS LAND DEALS

Fig. 2



growth wave did not go unnoticed (although it took some time before others saw it!) in the strategy departments of the world's major oil and gas companies.

As US shale players proved up and derisked the subsurface through 3D seismic, improved hole stability, longer laterals, improved completion techniques, and shorter drill times, the attractiveness of shale also increased.

As US gas prices started to free-fall from June 2008, activity levels in the Marcellus actually increased, for both permitting and drilling, due to the superior break-even prices of the play and the fact that many incumbent companies had overstretched their balance sheets during the early move and land grab phase offering further entry opportunities.

Several US independents found themselves with a huge inventory of acreage and lacked the capital and credit rating to develop these, hence enter the majors including Statoil, BP, Eni, BG, and most recently ExxonMobil and Total.

The strategic driver for the majors is that shale gas offers a long-life asset base with global applications at a time when international opportunities continue to look limited. Acquiring this skill set can be through large corporate deals (ExxonMobil's acquisition of XTO), through JVs (including BG-EXCO in the Haynesville and Eni-Quicksilver in the Barnett), or through a mixed cooperation approach as in the Statoil-Chesapeake strategic alliance in 2008.

In this deal Statoil gained 32.5% of Chesapeake's 1.8 million Marcellus acres. In addition both parties formed an international study group to scan shale opportunities outside North America, and within 1 year of the alliance, the first exploration application was submitted in the South African Karoo basin.

Statoil has seconded a large group of technical, drilling, and subsurface personnel working in Chesapeake's Oklahoma campus covering all technical aspects of the shale skill set as well as a dedicated Marcellus asset team based in Statoil's Houston office that cooperates with Chesapeake on a daily basis.

The strategic alliance entry choice, rather than a financial investment or a full corporate deal, was more aligned with the Statoil strategy and its Scandinavian culture of cooperation and partnerships. This approach has been honed since the early days of the Norwegian continental shelf in the 1970s and through the BP-Statoil strategic alliance between 1990 and 1999 that internationalized Statoil.

As a result of the Marcellus entry, Statoil has created a new organizational unit, Global Unconventional Gas (GUG), guided by a new business model approach very different to the company's traditional offshore model.

The key issue with all these deals is that entry to the Marcellus can be executed in a number of ways due to the unconsolidated nature of the play. Measuring success on the other hand requires a longer term time frame, both in terms of return on initial investment but also in transferring the US shale experience into a profitable international business.

As Rex Tillerson stated in the Q&A session on the XTO Energy announcement, "this is not a near-term decision. This is about the next 10 to 20 to 30 years of what we believe has now emerged as a very important part of the global resource portfolio."

The technology drivers of note during this phase include experimentation with drilling and completion techniques including drilling fluid type and compatibility, hole stability due to geological complexity, risk assessment of drilling in complex areas, faulting, proppant type, number of frac stages, cluster spacing, and longer lateral lengths. Aligning subsurface understanding with optimal drilling and completion techniques leads to the next development phase.

Core development

Defining the core is a natural step from experimentation and shows the tangible effects of moving up the learning curve.

With the Marcellus in its infancy, well results are varied across the play. Without a critical mass of statistics, positioning remains highly competitive

and typically scattered at best. More analysis of core data, seismic data, open hole logging data, and post completion analysis of results is required to identify core areas.

Two developing core areas of note are in northeastern Pennsylvania and southwestern West Virginia. Some recent deals of note that reflect the core development phase include Ultra Petroleum's $400 million land acquisition in Lycoming, Clinton, and Centre counties, Pa., at $5,000/acre. Hess Corp., Seneca Resources, Cabot Oil & Gas, and Chesapeake-Statoil have also been highly active in land acquisitions for infill acreage.

Even when the perceived core area is found (as we won't know until a lot more wells are drilled), companies must continue to build areas of contiguous acreage. As land is a finite resource, interests around the core get very crowded. This will involve more exploration JVs (for example, the Hess Corp.-Newfield Exploration deal covering 140,000 acres); the formation of new areas of mutual interest, and all manner of smaller, under-the-radar swaps, acquisitions, and divestments. Private equity is also a player, including deals from KKR with East Resources and Morgan Stanley Private Equity's majority investment in Triana Energy (Morgan Stanley's fourth investment in the Marcellus).

While the broader value propositions of private equity and established independent E&P shale players may vary, the underlying strategic drivers in the core development phase are the same. The value of contiguous acreage around the core play is worth up to double the value of late noncore entry (using the Fayetteville as an analog).

The value of a company's portfolio with acreage scattered around the core and noncore areas can be fully developed through land highgrading. Acreage positions can be used as mini portfolios, swapping, selling, and purchasing contiguous land tracts to build drill ready sites.

A company with drill ready sites of even small contiguous acreage in the sweet spots will offer considerably more value than a competitor with larger, scattered acreage as the drill-out probability increases and costs can be driven down through full pad development and more efficient logistics and permitting.

Total's $2.25 billion JV with Chesapeake in the Barnett from January 2010 is a direct entry into the core. This kind of entry is likely to occur in the Marcellus the next few years. The effect of a tighter and more focused land portfolio in the core leads to the final development phase, that of exploitation and optimization.

Exploitation and optimization

Because of the sheer size of the Marcellus play, and its geographic and subsurface variability, it will be some time until we can assume that operators are engaged in the exploitation and optimization development phase.

In this phase, new business models are likely to be developed to manage what is essentially a margin business very different from conventional oil and gas organization models. Brian Forbes, Joerg Ehlert, and Herve Wilczynski from Schlumberger Business Consulting have suggested the concept of the flexible factory in unconventional gas development, balancing repeatability and standardized design with the specifics of subsurface characterization (Fig. 3).

The strategic drivers likely to influence this particular development phase include gas price volatility, margin management, competitor benchmarking, lean processes, and aboveground regulatory issues.

Entry into the Marcellus may come from various actors.

Utilities are likely to see entry into the upstream as a hedge or strategic asset, particularly if gas receives a demand boost from legislation aimed at lowering US carbon dioxide emissions. Utilities are used to margin business models and have considerable experience in state and environmental relations.

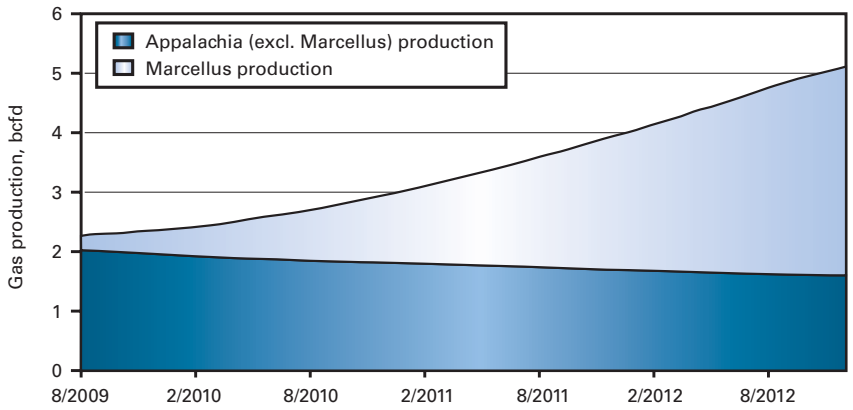
Private equity will also continue to see opportunities in this development phase looking for countercyclical gas price exposure, consolidation opportunities and providing improved management teams.

Sovereign wealth funds may also make bets on this play, as they have also done in mature basins including the UK continental shelf.

Sustainable success will be measured against those players with consistent top quartile cost positions, which is essentially the best long-term hedge in structurally volatile commodity markets

PROJECTED APPALACHIAN BASIN PRODUCTION*

Fig. 3



*Marcellus still early on the production curve; 100% production growth from Marcellus wells expected to 2012; forecasting 9 bcfd in 2020.
Source: Tudor, Pickering, Holt & Co. Appalachia infrastructure update January 2010

such as natural gas and offers investors superior returns. In this particular phase, the majors may already possess some distinct advantages, through the application of technological innovation, supply chain management, sophisticated IT systems and procurement economies of scale.

This particular operational model could imply that the winners in this phase may actually employ a business model similar to that of the oil and gas service industry, which again may create new cooperation opportunities between the service sector and E&Ps. This is especially true of the Appalachian region, which is a multishale play offering recovery upside through greater subsurface understanding.

Near-term technology developments will need to tackle some key issues including improving recovery rates, water management and recycling of frac fluids, and optimizing logistics. Long-term technological developments will occur as a result of continual problem solving and competition, making the Marcellus a very important place to be for transferring technology to global shale plays.

A wide open space

US shale plays, and the Marcellus in particular, offer a breadth of entry opportunities and are likely to continue to do so in the future due to the lack of consolidation in the shale gas sector.

As the Marcellus matures, the competitor landscape will change with it, bringing in new players that are measuring success and adding value in various ways.

There is no silver bullet application for sustainable success in shale plays, rather the tireless drive for operational efficiency and the application of repeatable technology. For some companies, this will require very different business models than they employ today, engaging aspects of manufacturing and just in time supply-chain management.

The growth of the joint venture model in US shale may also encourage new organizational structures and working practices getting the best out of the Independents and the majors. What is sure in this play is that the level of competition will continue to remain high in the future. ✦

The author

Stephen Bull (sbul@statoil.com) is the commercial leader of Statoil ASA's Marcellus shale gas asset. Currently based in Houston, he has previously worked for JP Morgan in London and has been with Statoil for 12 years covering positions within market analysis, risk management, and strategy. He holds an MSc (Econ.) from the London School of Economics.

Indonesia

Locations are being cleared out of dense jungle for two exploratory wells in the Lariang and Karama subbasins onshore central west Sulawesi, Indonesia.

Tately Budong-Budong NV, a subsidiary of Pexco NV, will operate the wells in the exploration phase on the 1.4 million acre Budong-Budong block. Harvest Natural Resources Inc., Houston, is to earn a 47% working interest.

The first well is to spud in mid-March 2010. The wells seek oil in stacked Miocene and Eocene clastics in the West Sulawesi fold belt.

Mexico

Seismic acquisition is under way on the 12,300 sq km Han Sur-Oeste de Tamil project, first 3D survey for Petroleos Mexicanos SA in the deepwater Gulf of Mexico.

CGGVeritas deployed the Nautilus acoustic positioning and streamer steering system on the Alize seismic vessel. The vessel set a 1-day production record of 117 sq km, exceeding targets.

The vessel deploys 12 Sercel Nautilus-Sentinel steered solid streamers, and with a 12 by 8-km by 100-m configuration, it is towing one of the largest areal receiver arrays in the industry.

New Zealand

New Zealand offered six blocks covering 105,230 sq km in the Reinga basin northwest of the North Island.

Newly acquired seismic reflection data and other information indicate that a large part of the basin is prospective for oil and gas and parts have high potential. The blocks are just north of the Northland blocks already on offer.

The basin has as much as 7 km of Mesozoic and Cenozoic sedimentary rocks and appears to have all elements of an active petroleum system in 1,750-2,000 m of water, Crown Minerals said. Large areas lie in the oil generation window in a sequence similar to that of the Taranaki basin.

The major risk relates largely to the low level of geologic knowledge of the basin. However, the Turi and the Waipawa formations are rich, and modeling suggests that a 100-m interval of source rock expelled as much as 7.5 million bbl/sq km of oil and more than 60 bcf/sq km of gas.

West Virginia

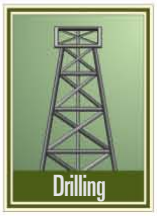
Gastar Exploration Ltd., Houston, said its first vertical Marcellus well just south of the West Virginia panhandle proved the company's belief that areas where the shale is thinner can yield "excellent results."

The James Yoho-1 well, in the Green district of Wetzel County, stabilized at 1.5 MMcfd of gas and 120 b/d of condensate with 1,000 psi flowing tubing pressure. It cut 46 ft of Marcellus shale and was completed with a single-stage frac.

Gastar has 100% working interest and has acquired 36,000 net acres in northern West Virginia and southwestern Pennsylvania. Its longer-term development will be geared toward horizontal drilling.

Unconventional basins require new rig types

Guntis Moritis
Production Editor



Even though more than 1,000 rigs are inactive in the US, drilling contractors are building new land rigs to satisfy operator demand for improved technology.

In the case of Nabors Drilling USA LP, Ronnie Witherspoon, senior vice-president marketing and business development, said that for newbuilds operators are requesting Nabors new AC rigs for their drilling programs, especially for drilling in unconventional basins.

He said, "To meet demand we are expanding our fleet with the new PACE rigs." Typically Nabors only builds new PACE rigs when customers make a long-term contractual commitment, he added.

PACE stands for programmable AC electric and the programmable refers to various functions and controls that are programmed in the rig's PLCs (programmable logic controllers), Witherspoon explained.

The automation in these rigs includes a drawworks-control joystick for raising, lowering, and stopping the traveling blocks. Drillers input all other drawworks operating parameters such as upper and lower hoist limits and speed, via a human-machine interface screen that controls the PLC and variable-frequency drive systems (Fig. 1).

These rigs have a top-drive joystick that operates the pipe handler rotation, link tilt extend-retract, and makeup and breakout functions. Drillers also use the HMI screens for operating and monitoring other equipment such as mud pumps, blowout preventer accumulator system, torque wrench, rotary table, catheads, and hydraulic power unit.

Witherspoon noted that before AC technology, joysticks were primarily

Drillers use joysticks and human-machine interfaces to control rig operations (Fig. 1).

Same ball. Whole new ball game.

Bringing proven ball-activated tool expertise to the drilling arena.

Across the E&P lifecycle the pressure is on to perform downhole. Now a single drilling valve bypass system can help meet the demands of challenging drilling operations.

Building on our success with downhole circulating equipment, M-I SWACO takes reliable downhole performance one step further. The WELL COMMANDER* tool enables the widest range of critical drilling functions to be performed with confidence, from cuttings removal to lost circulation treatment and kill weight fluid spotting.

As well as being simple to operate, versatility is maximized with seven full cycles activated with one-size ball, while other ball-activated tool access is maintained below this drilling valve. Engineered for reliability, an isolation sleeve protects the activation mechanism against debris and solids-laden fluids. The tool can be locked in either the open or closed state, and remain unaffected by high circulation rates and pressure changes. Using the WELL COMMANDER tool, sensitive BHA equipment can be protected from aggressive solids-laden treatments.

Optimize rig time and resources by eliminating additional auxiliary tools and avoiding unnecessary trips. When performing critical drilling operations with the WELL COMMANDER tool, the ball is in your court.

Drilling Solutions | Wellbore Productivity | Production Technologies | Environmental Solutions

*Mark of M-I LLC

MI SWACO

Customer-focused, solutions-driven

www.miswaco.com



Nabor's M-series rigs (left photo) can operate on locations with limited space (Fig. 2). One feature on the PACE rigs (middle photo) is an automated iron roughneck (Fig. 3). The PACE rigs (right photo) have automated catwalk pipe handling systems (Fig. 4).

utilized for drawworks braking applications.

Rig models

Nabor's more recently built rigs include the M-series rigs (Fig. 2) that drill in a broad range of depths and in a variety of geographical and geophysical areas. These rigs have a small footprint that allows them to operate on locations with limited space for drilling single wells or multiple wells from a single pad. Nabors deployed the first M-series rig in fourth-quarter 2006.

Witherspoon said different PACE rigs series are built for specific markets such as:

- PACE B-series, 1,500-hp rig with a skid system for the Bakken.
- PACE F-series and PACE 1500, 1,500-hp rig suited for the Haynesville and Eagle Ford shales.
- PACE Super Sundowner, 1,000-hp rig designed for pad drilling in the Rocky Mountains. The rigs can drill up to 22 wells from one well pad.
- PACE Academy, 1,000-hp rig built by Nabors in Canada for winterized drilling in Colorado, Wyoming, and North Dakota.
- PACE AC Hybrid Coil Tubing, PACE technology deployed in a coiled-tubing rig for shallow gas wells and deeper reentry drilling.

Witherspoon said Nabors first began building PACE rigs in 2005 and to date has built more than 200. The US total is 98 PACE drilling rigs and 1 coiled-tubing rig, with 53 M-series rigs, including 4 that Nabors will deploy in 2010, he said.

He added that in 2010, Nabors will also deploy two Box-on-Box PACE rigs, which is a rig specifically designed for the Bakken play in North Dakota.

Most PACE rigs are currently on contract including the 53 PACE M-series rigs with most of the M-series rigs working in the Haynesville shale and the remainder in shale plays such as the Marcellus, Eagle Ford, Fayetteville, and Barnett, as well as the tight gas sands in the Piceance basin in Colorado.

The PACE rigs typically are for drilling horizontal wells that range from 8,000 to 11,000 ft TVD with laterals that range from 3,000 to 6,000 ft.

Main features

Some of the main features of these rigs include:

- Mast and substructure design that allows for transportation in four loads for the rig, including the drawworks, rotary table, iron roughneck, traveling blocks, and top drive.
- Use of PLCs for monitoring and automatically controlling the hydraulic cylinders for raising the mast and substructure.
- Drawworks that rotate 90° on the drill floor to allow installation and transportation on the substructure center steel.

• 142-ft telescoping mast with integrated top drive.
• Custom-designed BOP handling and transportation system.
• Automated iron roughneck (Fig. 3).
• Automated catwalk pipe-handling system (Fig. 4).

Also available on the rigs is the Rockit, Canrig Drilling Technology Ltd.'s surface rotary steerable system for aiding directional drilling by increasing penetration rates during sliding, providing faster tool-face settings, and improving tool-face control.

All M-Series rigs can accommodate multiwell pad drilling and an optional walking system can enhance the move capability with full setback.

AC rigs

Nabors said that it is only building new AC rigs. The company notes that some competitors build new DC rigs, but "the way of the future is AC technology and we cannot justify large capital expenditures on new non-AC rigs, when that capital could more strategically be deployed toward the development and construction of PACE rigs."

Nabors says AC technology makes it easier to provide precise and automated rig controls such as:

• Drawworks efficiency and safety with a single joystick operation and effective autodrill function.
• Top-drive directional drilling efficiency.
• Mud pump speed and pressure controls.
• Improved drilling and tripping performance
• Reduced nonproductive time on well.

AC-driven equipment is smaller, more portable, and offers enhanced performance and reliability. DC motors cannot operate at zero speed for extended periods, while AC motors can run at zero and low speeds at full torque for prolonged extended periods.

The drawworks and top drives benefit operationally from the AC motor's ability to hold full torque and load at zero speed for extended periods. For instance, regeneration converts kinetic energy to electrical energy, enabling the motor to slow and stop rotation. This eliminates the need for separate eddy current and service brakes on drawworks.

Another difference is that DC motors require brushes for rotor current. AC motors are brushless, thereby requiring less maintenance, and are more suited for hazardous locations.

AC drives also improve the power factor and increase the overall efficiency. DC motor-drive systems have a varying power factor based on speed (0.30-0.95). AC motor-drive systems have a constant 0.95 power factor at all speeds. ✦

Pre-Caspian basin wells in salt-gypsum beds require an optimized drilling fluid

Yan Jin
Mian Chen
K. P. Chen
Henglin Yang
Yingjian Xiao
China University of Petroleum
Beijing

Shidong Ding
Sinopec
Beijing

Drilling wells through the ultrathick, salt-gypsum beds in the pre-Caspian basin requires an optimized drilling fluid. The fluid must effectively inhibit salt-gypsum creep, salt dissolution, and hydration expansion in the water-sensitive formation to keep the borehole stable under high pressure and high temperatures.

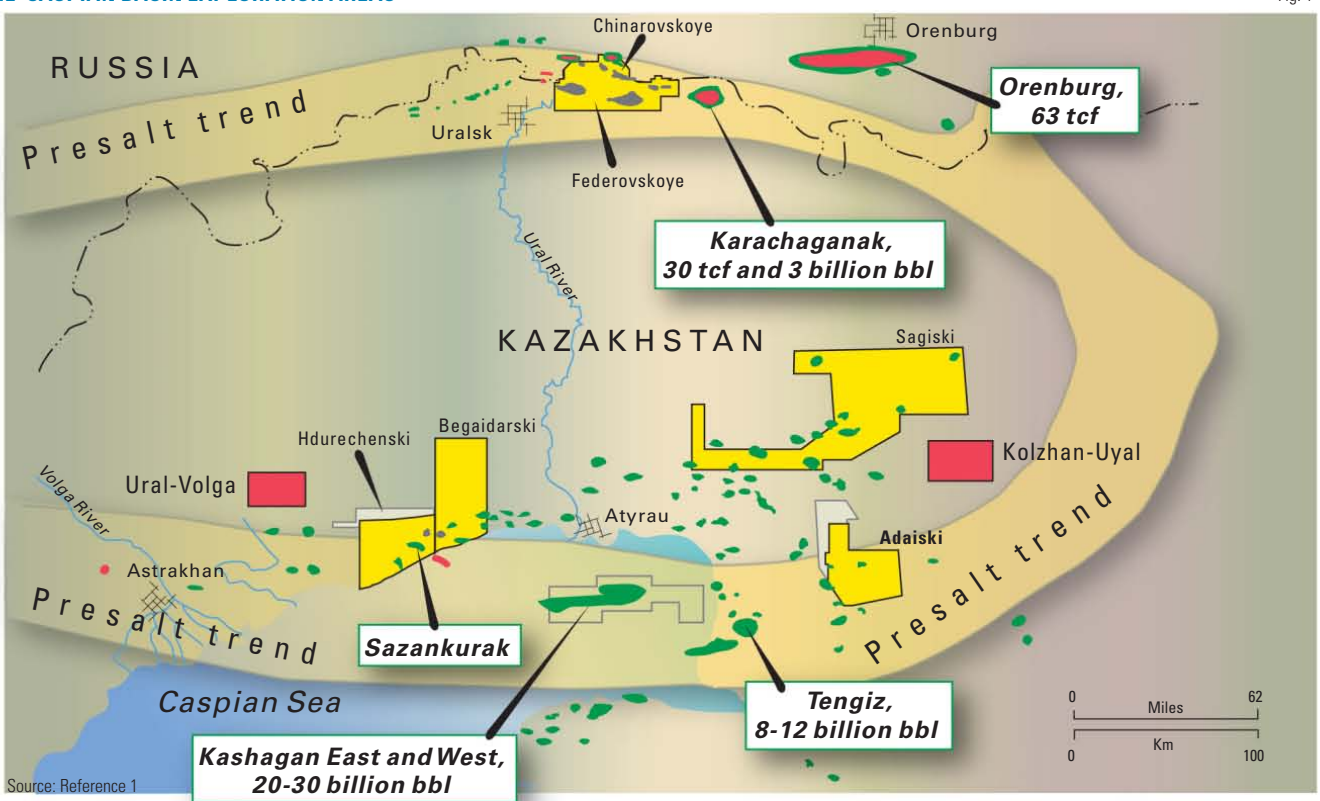
Pre-Caspian basin

The pre-Caspian basin has the most promising onshore deep oil and gas bearing zones in the former Soviet Union. Also it is already one of the world's most important oil producing areas.

A large portion of the basin lies in the southern part of Kazakhstan, and the rest is in Russia. The basin, with a total area of 50,104 sq km (1,000 km from east to west and 500 km from north to south), is north of the Caspian Sea.

The basin has widely spread, ultrathick, salt-gypsum beds in the Sagiski, Federovskoye, Adaiski, Ural-Volga, and Kolzhan-Uyaly blocks (Fig. 1)and well developed salt dome structures. There

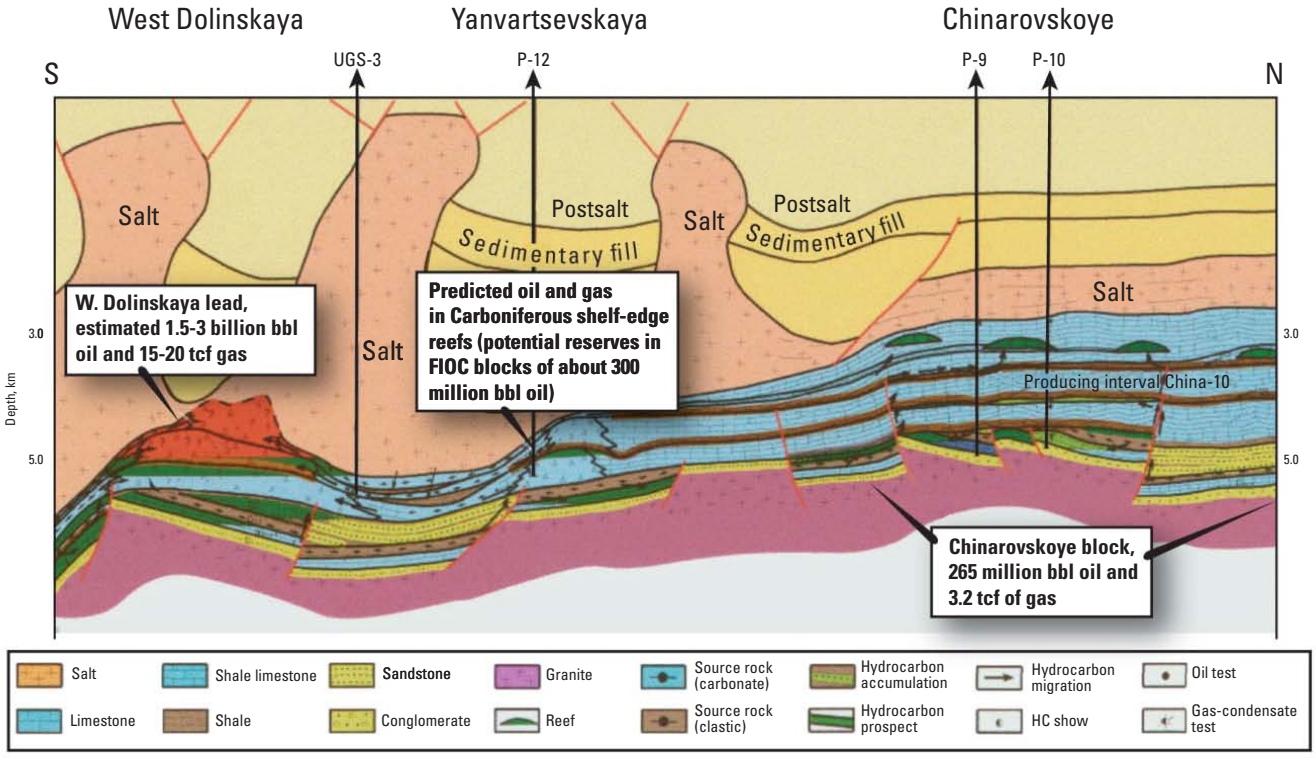
PRE-CASPIAN BASIN EXPLORATION AREAS Fig. 1



Source: Reference 1

Chinarovskoye-Federovskoye cross-section

Fig. 2



Source: Reference 1

are more than 1,500 salt domes, covering 25-30% of the basin's area.

Salt beds are mainly in the Permian Konggu formation, Lower Konggu stage. These beds have thickness of several hundreds meters along the basin boundary and up to 5,000 m inside the depression (Fig. 2).

Salt beds consist of salt rock and karstenite (anhydrite). In the basin boundary, the beds contain gypsum, limestone, dolomite, and shale.

Bentonite content

Table 1

Bentonite content, g/l.	70	50	40	30	25	20
Initial shear force, Pa	9.5	8.5	3.5	1.5	1.5	0.5
Ultimate shear force, Pa	16.0	9.5	4.5	3.5	2.5	0.5

Antisalt capability

Table 2

Polymer	Salt-resistant, mg/l.	Calcium-resistant, mg/l.
CMC (MV)	350,000	90,000
FA367	350,000	100,000
PMHC	350,000	100,000
KPAM	350,000	100,000
PAC141	350,000	100,000

Drilling salt

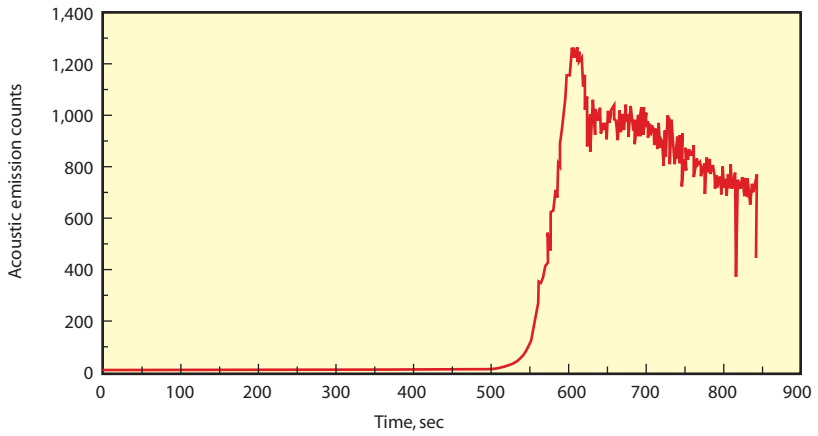
The major technical difficulties encountered in drilling salt beds in the pre-Caspian basin are:

- Drilling of the thick salt beds, 2,000-4,000 m, can lead to plastic flow of the salt, which threatens drilling safety.
- Salt beds mingled with karstenite dissolve while the gypsum in the beds expands and collapses after absorbing water. This contaminates drilling fluid and causes such incidents as borehole-shrinkage induced pipe sticking,

These cores are of salt from a Taskuduk well (Fig. 3).

CHANGE IN ACOUSTIC EMISSION COUNTS

Fig. 4



POLYMER TACKIFIER EFFECTS ON BRINE

Table 3

Test	Formula*	Plastic viscosity, mPa-sec	Yield point, Pa	Fluid loss, ml	pH
1	Basic mud + 0.4% PMHC	17	13	12	8.5
	Basic mud + 0.4% PMHC + 20% NaCl	12	11	16	8.5
2	Basic mud + 0.4% FA367	19	10	12	8.5
	Basic mud + 0.4% FA367 + 20% NaCl	12	9	17	8.5
3	Basic mud + 0.4% KPAM	14	6	15	8.5
	Basic mud + 0.4% KPAM + 20% NaCl	9	4.5	18	8.5
4	Basic mud + 0.4% 80A51	11	5	13	8.5
	Basic mud + 0.4% 80A51 + 20% NaCl	8	5	17	8.5
5	Basic mud + 0.4% PAC141	17	12	12	8.5
	Basic mud + 0.4% PAC141 + 20% NaCl	9	10	17	9

*Base mud is 2.5% prehydrated bentonite + 0.5% Na_2CO_3.

borehole-collapse induced pipe sticking, and casing collapse.

- Salt beds contain much karstenite and mudstone. Balancing the creeping of the salt-gypsum bed requires a high-density drilling fluid. This, however, can easily cause fluid loss to weaker formations such as salt beds and its interlayers.
- The rock salt has high purity, containing 97% salt (Fig. 3). Compared with compound and relatively weak salt beds, it creeps more rapidly. This calls for the use of more advanced drilling fluid.

Before 1990, two peripheral, 37 exploration, and three exploitation and assessment wells were successively drilled in Kenkyak oil field.

Statistics of 36 wells show that borehole collapse, borehole shrinkage, and severe pipe sticking occurred in 13 wells (36%). The problems occurred mostly in salt beds and sometimes led to not reaching drilling targets in the middle Carboniferous Period.

LASER GRANULOMETER DATA

Table 4

Formula	— 6% Bentonite meal — Median diameter, μm	— 6% Bentonite meal — Specific surface area, μm²/g	—— 6% Rock meal —— Median diameter, μm	—— 6% Rock meal —— Specific surface area, μm²/g
Clear water	3.9	162.9	11.6	59.8
2% PAC141	15	29.3	18.8	45.2
2% FA367	26.3	17.3	29.3	28.6
2% KPAM	27.5	16.2	30.5	27.6

Drilling fluid density

The traditional design approach for determining drilling fluid density for salt beds is based on the drilling fluid column pressure and the nonlinear viscoelastic deformation characteristics of salt rocks. The design includes an analysis of the borehole shrinkage rate under different liquid heads.

Proper drilling fluid density is then determined from the on site borehole shrinkage rate required for safe drilling. This method includes creep parameters measured in the laboratory and complicated shrinkage-rate calculations of salt rocks.

Analysis of borehole well rock deformation properties in deep salt beds requires an understanding of the short-term mechanical behavior of salt rock because such behavior determines the mechanisms for long-term rock deformation.

One can use the acoustic emission signal produced in a salt-rock triaxial compression test (Fig. 4) to determine the relationship between acoustic emission and inner damage of rock to provide a damage-expansion boundary curve of salt rock in an octahedron stress space (Fig. 5). This is also the shear yield strength along the crystal grain boundary in the salt rock.[2]

Equation 1 in the equation box calculates the maximum octahedron shear stress in a deep, ultra thick, salt-rock formation.[3] In the equation, ρ_o is the salt-rock density and ρ_w is the wellbore hydrostatic pressure.

If the borehole drilling-fluid head is less than the salt-bed ground stress, salt rock will creep toward the borehole. With an increase in both formation temperature and the differential between salt-rock ground stress and fluid head, borehole shrinkage rate also increases.

EQUATIONS

$$T_{Omax} = 0.817\,(\rho_o gz - p_w) \quad (1)$$

$$T_{Omax} = T_{od} \quad (2)$$

$$\rho_w = \rho_o - \frac{14.59}{gz} \times 10^3 \quad (3)$$

issues challenges SOLUTIONS

ASIA'S PREMIER OFFSHORE CONFERENCE & EXHIBITION

Don't miss this excellent opportunity to present your company's technology and operations expertise to this industry-leading assembly of attendees. For more information on exhibiting and sponsoring Offshore Asia please visitwww.offshoreasiaevent.com or contact:

Asia Pacific & Australasia	Northern Europe, Scandanavia & Middle East	Southern Europe & Africa	The Americas
Michael Yee T: +65 9616 8080 F: +65 6734 0655 yfyee@singnet.com.sg	**Jane Bailey** T: +44 (0) 1992 656 651 F: +44 (0) 1992 656 700 janeb@pennwell.com	**Ana Monteiro** T: +44 (0) 1992 656 658 F: +44 (0) 1992 656 700 anam@pennwell.com	**Sue Neighbors** T: +1 713 963-6256 F: +1 713 963-6212 sneighbors@pennwell.com

Owned & Produced by: PennWell Flagship Media Sponsors: Offshore OIL&GAS JOURNAL Incorporating: Multiphase Pumping and Technologies.

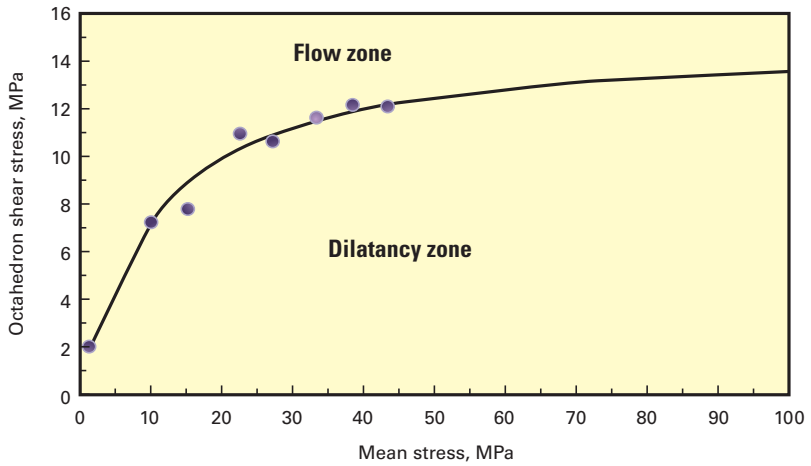
16 – 18 March 2010 ✷ KLCC, Kuala Lumpur, Malaysia

www.offshoreasiaevent.com

OFFSHORE ASIA™

SALT-ROCK COMPRESSION LIMIT BOUNDARY

Fig. 5



FILTRATE REDUCER OPTIMIZATION

Table 5

Additive	Formula*	Plastic viscosity, mPa-sec	Yield point, Pa	Fluid loss, ml
Base mud	PAM	7	3	16
SMP-II	Base mud + 4% SMP-II	6	3	11
	Base mud + 4% SMP-II + 20% NaCl	6	4	12
	Base mud + 6% SMP-II + 20% NaCl	9	2	9.5
SPC	Base mud + 2% SPC	9	2	10
	Base mud + 2% SPC + 20% NaCl	13.5	8.5	12
	Base mud + 4% SPC + 20% NaCl	16	6	11.5
JT888	Base mud + 2% JT888	4	1.5	9.5
	Base mud + 2% JT888 + 20% NaCl	6	2	11
	Base mud + 4% JT888 + 20% NaCl	10	3	9

*Base mud is 4% prehydrated bentonite + 0.5% Na_2CO_3 + 0.4% KPAM.

Under conditions of relatively high average ground stress, when octahedron shear stress is within the damage-expansion boundary curve, the salt-rock volume remains the same or increases slowly. Only when the octahedron shear stress is outside the damage-expansion boundary curve, the salt-rock volume will increase rapidly due to expansion.

On this basis, we propose the hypothesis that one can guarantee safe drilling if expansion deformation in a salt-bed borehole is zero. In other words, the maximum octahedron shear stress must be within the damage-expansion boundary curve (Equation 2). In the equation τ_{od} is the boundary value between compression and damage and τ_{od} = 11.92 MPa.[3]

Equation 3 calculates a safe drilling fluid density ρ_w.

Calculations of drilling fluid density (Fig. 6) and borehole shrinkage velocity (Fig. 7) show that, even with no expansion in the borehole enclosing rock, shrinkage velocity increases gradually with depth. For instance, when at 5,000-m, borehole shrinkage velocity is 0.0912 mm/hr and the shrinkage rate is 0.00084/hr.

Based on field experience, one can guarantee safe drilling if the shrinkage rate is within 0.1%/hr.

When one maintains the borehole enclosing rock stress state within the damage-expansion boundary curve, no drilling incidences will occur.

ROLL RECOVERY, EXPANSION RATIO

Table 6

Formula	Roll recovery of 40 mesh (R), %	Expansion ratio (K), %
Clear water	45	100
Drilling fluid	60	54
Drilling fluid + 4% NaCl	71	33
Drilling fluid + 4% KCl	83	27
Drilling fluid + 4% NaCl + 4% KCl	90	19

Fluid characteristics

When the thickness of salt beds is greater than 500 m, particularly when it is 1,000-4,000 m, one can use a medium-high density, saturated-brine drilling fluid to balance salt bed creep such as in well SLK3 in the Central Asia block and salt wells in the Sagiski block.

A proper high-density drilling fluid in a salt-gypsum bed should have the following characteristics:

- Effective inhibition of salt-gypsum bed creep, salt dissolution, and hydration expansion in the water-sensitive formation to keep the borehole stable.
- Excellent rheological behavior under high temperature.
- Excellent salt resistance, calcium resistance, and drill cutting ejection resistance, as well as excellent lubricity and saline recrystallization resistance.
- Relatively low filtration under high temperatures and high pressures, as well as an ability to form thin and tough mud cake with good compressibility.

Optimized fluid

It is difficult to adjust and control the rheological behavior of high-density drilling fluid. Excessive amounts of bentonite can cause difficulty in controlling viscosity, while inadequate amounts can lead to higher maintenance cost and worsen the degradation of the drilling fluid.

Our laboratory tests show that proper bentonite content is 25-40 g/l. This can guarantee an appropriate network structure in polymer drilling fluid (Table 1).

Antisalt properties are essential for polymer salt resistance. An antisalt test can determine the proper

polymer (Table 2). From Table 3, it is obvious that most polymer candidates do not deposit or flocculate in saturated brine and are capable of resisting calcium.

The viscosity of macromolecular polymer solution declines sharply in the process of adding salt (Table 3). This implies that under the influence of electrolyte, macromolecular polymer molecular chain curls and hydration capacity declines.

Metal zwitterionic polymer because of its molecular structure has a strong ability to resist electrolytes. The PMHC molecular chain stretches moderately in brine and has relatively thick hydration film cover. Salinity has little effect on solution viscosity of PMHC.

The clay's microscopic size in solution can determine the hydration and dispersion-resistant capability of the polymer solution. The test first combines three different polymer solutions with the concentration of 2%. The next step adds bentonite and rock meal into the solution under the same conditions, and then after full dispersion, one can measure the median diameter and specific surface area with a laser granulometer.

The results show that PMHC has a relatively large median diameter that can resist hydration and dispersion (Table 4).

The tests used several organic filtrate reducers capable of salt, calcium, and temperature resistance before contaminating the fluid with 25% brine to measure filtrate resistant (Table 5).

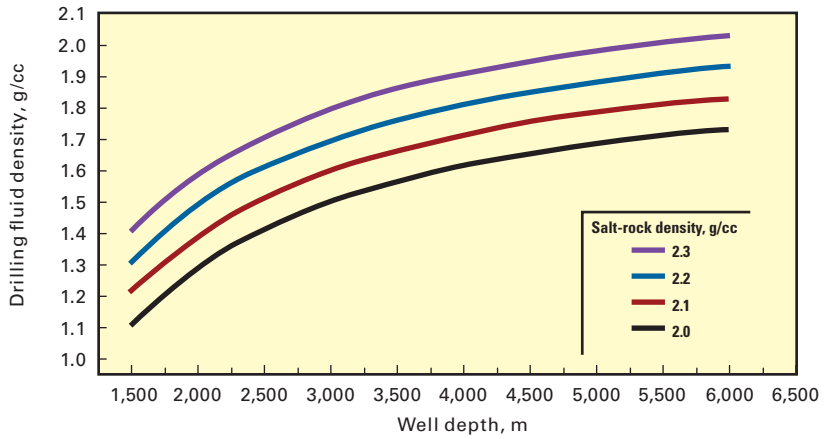
These tests noted that the number of bubbles increases after the addition of SMP-II, and hence it is one ingredient that should be controlled. Table 5 shows that SMP-II, SPC, and JT888 for resisting salt and calcium can effectively reduce the filtrate amount. All of them could be used in practice.

Inhibitor test

Data from drilled deep wells indicate that salt-gypsum beds mainly consist of salt rock and a gypsum layer, mingled with complex formations of distinct

Drilling fluid density window*

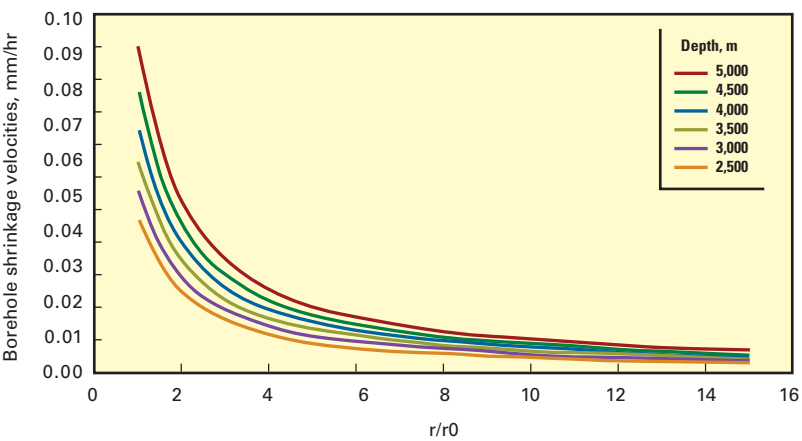
Fig. 6



*Based on no damage from expansion in borehole of enclosing rock.

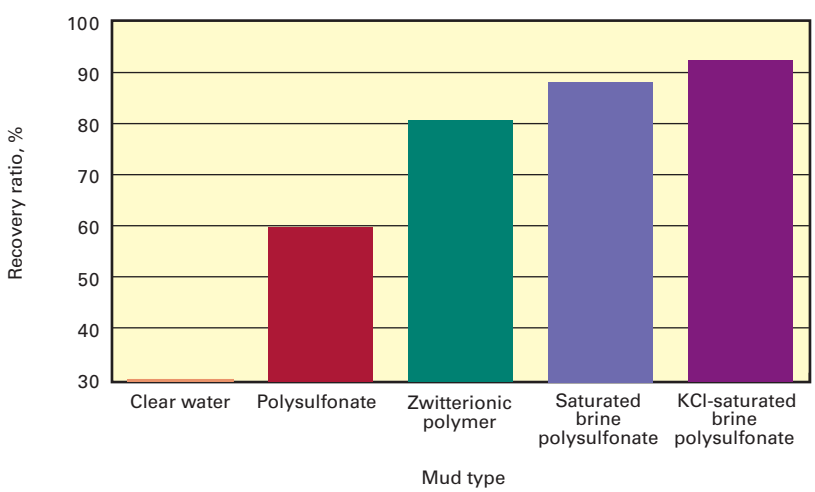
Borehole shrinkage velocities

Fig. 7



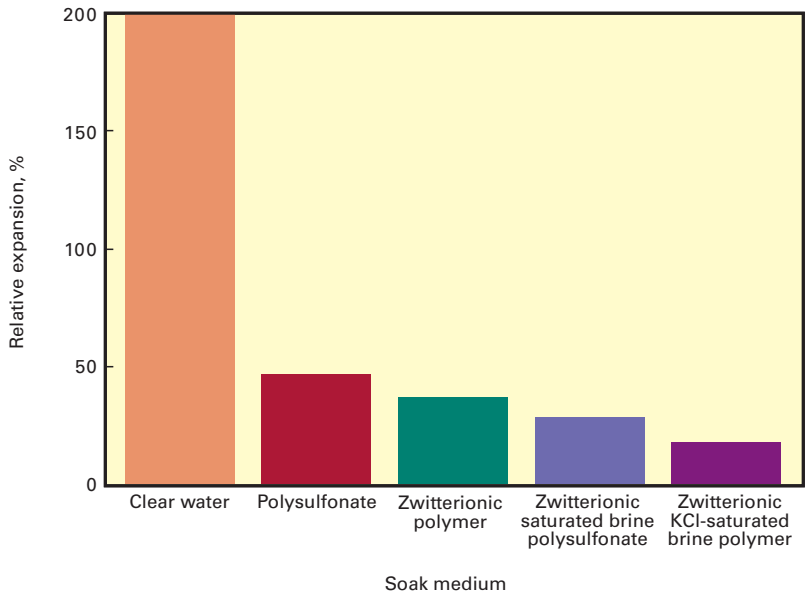
Drill cutting recovery ratios

Fig. 8



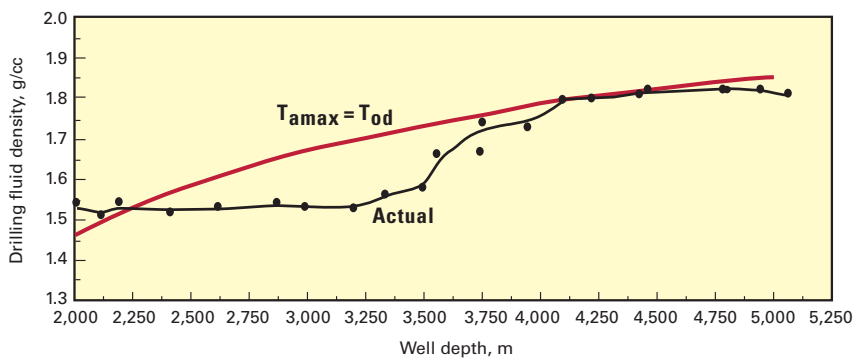
SHALE EXPANSION TESTS

Fig. 9



WELL SLK 3 MUD DENSITY

Fig. 10



thick argillutite, gypsum, mudstone, and red argillutite. As a result of the different lithology and physicochemical properties, formations differ in expansion and dispersion after encountering drilling fluids. Because of this, the drilling fluid needs to have a strong inhibitive ability

The properties of clay additives decrease in brine polymer drilling fluid because of the compression of the electrolytic double-layer of salt. Thus, selecting proper additives with strong inhibitive ability is key to increasing the inhibitive ability of brine drilling fluid.

We tested in our laboratory inhibitors or shale stabilizers such as FA367/KPAM, NaCl, KCl, and K_2SiO_3.

After the inclusion of polymers accompanied with the inorganic salt KCl, polymer absorption volume in clay surface increased and the procedure added metal cations to decrease the ζ-electric potential, which decreases hydration capability of clay and enhances inhibition of the drilling fluid. Synergistic action of organic and inorganic inhibitors used together can improve drilling fluid inhibition.

Table 6 shows that the addition of NaCl and KC1 markedly enhances hydration inhibition for shale.

Fluid evaluation

With the drilling characteristics of the ultrathick salt-gypsum bed in the Kolzhan block, the recommendation from our optimization process is for the use a zwitterionic polymer-KCl saturated brine drilling fluid.

Roll recovery tests compared several distinct fluids used in the area and the zwitterionic polymer-KCl saturated brine drilling fluid (Fig. 8). These data show that polysulfonate drilling fluid behaves the worst in inhabiting drill cuttings, while the recommended amphoteric KCl saturated brine and polysulfonate drilling fluid perform much better with the highest recovery and the strongest inhibition.

Other tests carried out were for high temperature, high-pressure expansion of shale (Fig. 9). These experimental results show that amphoteric KCl saturated brine and polysulfonate drilling fluid performs the best with the smallest relative expansion while clear water performs the worst with the largest relative expansion.

This is consistent with the roll recovery test results.

Field applications

Well SLK3 is a wildcat well drilled through salt by the Central Asia project department of Shengli Oilfield in the Kolzhan Block. The planned depth was 5,500 m.

The well used the zwitterionic and polysulfonate saturated brine drilling fluid after the upper borehole. Prehydrated bentonite slurry supplemented the drilling fluid, which included NTA to inhibit salt recrystallization, LV-CMC to reduce filtrate, HV-CMC to improve viscosity and colloid protection, and SDR-1. SDR-1 is an environment friendly and power lubricant with no fluorescence ring and is for increasing lubrication properties of the drilling fluid.

When drilling above some salt beds at 2,000-m, the drillers switch to the zwitterionic polymer-KCl saturated brine drilling fluid step by step, while adjusting mud density timely

and optimizing the drilling fluid properties.

Drilling fluid properties included a 1.49-1.76g/cc density; 50-75 sec viscosity, 2-5 ml filtrate, 0.5-ml mud cake thickness, 1-3/2-8 Pa shear force, 0.2-0.3% sand content, 8-9 pH, 32-37% total solid phase content, 42.9-58.6 g/l. MBT, and a 10-14 ml HTHP fluid loss.

The initial mud density was 1.45g/cc. Above 2,200 m, the salt-gypsum bed was relatively stable, while borehole shrinkage occurred in salt beds below 2,200 m. After 2,200 m, the driller gradually increased the mud density to 1.59 g/cc at 3,500 m.

The bottom of the salt-gypsum bed was at 5,026 m and the thickness of salt beds was 4,426 m. Fig. 10 illustrates the mud density variations with depth.

Drilling of the well went smoothly with no pipe sticking or fluid loss.

Acknowledgments

This drilling fluid design was supported by the Program for New Century Excellent Talents at the China University of Petroleum, the Ministry of Education of China, 973 Program (2010 CBN226700), and by the Exploration and Development Research Institute of SINOPEC. ✦

References

1. Drilling Proposal: Drilling Techniques for Ultra-Thick Salt-Gypsum Bed in the pre-Caspian basin of Kazakhstan, internal report, Exploration and Exploitation Research Institute of SINOPEC, 2007.

2. Hunsche, U., "Determination of the Dilatancy Boundary and Damage Up to Failure for Four Types of Rock Salt at Different Stress Geometries," 4th Mechanical Behavior of Salt Conference, Montreal, June 18-20, 1996.

3. Yang, H., Study on the Damage Deformation Mechanisms and Application of Deep Soft Rock PhD dissertation, China University of Petroleum, 2007.

The authors

Yan Jin (13701222683@vip.163.com) is a professor in the College of Petroleum Engineering of China University of Petroleum-Beijing. His current research interests are in rock mechanics and drilling engineering. He received all his degrees from China University of Petroleum (East China, and Beijing), in drilling engineering (BS, MS), and oil and gas well engineering (PhD). He is a member of International Society for Rock Mechanics, Chinese Society of Rock Mechanics and Engineering, and Chinese Society of Rock Mechanics at Great Depth.

Mian Chen (chenmian@vip.sina.com) is a professor and the dean of the College of Petroleum Engineering of China University of Petroleum-Beijing. His research interests focus on rock mechanics and drilling engineering. Chen received his degrees from Peking University (BS), Liaoning University (MS), and China University of Mining & Technology (PhD). He serves on the Professional Committee of International Society for Rock Mechanics and chairs Chinese Society of Rock Mechanics and Engineering, as well as the Chinese Society of Rock Mechanics at Great Depth.

Kang Ping Chen (k.p.chen@asu.edu) is an associate professor in the School of Mechanical, Aerospace, Chemical, and Materials Engineering of Arizona State University and a visiting professor at China University of Petroleum-Beijing. His research interests concern non-Newtonian fluid mechanics, multiphase flows, and flow in porous media. Chen has degrees from Peking University (BS) and the University of Minnesota (PhD). He is a member of ASME.

Henglin Yang (yhldri@cncp.com.cn) is a senior engineer at Drilling Research Institute of CNPC. His research interests are in rock mechanics in oil and gas engineering. Yang has a PhD from China University of Petroleum-Beijing.

Yingjian Xiao (cqxyj023@126.com) is a graduate student seeking an MS in drilling engineering at China University of Petroleum-Beijing. Xiao has a BS in petroleum engineering from China University of Petroleum (East China). He is a student member of SPE.

Shidong Ding (dingsd@sripe.cn) is a professor of engineering and the director of cementing and completion at Sinopec Research Institute of Petroleum Engineering. Ding has a PhD in drilling engineering from China University of Petroleum-Beijing.

Calculating H_2O solubility, Henry's Law constant for cycloalkanes in crude

Carl L. Yaws
Lamar University
Beaumont, Tex.

Water solubility and Henry's law constant in cycloalkanes found in crude oil have been calculated and set in an easy-to-use table.

In addition, we have developed a new correlation for solubility of water in crude oil that provides reliable solubility values down to very low concentrations (ppm). The correlation is based on boiling-point temperature of the hydrocarbon. Correlation values and experimental data are in agreement.

The results are usable in engineering applications involving processing, safety, hazard, and environmental considerations.

Water solubility

The importance of the solubility of water in crude oil will increase in view of processing, safety, hazard, and environmental considerations focusing on product quality and equipment sustainability. The following brief discussion illustrates the importance.

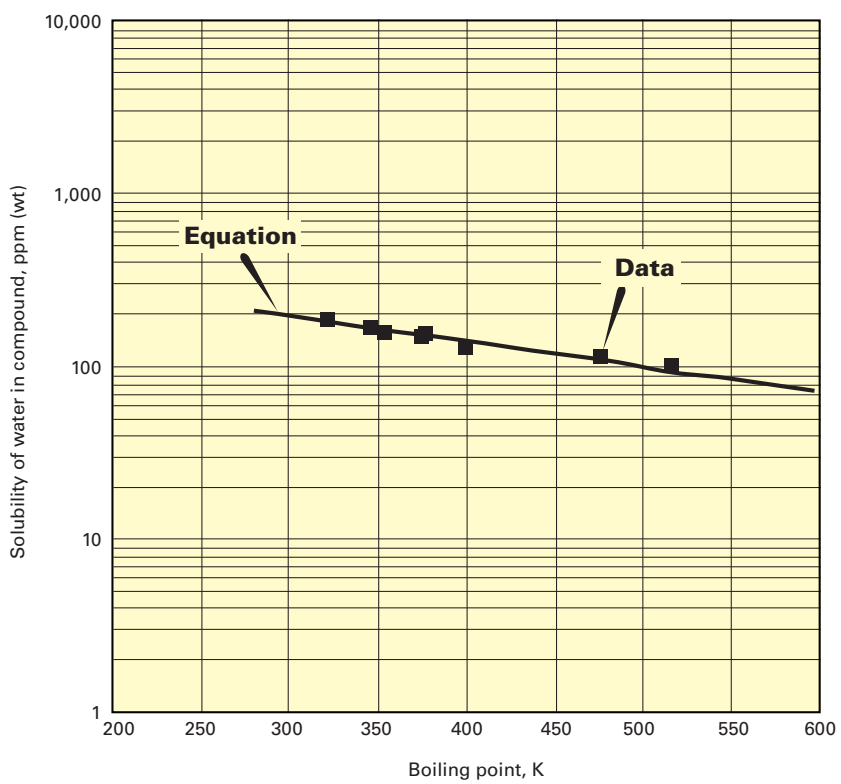
Any processing that lowers temperatures to near the freezing point of water may result in formation of solids (freezing of water or hydrate formation). Such formation will affect both fluid flows in piping and operational characteristics of equipment.

For catalytic reactions, any water in the hydrocarbon may poison the catalyst that promotes the hydrocarbon reaction.

For reactions in general, any water in the reaction species may result in formation of undesirable by-products issuing from the hydrocarbon reaction. The presence of water in the product may degrade quality and, if sufficient water is in the product, it may prove to be unusable by the customer.

This brief discussion indicates that solubility of water in hydrocarbons contained in crude oil is important in engineering applications involving processing, safety, hazard, and environmental considerations.

SOLUBILITY OF WATER IN CYCLOALKANES



Correlation

Earlier works correlated the solubility of hydrocarbons and other chemical types in water as a function of the boiling point of the compound.[11] In this work, it was determined that the boiling-point method was also applicable for correlation of solubility of water in cycloalkanes (cyclopentanes and cyclohexanes):

$$\log_{10}(S) = A + B*T_B$$

where: S = solubility of water in compound at 25° C., ppm (wt)

T_B = boiling point temperature of compound, K

A = 2.7470

SOLUBILITY, HENRY'S LAW CONSTANT FOR WATER IN CYCLOALKANES

					Solubility of water (S), ppm			Henry's Law constant (H)		
No.	ID	Formula	Name	Case no.	TB, K*	S @ 25° C., ppm (wt)	S @ 25° C., ppm (mol)	Code*	H @ 25° C., atm/mol frac	H @ 25° C., atm/mol/ cu m	Code*
1	5717	C_5H_{10}	cyclopentane	287-92-3	322.40	187.25	728.61	1	43.02	7.7442E-04	1,2
2	8690	C_6H_{12}	methylcyclopentane	96-37-7	344.96	164.82	769.53	1	40.74	7.3324E-04	1,2
3	8691	C_6H_{12}	cyclohexane	110-82-7	353.87	157.86	737.07	1	42.53	7.6553E-04	1,2
4	12207	C_7H_{14}	ethylcyclopentane	1640-89-7	376.62	152.40	830.09	1	37.76	6.7975E-04	1,2
5	12208	C_7H_{14}	1,1-dimethylcyclopentane	1638-26-2	361.00	160.51	874.21	2	35.86	6.4544E-04	1,2
6	12209	C_7H_{14}	1,2-dimethylcyclopentane	2452-99-5	370.00	155.60	847.47	2	36.99	6.6581E-04	1,2
7	12210	C_7H_{14}	cis-1,2-dimethylcyclopentane	1192-18-3	372.68	154.16	839.67	2	37.33	6.7199E-04	1,2
8	12211	C_7H_{14}	trans-1,2-dimethylcyclopentane	822-50-4	365.02	158.30	862.16	2	36.36	6.5446E-04	1,2
9	12212	C_7H_{14}	1,3-dimethylcyclopentane	2453-00-1	365.10	158.25	861.92	2	36.37	6.5464E-04	1,2
10	12215	C_7H_{14}	methylcyclohexane	108-87-2	374.08	147.40	802.87	1	39.04	7.0279E-04	1,2
11	15427	C_8H_{16}	propylcyclopentane	2040-96-2	404.11	138.30	860.87	2	36.41	6.5544E-04	1,2
12	15428	C_8H_{16}	isopropylcyclopentane	3875-51-2	399.58	130.41	811.75	1	38.62	6.9511E-04	1,2
13	15429	C_8H_{16}	1-methyl-1-ethylcyclopentane	16747-50-5	394.67	142.89	889.38	2	35.25	6.3443E-04	1,2
14	15434	C_8H_{16}	1,1,2-trimethylcyclopentane	4259-00-1	386.88	146.78	913.62	2	34.31	6.1760E-04	1,2
15	15435	C_8H_{16}	1,1,3-trimethylcyclopentane	4516-69-2	378.04	151.33	941.91	2	33.28	5.9905E-04	1,2
16	15442	C_8H_{16}	1-methyl-3-ethylcyclopentane	3726-47-4	394.20	143.12	890.82	2	35.19	6.3340E-04	1,2
17	15443	C_8H_{16}	ethylcyclohexane	1678-91-7	404.95	137.90	858.38	2	36.52	6.5734E-04	1,2
18	15444	C_8H_{16}	1,1-dimethylcyclohexane	590-66-9	392.70	143.86	895.45	2	35.01	6.3013E-04	1,2
19	18468	C_9H_{18}	butylcyclopentane	2040-95-1	429.76	126.58	886.34	2	35.37	6.3661E-04	1,2
20	18469	C_9H_{18}	isobutylcyclopentane	3788-32-7	421.10	130.42	913.23	2	34.33	6.1786E-04	1,2
21	18470	C_9H_{18}	sec-butylcyclopentane	4850-32-2	427.50	127.57	893.28	2	35.09	6.3166E-04	1,2
22	18471	C_9H_{18}	tert-butylcyclopentane	3875-52-3	418.00	131.83	923.05	2	33.96	6.1129E-04	1,2
23	18472	C_9H_{18}	1-methyl-1-propylcyclopentane	16631-63-3	419.15	131.30	919.39	2	34.10	6.1372E-04	1,2
24	18477	C_9H_{18}	1-methyl-1-isopropylcyclopentane	61828-00-0	421.15	130.40	913.07	2	34.33	6.1797E-04	1,2
25	18482	C_9H_{18}	1,1-diethylcyclopentane	2721-38-2	423.65	129.28	905.23	2	34.63	6.2332E-04	1,2
26	18485	C_9H_{18}	1,3-diethylcyclopentane	19398-75-5	423.15	129.50	906.79	2	34.57	6.2225E-04	1,2
27	18488	C_9H_{18}	1,1-dimethyl-2-ethylcyclopentane	54549-80-3	411.15	134.98	945.13	2	33.17	5.9701E-04	1,2
28	18489	C_9H_{18}	1,1-dimethyl-3-ethylcyclopentane	62016-61-9	407.15	136.86	958.27	2	32.71	5.8882E-04	1,2
29	18508	C_9H_{18}	1,1,2,2-tetramethylcyclopentane	52688-89-8	406.15	137.33	961.58	2	32.60	5.8679E-04	1,2
30	18525	C_9H_{18}	propylcyclohexane	1678-92-8	429.90	126.52	885.91	2	35.38	6.3692E-04	1,2
31	18526	C_9H_{18}	isopropylcyclohexane	696-29-7	427.91	127.39	892.01	2	35.14	6.3256E-04	1,2
32	18527	C_9H_{18}	1-methyl-1-ethylcyclohexane	4926-90-3	425.31	128.54	900.06	2	34.83	6.2691E-04	1,2
33	18534	C_9H_{18}	1,1,2-trimethylcyclohexane	7094-26-0	418.35	131.67	921.94	2	34.00	6.1203E-04	1,2
34	18535	C_9H_{18}	1,1,3-trimethylcyclohexane	3073-66-3	409.78	135.62	949.62	2	33.01	5.9418E-04	1,2
35	18536	C_9H_{18}	1,1,4-trimethylcyclohexane	7094-27-1	408.15	136.39	954.97	2	32.83	5.9086E-04	1,2
36	18537	C_9H_{18}	1,2,3-trimethylcyclohexane	1678-97-3	415.15	133.13	932.17	2	33.63	6.0531E-04	1,2
37	18546	C_9H_{18}	1,3,5,-trimethylcyclohexane	1839-63-0	411.00	135.05	945.62	2	33.15	5.9670E-04	1,2
38	18549	C_9H_{18}	1-ethyl-2-methylcyclohexane	3728-54-9	425.50	128.45	899.47	2	34.85	6.2732E-04	1,2
39	21553	$C_{10}H_{20}$	pentylcyclopentane	3741-00-2	453.76	116.51	906.45	2	34.58	6.2248E-04	1,2
40	21554	$C_{10}H_{20}$	butylcyclohexane	1678-93-9	454.13	116.36	905.29	2	34.63	6.2328E-04	1,2
41	21555	$C_{10}H_{20}$	tert-butylcyclohexane	3178-22-1	444.65	120.23	935.40	2	33.51	6.0322E-04	1,2
42	21556	$C_{10}H_{20}$	sec-butylcyclohexane	7058-01-7	452.45	117.04	910.56	2	34.43	6.1968E-04	1,2
43	21557	$C_{10}H_{20}$	isobutylcyclohexane	1678-98-4	444.45	120.32	936.05	2	33.49	6.0280E-04	1,2
44	21558	$C_{10}H_{20}$	1-methyl-1-propylcyclohexane	4258-93-9	445.15	120.03	933.79	2	33.57	6.0426E-04	1,2
45	21559	$C_{10}H_{20}$	1-methyl-2-propylcyclohexane	4291-79-6	449.15	118.38	920.99	2	34.04	6.1266E-04	1,2
46	21560	$C_{10}H_{20}$	1-methyl-3-propylcyclohexane	4291-80-9	437.65	123.18	958.27	2	32.71	5.8882E-04	1,2
47	21561	$C_{10}H_{20}$	1-methyl-4-propylcyclohexane	4291-81-0	448.65	118.58	922.58	2	33.98	6.1160E-04	1,2
48	21562	$C_{10}H_{20}$	1-methyl-2-isopropylcyclohexane	16580-23-7	444.15	120.44	937.02	2	33.45	6.0218E-04	1,2
49	21563	$C_{10}H_{20}$	1-methyl-3-isopropylcyclohexane	16580-24-8	439.65	122.33	951.68	2	32.94	5.9290E-04	1,2
50	21564	$C_{10}H_{20}$	1-methyl-4-isopropylcyclohexane	99-82-1	443.85	120.57	937.99	2	33.42	6.0155E-04	1,2
51	21567	$C_{10}H_{20}$	1,1,3,4-tetramethylcyclohexane	24612-75-7	433.15	125.11	973.27	2	32.21	5.7975E-04	1,2
52	21582	$C_{10}H_{20}$	1,1-diethylcyclohexane	78-01-3	449.82	118.11	918.86	2	34.12	6.1408E-04	1,2
53	21583	$C_{10}H_{20}$	1,2,3,4-tetramethylcyclohexane	3726-45-2	449.20	118.36	920.83	2	34.04	6.1276E-04	1,2
54	23447	$C_{11}H_{22}$	hexylcyclopentane	4457-00-5	476.26	112.38	961.68	1	32.60	5.8673E-04	1,2
55	23448	$C_{11}H_{22}$	pentylcyclohexane	4292-92-6	476.87	107.57	920.58	2	34.05	6.1293E-04	1,2
56	23449	$C_{11}H_{22}$	isopentylcyclohexane	54105-76-9	469.65	110.29	943.81	2	33.21	5.9785E-04	1,2
57	25496	$C_{12}H_{24}$	heptylcyclopentane	5617-42-5	497.30	100.24	935.83	2	33.50	6.0294E-04	1,2
58	25497	$C_{12}H_{24}$	hexylcyclohexane	4292-75-5	497.86	100.05	934.02	2	33.56	6.0411E-04	1,2
59	25498	$C_{12}H_{24}$	1-methyl-2-pentylcyclohexane	54411-01-7	490.65	102.57	957.55	2	32.74	5.8926E-04	1,2
60	27171	$C_{13}H_{26}$	octylcyclopentane	1795-20-6	516.86	93.69	947.57	2	33.08	5.9547E-04	1,2
61	27171a	$C_{13}H_{26}$	1-methylheptylcyclopentane	4810-01-9	516.86	98.38	994.91	1	31.51	5.6714E-04	1,2
62	27172	$C_{13}H_{26}$	heptylcyclohexane	5617-41-4	518.06	93.31	943.65	2	33.22	5.9794E-04	1,2
63	27173	$C_{13}H_{26}$	2-butyl-1,1,3-trimethylcyclohexane	54676-39-0	510.52	95.77	968.54	2	32.37	5.8258E-04	1,2
64	28572	$C_{14}H_{28}$	nonylcyclopentane	2882-98-6	535.26	87.92	957.61	2	32.74	5.8923E-04	1,2
65	28573	$C_{14}H_{28}$	octylcyclohexane	1795-15-9	536.76	87.47	952.66	2	32.91	5.9229E-04	1,2
66	28581	$C_{14}H_{28}$	(1-methyheptyl)-cyclohexane	2883-05-8	519.52	92.84	1011.04	2	31.01	5.5809E-04	1,2
67	29602	$C_{15}H_{30}$	decylcyclopentane	1795-21-7	552.54	82.83	966.55	2	32.43	5.8378E-04	1,2
68	29603	$C_{15}H_{30}$	nonylcyclohexane	2883-02-5	554.66	82.23	959.50	2	32.67	5.8806E-04	1,2
69	29604	$C_{15}H_{30}$	1-ethyl-1-methyl-2,4-diisopropylcyclohexane, [1R-(1alpha,2beta,4beta)]	515-12-8	549.62	83.67	976.33	2	32.11	5.7793E-04	1,2
70	30468	$C_{16}H_{32}$	undecylcyclopentane	6785-23-5	568.76	78.32	974.80	2	32.16	5.7883E-04	1,2
71	30469	$C_{16}H_{32}$	decylcyclohexane	1795-16-0	570.75	77.78	968.13	2	32.38	5.8282E-04	1,2
72	31081	$C_{17}H_{34}$	dodecylcyclopentane	5634-30-0	584.06	74.29	982.41	2	31.91	5.7435E-04	1,2
73	31082	$C_{17}H_{34}$	undecylcyclohexane	54105-66-7	586.26	73.72	974.98	2	32.15	5.7873E-04	1,2
74	31858	$C_{18}H_{36}$	tridecylcyclopentane	6006-34-4	598.56	70.66	989.37	2	31.68	5.7031E-04	1,2
75	31859	$C_{18}H_{36}$	dodecylcyclohexane	1795-17-1	600.86	70.10	981.55	2	31.94	5.7485E-04	1,2
76	32488	$C_{19}H_{38}$	tetradecylcyclopentane	1795-22-8	612.16	67.42	996.41	2	31.46	5.6628E-04	1,2
77	32489	$C_{19}H_{38}$	tridecylcyclohexane	6006-33-3	614.66	66.84	987.85	2	31.73	5.7119E-04	1,2
78	32491	$C_{19}H_{38}$	7-(cyclopentyl-methyl)tridecane	55044-77-4	566.58	78.91	1166.11	2	26.88	4.8387E-04	1,2
79	33287	$C_{20}H_{40}$	pentadecylcyclopentane	4669-01-6	625.00	64.49	1003.34	2	31.24	5.6237E-04	1,2
80	33288	$C_{20}H_{40}$	tetradecylcyclohexane	1795-18-2	627.16	64.01	995.89	2	31.48	5.6658E-04	1,2

*1-data; 2-estimate; TB = boiling point temp., K.

B = –1.50 E-03

The correlation applies to a range for boiling-point temperatures of about 280 K to 590 K.

The coefficients (A and B) for the correlation were determined from regression of the available data. In preparing the correlation, we conducted a literature search to identify data source publications.[1-15] The compilations by Englin et. al., International Union of Pure and Applied Chemistry, and Sorensen and Artl were consulted for solubility of water.[2 5 6 7] The compilation of Yaws was used for boiling point temperature.[13]

We screened the publications and copied appropriate data, then keyed the data into the computer to provide a data base for which experimental data are available. The data base also served as a basis to check the accuracy of the correlation.

The accompanying diagram shows the solubility of water vs. boiling-point temperature of compound for cyclopentanes and cyclohexanes. The data of Englin and compilation of Sorensen that are applicable at ambient conditions were selected for the graph.[2 7] The graph discloses favorable agreement of correlation values and experimental data.

Solubility; Henry's Law constant

The accompanying table gives the results for solubility of water and Henry's law constant. In the tabulation, the results for Henry's law constant are based on water solubility and vapor pressure at ambient conditions with appropriate thermodynamic relationships.[10] The compilation of Yaws was used for vapor pressure.[14] The presented values are applicable for water in a wide variety of cycloalkanes.

The tabulated values are based on both experimental data and estimates. In the absence of data, the estimates for isomers and large compounds (compounds with more than 10 carbons, i.e., compounds larger than C_{10}) should be considered rough values useful for initial analysis. If initial analysis is favorable, follow-up experimental determination is recommended.

The results in an easy-to-use tabular format are especially applicable for rapid engineering use with a personal computer or hand calculator. The tabulation is arranged by carbon number (C_5, C_6, C_7, …). This provides ease of use in quickly locating data with the chemical formula.

Examples

The results for solubility and Henry's law constant are useful in engineering applications involving water in cycloalkanes, per the following examples:

• *Example 1.* In hydrocarbon processing, cyclohexane (C_6H_{12}) comes into contact with water at ambient conditions (25° C., 1 atm). The organic and aqueous phases are subsequently separated. Estimate the concentration of water in the cyclohexane after separation.

Substitution of the coefficients and boiling point temperature into the correlation equation yields:

$\log_{10}(S) = 2.747 - 1.50 \text{ E-}03*353.87$

$= 2.2162$

$S = 164.51$ ppm (wt)

• *Example 2.* A hydrocarbon spill of cyclohexane (C_6H_{12}) into a body of water at ambient conditions (25° C., 1 atm). After separation, the concentration of water in the hexane at the surface is 0.000737 mol fraction (x_i = 0.000737). Estimate the concentration of water in the vapor at the surface.

From thermodynamics at low pressure, the vapor concentration is given by $y_i = H_i/P_t*x_i$.

Substitution of Henry's law constant from the table, total pressure (P_t = 1 atm) and liquid concentration into the above equation yields:

$y_i = 42.53/1*0.000737 = 0.0313$

$y_i = 3.13$ % (mol) ✦

References

1. Black, C., et al., Journal of Chemical Physics, Vol. 16 (1948), p. 537.

2. Englin, B.A., et al., Khim. Tekhnol. Topl. Massel, Vol. 42 (1965), No. 9.

3. Marche, C., et al., Journal of Chemical Engineering Data, Vol. 51 (2006), p. 355.

4. Ng, H.J., and Chen, C.J., "Mutual Solubility in Water-Hydrocarbon Systems," Tulsa: Gas Processors Association Research Report 150, 1995.

5. Solubility Data Series, International Union of Pure and Applied Chemistry, Vol. 37, Hydrocarbons with Water and Seawater, Part 1—Hydrocarbons C_5 to C_7, Oxford: Pergamon Press, 1989.

6. Solubility Data Series, International Union of Pure and Applied Chemistry, Vol. 38, Hydrocarbons with Water and Seawater, Part 1—Hydrocarbons C_8 to C_{36}, Oxford: Pergamon Press, 1989.

7. Sorensen, J.M., and Artl, W., Liquid Liquid Equilibrium Data Collection, Vol. V, Part 1, Frankfurt: Dechema Chemistry Data Series, 1979.

8. Tsonopoulos, C., and Wilson, G.M., "Mutual Solubilities of Hydrocarbons—Part I," AIChE Journal, Vol. 29 (1983), p. 990.

9. Tsonopoulos, C., et al., "Mutual Solubilities of Hydrocarbons—Part II," AIChE Journal, Vol. 31 (1985), p. 376.

10. Tsonopoulos, C., et al., "Mutual Solubilities of Hydrocarbons—Part III," AIChE Journal, Vol. 43 (1997), p. 535.

11. Tsonopoulos, C., Fluid Phase Equilibrium, Vol. 186 (2001), p. 185.

12. Yaws, C.L., Chemical Properties Handbook, New York: McGraw-Hill Inc., 1999.

13. Yaws, C.L., Yaws Handbook of Physical Properties for Hydrocarbons

The author

Carl L. Yaws (clyaws@my.lamar.edu) is professor of chemical engineering at Lamar University, Beaumont, Tex. His research interests include technology development; thermodynamic, transport, and environmental property data. He holds BS in chemical engineering from Texas A&I University and an MS and PhD in chemical engineering from University of Houston.

and Chemicals, Houston: Gulf Publishing Co., 2005.

14. Yaws, C.L., Yaws Handbook of Vapor Pressure—Antoine Coefficients, Houston: Gulf Publishing Co., 2007.

15. Yaws, C.L., Yaws Handbook of Properties for Environmental and Green Engineering, Houston: Gulf Publishing Co., 2008.

Correction

The table headline in "Table, correlation give water solubility, Henry's Law constant for alkanes in crude," Carl L. Yaws and Manish Rahate (OGJ, Mar. 2, 2009, p. 52), should have read "Solubility and Henry's Law constant for water in alkanes."

NELSON-FARRAR COST INDEXES

Refinery construction (1946 basis)

(Explained in OGJ, Dec. 30, 1985, p. 145, and at www.pennenergy.com/index/research-and_data/oil-and_gas/Statistic-Definitions.html; click "Nelson-Farrar Cost Indices")

	1962	1980	2006	2007	2008	Oct. 2008	Sept. 2009	Oct. 2009
Pumps, compressors, etc.	222.5	777.3	1,758.2	1,844.4	1,949.8	1,989.2	2,012.8	2,011.9
Electrical machinery	189.5	394.7	520.2	517.3	515.6	518.2	515.9	514.6
Internal-comb. engines	183.4	512.6	959.7	974.6	990.9	993.5	1,029.4	1,023.7
Instruments	214.8	587.3	1,166.0	1,267.9	1,342.1	1,362.8	1,396.4	1,411.7
Heat exchangers	183.6	618.7	1,162.7	1,342.2	1,354.6	1,374.7	1,253.8	1,253.8
Misc. equip. average	198.8	578.1	1,113.3	1,189.3	1,230.6	1,247.7	1,241.7	1,243.1
Materials component	205.9	629.2	1,273.5	1,364.8	1,572.0	1,566.5	1,368.9	1,375.1
Labor component	258.8	951.9	2,497.8	2,601.4	2,704.3	2,768.0	2,830.9	2,835.1
Refinery (Inflation) Index	237.6	822.8	2,008.1	2,106.7	2,251.4	2,287.4	2,246.1	2,251.1

Refinery operating (1956 basis)

(Explained in OGJ, Dec. 30, 1985, p. 145, and at www.pennenergy.com/index/research-and_data/oil-and_gas/Statistic-Definitions.html; click "Nelson-Farrar Cost Indices")

	1962	1980	2006	2007	2008	Oct. 2008	Sept. 2009	Oct. 2009
Fuel cost	100.9	810.5	1,569.0	1,530.7	1,951.3	1,419.3	867.4	978.1
Labor cost	93.9	200.5	204.2	215.8	237.9	260.7	258.9	273.5
Wages	123.9	439.9	1,015.4	1,042.8	1,092.2	1,182.0	1,190.5	1,212.1
Productivity	131.8	226.3	497.5	483.4	460.8	453.3	459.8	443.1
Invest., maint., etc.	121.7	324.8	743.7	777.4	830.8	844.1	822.7	824.6
Chemical costs	96.7	229.2	365.4	385.9	472.5	496.1	422.1	414.7
Operating indexes								
Refinery	103.7	312.7	579.0	596.5	674.1	642.8	576.4	592.1
*Process units**	103.6	457.5	870.7	872.6	1,045.1	870.4	669.2	713.0

**Add separate index(es) for chemicals, if any are used. See current Quarterly Costimating, first issue, months of January, April, July, and October. These indexes are published in the first issue of each month. They are compiled by Gary Farrar, OGJ Contributing Editor. Indexes of selected individual items of equipment and materials are also published on the Costimating page in the first issue of the months of January, April, July, and October.*

Subsea isolation techniques advance

Christopher E. Smith
Pipeline Editor

Two recent subsea pipeline isolations illustrate the advances made in isolation technology and methods. One isolation was for repair of the line itself, the other for replacement of motor-operated ball valves. This article examines each.

Malaysia

TDW Offshore Services AS in December 2009 completed a pipeline pressure isolation operation in Malaysia with Amserve Engineering on behalf of Malaysia LNG Sdn Bhd, a subsidiary of Petronas, the national oil company of Malaysia.

The operation occurred at the Petronas LNG complex in Bintulu, Sarawak. Natural gas moves from platforms in the South China Sea through four major trunklines to the onshore processing plant. Trunkline 4 (36-in. OD) required pipeline pressure isolation to replace six 22-ton motor-operated ball valves.

Codes generally don't require a cut out for dents less than 5% WT, only a leak repair-reinforcement clamp. Therefore no isolation is required. For dents between 5% and 10% WT, a train of two SmartPlugs with a slug of glycol between them launched into position on either side of the dent and activated in place allows immediate removal of the damaged section.

For dents larger than 10% WT, through which the SmartPlug cannot pass, an upstream SmartPlug moves from the pig launcher to the damage, while the downstream Smartplug is installed in situ via a coiled-tubing injection head through a hot tap and subsea launcher in a post-installed wye-piece.[1]

For the Malaysian operation TDW carried out pipeline pressure isolation on the receiving end of Trunkline 4, isolating the section by launching its SmartPlug tool at the receiver located at the gas terminal. The 36-in. diameter custom tool travelled about 750 m past the receiver and the beach valve where the tool was set, safely isolating the line while MLNG replaced the six existing MOVs with new ones.

TDW engineered, assembled, and tested the tools at its global headquarters in Stavanger, transporting them to Bintulu via Labuan. Persafe Engineering Sdn. Bhd. transported the new MOVs, with a collective weight of 66 tons, on three chartered MASkargo Boeing 747-400S jets from Germany to Kuala Lumpur before their arrival in Bintulu.

TDW completed the operation in 4 weeks, 6 days ahead of schedule, resulting in considerable savings for MLNG.

SmartPlug allows the operator to monitor pipeline pressure on both sides of the seal and, if appropriate, command the device's battery power into hibernation mode to preserve battery life during extended isolation applications. The longest a SmartPlug has been in position and successfully awakened exceeds 400 days.[1]

In 2007 a vessel collided with the southeast face of satellite platform jacket, damaging the 12-in. OD export riser (highlighted in red). The impact damaged the riser and a large portion of the connected topside pipeworks (Fig. 1).

North Sea

The work in Bintulu followed completion of a low-pressure isolation on an export pipeline riser in the North Sea. In 2007, a vessel collided with the southeast face of a satellite platform jacket, damaging the 12-in. OD export riser and a large portion of the connected topside pipeworks (Fig. 1). Any internal isolation would have to be pigged through a dent, a 1.5-D bend, and a narrow 45° traverse.[2] Production from the platform was shut in via emergency shutdown valves, leaving line pressure at about 4 barg.

The operator sought to cut and remove the damaged riser section and replace it with a new one.

TDW isolated the damaged section of the pipeline riser from the export pipeline gas inventory—allowing replacement of the damaged riser section and associated topside pipework—with multiple high-friction pigs

The topside pipeworks shown here (left photo) are not traditionally pigged, requiring pigging for the low-pressure isolation through nonstandard construction pipework fittings (Fig. 2). The nonstandard construction pipework fittings (middle photo) consisted of two 1.5-D bends and a narrow 45° traverse (Fig. 3). The geometry of the damaged section (right photo) of riser was unknown, requiring emphasis on maintaining the section's integrity while running the pig train through the riser (Fig. 4).

sealing off the damaged riser section and pipework. The solution consisted of the following elements:

- Custom-designed pig trap and pigging spread.
- High-friction pig train furnished with the SmartTrack remote tracking and pressure-monitoring system.
- SmartTrack subsea remote tracking and pressure-monitoring system.
- SmartTrack topside tracking and monitoring system with radio link to the dive support vessel.
- Pipeline isolation ball valve.

The customized pigs outfitted with SmartTrack transponders allow the accurate pig tracking (±2 in.), positioning, identification, and continual pressure monitoring deemed necessary with divers in the water. The SmartTrack system, when mounted in the pig body, provides two-way through-pipe-wall communication. Each pig in the train also has a unique identifier, further minimizing risk in the event the train moves.[2]

Factory acceptance tests confirmed pressure capabilities before executing the job. A test rig designed and built at TDW facilities in Stavanger had a pig launcher-receiver, a 1.5-D bend, and a 45° traverse to simulate the environment on the satellite platform. Tests of various configurations mirrored the expected scenario as much as possible. Pressure tests included pigging pressure tests, isolation pressure tests, and flip pressure tests.[2]

TDW isolated the damaged riser section from the gas inventory in the export pipeline in August 2009 without venting or flooding the pipeline, or displacing the pipeline inventory. A three-module high-friction pig train created isolation against the gas pressure in the pipeline.

TDW first verified and recorded the pipeline inventory gas pressure, closing and isolating Emergency Shutdown Valve 050. The company then removed redundant topside pipework upstream of the ESDV and installed a temporary spool and 12-in. diameter valve. ESDV leakage was monitored closely, with a desire to minimize pressure buildup in the spool.

A pig trap and pigging pump launched the high-friction isolation pig train and pigged with water to the predetermined isolation position within a straight spool section of the vertical riser (Figs. 2-4). Technicians aboard the dive support vessel tracked the position of each pig, verifying the HFIPT was below the damaged section of riser designated for replacement. Communication skids positioned over the three pigs and connected to the pig's monitoring system allowed the downstream pressure of each isolation pig to be continuously monitored throughout the operation.

Existing topside pipework was removed and replaced with new pipework. Divers deployed from the DSV successfully cut and removed the riser section with a crane aboard the DSV. A mechanical connector locked onto the existing riser. The new riser was attached to a crane on the platform and lowered to rope access workers who installed it to the topside pipework's closing spool and the existing riser above the HFIPT.

Following installation of the new riser section, TDW verified proper operation of the ESDV and new 12-in. valve. After purging the riser and topside pipework, TDW slowly increased water pressure to begin pigging the HFIPT downstream from the platform to the launcher. It then closed the ESDV and 12-in. valve, increasing pipeline-gas inventory pressure to keep the HFIPT moving forward.

TDW recovered all pigs in the temporary pig trap and closed the ESDV and new valve. The platform crane and remotely operated vehicle removed all pigging equipment and the crew demobilized.

Operations took about 10 weeks, May 20-Aug. 2, 2009, during which a continuous flow was maintained. ✦

References

1. Lim, G.K., and Major, J., "The Challenges of Emergency Pipeline Repairs—Introducing New Rapid Pipeline Repair Methods," 5th Asian Pipelines Conference & Exhibition, Kota Kinabalu, Sabah, Malaysia, Oct. 28-29, 2009.

2. Haldorsen, A.H., "Innovation Low-Pressure Pipeline Isolation," Pipeline Pigging Products and Services Association seminar, Aberdeen, Nov. 18, 2009.

New field-attachable packer system

This new field-attachable packer feed-through system promises a faster method of passing power cables through packers.

The system uses a field-attachable feed-through connector, a mating attachable cable connector, a crossover adapter, and accompanying hardware.

The system allows the connector to be installed on the top side of a packer using a crossover adapter, eliminating the need to splice downhole cables. The company says, "This in turn eliminates any potential stress on the cable, as the packer feed-through system includes a completely variable threaded adjustment system."

The variable threaded system allows vertical adjustment of as much as 3 in. It's also possible to install the termination contacts on the cable conductors before the cable is passed through the packer, potentially reducing the volume of work an installer is required to carry out in a vertical position over an open well.

The field-attachable packer feed-through system has a maximum diameter of 2.6 in. Length above the packer with a round cable ranges from 26.4 in. to 29.5 in., while length with a flat cable ranges from 30.4 in. to 33.4 in. Voltage rating is to 5,000 v AC, with current to 140 A, and pressure to 5,000 psig.

Maximum conductor temperature is 350° F.

Source: **ITT Interconnect Solutions,** 666 E. Dyer Rd., Santa Ana, CA 92705.

CITI Technologies Group,

Rueil Malmaison, France, has acquired Paris-based Litwin SA. Terms aren't disclosed. CITI was created in October 2009 and is fully owned by its founders and chief officers Henri Gagnaire and Bilal Anbari. Gagnaire, CEO, started his career in management consulting and in the automotive industry. Afterwards, he acquired and managed several industrial companies before co-founding Weinberg Capital Partners. He graduated from French Ecole Polytechnique. Anbari, COO, brings to the group his managing experience in the engineering and industrial sectors. He started his career with Renault and then directed the global engineering department of the Wagon Automotive Group. He then joined the Segula Technologies Group as CEO of its automotive department and afterwards as COO of the whole group. Anbari has an engineering degree from INSA in Lyon and a CEDEP management degree from INSEAD.

CITI is an engineering group that provides product process engineering, documentation, and general plant engineering.

Litwin is an engineering company that specializes in the oil, gas, power plant, renewable energies, biomass, carbochemical, and fertilizers industries.

Axens,

Rueil Malmaison, France, and Headwaters Inc., South Jordan, Utah, have agreed to form a strategic alliance to provide a single-source solution for producing ultraclean fuels by direct coal liquefaction (DCL) or in combination with refinery residues or biomass. The two companies will combine their technologies and licensing activities for coal-to-liquids (CTL) projects worldwide. Alliance DCL will incorporate Axens' ebullated-bed H-Coal process and proprietary catalyst and Headwaters' slurry catalyst technology and extensive CTL research facilities. Alliance DCL will market the technologies and offer project-specific services, from feedstock characterization, pilot plant evaluation, feasibility studies, and engineering design through plant start-up and ongoing technical support. Axens will also provide the coal liquids upgrading technologies necessary to achieve finished fuel specifications. Both companies provided technology packages and basic engineering contributing to the construction and start-up of the first commercial DCL plant in China in December 2008. Several new DCL projects are currently in development by the alliance.

Axens is an international provider of advanced technologies, catalysts, adsorbents, and services focused on the conversion of oil, coal, natural gas and biomass to clean fuels, as well as production and purification of major petrochemical intermediates.

Headwaters provides products, technologies, and services to the energy, construction, and home improvement industries.

Nalco,

Naperville, Ill., has committed to be a founding member of King Abdullah University of Science and Technology's (KAUST) Industrial Collaboration Program (KICP) at Thuwal, Saudi Arabia. KAUST is a newly opened graduate-level research university designed to promote science and technology in Saudi Arabia and throughout the region. Designed to maximize the effectiveness of industrial collaboration within the kingdom and internationally by engaging key partners, KICP's goal is to translate knowledge into economic growth and job creation. KICP funds are used to finance KICP initiatives to support educational outreach to the university community and others in the region, and to support strategic studies and collaboration with other academic resources in Saudi Arabia. Nalco's partnership with KAUST will focus on advancing environmental technologies such as water reuse, membranes, and desalination.

Nalco is a leading water treatment and process-improvement company providing services to the oil and gas, power, and industrial sectors.

GE Oil & Gas,

Florence, Italy, has agreed to acquire a minority equity interest in Shenyang Turbo Machinery Corp., a large-scale Chinese state-owned enterprise dedicated to the design and manufacture of turbomachinery equipment and the main operating subsidiary of Shenyang Blower Works Group Co. Ltd. Working alongside SBW Group, GE Oil & Gas was a major supplier of turbomachinery equipment to Petrochina, owner and developer of the milestone West-to-East gas pipeline infrastructure project, and to Sinopec's Sichuan-to-East China pipeline.

SBW Group, headquartered in Shenyang in China's Liaoning Province, was founded in 1934 to design, manufacture, and commercialize centrifugal and reciprocating compressors and pumps for application in the domestic petrochemical, fertilizer, coal, natural gas transportation, and power industries.

GE Oil & Gas is a world leader in advanced technology equipment and services for all segments of the oil and gas industry, from drilling and production, LNG, pipelines, and storage to industrial power generation, refining, and petrochemicals.

Patterson-UTI Energy Inc.,

Houston, has exited the drilling and completion fluid services business. Its Ambar Lone Star Fluid Services LLC subsidiary completed the sale of substantially all of its assets, other than billed accounts receivable, to National Oilwell Varco LP. The net cash proceeds from the sale and collection of billed accounts receivable, net of the payment of accrued expenses and transaction costs, are expected to be $48 million. Patterson-UTI expects to record a small loss on this transaction.

Patterson-UTI Energy provides onshore contract drilling and pressure pumping services to exploration and production companies in North America.

GulfMark Offshore Inc.,

Houston, has completed a new $200 million term-loan facility. The term-loan facility replaces a similar facility maturing June 30, 2010. The new facility will bear interest at the LIBOR (London Inter-Bank Offer Rate) plus a margin of 2.5% (compared to LIBOR plus a margin of 1.5% under the prior facility), will have quarterly principle repayments of $8.3 million, and will mature on December 31, 2012. The proceeds from the new $200 million facility, in conjunction with $20.6 million of cash on hand, were used to repay the remaining outstanding principle under the prior facility of $220.6 million.

GulfMark provides marine transportation and offshore support services to the oil and gas industry worldwide.

Imports of crude and products

	Districts 1-4 1-15 2010	Districts 1-4 1-8 2010	District 5 1-15 2010	District 5 1-8 2010	Total US 1-15 2010	Total US 1-8 2010	Total US *1-16 2009
	1,000 b/d						
Total motor gasoline	712	812	18	80	730	892	1,154
Mo. gas. blending comp.	490	567	18	80	508	647	958
Distillate	236	514	36	23	272	537	362
Residual	413	284	0	81	413	365	470
Jet fuel-kerosine	89	28	19	59	108	87	69
Propane-propylene	228	121	20	18	248	139	215
Other	240	78	96	(19)	336	59	491
Total products	**2,408**	**2,404**	**207**	**322**	**2,615**	**2,726**	**3,719**
Total crude	**7,488**	**8,019**	**1,052**	**876**	**8,540**	**8,895**	**9,866**
Total imports	**9,896**	**10,423**	**1,259**	**1,198**	**11,155**	**11,621**	**13,585**

*Revised.
Source: US Energy Information Administration
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

	*1-22-10	*1-23-09	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	84.13	53.53	30.60	57.2
Brent crude	74.31	43.26	31.05	71.8
Crack spread	9.82	10.28	–0.46	–4.4
FUTURES MARKET PRICES				
One month				
Product value	84.32	52.11	32.20	61.8
Light sweet crude	76.82	43.11	33.71	78.2
Crack spread	7.50	9.01	–1.51	–16.7
Six month				
Product value	88.30	57.98	30.32	52.3
Light sweet crude	79.41	51.22	28.19	55.0
Crack spread	8.89	6.76	2.14	31.6

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

Purvin & Gertz LNG netbacks—Jan. 22, 2010

Receiving terminal	Liquefaction plant: Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	7.46	5.29	6.60	5.18	5.90	6.52
Everett	5.99	3.76	5.61	3.83	4.34	6.30
Isle of Grain	4.31	2.07	3.67	1.97	2.68	3.70
Lake Charles	3.26	1.28	3.02	1.45	1.70	3.90
Sodegaura	5.64	7.82	5.89	7.51	6.76	4.94
Zeebrugge	6.81	4.24	6.09	4.13	4.98	6.18

Definitions, see OGJ Apr. 9, 2007, p. 57.
Source: Purvin & Gertz Inc.
Data available in OGJ Online Research Center.

Crude and product stocks

District	Crude oil	Motor gasoline: Total	Motor gasoline: Blending comp.[1]	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual	Propane–propylene
	1,000 bbl						
PADD 1	14,061	61,357	42,326	9,814	65,071	13,178	4,003
PADD 2	86,792	54,294	26,503	8,282	31,127	1,092	16,482
PADD 3	166,895	72,313	43,590	14,211	44,721	20,203	20,083
PADD 4	15,731	5,802	1,641	502	3,139	204	[1]1,432
PADD 5	47,086	33,676	29,213	10,924	13,080	4,104	—
Jan. 15, 2010	**330,565**	**227,442**	**143,273**	**43,733**	**157,138**	**38,781**	**42,000**
Jan. 8, 2010	**331,036**	**223,492**	**139,497**	**42,426**	**160,401**	**37,422**	**45,947**
Jan. 16, 2009[2]	**332,663**	**219,980**	**122,772**	**38,429**	**144,957**	**36,057**	**50,595**

[1]Includes PADD 5. [2]Revised.
Source: US Energy Information Administration
Data available in OGJ Online Research Center.

Refinery report—Jan. 15, 2010

District	Refinery operations: Gross inputs	Refinery operations: Crude oil inputs	Refinery output: Total motor gasoline	Refinery output: Jet fuel, kerosine	Refinery output: Fuel oils: Distillate	Refinery output: Fuel oils: Residual	Refinery output: Propane–propylene
	1,000 b/d		1,000 b/d				
PADD 1	1,014	1,011	2,221	66	328	67	24
PADD 2	3,240	3,229	2,214	223	892	40	256
PADD 3	6,824	6,869	2,428	613	1,670	357	621
PADD 4	491	492	273	24	139	4	[1]55
PADD 5	2,290	2,223	1,429	448	454	118	—
Jan. 15, 2010	**13,859**	**13,824**	**8,565**	**1,374**	**3,483**	**586**	**956**
Jan. 8, 2010	**14,374**	**14,005**	**8,511**	**1,426**	**3,855**	**567**	**1,039**
Jan. 16, 2009[2]	**14,670**	**14,145**	**8,729**	**1,361**	**4,153**	**550**	**1,047**
	17,681 Operable capacity		**78.4% utilization rate**				

[1]Includes PADD 5. [2]Revised.
Source: US Energy Information Administration
Data available in OGJ Online Research Center.

OGJ GASOLINE PRICES

	Price ex tax 1-20-10	Pump price* 1-20-10	Pump price 1-21-09
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	236.7	268.1	175.7
Baltimore	230.1	272.0	171.7
Boston	227.2	269.1	176.7
Buffalo	218.8	282.0	177.7
Miami	233.2	286.1	179.8
Newark	231.6	264.5	166.8
New York	218.9	282.1	186.7
Norfolk	224.3	262.0	166.8
Philadelphia	226.4	277.1	185.7
Pittsburgh	224.3	275.0	190.6
Wash., DC	236.2	278.1	195.5
PAD I avg	228.0	274.2	179.4
Chicago	248.7	303.8	210.4
Cleveland	245.7	292.1	197.2
Des Moines	227.7	268.1	187.6
Detroit	243.5	295.1	195.5
Indianapolis	234.7	284.8	194.5
Kansas City	226.3	262.0	181.6
Louisville	233.2	274.1	187.6
Memphis	220.3	260.1	180.3
Milwaukee	232.8	284.1	192.5
Minn.-St. Paul	222.7	268.3	185.6
Oklahoma City	206.8	242.2	168.8
Omaha	220.5	266.2	181.0
St. Louis	218.4	254.1	180.6
Tulsa	204.8	240.2	172.9
Wichita	209.7	253.1	178.7
PAD II avg	226.4	269.9	186.3
Albuquerque	226.2	263.4	173.8
Birmingham	225.1	264.4	171.7
Dallas-Fort Worth	222.0	260.4	173.6
Houston	224.0	262.4	166.5
Little Rock	217.2	257.4	175.4
New Orleans	230.9	269.3	171.7
San Antonio	227.9	266.3	169.6
PAD III avg	224.8	263.4	171.8
Cheyenne	221.3	253.7	149.8
Denver	236.7	277.1	165.9
Salt Lake City	216.5	259.4	164.4
PAD IV avg	224.9	263.4	160.0
Los Angeles	235.8	301.6	198.4
Phoenix	242.8	280.2	178.0
Portland	250.1	293.5	203.5
San Diego	238.4	304.2	209.4
San Francisco	240.5	306.3	213.3
Seattle	242.1	298.0	201.4
PAD V avg	241.6	297.3	200.7
Week's avg.	**228.6**	**273.4**	**182.3**
Dec. avg.	**214.4**	**259.2**	**171.1**
Nov. avg.	**218.8**	**263.6**	**215.5**
2010 to date	**225.1**	**269.9**	—
2009 to date	**129.5**	**175.1**	—

*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

	1-15-10 ¢/gal		1-15-10 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	204.79	New York Harbor	203.43
Gulf Coast	201.79	Gulf Coast	200.43
Los Angeles	188.04	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	199.71	ARA	199.18
Singapore	210.71	Singapore	201.67
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	203.54	New York Harbor	169.95
Gulf Coast	202.29	Gulf Coast	174.33
Los Angeles	194.04	Los Angeles	194.11
		ARA	176.58
		Singapore	184.45

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

BAKER HUGHES RIG COUNT

	1-22-10	1-23-09
Alabama	2	4
Alaska	7	14
Arkansas	39	49
California	24	30
Land	23	29
Offshore	1	1
Colorado	46	77
Florida	0	1
Illinois	0	0
Indiana	3	3
Kansas	20	17
Kentucky	8	12
Louisiana	195	174
N. Land	130	90
S. Inland waters	14	8
S. Land	13	23
Offshore	38	53
Maryland	0	0
Michigan	0	0
Mississippi	10	14
Montana	4	4
Nebraska	1	0
New Mexico	52	55
New York	3	2
North Dakota	72	66
Ohio	7	8
Oklahoma	105	149
Pennsylvania	64	26
South Dakota	0	0
Texas	528	683
Offshore	3	5
Inland waters	0	0
Dist. 1	20	10
Dist. 2	17	33
Dist. 3	36	53
Dist. 4	47	60
Dist. 5	72	139
Dist. 6	62	113
Dist. 7B	9	17
Dist. 7C	52	47
Dist. 8	114	86
Dist. 8A	22	24
Dist. 9	34	41
Dist. 10	40	55
Utah	23	26
West Virginia	26	26
Wyoming	37	59
Others—HI-1; NV-4; TN-1	6	16
Total US	**1,282**	**1,515**
Total Canada	**495**	**426**
Grand total	**1,777**	**1,941**
US Oil rigs	437	318
US Gas rigs	833	1,185
Total US offshore	42	65
Total US cum. avg. YTD	**1,235**	**1,574**

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	1-22-10 Percent footage*	Rig count	1-23-09 Percent footage*
0-2,500	87	2.2	68	--
2,501-5,000	51	72.5	70	51.4
5,001-7,500	143	27.2	201	25.3
7,501-10,000	255	6.2	344	2.0
10,001-12,500	252	9.9	301	2.6
12,501-15,000	188	2.6	304	0.3
15,001-17,500	185	—	149	—
17,501-20,000	74	—	67	—
20,001-over	34	—	43	—
Total	**1,269**	**9.7**	**1,547**	**6.6**
INLAND	16		19	
LAND	1,211		1,475	
OFFSHORE	42		53	

*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]1-22-10	[2]1-23-09
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	20	21
Alaska	704	682
California	645	653
Colorado	68	66
Florida	5	2
Illinois	22	22
Kansas	110	109
Louisiana	1,429	1,312
Michigan	17	17
Mississippi	62	62
Montana	85	82
New Mexico	165	159
North Dakota	225	192
Oklahoma	180	177
Texas	1,409	1,369
Utah	64	62
Wyoming	148	142
All others	69	76
Total	**5,427**	**5,205**

[1]OGJ estimate. [2]Revised.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

US CRUDE PRICES

	1-22-10 $/bbl*
Alaska-North Slope 27°	64.51
South Louisiana Sweet	77.00
California-Midway Sunset 13°	66.60
Lost Hills 30°	75.45
Wyoming Sweet	65.04
East Texas Sweet	70.50
West Texas Sour 34°	66.00
West Texas Intermediate	71.00
Oklahoma Sweet	71.00
Texas Upper Gulf Coast	64.00
Michigan Sour	63.00
Kansas Common	70.00
North Dakota Sweet	55.75

*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]	1-15-10
United Kingdom-Brent 38°	78.88
Russia-Urals 32°	78.48
Saudi Light 34°	77.53
Dubai Fateh 32°	79.62
Algeria Saharan 44°	79.76
Nigeria-Bonny Light 37°	80.99
Indonesia-Minas 34°	83.13
Venezuela-Tia Juana Light 31°	78.97
Mexico-Isthmus 33°	78.86
OPEC basket	79.37
Total OPEC[2]	78.68
Total non-OPEC[2]	78.61
Total world[2]	78.65
US imports[3]	77.90

[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]

	1-15-10	1-8-10	1-15-09	Change, %
	bcf			
Producing region	810	906	862	**–6.0**
Consuming region east	1,401	1,532	1,361	**2.9**
Consuming region west	396	414	362	**9.4**
Total US	**2,607**	**2,852**	**2,585**	**0.9**
	Oct. 09	**Oct. 08**	**Change, %**	
Total US[2]	**3,807**	**3,399**	**12.0**	

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

Statistics

PACE REFINING MARGINS

	Nov. 2009	Dec. 2009	Jan. 2010	Jan. 2009	Change	Change, %
	$/bbl					
US Gulf Coast						
West Texas Sour	1.62	3.46	3.76	10.20	–6.45	–63.2
Composite US Gulf Refinery	2.98	4.38	4.83	10.45	–5.61	–53.7
Mars (cracking)	0.53	1.39	2.14	5.69	–3.55	–62.4
Bonny Light	–1.01	0.10	–0.67	3.05	–3.73	–122.1
US PADD II						
Chicago (WTI)	0.35	2.36	1.00	9.63	–8.64	–89.7
US East Coast						
Brass River	0.57	1.36	0.89	3.81	–2.92	–76.5
East Coast Comp–RFG	1.58	2.90	2.20	8.02	–5.81	–72.5
US West Coast						
Los Angeles (ANS)	7.80	10.23	4.58	20.79	–16.21	–78.0
NW Europe						
Rotterdam (Brent)	0.66	1.14	2.05	5.46	–3.41	–62.5
Mediterranean						
Italy (Urals)	–2.82	–1.85	–5.39	3.83	–9.21	–240.7
Far East						
Singapore (Dubai)	–1.36	0.02	1.30	5.44	–4.14	–76.1

Source: Jacobs Consultancy Inc.
Data available in OGJ Online Research Center.

US NATURAL GAS BALANCE
DEMAND/SUPPLY SCOREBOARD

	Oct. 2009	Sept. 2008	Oct. 2008	Oct. 2009–2008 change	Total YTD 2009	Total YTD 2008	YTD 2009–2008 change
	bcf						
DEMAND							
Consumption	1,658	1,567	1,632	26	18,552	18,948	–396
Addition to storage	258	346	334	–76	3,066	3,032	34
Exports	76	84	69	7	858	801	57
Canada	41	47	37	4	548	447	101
Mexico	33	33	28	5	285	312	–27
LNG	2	4	4	–2	25	42	–17
Total demand	**1,992**	**1,997**	**2,035**	**–43**	**22,476**	**22,781**	**–305**
SUPPLY							
Production (dry gas)	1,785	1,697	1,702	83	17,565	16,903	662
Supplemental gas	5	4	5	0	51	44	7
Storage withdrawal	97	57	91	6	2,085	3,178	–1,093
Imports	307	306	321	–14	3,134	3,299	–165
Canada	278	274	288	–10	2,729	2,971	–242
Mexico	2	0	6	–4	25	30	–5
LNG	27	32	27	0	380	298	82
Total supply	**2,194**	**2,064**	**2,119**	**75**	**22,835**	**23,424**	**–589**

NATURAL GAS IN UNDERGROUND STORAGE

	Oct. 2009	Sept. 2008	Aug. 2008	Oct. 2008	Change
	bcf				
Base gas	4,279	4,278	4,268	4,235	44
Working gas	3,807	3,643	3,352	3,399	408
Total gas	**8,086**	**7,921**	**7,620**	**7,634**	**452**

Source: DOE Monthly Energy Review.
Data available in OGJ Online Research Center. **NOTE: No new data at press time.**

US HEATING DEGREE–DAYS

	Nov. 2009	Nov. 2008	Normal	2009 % change from normal	Total degree–days July 1 through Nov. 30 2009	2008	Normal	% change from normal
New England	619	759	727	–14.9	1,381	1,432	1,384	–0.2
Middle Atlantic	546	698	667	–18.1	1,078	1,198	1,193	–9.6
East North Central	609	787	757	–19.6	1,314	1,355	1,337	–1.7
West North Central	588	806	840	–30.0	1,376	1,393	1,447	–4.9
South Atlantic	294	417	339	–13.3	479	625	528	–9.3
East South Central	408	535	449	–9.1	676	778	695	–2.7
West South Central	220	273	293	–24.9	364	389	385	–5.5
Mountain	552	540	676	–18.3	1,106	981	1,219	–9.3
Pacific	354	275	396	–10.6	606	469	690	–12.2
US average*	**442**	**538**	**539**	**–18.0**	**865**	**899**	**922**	–6.2

*Excludes Alaska and Hawaii.
Source: DOE Monthly Energy Review.
Data available in OGJ Online Research Center. **NOTE: No new data at press time.**

WORLDWIDE NGL PRODUCTION

	Oct. 2009	Sept. 2009	10 month average production 2009	10 month average production 2008	Change vs. previous year Volume	Change vs. previous year %
	1,000 b/d					
Brazil	80	77	78	87	–9	–10.0
Canada	560	587	571	641	–70	–11.0
Mexico	361	364	369	367	2	0.6
United States	1,953	1,941	1,872	1,804	69	3.8
Venezuela	200	200	200	200	—	—
Other Western Hemisphere	205	203	202	197	5	2.7
Western Hemisphere	**3,359**	**3,373**	**3,293**	**3,295**	**–3**	**–0.1**
Norway	283	249	275	274	1	0.5
United Kingdom	110	105	126	164	–38	–23.0
Other Western Europe	10	10	10	10	—	4.0
Western Europe	**403**	**364**	**411**	**447**	**–36**	**–8.0**
Russia	436	436	420	422	–2	–0.5
Other FSU	150	150	150	150	—	—
Other Eastern Europe	14	11	14	15	–1	–6.0
Eastern Europe	**600**	**597**	**584**	**587**	**–3**	**–0.5**
Algeria	350	350	344	357	–13	–3.6
Egypt	70	70	70	70	—	—
Libya	80	80	80	80	—	—
Other Africa	131	131	131	128	3	2.5
Africa	**631**	**631**	**625**	**635**	**–11**	**–1.7**
Saudi Arabia	1,511	1,493	1,408	1,440	–32	–2.2
United Arab Emirates	250	250	250	250	—	—
Other Middle East	835	835	835	875	–40	–4.6
Middle East	**2,596**	**2,578**	**2,493**	**2,565**	**–72**	**–2.8**
Australia	73	73	70	66	4	6.0
China	650	650	650	632	18	2.8
India	—	—	—	—	—	—
Other Asia–Pacific	169	169	169	178	–9	–5.2
Asia–Pacific	**892**	**896**	**889**	**875**	**13**	**1.5**
TOTAL WORLD	**8,482**	**8,435**	**8,295**	**8,406**	**–111**	**–1.3**

Totals may not add due to rounding.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

OXYGENATES

	Oct. 2009	Sept. 2008	Change	YTD 2009	YTD 2008	Change
	1,000 bbl					
Fuel ethanol						
Production	22,956	21,752	1,204	208,133	179,531	28,602
Stocks	15,080	15,688	(608)	15,080	15,192	(112)
MTBE						
Production	938	1,386	(448)	14,407	14,820	(413)
Stocks	985	543	442	985	762	223

Source: DOE Petroleum Supply Monthly.
Data available in OGJ Online Research Center. **NOTE: No new data at press time.**

Marketplace

DEADLINE for MARKETPLACE ADVERTISING is 10 A.M. Tuesday preceding date of publication. Address advertising inquiries to MARKETPLACE SALES, 1-800-331-4463 ext. 6301, 918-832-9301, fax 918-832-9201, email: glendah@pennwell.com.

- *DISPLAY MARKETPLACE: $390 per column inch, one issue. 10% discount three or more CONSECUTIVE issues. No extra charge for blind box in care. Subject to agency commission. No 2% cash discount.*
- *UNDISPLAYED MARKETPLACE: $4.00 per word per issue. 10% discount for three or more CONSECUTIVE issues. $80.00 minimum charge per insertion. Charge for blind box service is $60.00 No agency commission, no 2% cash discount. Centered/Bold heading, $12.00 extra.*
- *COMPANY LOGO: Available with undisplayed ad for $85.00. Logo will be centered above copy with a maximum height of 3/8 inch.*
- *NO SPECIAL POSITION AVAILABLE IN MARKETPLACE SECTION.*
- *PAYMENT MUST ACCOMPANY ORDER FOR MARKETPLACE AD.*

EMPLOYMENT

Lead Reservoir Simulation Eng.

Chevron seeks Lead Reservoir Simulation Eng. in San Ramon, CA. MS in Pet. Engineering + 2 yrs exp in job offered or as Research Asst/Pet. Eng or Rsrvr Sim. Eng. Reqd skills: finite difference & rsrvr sim. methods & software; thermodynamic properties of oil & gas fluid sys., fluid flow in porous media & oil & gas recovery mechanisms; clastic & carbonate depositional sys., geological modeling & geostatitistical methods; UNIX/LINUX & Windows software operating sys. Mail resume: Chevron, 1500 Louisiana St., Houston, TX 77002 attn Y. Gomez Ref job 146.

OIL & GAS PROSPECTS

UINTA BASIN, UTAH RESOURCE PLAY
Multiple direct offset locations
18 MMBO from Green River at 5500'
900 BCFG from gas sands in Wasatch through Dakota plus Mancos shale gas. Multiple producing horizons. 100% WI in 7400+ acres, 80% NRI.
For info call (970) 245-3951 or email enoblitt@bresnan.net (see us at NAPE, booth 1928)

50 MMBO @ 4500'
BASIN & RANGE EXPLORATION PROSPECT
2 structures, excellent source rocks, viable seals for reservoirs. Defined by seismic, gravity, geochem and surface mapping. 100% WI and operations available. For info call (435) 658-3423 or email titan-energy@comcast.net (see us at NAPE, booth 1930)

BUSINESS OPPORTUNITIES

UTAH & WYOMING PROJECT
OVERTHRUST BELT
>90,000 CONTIGUOUS ACRES, 80% FEE
Extensive Pipeline infrastructure
DEEP TARGETS; Twin Creek, Nugget, Big Horn, & Mission Canyon.
RESERVE POTENTIAL - 703 MMBO, 7 TCF
75% to 87.5% OPERATING WI AVAILABLE, TERMS NEGOTIABLE.
SHALLOW TARGETS; Bear River & Frontier Coal 200 to 600 feet of Carbonaceous Shale w/116 scf
RESERVE POTENTIAL - 3.5 to 7 TCF
50% WI AVAILABLE, TERMS AND OPERATIONS NEGOTIABLE.
CONTACT; Harrison Schumacher; 818-225-5000, Paul Mysyk; 440-954-5022.

Read OGJ Marketplace

BUSINESS OPPORTUNITIES

GEOLOGIST has extensive Gulf Coast 2-D seismic data-base with numerous mapped prospects and anomalies. Seeks funding for additional seismic, leasing and drilling. 713-504-7291.

Revolutionary computerized oil pump under 10k. Pumps oil at less than $1 barrel. Prototype patent ready. Must sell 150K. Steal. 805-569-5402.

WANTED: Operated properties in Oklahoma (Kingfisher, Canadian, Grady and McClain Counties). Buyer is willing to pay a premium for the right package. For inquiries please call 262-248-1998 or fax 262-248-2027.

EQUIPMENT FOR SALE

FOR SALE / RENT
5.2 MW MOBILE GEN SETS
CALL: 800-704-2002

SOLAR TAURUS 60

- GAS - LOW NOx (OIL)
- 60 Hz - 13.8KV or 50 Hz - 11KV
- LOW HOUR - SOLAR SERVICED

DIESELS • TURBINES • BOILERS

24/7 EMERGENCY SERVICE
IMMEDIATE DELIVERY

www.wabashpower.com | info@wabashpower.com
Phone: 847-541-5600 Fax: 847-541-1279

wabash POWER EQUIPMENT CO.
444 Carpenter Avenue, Wheeling, IL 60090

4 MMSCFD H2 REFORMING PLANT

Plant is mounted on skids and is used to produce high purity hydrogen using steam reforming and a PSA system. Built in: 2003
Year shutdown: 2006
Excellent Condition
Built by Linde
Designed by Hydro Chem

Please let me know if you have an interest and would like further details.
Larry Medford
Louisiana Chemical Equipment Co., L.L.C.
Office: 225.923.3602 – Cell: 713.553.8339
** Email: larrym@lcec.com

LEASES OR DRILLING BLOCKS

200 Acre Barnett Shale lease available to drill in Johnson County, TX. Lessee will contribute lease as their participation. Production surrounding property. Property never drilled. Contact 214-224-4634 or gedwards@ucdcorp.com.

CONSULTANT

Brazil: EXPETRO can be your guide into this new investment frontier.
Effective strategic analysis, quality technical services, compelling economic/regulatory advice, and realistic approach regarding Brazilian business environment-120 specialists upstream, downstream gas and biofuels.
Email: contato@expetro.com.br
Web: www.expetro.com.br-Rio de Janeiro, Brazil

GULF COAST PROSPECTS

Gulf Coast Prospects, 30 BCF—700 BCF potential. Miocene, Frio, Yegua, ORRI and finders fee basis. Serious inquiries only. Confidentiality required. 281-577-5170.

Hiring?
Selling Equipment?
Need Equipment?
New Business Opportunity?

Contact: Glenda Harp
+1-918-832-9301 or
1-800-331-4463, ext. 6301
Fax: +1-918-831-9776

PennEnergy jobs

March 30, 2010 • 9:00 AM - 5:00 PM CST

Join us for the energy industry's most advanced career fair event:

The PennEnergy Jobs Virtual Career Fair

Take part in our online-only job fair and experience the full power and reach of online networking. This event is power and petroleum-industry focused and provides industry professionals with the rare opportunity to communicate directly with recruiters and hiring managers.

WHAT TO EXPECT:

- Conduct comprehensive research on industry employers
- Search and apply instantly to job openings
- Chat directly with recruiters and hiring managers
- Visit the comprehensive research center

Visit www.PennEnergyJOBS.com/VCF for more information and to register.

To participate as an exhibitor at this event, contact: sales@PennEnergyJOBS.com.

PennWell® Turning Information into Innovation | Serving Strategic Markets Worldwide since 1910

PennEnergyJOBS.com

Advertising Sales / Advertisers Index

Houston
Director of Sales, Tripp Wiggins; Tel: (713) 963-6244, Email: trippw@pennwell.com. U.S. Sales Manager, Marlene Breedlove; Tel: (713) 963-6293, E-mail: marleneb@pennwell.com. Regional Sales Manager, Mike Moss; Tel: (713) 963-6221, E-mail: mikem@pennwell.com. PennWell - Houston, 1455 West Loop South, Suite 400, Houston, TX 77027. Fax: (713) 963-6228

South/Southwest /Texas/Northwest / Midwest / Alaska
Marlene Breedlove, 1455 West Loop South, Suite 400, Houston, TX 77027; Tel: (713) 963-6293, Fax: (713) 963-6228; E-mail: marleneb@pennwell.com

Northeast / Texas/Southwest
Mike Moss, 1455 West Loop South, Suite 400, Houston, TX 77027; Tel: (713) 963-6221, Fax: (713) 963-6228; E-mail: mikem@pennwell.com

Louisiana / Canada
Stan Terry, 1455 West Loop S. Ste. 400, Houston, TX 77027; Tel: (713) 963-6208, Fax: (713) 963-6228; E-mail: stant@pennwell.com

United Kingdom / Scandinavia / Denmark / The Netherlands
Roger Kingswell, 9 Tarragon Road, Maidstone, Kent, ME 16 OUR, United Kingdom; Tel. 44.1622.721.222; Fax: 44.1622.721.333; Email: rogerk@pennwell.com

France / Belgium / Spain / Portugal / Southern Switzerland/Monaco
Daniel Bernard, 8 allee des Herons, 78400 Chatou, France; Tel: 33(0)1.3071.1119, Fax: 33(0)1.3071.1119; E-mail: danielb@pennwell.com

Germany / Austria / Northern / Switzerland / Eastern Europe / Russia / Former Soviet Union
Sicking Industrial Marketing, Kurt-Schumacher-Str. 16, 59872, Freienohl, Germany. Tel: 49(0)2903.3385.70, Fax: 49(0)2903.3385.82; E-mail: wilhelms@pennwell.com; www.sicking.de <http://www.sicking.de> Andreas Sicking

Japan
e.x.press sales division, ICS Convention Design Inc. 6F, Chiyoda Bldg., 1-5-18 Sarugakucho, Chiyoda-ku, Tokyo 101-8449, Japan, Tel: +81.3.3219.3641, Fax: 81.3.3219.3628; Kimie Takemura, Email: takemura-kimie@ics-inc.co.jp; Manami Konishi, E-mail: konishi-manami@ics-inc.co.jp; Masaki Mori, E-mail: masaki.mori@ics-inc.co.jp

Brazil
Grupo Expetro/Smartpetro, Att: Jean-Paul Prates and Bernardo Grunewald, Directors, Ave. Erasmo Braga 22710th and 11th floors Rio de Janeiro RJ 20024-900 Brazil; Tel: 55.21.3084.5384, Fax: 55.21.2533.4593; E-mail: jpprates@pennwell.com.br and bernardo@pennwell.com.br

Singapore /Australia / Asia-Pacific
Michael Yee, 19 Tanglin Road #09-07, Tanglin Shopping Center, Singapore 247909, Republic of Singapore; Tel: 65 6737.2356, Fax: 65.6734.0655; E-mail: yfyee@singnet.com.sg

India
Rajan Sharma, Interads Limited, 2, Padmini Enclave, Hauz Khas, New Delhi-110 016, India; Tel: +91.11.6283018/19, Fax: +91.11.6228 928; E-mail: rajan@interadsindia.com

Italy
Paolo Silvera, Viale Monza, 24 20127 MILANO Italy; Tel:+02.28.46 716; E-mail: info@silvera.it

From the Subscribers Only area of OIL&GAS JOURNAL online www.ogjonline.com

US energy market wouldn't notice loss of biodiesel

Live by the subsidy, die by the subsidy. Because a generous tax credit for biodiesel expired at the end of 2009, makers of the fuel fear commercial demise is near.

Distracted by the politics of health care reform, Congress didn't extend the $1/gal credit for blenders of the diesel substitute made from soybean oil, yellow grease, or animal fat.

Loss of the credit would ruin biodiesel

The Editor's Perspective

by Bob Tippee, Editor

economics already squeezed by adverse margins between diesel prices and feedstock costs. Producers of biofuels are reported to be closing plants and laying off workers.

If hype were true, US employment (green jobs!) and energy supply (homegrown energy!) should feel strain from the threat to biodiesel.

They do not.

According to Sen. Chuck Grassley (R-Iowa), the biodiesel industry lost 29,000 jobs last year after supporting "more than 51,000 green jobs" in 2008.

The decline, however difficult for the workers involved, represents less than 0.2% of the 15.3 million Americans out of work in December.

And imperiled biodiesel production is even less consequential to energy supply.

In the first 9 months of 2009, according to the Energy Information Administration, biodiesel output averaged 23,500 b/d. That's 0.1% of the US oil market. And 54% of it was exported, 37% net of imports. If biodiesel production ceased, the market wouldn't notice.

For commercial reasons, moreover, biodiesel growth had stalled before Congress got busy with other concerns.

Last year's January-September production average was down from 38,200 b/d in the comparable period of 2008 and barely up from 2007.

But total-year tax credits were worth $776 million in 2008 and $490 million in 2007 to the good green folks who made and blended the material and who now need only to hang on.

Congress will reinstate the subsidy. It will have to if biodiesel sales are to triple as they must to meet a mandate at the plateau level taking effect in only 2 years.

Besides, those shiny, tiny biodiesel plants provide wonderful photo opportunities for lawmakers who want to appear to have acted meaningfully on energy but who have no real idea how to go about it.

(Online Jan. 22, 2010; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

OPEC capacity caps prices

The International Energy Agency in Paris estimated in December the sustainable production capacity for the Organization of Petroleum Exporting Countries at 35.4 million b/d, with actual output at 29.05 million b/d, leaving a spare capacity of 6.35 million b/d. That spare capacity drops to 5.37 million b/d if less dependable producers such as Iraq, Nigeria, and Venezuela are eliminated.

The US Energy Information Administration put OPEC's spare production capacity in December at 5.03 million b/d, zeroing out Algeria, Ecuador, Iraq, Nigeria, and Venezuela. It estimates OPEC's maximum production capacity at 34 million b/d.

Using both the IEA and EIA numbers, Adam Sieminski at Deutsche Bank, Washington, DC, said, "We estimate that capacity utilization in OPEC is running at circa 85%. Both the IEA and EIA agree that the bulk of OPEC's spare capacity is in Saudi Arabia, with some 3.5-3.8 million b/d of incremental output available to the markets." Of course, Saudi crude is heavier and more sour than the frequently disrupted Bonnie Light crude of Nigeria. Nevertheless, Sieminski sees the spare OPEC capacity keeping a lid on crude prices this year, with West Texas Intermediate projected at $65/bbl vs. a consensus of $75-80/bbl.

Meanwhile, the US Geological Survey recently raised its estimate of heavy oil "technically recoverable" from the oil sands in Venezuela's Orinoco belt to 513 billion bbl, up from 235 billion previously (OGJ Online, Jan. 22, 2010). The estimate is based on published geologic and engineering data. USGS figures recovery rates from a minimum 15% for cold production using horizontal wells up to a median 45% and a maximum of 70%. "Some of the assumptions, notably the 45% median recovery factor, look quite aggressive," said analysts in the Houston office of Raymond James & Associates Inc., "but the more important point here is this: The reason for the 30%-plus meltdown in Venezuelan oil production since Hugo Chavez took power in 1998 is not a matter of geology but rather politics. With some of the world's worst policies towards foreign investment, Venezuela's oil industry is set to continue stagnating."

Pipeline factors

OPEC's production capacity isn't the only thing influencing the oil market, of course. Enbridge Inc. recently announced its Alberta Clipper pipeline from Canada to the Midwest will start operations in early April rather than in the third quarter as previously projected. "Combined with the start-up of the Keystone pipeline this means that we suddenly have 900,000 b/d of additional pipeline capacity from Canada to the US Midwest starting in the second quarter," said Olivier Jakob at Petromatrix, Zug, Switzerland.

The line fill is taking some crude off the market, and it will take some time before the increase in Canadian production matches the pipeline capacity increase. "But given that the Enbridge Southern Lights pipeline (carries diluents up north to increase the flow rate of the crude oil coming south) will also start ahead of schedule, we should nevertheless expect to see increased flows from Canada to the Midwest in the second half of 2010, and we maintain our estimate that the US Midwest will have cut to zero its dependency on non-Canadian foreign crude oil by the end of this year," Jakob said.

Meanwhile, other EIA data show pipeline imports of natural gas from Canada fell nearly 1 bcfd in 2009. But with US demand for gas down 1.5% because of the economic downturn, Sieminski said, LNG imports were kept near contract minimums. Now, he said, "With the economy reviving and the expectation of continued low Canadian pipeline supplies, the need for LNG should rise toward 1.75 bcfd from an estimated 1.25 bcfd level in 2009."

Sieminski reported, "The wave of new and ramped-up LNG projects around the globe is still building. Facilities streamed in 2009 include Tangguh, Qatargas 2, Sakhalin 2, Yemen, Ras Laffan 3, Snohvit, North West Shelf 5, and Atlantic LNG 4. Over the course of 2010-11, we expect significant increases from these projects, as well as Pluto, Algeria, Peru LNG, and [Nigerian] LNG come on line."

According to EIA estimates, Sieminski said, "Total [US] natural gas production increased by 3.7% in 2009 even though the rig count fell by almost 60% from peak to trough September 2008 to July 2009. The EIA believes that steep declines from existing fields and lagged effects of the lower rig count will contribute to a 3% decline in 2010 production, making more room for LNG despite the potential for lower gas demand from electric utilities. The surprise, if there is one, in this outlook is likely to come from stronger-than-expected shale gas production."

(Online Jan. 25, 2010; author's e-mail: samf@ogjonline.com)

DEEP OFFSHORE TECHNOLOGY INTERNATIONAL®

30 NOVEMBER – 2 DECEMBER 2010
AMSTERDAM RAI | AMSTERDAM | NETHERLANDS

DISCOVER THE UNKNOWN

CELEBRATING 29 YEARS OF DOT

For 29 years DOT International has been recognized as THE event where operators, equipment manufacturers, contractors and service-providers introduce deepwater solutions.

The event provides a unique platform where knowledge is shared and distributed throughout the global industry. Through this sharing, the industry increases its understanding of the challenges and solutions involved in deepwater and ultra-deepwater operating conditions.

Don't miss your chance to join the distinguished list of exhibitors, delegates, visitors and speakers.

CALL FOR ABSTRACTS OPEN
DEADLINE 6 APRIL 2010

For more information contact:

Conference Director
Eldon Ball
T: +1 713 963 6252
E: eldonb@pennwell.com

Conference Manager
Niki Vrettos
T: +44 (0) 1992 656 600
E: nikiv@pennwell.com

SUBMIT ONLINE TODAY

www.deepoffshoretechnology.com

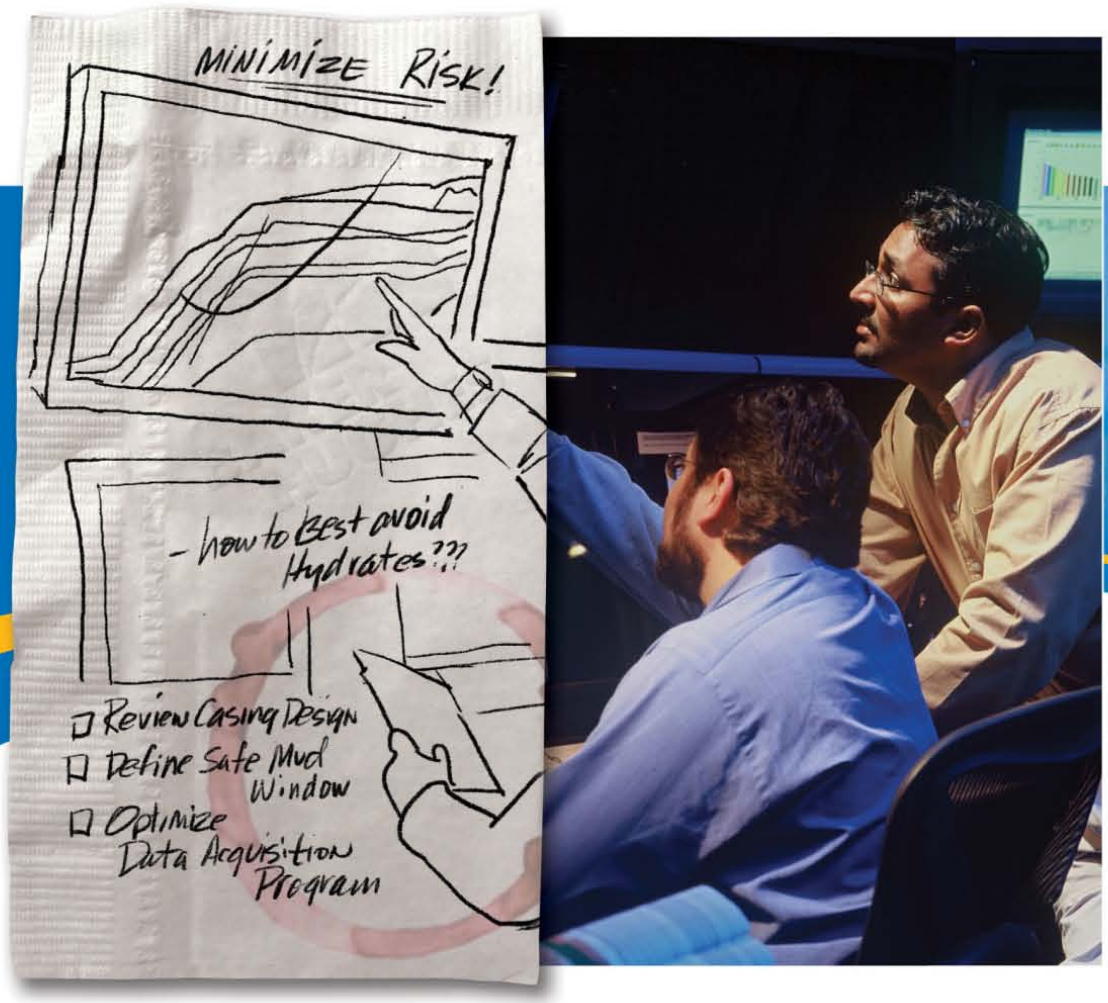
Owned and produced by:

PennWell EST. 1910 100TH ANNIVERSARY

Flagship Media Sponsors:

Offshore | OIL&GAS JOURNAL | Oil, Gas & Petrochem EQUIPMENT | OIL&GAS FINANCIAL JOURNAL

Today's Baker Hughes



Our pre-planning solutions help keep drilling and production risks out of the picture.

You're always under pressure to avoid setbacks in the field. But it's extremely difficult to anticipate every problem when you're working thousands of feet beneath the surface.

That's where Baker Hughes can help. We offer you a variety of options for dealing with potential challenges ahead of time. Our Reservoir Technology and Consulting Group has the engineering and geomechanics expertise you need to ensure peak drilling performance—with less non-productive time. And our FATHOM™ certified chemicals prevent hydrate formation and are tested for material compatibility to avoid production interruptions. What's more, these are just a few of the ways our pre-planning initiatives help eliminate costly surprises.

To learn about all the ways we can mitigate your risk, contact your Baker Hughes representative or visit www.bakerhughes.com/lessrisk. We'll help you address unseen problems with real-world solutions.

Come visit us at IADC/SPE Drilling Conference, Booth 317.

www.bakerhughes.com/lessrisk

BAKER HUGHES