Drill Faster. Last Longer. Go Further.

QUANTEC

New Technology for Record-Breaking Performance

Superior durability. Superior stability. Superior drilling.
The revolutionary new Quantec premium PDC drill bits from Hughes Christensen set new standards for high-performance drilling, shattering records in challenging environments from hard granite to highly abrasive sandstone and shale. Precision depth of cut and incomparable wear resistance deliver extended operating life and accelerated rates of penetration that can save you days of rig time. Quantec — only from Hughes Christensen.

The Drill Bit Company.

BAKER HUGHES Hughes Christensen

Worldwide Headquarters The Woodlands, Texas Tel: 713 625 6654 Fax: 713 625 6655

Statistically SUPERIOR

Energy Industry Information Products to Fit Your Needs

Energy Industry Surveys In Excel

Detailed surveys for sectors of the energy industry from Oil & Gas Journal, Offshore, and other industry sources. Presented in Excel format to aid industry analysis. The most efficient tool for evaluating industry activity. Surveys cover the refining, exploration & production, processing and transportation energy sectors. Both current and historical data available. Multi-user license available for company use.

Energy Industry Directories in Electronic Format

Comprehensive directories for sectors of the energy industry worldwide. Electronic directories -- updated frequently, along with key web site and e-mail links to company listings. An indispensable tool for locating current industry contacts. Most complete set of listings available in the energy industry.

Energy Industry Statistics in Excel

Statistics for all segments of the energy industry from two sources. The massive "OGJ Energy Database-HaverData" comprehensive database of energy industry statistics and the OGJ Online Research Center set of key statistical tables measuring industry activity "Energy Industry Statistical Tables in Excel". Easy to use menu systems for finding the relevant data. All of the historical statistical data you will need for analyzing ongoing industry activity in convenient spreadsheet format. One time purchase or annual subscriptions available.

Energy Industry Research, Strategic and Executive Reports

In-depth reports covering a wide variety of energy industry topics. Reports from Oil & Gas Journal and recognized energy industry experts. Regional reports on key producing areas in the world. Topical information on subjects such as: E&P Risk Evaluation, Natural Gas Futures Market, Unconventional Gas, Marginal Wells, guides to doing business internationally and much more.

Detailed product descriptions, free samples and ordering information on the web site.

OIL&GAS JOURNAL online research center™

Web Site: **www.ogjresearch.com**

E-mail: **orcinfo@pennwell.com**

Tel for Information: (918) 831-9488

What is your energy information need?

OGJ Online Research Center has the product

For details and samples, go to:

www.ogjresearch.com

Week of Oct. 27, 2008/US$10.00

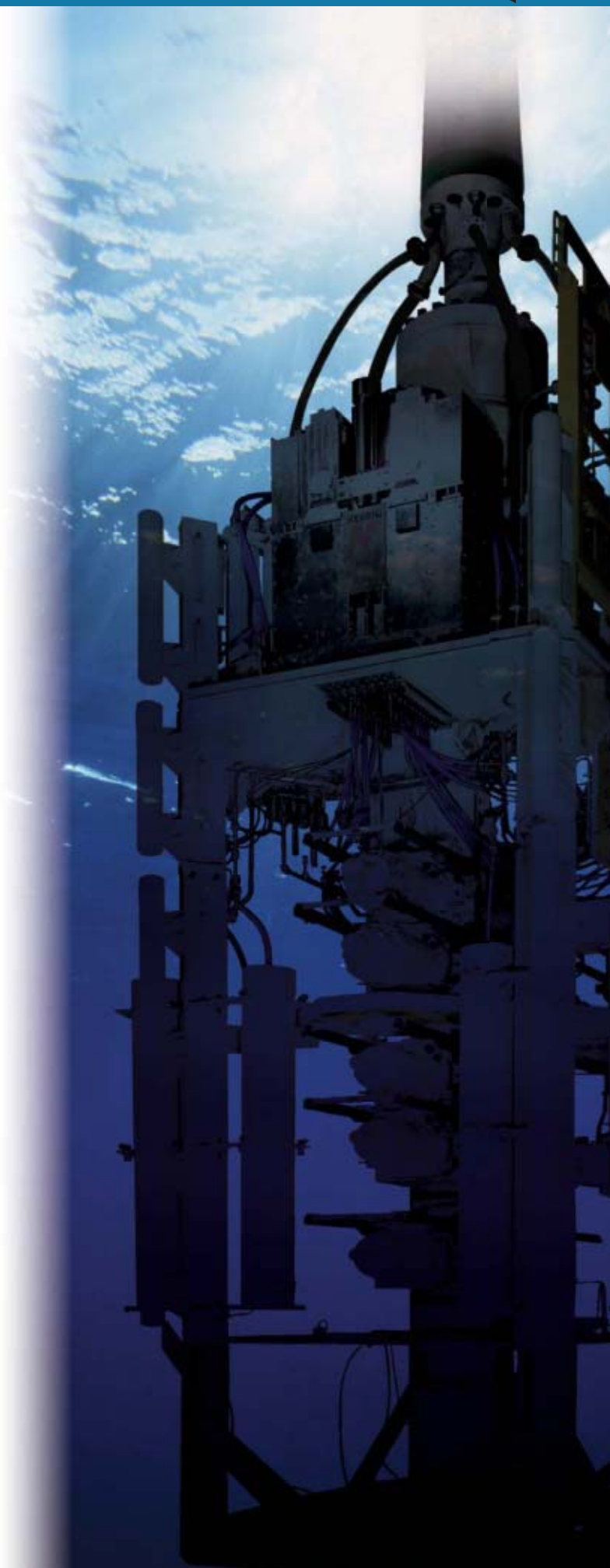
OIL&GAS JOURNAL®

PennWell®

International Petroleum News and Technology / www.ogjonline.com

Drilling Report

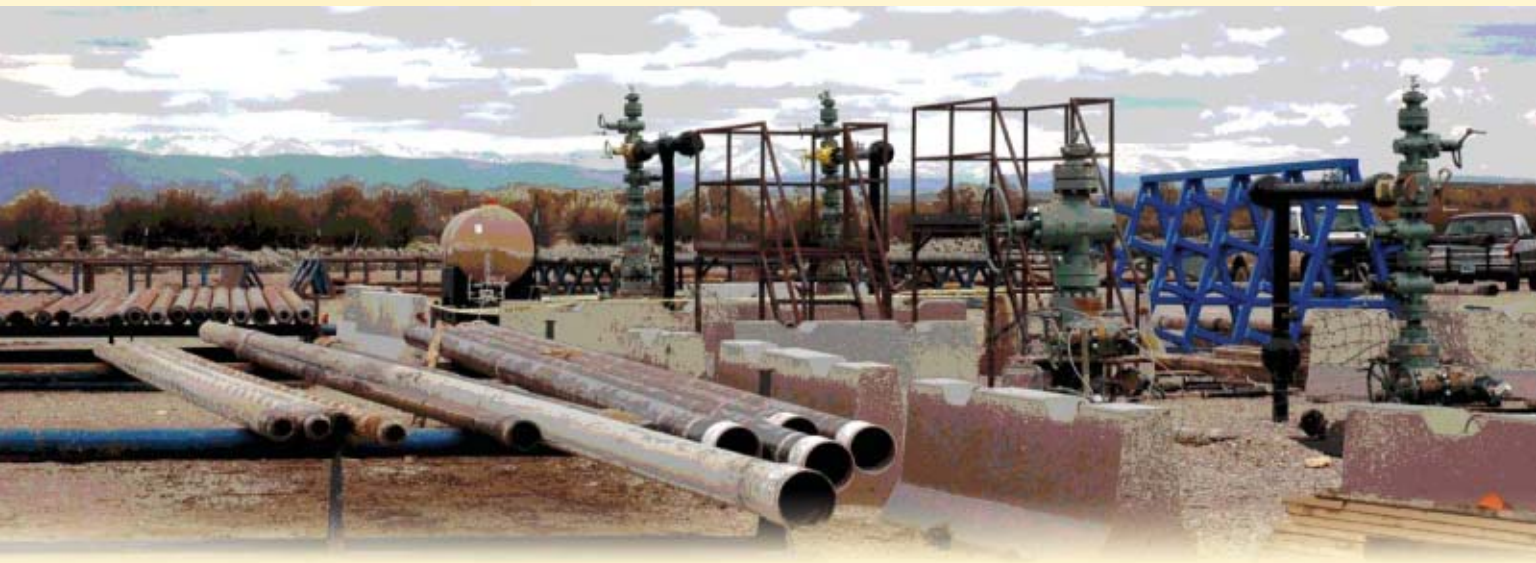
Fischer-Tropsch coal-to-liquids method economics updated
Ecuador's giant Pungarayacu to see heavy oil appraisal
Effective risk evaluations prevent refinery shutdowns
Pipeline fractures: prediction steel-grade dependent



OIL&GAS JOURNAL®

Oct. 27, 2008
Volume 106.40

DRILLING REPORT



REGULAR FEATURES

COVER

Photographer Gaylon Wampler captured two Grey Wolf Inc. drillers at work on Rig 10 in Panola County, Tex., from an unusual perspective. The annual Drilling Report, starting on p. 45, reviews worldwide drilling, rig fleets, and operator and contractor plans. Natural gas demand has been driving activity in North America this year, and pad drilling has increased. Tubulars and wellheads in the image above, occupy a Shell drilling pad in Wyoming's Pinedale field, the second-largest natural gas field in the US (photo by Nina M. Rach). The Canadian drilling report, p. 56, includes drilling forecasts and a review of current projects. Two Gulf of Mexico hurricanes disrupted drilling and damaged infrastructure in September, discussed on p. 64. Cover photo by Gaylon Wampler (www.gaylonwamplerphotography.com), courtesy of Grey Wolf.

Cross the finish line first with prototype seals from Parco.

Rely on Parco to deliver prototype packing elements in one week or less.

Parco developed its Rapid Prototype Program to get you the parts you need, when you need them. Through that program, Parco can provide prototype parts in as few as five working days for packing elements, non-standard O-rings, and custom shapes. Parco can also provide prototype parts in as few as three working days for standard O-rings and back-up rings.

Prototype parts can be made from any of Parco's 340 compounds. Seals made from those compounds resist the most challenging oil field applications. You can rely on our expertise for the best explosive decompression, abrasion, high temperature, and chemical resistant seals.

Leading oil field companies have specified Parco for more than 65 years for quality seals and responsive service. Give us a call the next time you need prototype parts. We'll work with you to find a solution for your time sensitive projects.

Parco, Inc., 1801 S. Archibald Ave., Ontario, CA 91761
909-947-2200 Fax 909-923-0288 parcoinc.com

Parco

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

 Oil & Gas Journal (ISSN 0030-1388) is published 48 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. 1,500 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. 106, No. 40) 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 G. Alan Petzet, alanp@ogjonline.com
Chief Technology Editor-LNG/Gas Processing Warren R. True, warrent@ogjonline.com
Production Editor Guntis Moritis, guntism@ogjonline.com
Drilling Editor Nina M. Rach, ninar@ogjonline.com
Refining/Petrochemical Editor David N. Nakamura, davidn@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 Associate Editor Judy R. Clark, judyrc@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
Editorial Assistant Linda Barzar, lbarzar@pennwell.com

Petroleum Group President Michael Silber, msilber@pennwell.com
Vice-President/Group Publisher Bill Wageneck, billw@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@ogjonline.com
Associate Presentation Editor Michelle Gourd, michelleg@pennwell.com
Statistics Editor Laura Bell, laurab@ogjonline.com
Illustrators Kermit Mulkins, Mike Reeder, Kay Wayne
Editorial Assistant Donna Barnett, donnab@ogjonline.com
Production Director Charlie Cole

London

Tel +44 (0)20.8884.4246
International Editor Uchenna Izundu, uchennai@pennwell.com

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
Circulation 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

What is reliability worth?

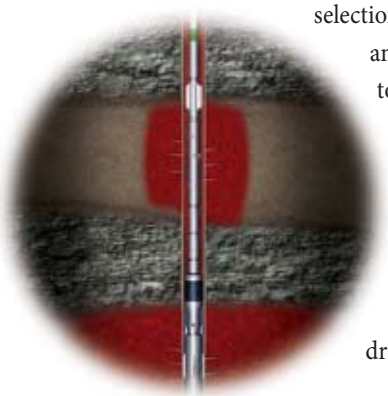
Improved production from deep, multiple-interval, tight sands.

Industry Challenge

Achieving the improved speed and efficiency of pinpoint stimulation while handling high pressures and large treatment volumes.

Halliburton Solution

Halliburton's industry-leading **Hydraulic Workover (HWO)** service lets you complete your well with no limitations on zone selection or volumes of fracturing fluid and proppant. And it enables you to do it quickly and efficiently in every scenario from deepwater to mature onshore fields. Of course, Halliburton's HWO service is a cost-effective intervention service for under-balanced applications, drilling lateral extensions, fishing, squeeze-cementing and more.



Operator Benefit

Increase your options for well completions with Halliburton's HWO service and access to Halliburton's industry-leading completion and fracturing technologies.

To learn more about how Halliburton puts reliability in action, visit www.halliburton.com/reliability or e-mail us at wellintervention@halliburton.com.

HALLIBURTON

OGJ Newsletter

Oct. 27, 2008

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

General Interest — Quick Takes

EU ministers agree on energy compromise

Strongly backed by France, which is president of the European Union through 2008, the unbundling compromise reached June 6 (OGJ, June 16, 2008, Newsletter) was adopted unanimously Oct. 10 at the Energy Ministers meeting in Luxembourg. Controversial legislation otherwise could have separated the network operation of electricity and gas from production and supply activities.

Described as "a major political agreement," the compromise confirms that ownership of both transportation and marketing networks will be retained by the producers, but the units will be operated independently from the parent company and supervised by an Independent Transmission Operator.

A European regulatory agency will be set up, which will "considerably bolster the coordination of the national regulators," according to the ministers' press release.

The European Parliament definitely will adopt these texts in a second reading. In its first reading, the Parliament had opted for full unbundling.

The ministers also reaffirmed the crucial importance of energy efficiency both to achieve climate objectives and to guarantee energy security.

The ministers also discussed the energy-climate package and especially the renewables directive under which these energies should account for 20% of the energy mix by 2020. It is one of the leading priorities of the French presidency, and an agreement at its first reading is targeted by yearend.

France leads EU Council's Kyoto extension push

France's National Assembly voted almost unanimously Oct. 21 on the draft law implementing the country's environment package, concluding a widespread debate with all relevant stakeholders over the past year.

The result "should considerably bolster France's credibility and voice within the European and international climate negotiations" said Jean-Louis Borloo, minister of ecology, energy, and sustainable development.

Borloo was alluding to the back-tracking of a number of European Union member states on the energy-climate package, which France wants to see adopted at the next EU Council meeting Dec. 11-12. It will coincide with the United Nations climate conference in Poznan, Poland, Dec. 1-12 to extend the Kyoto Protocol treaty beyond 2012.

The energy-climate targets to 2020 are "the three 20s," namely to reduce greenhouse gas emissions by 20%, increase the share of renewables in energy consumption to 20%, and improve energy efficiency by 20%. It is one of the priorities of France, which currently holds the rotating EU presidency until yearend, to have the package adopted in December.

President Nicolas Sarkozy, at the last 27 leaders summit meeting in Brussels Oct. 15-16, said solutions would be found for countries that have expressed concern over the cost of the package in the current unfavorable financial and economic environment.

Italy, Poland, and several new EU member states, including Bulgaria, Hungary, Latvia, Lithuania, Romania, and Slovakia, have threatened to veto the package, while a consensus is needed for its adoption. Many are coal-dependent countries that are also worried that the EU's Emission Trading Scheme would be too costly for them, as they would need to buy certificates allowing them to emit carbon dioxide as of 2013. They want the deadline extended to 2020. Their view is that the EU's policy should be "to reconcile environmental targets with the need for sustainable development."

The European Commission has already provided for some flexibility in the application of the package. But as its president Jose Manuel Barroso firmly said at the Oct. 15-16 meeting: "What the Commission is adamantly opposed to is anything that undermines the overall architecture of the package" [the three 20s].

Any major backtracking would jeopardize the EU's environmental leadership because it hopes to influence other countries worldwide to follow its suit.

Eni, Enel to develop Italy's first CCS project

Italy's Eni SPA and electric power utility ENEL will integrate their carbon capture and storage (CCS) projects to construct a pilot plant in Brindisi under a strategic cooperation agreement signed in Rome.

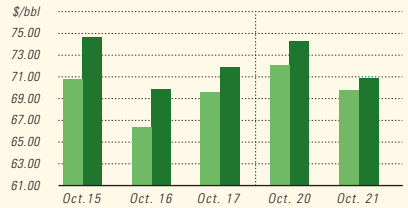
Eni, Enel, and the Italian Environment Ministry will also work on developing carbon dioxide capture technologies and renewable energy, according to separate memorandum of understanding.

At the Brindisi thermal power station, Enel is working on a pilot plant that will be able to remove 2.5 tonnes/hr of gas and transport it to the Cortemaggiore site in fall 2009. Eni has started an injection project that could offload 8,000 tonnes/year of CO_2 into depleted, exhausted Stogit field at Cortemaggiore (Piacenza) in fall 2010. Both companies have committed to lay a pilot dense-phase CO_2 transport line at the Brindisi site to bolster their experience in transporting CO_2.

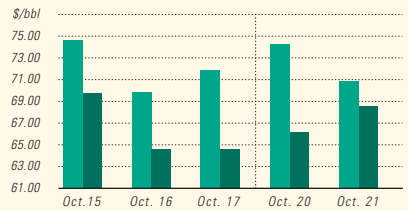
They will study Italy's CO_2 storage potential in partnership with Italian research bodies as the European Commission has strongly urged that this technology be widely deployed across its member states to enhance security of energy supplies. Enel and Eni plan to carry out a detailed feasibility study on the construction of a large-scale integrated demo plant for Enel's clean-coal power station. ✦

Industry Scoreboard

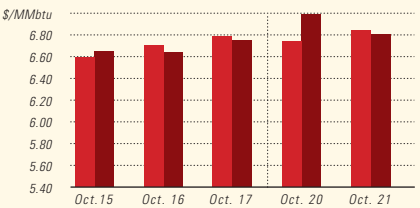
IPE BRENT / NYMEX LIGHT SWEET CRUDE



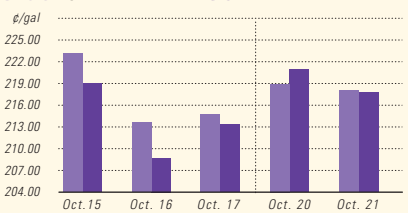
WTI CUSHING / BRENT SPOT



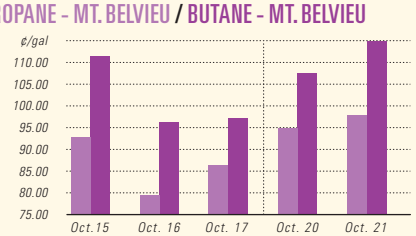
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



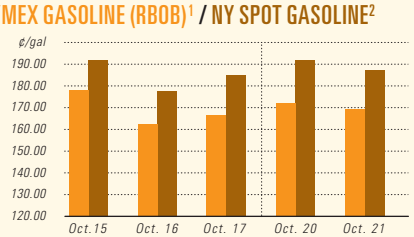
IPE GAS OIL / NYMEX HEATING OIL



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.

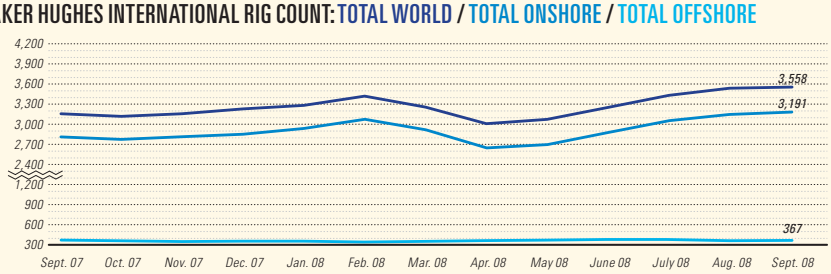
US INDUSTRY SCOREBOARD — 10/27

Latest week 10/10	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	8,764	9,248	–5.2	9,041	9,299	–2.8
Distillate	3,888	4,178	–6.9	4,009	4,208	–4.7
Jet fuel	1,467	1,567	–6.4	1,548	1,626	–4.8
Residual	414	659	–37.2	606	732	–17.2
Other products	4,081	4,783	–14.7	4,678	4,811	–2.8
TOTAL DEMAND	18,614	20,435	–8.9	19,670	20,707	–5.0
Supply, 1,000 b/d						
Crude production	4,191	4,935	–15.1	4,974	5,072	–1.9
NGL production[2]	2,105	2,427	–13.3	2,254	2,377	–5.2
Crude imports	9,160	10,123	–9.5	9,729	10,072	–3.4
Product imports	3,599	3,293	9.3	3,177	3,527	–9.9
Other supply[3]	1,299	935	38.9	1,378	1,033	33.4
TOTAL SUPPLY	20,354	21,713	–6.3	21,512	22,081	–2.6
Refining, 1,000 b/d						
Crude runs to stills	14,671	14,976	–2.0	14,671	15,144	–3.1
Input to crude stills	14,905	15,413	–3.3	14,905	15,434	–3.4
% utilization	85.0	88.4	—	85.0	88.5	—

Latest week 10/10	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	302,587	294,464	8,123	320,081	–17,494	–5.5
Motor gasoline	186,815	179,640	7,175	193,000	–6,185	–3.2
Distillate	122,601	123,090	–489	135,324	–12,723	–9.4
Jet fuel–kerosine	36,783	36,050	733	41,353	–4,570	–11.1
Residual	37,809	36,228	1,581	36,566	1,243	3.4
Stock cover (days)[4]			Change, %		Change, %	
Crude	23.6	23.2	1.7	21.1	11.8	
Motor gasoline	21.3	20.3	4.9	21.0	1.4	
Distillate	32.1	32.3	–0.6	32.1	0.0	
Propane	79.7	72.0	10.7	54.7	45.7	
Futures prices[5] **10/17**			**Change**		**Change**	**%**
Light sweet crude ($/bbl)	86.22	96.68	–10.46	80.66	5.56	6.9
Natural gas, $/MMbtu	6.74	7.45	–0.70	7.25	–0.51	–7.0

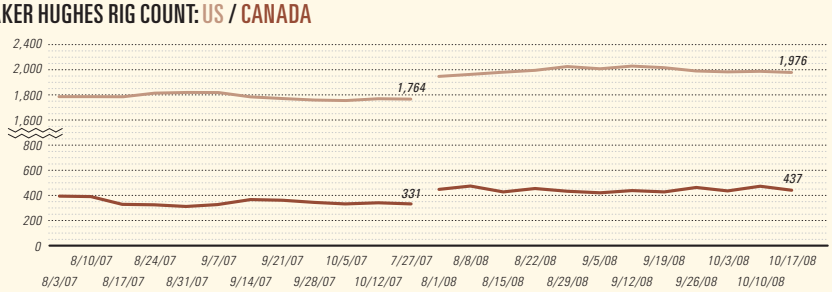
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average 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

Exploration & Development — *Quick Takes*

CNX Gas pushes Chattanooga shale exploration

CNX Gas Corp., Pittsburgh, has expanded its position the Devonian Chattanooga shale gas play to 235,000 acres in northeastern Tennessee and plans a two-rig program to drill 10 wells in the rest of 2008.

The acreage in Scott, Campbell, Anderson, and Morgan counties, Tenn., is largely contiguous and is composed of only a small number of leases, a rarity in the Appalachian basin, the company noted. It expanded by buying out its 50% partner Knox Energy Inc. and acquiring several other leases.

Chattanooga is 50-80 ft thick at about 3,500 ft and rich in total organic carbon. The company has drilled eight horizontal wells in the play.

The most recent well cost $900,000 to drill and complete. The wells were drilled with a truck-mounted, top-drive rig with a 185,000-lb hookload capacity.

CNX Gas, which connected the fifth well in mid-October, said gas rates at the first four wells are 230, 160, 100, and 230 Mcfd. Daily rates for the better wells have been stable.

New drilling is occurring in areas that have shown better initial results, and the company plans microseismic work in late 2008 to better understand the variances in individual well production.

PetroChina to drill in Uzbekistan

China National Petroleum Corp. subsidiary PetroChina will form a joint venture with state-owned Uzbekneftegaz to develop Mingbulak oil field in Namangan province on the northern edge of the Fergana Valley in northeastern Uzbekistan.

The joint venture "will help meet Uzbekistan's demand for oil and boost the development of China's natural gas upstream business and the Central Asia-China natural gas pipeline project," CNPC said.

CNPC in January started building the CAC pipeline, which will transport gas from Turkmenistan, through Uzbekistan and southern Kazakhstan, to western China's Xinjiang region. The pipeline, scheduled to start operations in 2009, will have a transmission capacity of 1.1 tcf/year of gas.

CNPC, which did not disclose any financial details of the new agreement, said production from Mingbulak field, which has reserves estimated at more than 30 million tonnes, is expected to reach 2 million tonnes/year.

Sentell Bossier-Haynesville well logged

Southern Star Energy Inc., Houston, said logs indicate that its Atkins-Lincoln 17-2 well in Sentell field, Bossier Parish, La., north of Shreveport, encountered gas in the Jurassic Lower Bossier and Haynesville shales.

The well logged 205 ft of highly laminated, silty, and naturally fractured shale zone with crossplot porosities of 9-12%. Mud logs indicated abundant gas shows throughout of 400-600 units with trip gas as high as 3,000 units. The interval exhibits the characteristics of the Lower Bossier shale, the company said.

Just below the laminated section it cut 185 ft of quality dark black organic rich shale with 1,100-3,000-unit gas shows. This interval exhibits the characteristics the industry classifies as Haynesville shale. TD is 11,300 ft.

The wellbore is suspended with 7-in. intermediate casing through the Cotton Valley formation at 9,500 ft to preserve the company's options to complete as a vertical producer or reenter for horizontal drilling pending the development of completion techniques.

As a member of the Core Laboratories Integrated Reservoir Solution's regional Haynesville Shale Study, the company's data are being incorporated into the Core Lab database for use in designing optimum completion techniques for horizontal drilling in the Haynesville play.

Eagle Ford shale gas-condensate find gauged

Petrohawk Energy Corp., Houston, said it placed a horizontal new field discovery well in Upper Cretaceous Eagle Ford shale in South Texas on production at the rate of 7.6 MMcfd of gas and 250 b/d of condensate.

The South Texas find is in southwestern La Salle County just south of Stuart City gas field on the Edwards reef trend (see map, OGJ, Aug. 13, 2007, p. 38). Petrohawk Energy has leased more than 100,000 net acres in what it believes to be the most prospective areas for commercial production from the Eagle Ford.

The company drilled the STS 241-1H discovery well to 11,300 ft true vertical depth and ran fracs totaling more than 2 million lb of sand in 10 stages in a 3,200-ft lateral.

It also cored, logged, and is drilling the lateral at the Dora Martin 1H, a confirmation well 15 miles away, where Eagle Ford quality appears to be superior to that in the discovery well. Petrohawk Energy expects to spud a third well by mid-November.

The company estimated development well drilling and completion cost at $5-7 million. It plans to run one rig continuously and will access existing gathering and transportation facilities. ✦

Drilling & Production — *Quick Takes*

Agip taps WorleyParsons group for contract

Agip KCO has chosen an engineering consortium led by WorleyParsons Europe Ltd. to design facilities for the second phase of massive Kashagan oil field in Kazakhstan.

In a letter of intent, valid until Dec. 31, Agip requested front-end engineering and design services for onshore and offshore facilities. The work is valued at $31 million.

"There are also options for services post-Phase II FEED, which include early works, detailed engineering and procurement services, technical assistance, and design-system integrity," said Aker Solutions ASA, one of the companies in the engineering consortium.

Kashagan, which has 34.5 billion bbl of oil in place, is a challenging field having high pressure and high hydrogen sulfide levels.

In addition, it is in an environmentally sensitive area with difficult weather conditions. An initial output of 150,000 b/d of production from the field was originally scheduled to start in 2005, but it has been delayed until fourth-quarter 2012 due to the technical challenges, cost increases, and a reconfiguration of the offshore plant to boost efficiency levels and safety standards (OGJ Online, Sep. 19, 2008).

Kashagan, 80 km southeast of Atyrau in the North Caspian Sea, will be developed in three phases.

WorleyParsons and Aker Solutions secured the engineering services, fabrication, and hookup for the first phase, which is expected to cost $19 billion.

Group seeks greater New Albany gas output

GTI is leading a research consortium to turn noncommercial natural gas wells into commercial producers in the Devonian New Albany shale in the Illinois basin.

GTI signed a contract for a multiyear program with the Research Partnership to Secure Energy for America, which is focused on meeting US gas demand and lowering costs for consumers. GTI is a research, development, and training organization.

The consortium involves GTI and 14 participants. They include Atlas Gas & Oil, Aurora Oil and Gas, BreitBurn Energy, CNX Gas Corp, Inflection Energy, NGAS Resources, Noble Energy, and Trendwell Energy Corp.

The consortium plans joint research targeting the 10.5 tcf of technically recoverable gas in the New Albany shale formation. ✦

Processing — *Quick Takes*

Pennsylvania plant to process Marcellus gas

MarkWest Energy Partners LP has started up a 30 MMcfd refrigeration plant southwest of Pittsburgh to process natural gas from the Devonian Marcellus shale.

MarkWest, meanwhile, is installing a 30 MMcfd cryogenic gas processing plant next to the refrigeration unit near Houston in Chartiers Township in Washington County for start-up in the first quarter of 2009 and plans to build a 120 MMcfd cryogenic plant with a depropanizer by late 2009. It also is evaluating the addition of a fractionator.

The refrigeration plant represents Pennsylvania's first large-scale gas processing infrastructure, said Mark West and Marcellus gas producer Range Resources Corp., Fort Worth.

MarkWest is investing $200 million in facilities to gather and process gas that Range Resources is extracting from the Marcellus, and Range has invested more than $700 million in leases, drilling, and facilities in the past 4 years.

The refrigeration plant "signals the beginning of material natural gas production from the Marcellus shale formation," Range Resources said. The company plans to be producing 30 MMcfd by yearend 2008 and 80-100 MMcfd by yearend 2009.

Takreer moves ahead with Ruwais expansion

Abu Dhabi Oil Refining Co. (Takreer), an arm of state-owned Abu Dhabi National Oil Co. (ADNOC), has selected Honeywell unit UOP LLC to supply technology and engineering services for an expansion at the Ruwais refinery in the UAE.

The refinery will produce propylene, unleaded gasoline, naphtha, LPG, aviation turbine fuel, kerosine, gas oil, bunker fuel, and other products. Basic engineering design is currently in progress, and the refinery is expected to be complete in 2014.

Honeywell said the new facility will utilize "a wide range of UOP technologies for the production of clean, low-sulfur distillate and gasoline."

In July, Takreer selected Shaw Group's Energy & Chemicals Group to supply engineering services and licensing for its proprietary residue fluid catalytic cracking technology.

In addition to its RFCC technology, Shaw also will provide engineering services to integrate and coordinate 11 process units from other licensors at the site.

In February Takreer announced plans to more than double the capacity of the Ruwais facility to 817,000 b/d.

At the time Takreer general manger Jasem Ali al-Sayegh said the engineering and design study for the expansion should be completed by yearend 2008 or early 2009.

Refined products consumption in the UAE is set to rise about 4.5% this year, according to forecasts of analyst BMI, which also said, "Takreer sees the Ruwais expansion as one of its most important projects."

Ruwais produces light products mainly for export to Japan and elsewhere in Asia. Fuel oil is sold as bunkers by the ADNOC and also used for domestic electric power generation.

Once expanded, Ruwais will be integrated with a petrochemicals complex and an oil lubricants plant, due online in 2012 and currently under construction by Takreer along with joint venture partners Neste Oil and OMV.

PDVSA awards JGC modernization contract

Venezuela's state-owned Petroleos de Venezuela SA (PDVSA), as part of its on-going Siembra Petrolera plan, has signed an agreement with JGC Corp. to form a strategic alliance aimed at improving the country's refining capacity. In particular, the accord with JGC will foster the development of Venezuela's refining projects, especially those involving the conversion of heavy oil, according to Asdrubal Chavez, PDVSA refining, commerce, and supply vice-president.

JGC was involved in the construction of the Cerro Negro heavy crude upgrader in the Orinoco belt, and the Japanese firm also is completing basic engineering for an expansion at the Puerto La Cruz refinery.

The PDVSA announcement follows several earlier ones concerning financial arrangements for the projects.

In September, Venezuela said it signed a $1.2 billion loan with the Japanese Bank for International Cooperation.

According to Oil Minister Rafael Ramirez, who doubles as president of PDVSA, the loan will enable modernization of two refineries: at El Palito and Puerto La Cruz.

The amount of Japanese financing for the two projects is con-

siderably lower than PDVSA had earlier hoped for. In May, PDVSA made an unsuccessful bid for $3.5 billion in credit from Japan's Sumitomo Corp. and Itochu Corp. "For the expansion of the El Palito and Puerto La Cruz refineries we're using technology…for deep crude conversion. For this we need specialized equipment manufactured overseas, and that's why we've secured the Japanese company financing," Ramirez said at the time.

The hoped-for accord was similar to a $3.5 billion loan PDVSA obtained in February 2007 from Marubeni Corp. and Mitsui & Co. as an advanced payment for oil shipments to be made later in the year. The Japanese funds were provided to PDVSA via two special purpose companies established in the Netherlands by Marubeni and Mitsui: Yucpa Finance and Caribe Financing Co.

PDVSA was expected to repay that loan through sales cash flow generated by its crude oil and petroleum products. The first oil exports to Japan—20,000-30,000 b/d of oil and products—were expected to begin by mid-2007.

In July, Venezuela's El Universal newspaper reported that rising costs and rising oil prices had led PDVSA to "realign its Siembra Petrolera investment plan up to 2012."

According to information provided by PDVSA to Banco Central de Venezuela, the firm now plans to invest $78.116 billion in 2007-12, an increase of 40% over the $56 billion calculated for the same period in 2005.

The paper said that 2008 is "the main" year for investment within the plan, with a total outlay of $15.671 billion planned. That amount includes $4.102 billion for production, $3.91 billion for natural gas, and $2.276 billion for refining. ✦

Transportation — *Quick Takes*

Sakhalin-2 deliveries to start in early 2009

Shipments of LNG to Japan from the Sakhalin-2 project in far eastern Russia are expected to begin early next year, according to two Japanese partners in the project.

"We probably can start delivery in the first quarter," said a spokesman of Mitsubishi Corp., while one for Mitsui & Co. said "Construction work is more than 98% completed, so we will be able to start delivery early next year."

The Sakhalin Energy Investment Co. (SEIC) partners originally aimed to start delivery in 2008, but delayed the schedule to 2009 citing a shortage of resources. Russia also briefly froze the project, citing environmental problems, which contributed to the delay.

Earlier this month, Russian authorities visited the site and said it no longer posed any threat to the environment. "This project is exemplary from the point of view of the environment," said Russian Natural Resources Minister Yuri Trutnev after the inspection.

In September, Sakhalin Energy started to send natural gas from the Molikpaq offshore drilling platform to a gas processing facility on the coast of Sakhalin Island. It said gas would then be piped from the processing facility to its LNG plant on the island.

Since then, there have been new developments concerning the arrangement for ships to transport the LNG to markets.

In early October, the Japan Bank of International Cooperation (JBIC) joined the two banks already financing Sovcomflot's project to build two LNG tankers for the project.

In addition to JBIC, the consortium of creditor banks includes Mizuho Corporate Bank and Bayerische Landesbank. "JBIC's entry into the project will make it possible to optimize [the] financing expense for the borrowers," said Russia's state-owned Sovcomflot, which is constructing the ships along with NYK.

The two 145,000 cu m ships—the Grand Aniva and the Grand Yelena—are being financed by a $320 million loan for 12 years.

The loan is secured by earnings from the operation of the vessels under long-term contracts to deliver LNG to Japan, South Korea, and the US. The Grand Elena, built in 2007, and the Grand Aniva, built in 2008, were delivered on schedule from Mitsubishi Heavy Industries.

Both vessels have since been sublet to Taiwan Maritime Transport (TMT) in the interim year before the Sakhalin-2 project gets ready for start-up. Delivery of the third and final ship ordered by the Sakhalin partners, the 147,200-cu m Grand Mereya, is due this month after several delays.

The ship was originally listed as being due for handover from Japan's Mitsui Engineering & Shipbuilding Co. in April. Later, a date in May was given. In July, project officials said the vessel would be delivered in August.

"We are finally getting to the end of the technical problems," one MES official said. "The delays were caused by failure of the [ship's] low-duty boil-off gas compressors," he said.

Industry sources also suggested that SEIC was in no hurry to take delivery of the vessel, which it had planned to trade on the spot market until exports from the project start next year. In terms of exports, SEIC already has signed long-term supply contracts with Japanese, South Korean, and US buyers for nearly all of the LNG from the island's 9.6 million tonnes/year capacity plant.

More than 60% of that output will go to Japanese utilities firms including Tokyo Electric Power Co. and Tokyo Gas Co., accounting for 7.5% of Japan's total natural gas imports. The remainder of Sakhalin-2's output will be sold to the US and South Korea.

Pemex awards Ku-Maloob-Zaap pipeline contract

Petroleos Mexicanos (Pemex) has let a contract to Global Industries Ltd. for oil and natural gas pipeline work in Pemex's Ku-Maloob-Zaap field in the Bay of Campeche, which it had announced in July.

The project, worth about $46 million, is scheduled to begin in March 2009 and be completed by the end of July 2009. Global will utilize its Shawnee construction vessel as the main pipelaying vessel, with additional support vessels assisting.

Global will install two pipelines in water about 300 ft deep: 2.1 km of 24-in. line extending from PP-Maloob-C platform to PP-Ku-H platform, and ½-km of 12-in. from a subsea connection to the PP-Maloob-C. The project also includes pipeline crossings, risers, and expansion curves, the firm said.

Ku-Maloob-Zaap is one of Pemex's central projects for offsetting the natural decline at Cantarell field, which currently accounts for more than 40% of the company's output. ✦

Letters

Warming letter reply

You know you are being effective when people complain about you. The letter in the Sept. 8 issue of Oil & Gas Journal, though, followed an established formula, starting with an impugned association with the coal industry (OGJ, Sept. 8, 2008, p. 12).

A point by point refutation would be tedious, but I am compelled to say that neither I nor the Lavoisier Society has any association with or funding from the coal industry. I left the coal industry in 1980 to join the oil industry. Right now I am the very happy operator of oil exploration permits totaling 8.6 million acres of Palaeozoic intracratonic rift sediments in the Canning basin of northwestern Australia.

The oil industry in this country embraced global warming as a way of selling more natural gas to the power industry, displacing coal. That supping with the devil, though, has resulted in serious blowback, as the Australian government has undertaken to introduce carbon taxes which will severely impinge the LNG industry here.

At the same time, there is strong government support in Australia for expansion of the export coal industry, so that other countries can increase their carbon dioxide emissions.

A peer-reviewed paper of mine predicting a 2° C. decline in temperature next decade has been accepted for publication in January in a UK scientific journal. Previous papers of mine on the subject of climate are available on the Lavoisier website: "The Past and Future of Climate," "Failure to Warm," and "Solar Cycle 24: Implications for the United States." The web locations are:

http://www.lavoisier.com.au/articles/greenhouse-science/solar-cycles/Archibald2007.pdf

http://www.lavoisier.com.au/articles/greenhouse-science/solar-cycles/ArchibaldLavoisierAGM.pdf

http://www.lavoisier.com.au/articles/greenhouse-science/solar-cycles/ArchibaldMarch2008.pdf

David Archibald
Perth
david.archibald@westnet.com.au

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.

OCTOBER

AAPG International Conference & Exhibition, Cape Town, (918) 560-2679, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org. 26-29.

GPA Houston Midstream Conference, Houston (713) 222-0852, (713) 222-0858 (fax), e-mail: tom.rommel@accessed.com, website: www.gasprocessors.com. 28-29.

Gas to Liquids Conference, London, +44 (0) 20 7827 6000, +44 (0) 20 7827 6001 (fax), website: www.smi-online.co.uk/08gtl44.asp. 28-29.

Biofuels Conference, Berlin, +44 207 067 1800, +44 207 430 0552 (fax), e-mail: c.taylor@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 28-30.

SPE Russian Oil & Gas Technical Conference & Exhibition, Moscow, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 28-30.

Arab Oil & Gas Show, Dubai, +971 4 3355001, +971 4 3355141 (fax), e-mail: info@icedxb.com, website: www.ogsonline.com. 28-30.

Offshore Middle East Conference, Doha., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: http://ome08.events.pennnet.com/fl/index.cfm. 28-30.

IADC Contracts & Risk Management Conference, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 29-30.

NOVEMBER

Sulphur International Conference and Exhibition, Rome, +44 20 7903 2410, +44 20 7903 2432 (fax), e-mail: conferences@crugroup.com, website: www.sulphurconference.crugroup.com. 2-5.

ASME International Mechanical Congress & Exposition, Boston, (973) 882-1170, (973) 882-1717 (fax), e-mail: infocentral@asme.org, website: www.asme.org. 2-6.

Deepwater Operations Conference & Exhibition, Houston, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepwateroperations.com. 3-5.

Abu Dhabi International Petroleum Exhibition & Conference (ADIPEC), Abu Dhabi, +971 (0) 2 4444 909, +971 (0) 2 4444 383 (fax), e-mail: info@adipec.com, website: www.adipec.com. 3-6.

Purvin & Gertz Latin American LPG Seminar, Rio de Janeiro, (713) 331-4000, (832) 209-4451 (fax), e-mail: ts@prvingertz.com, website: www.purvingertz.com. 3-6.

North African Oil and Gas Summit, Vienna, +44 (0) 207 067 1800, +44 207 430 0552 (fax), e-mail: c.brown@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk/nas3register.html. 4-6.

Mangystau International Oil & Gas Exhibition, Aktau, + (44) 020 7596 5000, + (44) 020 7596 5111 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 5-7.

GPA North Texas Annual Meeting, Dallas, (918) 493-3872, (918) 493-3875 (fax), email: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 6.

GITA's GIS Annual Oil & Gas Conference, Calgary, (303) 337-0513, (303) 337-1001 (fax), e-mail: info@gita.org, website: www.gita.org/ogca. 6-7.

IADC Annual Meeting, Paradise Valley, Ariz., (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 6-7.

SEG International Exposition and Annual Meeting, Las Vegas, (918) 497-5542, (918) 497-5558 (fax), e-mail: register@seg.org, website: www.seg.org. 9-14.

IPAA Annual Meeting, Houston, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 10-12.

Houston Energy Financial Forum, Houston, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.accessanalyst.net. 11-13.

Financial Modelling in the Oil and Gas Industry Conference, London, +44 (0) 20 7827 6000, +44 (0) 20 7827 6001 (fax), website: www.smi-online.co.uk/oilgasmodelling38.asp. 12-13.

American Institute of Chemical Engineers (AIChE) Annual Meeting, Philadelphia, (212) 591-8100, (212) 591-8888 (fax), website: www.aiche.org. 16-21.

ERTC Annual Meeting, Vienna, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 17-19.

Annual Houston Energy Financial Forum, Houston, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.accessanalyst.net. 18-20.

Annual European Autumn Gas Conference (EAGC), Cernobbio, Italy, +44 (0) 1737 855281, +44 (0) 1737 855482 (fax), e-mail: vanessahurrell@dmgworldmedia.com, website: www.theeagc.com. 25-26.

DECEMBER

IADC Well Control Middle East Conference & Exhibition, Muscat, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 2-3.

Annual Refining & Petrochemicals in Russia and the CIS Countries Roundtable, Prague, +44 207 067 1800, +44 207 430 0552 (fax), e-mail: e.polovinkina@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 2-4.

Downstream Asia Refining & Petrochemicals Conference, Singapore, +44 (0) 207 067 1800, +44 207 430 0552 (fax), e-mail: a.ward@theenergyexchange.co.uk, website: www.wraconferences.com/FS1/dalregister.html. 3-4.

IADC Drilling Gulf of Mexico Conference & Exhibition, Galveston, Tex., (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 3-4.

Deep Offshore Technology International Asia/Pacific Conference & Exhibition, Perth, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepoffshoretechnology.com. 3-5.

Calendar

International Petroleum Technology Conference (IPTC), Kuala Lumpur, +971 (0)4 390 3540, +971 (0)4 366 4648 (fax), e-mail: iptc@iptcnet.org, website: www.iptcnet.org. 3-5.

USAEE/IAEE North American Conference, New Orleans, (216) 464-2785, (216) 464-2768 (fax), website: www.usaee.org. 3-5.

PIRA Natural Gas Markets Conference, New York, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 8-9.

PIRA Understanding Global Oil Markets Conference, New York, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 10-11.

Seatrade Middle East Maritime Conference & Exhibition, Dubai, +44 1206 545121, +44 1206 545190 (fax), e-mail: events@seatrade-global.com, website: www.seatrade-middleeast.com. 14-16.

SPE Progressing Cavity Pumps Conference, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 27-29.

2009

JANUARY

Petrotech International Oil & Gas Conference & Exhibition, New Delhi, +91 11 2436 4055, +91 11 2436 0872 (fax), e-mail: convenor_petrotech@iocl.co.in, website: www.petrotech2009.org/registration.aspx. 11-15.

Oil & Gas Maintenance Technology Conference & Exhibition, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: attendingOGMT@pennwell.com, website: www.oilandgas-maintenance.com. 19-21.

Pipeline Rehabilitation & Maintenance Conference, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: attendingOGMT@pennwell.com, website: www.pipeline-rehab.com. 19-21.

SPE Hydraulic Fracturing Technology Conference, The Woodlands, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 19-21.

World Future Energy Summit, Abu Dhabi, +971 2 444 6011, +971 2 444 3987 (fax), e-mail: sales@turretme.com, website: www.worldfutureenergysummit.com. 19-21.

API Exploration & Production Winter Standards Meeting, San Antonio, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 19-23.

API/AGA Oil and Gas Pipeline Welding Practices Conference, San Antonio, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 21-23.

International Process Analytical Technology Forum (IFPAC), Baltimore, (847) 543-6800, (847) 548-1811 (fax), e-mail: info@ifpacnet.org, website: www.ifpac.com. 25-28.

Global E&P Summit, Madrid, +44 (0)20 7202 7500, +44 (0)20 7202 7600 (fax), e-mail: info@wtgevents.com, website: www.epsummit.com. 26-28.

Offshore West Africa Conference, Abuja, (918) 831-9160, (918) 831-9161 (fax), e-mail: attendOWA@pennwell.com, website: www.offshorewestafrica.com. 27-29.

The European Gas Conference, Vienna, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 27-29.

SIHGAZ International Hydrocarbon & Gas Fair, Hassi Messaoud, + 213 21 21 58 74, + 213 21 21 58 72/76 (fax), e-mail: contact@foirex.com, website: www.sihgaz2009.com. 28-31.

FEBRUARY

SPE Reservoir Simulation Symposium, The Woodlands, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 2-4.

IADC Health, Safety, Environment & Training Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 3-4.

Deep Offshore Technology International Conference & Exhibition (DOT), New Orleans, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.dotinternational.net. 3-5.

Global Petrochemicals Conference & Annual Meeting, Cologne, +44 (0) 1242 529 090. +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 3-5.

Russia Offshore Annual Meeting, Moscow, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 4-6.

NAPE Expo, Houston, (817) 847-7700, (817) 847-7704 (fax), e-mail: info@napeexpo.com, website: www.napeonline.com. 5-6.

Pipeline Pigging & Integrity Management Conference, Houston, (713) 521-5929, (713) 521-9255 (fax), e-mail: clarion@clarion.org, website: www.clarion.org. 9-12.

SPE Unconventional Fields Conference, Margarita Island, Venezuela, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 10-12.

Pipe Line Contractors Association Annual Conference (PLCA), Carlsbad, Calif., (214) 969-2700, e-mail: plca@plca.org, website: www.plca.org. 11-15.

IADC/SPE Managed Pressure Drilling & Underbalanced Operations Conference & Exhibition, San Antonio, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 12-13.

International Petrochemicals Technology Conference & Exhibition, London, +44 (0) 20 7357 8394, +44 (0) 20 7357 8395 (fax), e-mail: enquiries@europetro.com, website: www.europetro.com. 16-17.

IP Week, London, +44 (0)20 8561 6030, +44 (0)20 8561-0131 (fax), e-mail: events@energyinst.org.uk, website: www.energyinst.org.uk. 16-19.

International Downstream Technology & Catalyst Conference & Exhibition, London, +44 (0) 20 7357 8394, +44 (0) 20 7357 8395 (fax), e-mail: enquiries@europetro.com, website: www.europetro.com. 18-19.

ASEG/PESA International Geophysical Conference & Exhibition, Adelaide, +61 8 8352 7099, +61 8 8352 7088 (fax), e-mail: ASEG2009@sapro.com.au, website: www.sapro.com.au/aseg.htm. 22-25.

Laurance Reid Gas Conditioning Conference, Norman, Okla., (405) 325-2248, (405) 325-7164 (fax), e-mail: bettyk@ou.edu, website: www.engr.outreach.ou.edu. 22-25.

Nitrogen + Syngas International Conference and Exhibition, Rome, +44 20 7903 2167, +44 20 7903 2432 (fax), e-mail: conferences@crugroup.com, website: http://crugroup.com. 22-25.

International Pump Users Symposium, Houston, (979) 845-7417, (979) 847-9500 (fax), e-mail: inquiry@turbo-lab.tamu.edu, website: http://turbolab.tamu.edu. 23-26.

MARCH

EAGE North African/Mediterranean Petroleum and Geosciences Conference & Exhibition, Tunis, +31 88 995 5055, +31 30 6343524 (fax), e-mail: eage@eage.org, website: www.eage.org. 2-4.

SPE Research & Development Conference, Lisbon, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 3-4.

APPEX Prospect and Property Expo, London, (918) 560-2616, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org. 3-5.

Subsea Tieback Forum & Exhibition, San Antonio, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.subseatiebackforum.com. 3-5.

GPA Annual Convention, San Antonio, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 8-11.

Doha Natural Gas Conference & Exhibition, Doha, e-mail: gascon@qp.com.qa, website: www.dohagascon.com.qa. 9-12.

ARTC Annual Meeting, Kuala Lumpur, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 10-12.

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. 10-12.

Turkish International Oil & Gas Conference & Showcase (TUROGE), Ankara, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 10-12.

Middle East Oil & Gas Show & Conference (MEOS), Manama, +973 17 550033, +973 17 553288 (fax), e-mail: aeminfo@batelco.com.bh, website: www.allworldexhibitions.com/oil. 15-18.

Annual International LPG Seminar, The Woodlands, Tex., (281) 367-9797, website: www.purvingertz.com. 16-19.

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. 17-18.

SPE/IADC Drilling Conference & Exhibition, Amsterdam, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website; www.spe.org. 17-19.

Latin American Meeting on Energy Economics, Santiago, 56 2 3541411, 56 2 5521608 (fax), e-mail: info@elaee.org, website: www.elaee.org. 22-24.

NPRA Annual Meeting, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 22-24.

ACS Spring National Meeting & Exposition, Salt Lake City, (202) 872-4600, e-mail: service@acs.org, website: www.acs.org. 22-26.

NACE Corrosion Conference & Expo, Atlanta, (281) 228-6200, (281) 228-6300 (fax), website: www.nace.org/c2009. 22-26.

PIRA Understanding Global Oil Markets Seminar, Dubai, 65 6581 4122, e-mail: jay@pira.com, website: www.pira.com. 23-24.

SPE Americas E&P Environmental and Safety Conference, San Antonio, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website; www.spe.org. 23-25.

API Spring Petroleum Measurement Standards Meeting, Dallas, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 23-26.

Asian Biofuels Roundtable, Kuala Lumpur, +44 (0) 207 067 1800, +44 207 430 0552 (fax), e-mail: a.ward@theenergyexchange.co.uk, website: www.wraconferences.com/FS1/AB1register.html. 24-25.

SPE Western Regional Meeting, San Jose, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website; www.spe.org. 24-26.

Offshore Mediterranean Conference & Exhibition (OMC), Ravenna, +39 0544 219418, +39 0544 39347 (fax), e-mail: conference@omc.it, website: www.omc2009.it. 25-27

NPRA International Petrochemical Conference, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 29-31.

Petroleum Geology Conference, London, +44 (0)20 7434 9944, +44 (0)20 7494 0579 (fax), e-mail: georgina.worrall@geolsoc.org.uk, website: www.geolsoc.org.uk. Mar. 30-Apr. 2.

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. Mar. 31-Apr. 1.

Offshore Asia/Multiphase Pumping & Technologies Conference & Exhibition, Bangkok, 918) 831-9160, (918) 831-9161 (fax), e-mail: attendingOA@pennwell.com, website: www.offshoreasiaevent.com. Mar. 31-Apr. 2.

APRIL

Georgian International Oil, Gas, Energy and Infrastructure Conference & Showcase (GIOGIE), Tbilisi, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 2-3.

SPE Production and Operations Symposium, Oklahoma City, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 4-8.

ATYRAU Regional Oil & Gas Exhibition & OilTech Kazakhstan Petroleum Technology Conference, Atyrau, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 7-9.

Calendar

GPA Mid-continent Annual Meeting, Oklahoma City, (918) 493-3872, (918) 493-3875 (fax), website: www.gasprocessors.com. 16.

ERTC Coking & Gasification Conference, Budapest, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 20-22.

Pipeline Technology Tradeshow, Hannover, +49 511 89 31240, +49 511 89 32626 (fax), website: www.hannovermesse.de. 20-24.

IADC Drilling HSE Middle East Conference & Exhibition, Abu Dhabi, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 21-22.

API Pipeline Conference, Fort Worth, Tex., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 21-22.

Base Oils and Lubricants in Russia & CIS Conference, Moscow, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 22-23.

Instrumentation Systems Automation Show & Conference, (ISA), Calgary, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 22-23.

CPS/SEG International Geophysical Conference & Exposition, Beijing, (918) 497-5500, (918) 497-5557 (fax), e-mail: semery@seg.org, website: www.seg.org. 24-27.

AIChE Spring National Meeting, Tampa, (203) 702-7660, (203) 775-5177 (fax), website: www.aiche.org. 26-30.

API Spring Refining and Equipment Standards Meeting, Denver, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 27-29.

EAGE European Symposium on Improved Oil Recovery, Paris, +31 88 995 5055, +31 30 6343524 (fax), e-mail: eage@eage.org, website: www.eage.org. 27-29.

ENTELEC Conference & Expo, Houston, (972) 929-3169, (972) 915-6040 (fax), e-mail: blaine@entelec.org, website: www.entelec.org. Apr. 29-May 1.

MAY

EAGE International Petroleum Conference & Exhibition, Shiraz, +31 88 995 5055, +31 30 6343524 (fax), e-mail: eage@eage.org, website: www.eage.org. 4-6.

Offshore Technology Conference (OTC), Houston, (972) 952-9494, (972) 952-9435 (fax), e-mail: service@otcnet.org, website: www.otcnet.org. 4-7.

GPA Permian Basin Annual Meeting, Austin, (918) 493-3872, (918) 493-3875 (fax), website: www.gasprocessors.com. 5.

Interstate Oil and Gas Compact Commission Midyear Meeting (IOGCC), Anchorage, (405) 525-3556, (405) 525-3592 (fax), e-mail: iogcc@iogcc.state.ok.us, website: www.iogcc.state.ok.us. 10-12.

ERTC Asset Maximisation Conference, Prague, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 11-13.

ACHEMA International Exhibition Congress, Frankfurt, +1 5 168690220, +1 5 168690325 (fax), e-mail: amorris77@optonline.net, website: http://achemaworldwide.dechema.de. 11-15.

IADC Environmental Conference & Exhibition, Stavanger, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 12-13.

North American Unconventional Oil & Gas Conference & Exposition, Denver, (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 12-13.

NPRA National Safety Conference, Grapevine, Tex., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 12-13.

International School of Hydrocarbon Measurement, Norman, Okla., (405) 325-1217, (405) 325-1388 (fax), e-mail: lcrowley@ou.edu. Website: www.ishm.info. 12-14.

Uzbekistan International Oil & Gas Exhibition & Conference, Tashkent, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 12-14.

NPRA Reliability & Maintenance Conference, Grapevine, Tex., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 19-22.

IADC Drilling Onshore Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 21.

Gastech International Conference & Exhibition, Abu Dhabi, +44 (0) 1737 855000, +44 (0) 1737 855482 (fax), website: www.gastech.co.uk. 25-28.

APPEA Conference & Exhibition, Darwin, +61 7 3802 2208, e-mail: jhood@appea.com.au. website: www.appea2009.com.au. May 31-Jun. 3.

SPE Latin American and Caribbean Petroleum Engineering Conference, Cartagena, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. May 31-Jun. 3.

JUNE

Caspian International Oil & Gas/Refining & Petrochemicals Exhibition & Conference, Baku, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 2-5.

Asia Oil & Gas Conference, Kuala Lumpur, 65 62220230, 65 62220121 (fax), e-mail: info@cconnection.org, website: www.cconnection.org. 7-9.

AAPG Annual Meeting, Denver, (918) 560-2679, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org. 7-10.

ILTA Annual International Operating Conference & Trade Show, Houston, (202) 842-9200, (202) 326-8660 (fax), e-mail: info@ilta.org, website: www.ilta.org. 8-10.

SPE EUROPEC/EAGE Conference and Exhibition, Amsterdam, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 8-11.

PIRA Understanding Global Oil Markets Seminar, Houston, (212) 686-6808, (212) 686-6628 (fax), website: www.pira.com. 9-10.

GO-EXPO Gas and Oil Exposition, Calgary, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 9-11.

Petro.t.ex Africa Exhibition & Conference, Johannesburg, +27 21 713 3360, +27 21 713 3366 (fax), website: www.fairconsultants.com. 9-11.

Oil and Gas Asia Exhibition (OGA), Kuala Lumpur, +60 (0) 3 4041 0311, +60 (0) 3 4043 7241 (fax), e-mail: oga@oesallworld.com, website: www.allworldexhibitions.com/oil. 10-12.

ASME Turbo Expo, Orlando, (973) 882-1170, (973) 882-1717 (fax), e-mail: infocentral@asme.org, website: www.asme.org. 13-17.

Society of Petroleum Evaluation Engineers (SPEE) Annual Meeting, Santa Fe, NM, (713) 286-5930, (713) 265-8812 (fax), website: www.spee.org. 14-16.

IPAA Midyear Meeting, Dana Point, Calif., (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 15-17.

Atlantic Canada Petroleum Show, St. John's, Newfoundland & Labrador, 403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 16-17.

IADC World Drilling Conference & Exhibition, Dublin, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 17-18.

PIRA Understanding Global Oil Markets Seminar, London, 44 1493 751 316, e-mail: miles@pira.com, website: www.pira.com. 17-18.

AAPL Annual Meeting, Clearwater Beach, Fla., (817) 847-7700, (817) 847-7704 (fax). e-mail: aapl@landman.org, website: www.landman.org. 17-20.

IAEE International Conference, San Francisco, (216) 464-2785, (216) 464-2768 (fax), website: www.usaee.org. 21-24.

Society of Professional Well Log Analysts Annual Symposium (SPWLA), The Woodlands, Tex., (713) 947-8727, (713) 947-7181 (fax), website: www.spwla.org. 21-24.

SPWLA Annual Symposium, The Woodlands, Tex., (713) 947-8727, (713) 947-7181 (fax), e-mail: webmaster@spwla.org, website: www.spwla.org. 21-24.

International Offshore and Polar Engineering Conference (ISOPE), Osaka, (650) 254-1871, (650) 254-2038 (fax), e-mail: meetings@isope.org, website: www.isope.org. 21-26.

Asia LPG Seminar, Singapore, (713) 331-4000. (713) 236-8490 (fax), website: www.purvingertz.com. 22-25.

API Exploration & Production Standards Oilfield Equipment and Materials Conference, Westminister, Colo., (202) 682-8000, (202)

682-8222 (fax), website: www.api.org. 22-26.

Moscow International Oil & Gas Exhibition (MIOGE) & Russian Petroleum & Gas Congress, Moscow, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 23-26.

JULY

Rocky Mountain Energy Epicenter Conference, Denver, (303) 228-8000, e-mail: conference@epicenter2008.org, website: www.denvercon-vention.com. 7-9.

API Offshore Crane Operations and Safety Conference, Houston, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 14-15.

Oil Sands and Heavy Oil Technologies Conference & Exhibition, Calgary, Alta., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: http://oshot09.events.pennnet.com/fl/index.cfm. 14-16.

AUGUST

SPE Asia Pacific Health, Safety, Security and Environment Conference and Exhibition, Jakarta, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 4-6.

SPE Asia Pacific Oil and Gas Conference and Exhibition, Jakarta, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 4-6.

ACS Fall National Meeting & Exposition, Washington, (202) 872-4600, e-mail: service@acs.org, website: www.acs.org. 16-20.

IADC Well Control Conference of the Americas & Exhibition, Denver, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 25-26.

Summer NAPE, Houston, (817) 847-7700, (817) 847-7704 (fax), e-mail: info@napeexpo.com, website: www.napeonline.com. 27-28.

SEPTEMBER

EAGE Near Surface European Meeting, Dublin, +31 88 995 5055, +31 30 6343524 (fax), e-mail: eage@eage.org, website: www.eage.org. 7-9.

IAEE European Conference, Vienna, (216) 464-5365, e-mail: iaee@iaee.org, website: www.iaee.org. 7-10.

Offshore Europe Conference, Aberdeen, +44 (0) 20 7299 3300, e-mail: nbradbury@spe.org, website: www.offshore-europe.co.uk. 8-11.

GITA's GIS Annual Oil & Gas Conference, Houston, (303) 337-0513, (303) 337-1001 (fax), e-mail: info@gita.org, website: www.gita.org/ogca. 14-16.

Polar Petroleum Potential 3P Conference, Moscow, (918) 584-2555, (918) 560-2665 (fax), website: www.aapg.org. 16-18.

ADC Drilling HSE Europe Conference & Exhibition, Amsterdam, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 23-24.

SPE Eastern Regional Meeting, Charleston, W.Va., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 23-25.

ERTC Sustainable Refining Conference, Brussels, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 28-30.

Unconventional Gas International Conference & Exhibition, Fort Worth, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.unconventional-gas.net. Sept. 29-Oct. 1.

ERTC Biofuels+ Conference, Brussels, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. Sept. 30-Oct. 2.

OCTOBER

Interstate Oil and Gas Compact Commission Annual Meeting (IOGCC), Biloxi, Miss., (405) 525-3556, (405) 525-3592 (fax), e-mail: iogcc@iogcc.state.ok.us, website: www.iogcc.state.ok.us. 4-6.

SPE Annual Technical Conference and Exhibition, New Orleans, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 4-7.

ISA EXPO, Houston, (919) 549-8411, (919) 549-8288 (fax), e-mail: info@isa.org, website: www.isa.org. 6-8.

Kazakhstan International Oil & Gas Exhibition & Conference (KIOGE), Almaty, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 6-9.

API Fall Petroleum Measurement Standards Meeting, Calgary, Alta., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 12-15.

International Oil & Gas Exploration, Production & Refining Exhibition, Jakarta, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: ogti@oesallworld.com, website: www.allworldexhibitions.com. 14-17.

SPE/EAGE Reservoir Characterization and Simulation Conference and Exhibition, Abu Dhabi, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 18-21.

GSA Annual Meeting, Portland, (303) 357-1000, (303) 357-1070 (fax), e-mail: meetings@geosociety.org, website: www.geosociety.org. 18-21.

GSA Annual Meeting, Portland, (303) 357-1000, (303) 357-1070 (fax), e-mail: meetings@geosociety.org, website: www.geosociety.org. 18-21.

SEG International Exposition and Annual Meeting, Houston, (918) 497-5500, (918) 497-5557 (fax), e-mail: register@seg.org, website: www.seg.org. 25-30.

Journally Speaking

Musings on 'M'

Warren R. True
Chief Technology Editor-LNG/Gas Processing

Symbology is a big word that refers to a simple process—a shorthand of symbols or abbreviations to stand for longer words, phrases, concepts, calculations, and so forth. Symbols let us communicate economically with others who either are familiar with them or can tease out their meanings.

As do all industries, the oil and gas industry has its own symbols. Oil & Gas Journal has adopted most of them. It does not explain b/d, fph, or psia because editors assume readers (of OGJ) will understand the abbreviation, indeed even mentally say "barrels per day."

But all linguistic symbols arise and evolve just as language has, just as any organism in nature has and does. That evolution, however, often follows a logic that sometimes may be illogical. That's because humans invented it.

Some of us see problems with a certain untidiness in our industry's symbology. Enter retired geologist Chuck Norman. Trained at the California Institute of Technology and then at the Massachusetts Institute of Technology, he spent more than 25 years helping Conoco find oil and gas.

Norman believes industry's sloppy use of symbolic "m," "M," and "MM," and all the combinations with each other and with other letters, threatens understanding in writing and accuracy in conversions. In fact, he wants to jettison the Roman numeral "M" (meaning thousand) in favor of the widely used and rarely misunderstood "k"—also meaning thousand.

The meaning of M

Norman's concern has had him culling publications in his industry for examples of confusing or erroneous use, specifically the AAPG Explorer and the Houston Geological Society Bulletin. These are no dry academic tomes but among the most important publications for active geologists.

In them, Norman has found "MMcfg/d," "Mmcf/d," "mmcfd," as well as several instances in which mcf clearly means million—not thousand—cubic feet. He has found "MMBOE," "MMBO," as well as "mmbo."

In more recent issues, in which both metric and English units appear side by side, Norman has identified apparent mathematical errors resulting from authors' confusing use (or understanding) of various forms of M. He will present his argument in the November 2008 issue of the HGS Bulletin.

And it's a convincing argument. Such inconsistencies irritate and distract readers even if calculations don't always suffer because of them.

How does OGJ fare under Norman's scrutiny?

In OGJ, readers find Mcf for "thousand cubic feet," but also find kg, kv, and kw. For "million," they find MMcf, MMbtu, and Mw. And they find m for "milli": ma, md, mg, ml, and ms.

Confused? Probably not, and the reason lies in the editing.

That's because a style manual, unique to OGJ, guides all OGJ editors. It tries to anticipate all stylistic, grammatical, and mechanical questions in order to impose rigorous consistency on OGJ's editorial pages.

OGJ editors spend hours each week pouring over manuscripts and proof pages, changing numerous style and symbol systems into something readers recognize as "OGJ Style." Along with its distinctive type font and page layout, that consistency expresses OGJ's identity.

With all due respect to AAPG and HGS, more consistent and rigorous editing—whatever the abbreviations—would probably go a long way toward mollifying Norman and those who have joined his campaign.

But from what source do these inconsistencies come?

Back to evolution

With apologies for the lecture, please hear me out:

Language that people use—and that moves from geographic place to place, from one cultural and economic environment to another—is going to change. If it changes enough, it's going to become another language. This process has governed every language humans have used for at least 50,000 years, according to people who know a lot more about it than I do.

Latin—a language no one uses any more—died; it stopped changing. In its place sprang Italian, Spanish, French, Romanian, and Portuguese. These in turn further evolved under linguistic and cultural influences: Think what French did for English, Arabic for Spanish.

But there's a curious modern twist. Species and languages have always evolved toward variety. Under the current pervasive influence of worldwide communications, the various symbologies of the oil and gas industry are moving in the opposite direction: They are consolidating.

Norman's effort is an element in that movement, as is the global influence of OGJ's use of industry symbology. ✦

Insurance
Risk Management

Zurich HelpPoint

One global insurance program for your expanding business. Even for places you've never been.

Zurich HelpPoint is here when you need more than just insurance. So we offer the Zurich Multinational Insurance Proposition (MIP)*. It helps you keep global insurance programs compliant when you expand your business to a new market and expose yourself to new risks. The strength of Zurich MIP lies in a transparent and thorough set of solutions for writing and maintaining global insurance programs in over 170 countries. Our game-changing solution can help you sleep better at night, no matter the time zone. For more details about *Zurich HelpPoint*, visit www.zurich.com

Here to help your world.

ZURICH®

Because change happenz℠

In the United States, coverages are underwritten by member companies of Zurich in North America, including Zurich American Insurance Company. Certain coverages not available in all states. Some coverages may be written on a non-admitted basis through licensed surplus lines brokers. Risk engineering services are provided by Zurich Services Corporation.* patent pending.

Editorial

Makings of a new mess

A sobering aspect of the global financial crisis is comprehensive failure of officials and experts, first, to see the problem coming and, next, to appreciate its severity until full-blown calamity was at hand. Well into 2008, US officials were providing assurances that financial troubles could be confined to the mortgage industry. Then, one after another, venerable financial institutions run by the industry's brightest minds began in various ways to topple, their previously hidden vulnerabilities suddenly on shocking display.

Among multiple shortcomings contributing to the fiasco is one that festered at the core of earlier, less-sweeping financial breakdowns. It's the inability of modern, sophisticated risk management adequately to manage risk. The spectacular collapses of enterprises like Metalgesellschaft, Barings Bank, and Enron had in common the loss of control over risk amid aggressive trading of complex derivative instruments. This time, the failure didn't confine itself to a single institution. It's systemic. And it may yet undermine the global economy.

New market

Against this background, the US soon may create a massive derivatives market with no commercial foundation. The government will determine the underlying value of the traded instruments. Rules will be complex. Trading will be hard for anyone but traders to understand.

Current events provide no reason for confidence that the government can effectively administer a synthetic market such as this or that industry can manage risks within it. That such a monstrosity is even under discussion defies belief. But so does much that flows from popular anxiety over global warming.

Both presidential candidates propose "cap-and-trade" schemes to limit emissions of the gases thought to aggravate observed warming. The programs would set emission caps and provide for the trading of emission allowances, the supply of which the government would control. The main difference between the candidates' proposals is the ultimate target. Sen. John McCain (R-Ariz.) wants emissions to be 60% below 1990 levels by 2050. Sen. Barack Obama (D-Ill.) wants the reduction over that period to be 80%.

Like anyone who has proposed a cap-and-trade response to climate change, the candidates promote their ideas as market-based strategies able to capitalize on technical ingenuity. Their programs are in fact highly prescriptive and very complex, enforcing staged reductions in emissions by phasing down over time the availability of emissions allowances. Two features are important: the creation of a market for emissions allowances, or "offsets," and limits on emissions of greenhouse gases.

The prospective market's size depends on the value of allowances, which depends greatly on regulatory details such as whether buyers can hold allowances for future use. An allowance value of $25/tonne of carbon dioxide-equivalent is a reasonable guess. At that value and at current emission levels, allowance trading could be worth a tantalizing $150 billion/year. It's enough to inspire considerable risk-taking, corruption of regulators and lawmakers, and surely some measure of the type of accounting deception that camouflaged the housing-credit mess. And it all will serve an activity that produces nothing of genuine economic value.

House of horrors

Why would anyone propose to build another financial house of horrors?

The answer is simple and troubling: Cap-and-trade systems mask the inescapable and inescapably large costs of global-warming responses. However they're achieved, emission cuts replace low-cost with high-cost energy. A market for allowances can in no way assuage the consequent economic harm and might, by diverting resources to the pursuit of trading profits unrelated to real goods and services, make things worse. Supporters of cap-and-trade schemes say new businesses related to nonfossil energy would offset the damage. Given the subsidies needed to bring alternatives to market, not to mention the effects on consumers forced to pay more for energy, that assertion is delusional.

In the perilous second half of 2008, a cap-and-trade remedy for global warming should be unthinkable. If there must be warming response, the people forced to pay the bill—that is, all who consume energy and pay taxes—deserve an honest view of the cost. In the perilous second half of 2008, new economic hazard is not something politicians should paper over with program tricks. ✦

Economics on Fischer-Tropsch coal-to-liquids method updated

Ken K. Robinson
David F. Tatterson
Mega-Carbon Co.
St. Charles, Ill.

Montana's Crow Nation and Australian-American Energy Co. reported in August that they will jointly construct a $7 billion coal-to-liquid (CTL) fuels plant in southeastern Montana. Plans for the plant were unveiled Aug. 8, with 2016 announced as the likely date for the start of production at the plant.

CTL seems to present an ideal scenario for coal, utility, and petroleum companies to work together. Utility companies want to turn coal into electricity, while coal companies seek to expand their market from solely electric power generation to liquid hydrocarbon conversion, and petroleum companies can use the carbon dioxide (CO_2) produced for enhanced oil recovery (EOR).

The economic incentives of using coal with green technology to make electricity and transportation fuel was explained in the OGJ, Feb. 26, 2007, article, "Fischer-Tropsch oil-from-coal promising as transport fuel."[1] Specifically, the method couples the integrated gasification combined cycle (IGCC) process with Fischer-Tropsch syngas conversion to develop an advantageous, green CTL system from pairing the two technologies.

New economic conditions

However, much has happened since that economic analysis. Crude oil prices ramped up to more than $140/bbl from about $60/bbl, while plant construction prices escalated greatly as well—although not quite to the degree of crude oil.

Furthermore, CO_2 can now be valued higher because its use in EOR floats with the value of crude oil. Originally $1/Mcf, it recently commanded a price as high as $5/Mcf. IGCC investment costs also have risen—to $2,000-3,000/kw capacity from $1,400/kw capacity.

This article presents the best and worst-case scenarios for CTL based on recent economic conditions. The best-case scenario includes oil valued at $135/bbl, investment costs for IGCC increased to $2,000/kw capacity from $1,400, and CO_2 valued at $5/Mcf. The worst-case scenario has oil valued at $75/bbl, investment costs at $3,000/kw capacity and CO_2 valued at $2/Mcf. The cost for the Fischer-Tropsch section of the IGCC plant was scaled by the same amount.

The economics shown in Table 1 illustrate that a huge increase in capital costs was offset by higher crude oil prices. Specifically, the discounted cash flow (DCF) rate of return increased to 27% for the best-case scenario from the original 15% (Case 3 in the February 2007 article), and it dropped only slightly—to 12%—for the worst-case scenario.

The announcement of the Crow Nation-Australian-American Energy Co. Montana CTL project is evidence that this clean technology merits serious consideration for future energy projects, particularly when the coproduced CO_2 can be used for EOR.

IGCC plant operations

In a typical IGCC plant, coal is first gasified to synthesis gas—hydrogen and carbon monoxide (CO). The synthesis

BEST, WORST CASE COAL-TO-LIQUIDS ROI SCENARIOS

Table 1

Scenario	Coal, tons/day	Diesel, b/d	Electricity, Mw	CO_2, MMscfd	CO_2 value, $/Mcf	Crude oil price, $/bbl	Capital investment, billion $	DCF* rate of return, %
Best	10,733	4,428	525	273	5	135	1.603	27
Worst	10,733	4,428	525	273	2	75	2.404	12

*Discounted cash flow.

gas is scrubbed to remove acid gases and mercury. The synthesis gas is then burned in the combustion turbine, and the hot exhaust is used to raise steam to drive a second turbine. Both turbines produce electricity, with the thermal efficiency increasing to 40% for combined-cycle operation from 33% for a direct-fired coal unit.

If the synthesis gas is passed through a water gas shift converter before reaching the turbines, the CO converts to CO_2 and hydrogen. The CO_2 can then be scrubbed, providing a hydrogen-rich stream to the turbines. This is an "ultra-green" scenario because there is very little CO_2 emitted from the power plant. CO_2 cannot be eliminated entirely because some CO must be left in the feed to the power plant for flame stability. The figure shows the process flow for converting coal to electricity and liquid hydrocarbons.

With newer technologies, such as IGCC, coal conversion is an environmentally friendly process. Pollutants such as mercury, sulfur oxides (SOx), and oxides of nitrogen (NOx) are essentially eliminated because coal gasification instead makes hydrogen sulfide and ammonia, and these easily can be removed in acid gas scrubbers. CO_2 also can be captured and sequestered. If oil fields are nearby and responsive to CO_2 flooding for EOR, then CO_2 can provide a significant income stream.

Clean coal benefits

Although most people deem coal to be a "dirty" fuel, it can easily be cleaned. Its bad reputation is grounded in its use for many years in direct-burning power plants. It is unfortunate that opposition to coal as part of the solution for US energy needs is based on this older, direct coal burning technology rather than IGCC, which makes an electric power generation facility more like a chemical plant than a coal-fired plant with a tall smoke stack.

With IGCC, coal conversion can be a green technology; the plant can easily capture CO_2 from the oxygen-blown coal gasifier because the offgas is not diluted with nitrogen. The CO_2 can then be injected into the ground and stored.

In addition, the CO_2 produced in the CTL process has tremendous potential for EOR use if a mature, light-oil field is nearby. These synergies suggest that the coal and petroleum industries should cooperate to enable green coal technology to be exploited to increase oil production via EOR.

Benefits of this technology for the US can be enormous because US coal reserves are huge, representing 27% of the total world supply. Consequently this energy resource deserves serious consideration. Coal from the states of Montana, Illinois, and Wyoming alone could be converted, via Fischer-Tropsch syngas conversion, to 300 billion bbl of diesel fuel.

And CTL technology is already off the shelf. Sasol in South Africa is producing 160,000 b/d with this technology, so it is not an immature, undeveloped process.[2]

Enhanced oil recovery

In this economic analysis, CO_2 production during the CTL process represents a major revenue stream that can offset some of the project's investment costs. Currently CO_2 for EOR commands a price of $1-5/Mcf. Because it takes roughly 5 Mcf of CO_2 injection to produce 1 bbl of oil, the price of CO_2 will continue to rise correspondingly as oil becomes more valuable.

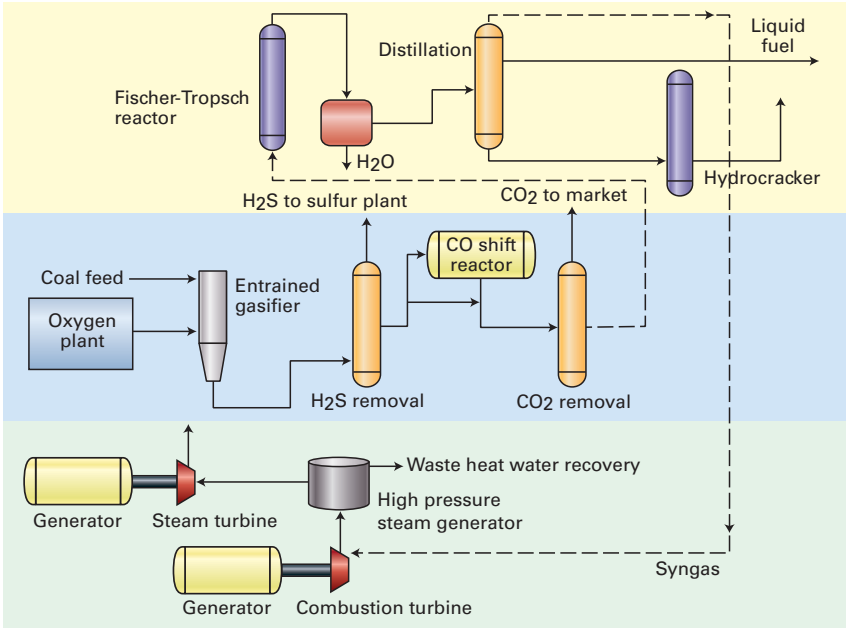
Oil & Gas Journal's most recent EOR survey shows EOR projects using CO_2 injection increasing, with the 100 ongoing CO_2 miscible injection projects accounting for 240,000 b/d of additional US oil production. Despite these advances, scant availability of CO_2 currently limits the US petroleum industry's ability to expand CO_2 flooding.[3]

Because CO_2 has become a viable product in its own right rather than simply a byproduct, CO_2 handling today differs considerably from its handling during the energy crisis of the 1970s and 1980s when it was simply emitted into the atmosphere. As incentive to curtail CO_2 emissions, the US Department of Energy has been funding CO_2 sequestration partnerships around the country.

Updated economics

The updated economics are shown in Table 2 for the previous cases using Montana Rosebud subbituminous coal.

INTEGRATED GASIFICATION COMBINED CYCLE WITH LIQUID FUELS PRODUCTION



UPDATED[1] COAL-TO-LIQUIDS CASE STUDIES

Table 2

Case[2]	Coal,[3] tons/day	Diesel, b/d	Electricity, Mw	CO_2, MMscfd	Old capital investment, billion $	Old DCF[4] rate of return,%	New capital investment, billion $	New DCF[4] rate of return, % ($135/bbl crude)	New DCF[4] rate of return, % ($75/bbl crude)
1	10,773	9,019	—	342	1.300	14	1.850	20	15
2	5.693	—	525	121	0.785	12	1.048	13	13
3	10,733	4,428	525	273	1.100	15	1.603	20	16.5
4	10,733	4,439	525	387	1.200	16	1.720	30	26

[1]From OGJ, Feb. 26, 2007, p. 20. [2]See case descriptions in text. [3]Montana Rosebud subbituminous coal. [4]Discounted cash flow.

CHANGING CAPITAL INVESTMENT, CO_2[1] VALUATION

Table 3

Case[2]	Coal,[3] tons/day	Diesel, b/d	Electricity, Mw	CO_2, MMscfd	New capital investment billion $	New DCF[4] rate of return, % ($135/bbl crude)
3	10,733	4,428	525	273 ($2/Mcf)	1.603	20
3a	10,733	4,428	525	273 ($2/Mcf)	2.404	15
3b	10,733	4,428	525	273 ($5/Mcf)	1.603	27

[1]Carbon dioxide. [2]See case description in text. [3]Montana Rosebud subbituminous coal. [4]Discounted cash flow.

The updated economics assigns diesel fuel a value of $3.90/gal for $135/bbl crude and $2.12/gal for $75/bbl crude vs. the old $1.80/gal. CO_2 in the new scenario would cost $2/Mcf, and the capital investment costs for IGCC are updated to $2,000/kw capacity vs. the old $1,400/kw. The table shows the economics for four processes:

- *Case 1*—CTL transportation fuels using Fischer-Tropsch synthesis.
- *Case 2*—Coal-to-electric power using IGCC.
- *Case 3*—Coal to both liquid transportation fuels and electric power.
- *Case 4*—Ultragreen technology to eliminate CO_2 emissions from the IGCC plant using hydrogen-rich gas for the combustion turbine. CO in the syngas is shifted to hydrogen in a water gas shift reactor, and the CO_2 is removed and sold.

The good news is that the rate of return is now higher for all of the cases. They benefit from the increased price of diesel fuel and CO_2 even with the higher investment costs. In fact, Case 4 for the ultragreen technology looks very attractive at a 30% DCF rate of return for $135/bbl crude and 26% for $75/bbl crude. The CO_2 produced from Case 4, represents a major revenue stream and shows that plant location is important. The coal conversion plant needs to be within 100-450 miles of the oil field that will be using the CO_2 for EOR. As one example, CO_2 is transmitted via pipeline about 450 miles from Cortez in southwest Colorado to the Texas panhandle. Other examples are given in the OGJ EOR survey.[3]

Cost sensitivity studies

The impacts of higher capital costs and higher value for the CO_2 in Case 3 are illustrated in Table 3. It shows the results of a cost sensitivity analysis of capital costs for Case 3, using the much higher value of $3,000/kw to show its impact on the DCF rate of return.

Case 3a shows the result of changing the capital investment basis to $3,000/kw capacity from $2,000 while keeping CO_2 valuation at $2/Mcf. The second sensitivity, illustrated as Case 3b, shows results of changing the CO_2 valuation to $5/Mcf from $2/Mcf, and with everything else held constant from Case 3a. These new cases are shown in the Table 3 cost sensitivity study results.

Case 3a, using the higher capital investment of $2.4 billion, results in the return on investment dropping to15% from 20%. This rate of return is still attractive at the higher investment costs and gives some confidence that a potential investor in this project would not be subject to an economic failure, even if construction costs escalated during the 4-year construction period.

Case 3b shows that if CO_2 is valued at $5/Mcf—equivalent to spending $25 in CO_2 to get 1 bbl of oil production—the DCF rate of return for the project increases to 27% from 20%.

Changing coal's image

It is hoped that the new clean coal-green technology will change the image of coal from being considered a "dirty" fuel. Although coal in the direct-fired utilities is problematic for emissions of SOx, NOx, mercury, and CO_2, these emissions are either eliminated or greatly reduced when the coal is gasified to syngas followed by acid gas scrubbing, using clean coal technology. The technology will easily apply to petroleum coke, so rather than trying to market a large pile of delayed coke, the refiner can consider converting it to electricity and liquid hydrocarbons.

It also is important for the US government to take a comprehensive look at the overall energy picture and realize that coal has few environmental demerits when used in modern clean coal technology and that clean coal should hold an important place as a future

source of energy in the US. It will take a clear government policy on energy and the environment to convince investors to move forward with these kinds of projects.

There are a number of ways the US government should take the lead in this effort:

- Organize a consortium of oil, coal, and power companies to design, build, and operate the plants. Production of electricity and CO_2 for EOR will cushion the economic downside when crude prices drop.
- Continue the 80% loan guarantee for synfuels plants.
- Provide a price support for the product from the plants, perhaps guaranteeing to purchase the entire liquid product at a set price. This guarantee would not be substantial for the initial plants, which would produce 5,000-10,000 b/d of liquid fuels.
- Offer tax credits to corporations to build and operate "green" and "ultra-green" coal plants that produce either electricity or liquid fuels.
- Streamline environmental permitting so that construction can proceed in a timely manner.

These initiatives could pave the way for a new, robustly ample and clean domestic energy supply for the US. ✦

References

1. Robinson, Ken K., and Tatterson, David F., "Fischer-Tropsch oil-from-coal promising as transport fuel," OGJ, Feb 26, 2007, p. 20.
2. Barta, Patrick, "South Africa has a way to get more oil: Make it from coal," Wall Street Journal, Aug. 6, 2006.
3. OGJ, Apr. 21, 2008, p. 41.

The authors

Ken K. Robinson (kkrob@earthlink.net) is president of Mega-Carbon Co. He has several years of industrial experience working at Monsanto, Amoco, and Argonne National Laboratory where he held positions such as director of coal utilization; research associate; manager, technical university relations; and associate director, technology transfer. He also was associated with California Institute of Technology as associate director of corporate relations and taught chemical engineering courses for 10 years at Northwestern University. Robinson has published 20 articles and holds 9 patents. He is coinventor of the Robinson-Mahoney spinning basket reactor and, with Ralph Bertolacini, the Amocat coal liquefaction catalysts used at the H-Coal pilot plant in Catlettsburg, Ky. At Monsanto, Robinson was a member of the development team for the homogeneously catalyzed acetic acid process commercialized worldwide.

David F. Tatterson (tatter@corecomm.net) is involved in businesses development for Mega-Carbon Co. He has 33 years of experience within the petroleum, alternative energy, and activated carbon industries. His expertise includes hydrocarbon process development, product development, marketing, marketing research, and business development. In the marketing area, he has extensive experience in global markets, including China, Russia, Mexico, Brazil, Turkey, Azerbaijan, and India. Tatterson holds eight US patents and has published a number of technical and marketing papers.

USGS estimates ANS holds 85.4 tcf of gas hydrates

Nick Snow
Washington Editor

There are 85.4 tcf of undiscovered, technically recoverable natural gas resources in gas hydrates on the Alaskan North Slope, reported the US Geological Survey on Oct. 18.

The US Department of the Interior agency said scientists recently completed the first assessment of an area extending from the National Petroleum Reserve-Alaska (NPR-A) on the west through the Arctic National Wildlife Refuge (ANWR) on the east, and from the Brooks Range on the south, to the state-federal offshore boundary 3 miles into the Arctic Ocean off the northern coast.

The 55,894 sq miles consists mostly of federal, state, and Alaskan native lands, USGS noted in a new report. "Approximately 35 years ago, Russian scientists made what was then a bold assertion that gas hydrates, long a curiosity of physical scientists, should occur in nature. Since then, the USGS and others have built a strong foundation supporting the conclusion that gas hydrates are a global phenomenon containing potentially huge volumes of gas in terrestrial Polar regions and the deepwater portions of most continental margins," it said.

It explained that gas hydrates are naturally occurring, ice-like solids in which water molecules trap gas molecules in a cage-like structure known as a clathrate. Although many gases form hydrates in nature, methane hydrate is the most common by far, it added.

The report said that when USGS conducted the first systematic assessment of US in-place natural gas hydrate resources in 1995, the study suggested that the amount of gas there greatly exceeds the volume of known conventional gas resources. Recognizing gas hydrates' importance as a potential energy resource, USGS and the US Bureau of Land Management agreed in 2002 to assess the volume of hydrates that could be produced in northern Alaska, it said.

A producible resource

"For the first time, the USGS has assessed gas hydrates—a traditionally unconventional source with no confirmed production history—as a producible resource occurring in discrete hydrocarbon traps and structures," it pointed out.

The assessment's primary purpose was to conduct a geology-based analysis of gas hydrates' occurrence within northern Alaska to determine the role

He showed people how to use the warmth of the summer sun in the dead of winter.

Making an entire subdivision run on a combination of solar and geothermal is just one of our many jobs. We're Science Applications International Corporation – 44,000 smart, dedicated people who have the deepest understanding of their fields and a passion to find the right solution. People like Bill Wong. Smart people solving hard problems.

For detailed information, visit **www.saic.com/solar**

Energy | Environment | National Security | Health | Critical Infrastructure

SAIC® From Science to Solutions

WATCHING GOVERNMENT

Nick Snow, Washington Editor

Blog at www.ogjonline.com

Energy debate in final weeks

As the 2008 election campaigns entered the home stretch, the two major presidential nominees left discussion of energy issues to surrogates. Two such lively discussions were recently held in Washington, DC.

In one, Virginia Gov. Timothy M. Kaine (D) and a predecessor George Allen (R) represented the campaigns of Sens. Barack H. Obama and John S. McCain, respectively, at an Oct. 15 Dulles Regional Chamber of Commerce breakfast debate.

Virginia became part of the US Minerals Management Service's 2007-12 Outer Continental Shelf leasing plan after its legislators passed a comprehensive energy plan, including possible offshore lease sales, and Kaine signed it in 2006. "We'd like to learn what's out there and then determine whether it should be leased and developed," Kaine said.

Allen said the state has tried for 2 years to get out from under a federal OCS moratorium but was repeatedly frustrated by Democratic congressional leaders. "Once it does, Georgia and the Carolinas won't be far behind," he predicted.

'Use it or lose it'

Allen and Kaine said their respective candidates support more access to domestic resources. But Kaine said Obama wants to see lessees develop tracts more quickly and suggested that so-called "Use it or lose it" legislation might be needed. Allen responded that this would be redundant because federal leases already have time limits.

"I don't think Americans are addicted to oil. They're addicted to the freedom to move anywhere at any time, whether with petroleum products, cellulosic ethanol, biodiesel, peanut oil, or other alternatives," said Allen. McCain favors an "all of the above" approach, he said.

Kaine said Obama wants more alternative and renewable energy research and development. "Drilling for more oil and gas domestically should be part of a total package, but he wants it to be a small part. It's a short-term strategy that's a dead end without alternatives," he said.

Major role for gas

The two major nominees' energy policy advisors also debated at an American Gas Association Natural Gas Roundtable luncheon Oct. 16. John McCarrick, representing McCain, and L.G. Holstein, representing Obama, agreed that gas will continue to play a major US energy role. Both candidates want to increase domestic production, support opening more of the OCS, but oppose leasing within the Arctic National Wildlife Refuge.

Holstein suggested that the nominees' biggest energy policy difference is over nuclear power, which McCain encourages. He said Obama would promote gas and realizes its increased use would require more domestic production.

McCarrick responded that the International Energy Agency has said 1,200-1,400 more nuclear plants would be needed to meet future worldwide demand, and the US needs to regain the technological lead. ✦

gas hydrates may play in the US energy future, according to USGS.

The project included three concurrent phases. The first focused on the Eileen gas hydrate occurrences overlying Prudhoe Bay, Kuparuk River, and Milne Point oil fields. The second set out to identify and characterize potential gas hydrate accumulations within ANWR and NPR-A and on state-managed land between the Colville and Canning rivers. The third involved a systematic, geology-based appraisal of the volumes of gas that technically can be produced from gas hydrates on the North Slope.

The report said the Northern Alaska Gas Hydrate Total Petroleum System includes Cretaceous and Tertiary reservoir rocks, which have been divided into three assessment units, from oldest to youngest: the Nanushuk formation, the Tulavak-Schrader Bluff-Prince Creek formations, and the Sagavanirktok formation. Only gas hydrates lying below permafrost were assessed. Free gas potentially trapped below the gas hydrate stability zone was not assessed.

"Also, as part of the gas hydrate petroleum system assessment, geochemical analysis of known gas hydrate occurrences revealed a link between gas hydrate accumulations and more deeply buried conventional oil and gas occurrences in which methane migration from depth has charged the reservoir rocks in the gas hydrate stability zone," the report continued.

Standard methods

Researchers used standard geology-based USGS methods originally developed to assess conventional oil and gas resources, it said. In order to use this approach, scientists analyzed three-dimensional seismic data acquired by the oil and gas industry to document that North Slope gas hydrates occupy limited, discrete volumes of rock bounded by faults and downdip water contacts.

"For the most part, it appears that the seismically imaged gas hydrate accumulations were once conventionally trapped free-gas accumulations that

were converted to gas hydrates at the onset of cold arctic conditions at the beginning of the Pleistocene Epoch," USGS said.

While the evaluation assumed that the assessed hydrocarbon resources can be produced by existing conventional technology, the report added that the production potential of northern Alaska's known and seismically inferred gas hydrate accumulations has not been adequately field-tested, although it has been the focus of a research effort led by the US Department of Energy.

"Although verified by only limited field testing, numerical production models of gas hydrate-bearing reservoirs at the Milne Point and Prudhoe Bay oil fields suggest that gas can be produced from gas hydrates with existing technology. Among the various techniques…depressurization appears to be the most promising method," it said.

Of the 85.4 tcf, which represents a mean estimate, the USGS report said that about 20.6 tcf, or 24%, is in the Sagavanirktok formation; 28 tcf, or 33%, is in the Tulavak-Schrader Bluff-Prince Creek formations, and 36.9 tcf, or 43%, is in the Nanushuk formation.

"Given that relatively few wells have penetrated the expected gas hydrate accumulations in these three assessment units, there is significant geologic uncertainty, which is reflected in the range of estimates," it said. The new mean estimate is lower than the 590 tcf reported in the 1995 assessment because it deals only with technically recoverable amounts instead of total in-place gas hydrates, it pointed out. ✦

Alaska to get $80 million in coastal impact aid

Nick Snow
Washington Editor

Alaska will receive as much as $80 million of coastal impact assistance authorized under Section 384 of the Energy Policy Act of 2005 (EPACT 2005), said the US Minerals Management Service on Oct. 16. The state and eight eligible boroughs will share that money, it said.

The law, including the Coastal Impact Assistance Program (CIAP), authorizes the US Interior secretary to distribute $250 million/year to six Outer Continental Shelf oil and gas-producing states in fiscal 2007-10, MMS said. Alabama, Mississippi, Louisiana, Texas, and California and are the other five states, it indicated. Alaska is the second of the six eligible states to receive funding under the program, MMS Director Randall B. Luthi said during a ceremony at Kincaid Park in Anchorage.

CIAP funding must be used for coastal area and wetlands conservation, preservation, or restoration projects; fish, wildlife, or natural resources damage mitigation; planning assistance and costs associated with CIAP legislative compliance; implementation of a federally-approved marine, coastal, or comprehensive management plan; or mitigation of the impact of OCS activities through funding of onshore infrastructure projects and public service needs, according to the US Department of the Interior agency.

Annual payouts to rise

MMS said Alaska will receive $2.5 million/year each for fiscal years 2007 and 2008. The annual payout will climb to $30-40 million in fiscal 2009 and 2010 as a result of federal OCS Lease Sale No. 193 in the Chukchi Sea, which was held this past February. Funding revenue was determined by OCS revenue, with the first 2 years based on the fiscal 2006 total and the last 2 years based on the fiscal 2008 figure, MMS said.

It said Alaska will receive 65% of the funding, and the balance will be shared by the Anchorage, Bristol Bay, Kenai Peninsula, Kodiak Island, Lake & Peninsula, Matanuska-Susitna, North Slope, and Northwest Arctic boroughs. Borough shares, which range from 0.08% for Bristol Bay to 35.27% for North Slope, are determined by a formula in EPACT, it said.

Alaska's plan currently contains 51 projects covering all 4 years of the program, but it was developed before the Chukchi Sea lease sale results were known, MMS said. Consequently, the state is amending its plan to consider a broader array of projects, it noted.

In a separate announcement, Alaska Gov. Sarah Palin's office said on Oct. 15 that the state would solicit additional projects soon through the Governor's Office Policy Cabinet for implementation by the state's Department of Natural Resources. ✦

DOE generates electricity from producing well's hot water

Nick Snow
Washington Editor

Electricity has been generated successfully from a producing oil well's geothermal hot water for the first time, reported the US Department of Energy's Fossil Fuel Office on Oct. 18.

DOE's Rocky Mountain Oilfield Testing Center (RMOTC) and Ormat Technologies Inc., Reno, Nev., began a 12-month test in September at RMOTC's Naval Petroleum Reserve No. 3 (NPR-3) site north of Casper, Wyo., DOE said. A standard commercial Ormat

Organic Rankine Cycle power plant is being used, using hot water from a producing oil well to exchange heat in an Ormat Energy Converter, it indicated.

"This project is unique in its production of onsite renewable power and has the potential to increase the productivity and longevity of existing US oil fields. Harnessing hot water produced during production to power the oil field could lead to more economical access, especially in older, depleted fields," said James A. Slutz, DOE's acting assistant secretary for fossil energy.

A large number of US oil and gas fields produce hot water as well as hydrocarbons, he noted. Such wells, which typically produce fluids at temperatures below 220° F., could be capable of generating more than 5,000 Mw of electricity, he said.

In the current test, a binary power unit moves hot water from a producing well to a heat exchanger, where it vaporizes a secondary fluid with a lower boiling point, according to DOE. The secondary fluid's vapor is used to turn a turbine coupled to a power generator. Electricity is then supplied to the field's electrical system, where it runs production equipment, it said.

150-200 gross kw

DOE said the generated electricity is metered and monitored for both reliability and quality. The test has been producing 150-200 gross kw of power since it started in early September, it said.

It said the cooled geothermal fluid from power production can be reinjected into the reservoir or discharged, depending on the location. Currently, the 190° F. water produced from NPR-3's Tensleep sandstone formation is treated before being safely discharged into a nearby stream. The unit's energy converter captures the water's heat and uses it before the water is discharged.

DOE said that while the unit at NPR-3 is the first to use geothermal water from a producing oil field, it is similar to a 250 kw Ormat unit, which has generated electricity at an Austrian resort from 210° F. geothermal water for more than 6 years. Similar units also have been in continuous operation in Nevada and Thailand since the 1980s and have been field-proved in 1,000 installations worldwide, it said.

About 8,000 wells that produce both hot water and hydrocarbons have been identified in Texas alone, DOE said. Ormat is assessing the feasibility of using such wells to support onsite power generation by employing its sub-Mw geothermal power units, it added. ✦

FACTS: Iran needs timely completions in South Pars

Iran's natural gas production from South Pars gas field Phases 6, 7, 8, and 9—all expected to be completed this fall—could prevent another massive energy crisis in Iran this winter, according to Siamak Adibi in a September FACTS Global Energy Energy Briefs report. Much would depend on the phases' completing on schedule and on the winter's not being excessively cold.

In the frigid 2007-08 winter, Iran consumed a peak 21.2 bscfd of gas, Adibi reported, while total production averaged 16.5 bscfd. The shortage resulted in a massive reduction of gas reinjection into Iranian oil fields and a supply cut to electric power plants, industrial projects, and 200,000 residential and commercial consumers. Iran also halted gas exports to Turkey.

Although Iran agreed to increase its gas imports from Turkmenistan in second-quarter 2008 to as much as 1.1 bscfd this winter to decrease Iran's gas deficit, it found Turkmenistan gas imports last year to be unreliable. Turkmenistan stopped deliveries of 800 MMscfd of gas in January when Iran's gas shortage increased to maximum levels and then raised the price of its gas to $4.90/MMbtu from the 2007 fixed price of $2.64/MMbtu.

In April, Iran agreed to pay the higher price and renewed imports. Turkmenistan said that after 2009, its gas price would be linked to oil in a new price formula, FACTS reported.

Demand increasing

In an attempt to control growing domestic gas demand and decrease subsidies for high-volume end users, Iran raised domestic prices substantially, especially for residential and commercial use, using a pricing mechanism based on consumption that can elevate the price to nearly eight times the former base price of 39¢/MMbtu. However, this mechanism has been unsuccessful in reducing demand. The country is expected to experience strong gas demand growth of 7-8% during 2008-20, FACTS Global Energy forecast.

Accelerating demand in Iran is beyond National Iranian Oil Co.'s control "because of a disconnect between downstream and upstream activities in Iran," FACTS reported. "[National Iranian Gas Co.], which controls Iran's downstream development, is separate from NIOC and has different planning views. The development of the downstream section has always been faster than upstream activities, and gas shortages may not be surprising, especially in peak winter demand."

NIGC estimates that a cold 2008-09 winter could raise domestic gas consumption to a peak of 24.7 bscfd, according to the FACTS report. Based on NIOC official statistics, the country's maximum total gas production will be 19 bscfd at yearend. This could result in a repeat of last winter's gas shortage and supply crisis—although it could be more moderate than that of early 2008 because of the new South Pars phases completion.

Near-term gas output

In 2007 NIOC subsidiary National

Iranian South Oil Co. (NISOC) supplied 65% of Iran's gas production. Although it expects to increase production by an additional 0.9 bscfd of gas this year by developing Tange Bijar gas field and drilling more wells in Nar, Kangan, Homa, Shanul, Varavi, or Tabnak gas fields, the gas from South Pars Phases 9 and 10 will be urgently needed to prevent "a massive energy crisis" this winter, FACTS reported.

• *Phases 9 and 10.* Development of Phases 9 and 10 of the South Pars gas field development, which would release 2 bscfd of gas to the domestic market, was nearing completion in September, and gas is expected to flow from Phase 9 this month, with Phase 10 flow expected in November.

"The gas crisis may be more critical for years 2009-11 when delayed South Pars phases will not be completed earlier than 2012," FACTS reported.

• *Phases 6-8.* Although South Pars Phases 6-8 will produce another 3.6 bscfd of gas, 152,000 b/d of condensate, and 1.6 million tonnes/year of LPG, the gas is scheduled to be delivered via a 512-km, 56-in. pipeline to Agha-Jari oil field in Khuzestan Province for reinjection. Phase 6 was scheduled for completion this summer, and gas is expected to flow from Phases 7 and 8 late this year and early 2009.

Later South Pars phases

"The gas crisis may be more critical for years 2009-11 when delayed South Pars phases will not be completed earlier than 2012," FACTS reported.

• *Phase 12.* This phase, which will produce 3 bscfd of gas and 110,000 b/d of condensate, will not be completed until late 2012-early 2013. About 1 bscfd of gas from Phase 12 has been allocated for Iran's domestic market.

However, another 2 bscfd of gas from Phase 12, which has been designated as feedstock for Iran's LNG plant, might well be delivered to the domestic market until the long-delayed LNG project starts up in 2015, said FACTS.

• *Phases 17 and 18.* NIOC and National Iranian Drilling Co. recently signed a contract valued at more than $1 billion for drilling 27 wells in Phases 17 and 18, which are intended to produce 2 bscfd of gas and 80,000 b/d of condensate. They are expected to be completed in 2013-14.

• *Phase 13.* Although Phases 13 and 14 formerly were allocated to Iran's LNG project, Royal Dutch Shell PLC and Repsol YPF SA have delayed a final investment decision (FID) on participating in the Persian LNG project, thus delaying it.

However, because Phase 13 is located near the Iran-Qatar marine border, its development is generating sense of urgency. "The longer Iran delays development of Phase 13, the more likely it is to lose some of its gas reserves to gas migration, as Qatar is extensively exploiting the adjoining North Field," said FACTS. Phase 13 is thought to have a relatively high output of gas and condensate productivity levels.

So although Iran originally scheduled Phase 13 development to follow Phases 15 and 16, it is now expected to reverse the order of their development

• *Phases 15 and 16.* NIOC signed a contract with a consortium of Khatam Al Anbia Construction Headquarters of Iran, the Iranian Offshore Engineering & Construction Co., Saaf, and Iran Shipbuilding & Offshore Industries Complex Co. to produce 2 bscfd of gas and 80,000 b/d of condensate from South Pars in Phases 15 and 16.

However, the EPC contractor will install the offshore platforms in the Phase 13 areas instead of the area of Phases 15 and 16, and Phases 14-16 will be considered for the Persian LNG project.

After 2015 development

Other phases are unlikely to be completed before 2015.

• *Phase 11.* Long delays have precluded Phase 11's providing gas for the domestic market before 2015. Considered for Pars LNG, Phase 11 is unlikely to see its FID before Iran's next presidential election—in summer 2009 at the earliest, FACTS said.

Total SA recently said Iran's political environment is too risky right now for investment, and it has postponed making an investment decision. NIOC responded that it will not wait for Total's decision and is able to develop Phase 11with local companies.

"We think Total effectively has withdrawn from the project by postponing its FID because of Iran's current political situation. However the company is still officially involved," Adibi said in the FACTS report. "Even the cancellation of Pars LNG and the appointment of new contractors to develop Phase 11 is unlikely to provide gas from Phase 11 for the Iranian domestic market before 2015."

• *Phases 19-24.* These phases have also been delayed, and their development is expected to be completed after 2015. ✦

IEA: Rising demand threatens long-term gas supply security

Doris Leblond
OGJ Correspondent

Over the last 18 months, natural gas prices have continued to rise steadily in both established and new markets "not only a reflection of higher demand, but also of a delayed supply response," said Nabuo Tanaka, executive director of Paris-based International Energy Agency, in his introduction of the 2008 Natural Gas Market Review, released last week.

"Investments uncertainties, cost increases, and delays continue to be a major problem in most gas markets and are continuing to constitute a threat to long-term security of supply," Tanaka

stressed. These factors no doubt will be compounded by the world financial turmoil, which has erupted since the review was published and which will forcibly result in a credit squeeze for energy investments.

Investment lag

Ian Cronshaw, head of IEA's Energy Diversification Division, who designed and managed the review, was already concerned that increasing gas demand, especially for power generation, was not being met by sufficient investment. While he said projects currently under way will proceed, he also said the lag in LNG investments beyond 2012 "is a concern for all gas users in both the IEA and non-IEA markets."

The review pointed out other issues that pose a threat to long-term supply security: the escalation of engineering, procurement, and construction costs (EPC); the tight engineering market; and the growing propensity of producing countries to reserve a greater share of gas production for their own growing domestic markets.

High natural gas prices, which also are pushing up electricity prices because of the close link being established between gas and power, have not slowed demand in consuming markets either inside the IEA or nonmember countries. In the US gas demand grew by 6.5% in 2007 and about 4% in first-quarter 2008. In Japan, growth in 2007-08 was 9% on the back of a 50% lower nuclear power utilization.

In Europe, gas consumption was dampened by warm weather but in early 2008, growth jumped to more than 8%, most notably in Spain, where first-half 2008 demand increased by 20% despite an economic slowdown.

Meeting gas demand

To meet this growing demand LNG trade is on the way to playing a stronger role in regional markets within the Organization for Economic Cooperation and Development (OECD) countries in the short and medium term, forecasts the review. While LNG is already pivotal in OECD Pacific, it is expected to reach 20% in Europe, where imports will account for over half of total supplies.

In North America, indigenous production will still supply more than 90% of expected demand by 2015, yet LNG imports are expected to more than double 2007 levels.

Increasing LNG trade will globalize regional gas markets, a trend that seems irreversible, says the review. Driving global interactions are the prevalence of more producing and consuming countries, a growing dependence on external markets in OECD Europe, tighter balances, increasing volumes of spot and short-term LNG, and higher gas prices.

But, insists the review, to benefit from the globalization of the gas market, improved transparency on flows and prices and more-competitive internal markets are needed. Interregional competition will improve global gas security in the long term. Making its point, the review notes that liquidity on European hubs—both on the UK's National Balancing Points and on most continental hubs—has "grown considerably, promoting more flexible market responses, more transparency, and more-accurate price signals."

Gas traded among regions will grow to 17% in 2015 from 13% in 2005, with LNG accounting for about 84% of the increase in interregional trade as exports grow to some 400 billion cu m in 2015 from 192 billion cu m in 2005.

Gas supply sufficient

Examining gas supply, IEA's review sees worldwide gas resources more than sufficient to meet global demand, which it establishes at 3.689 trillion cu m by 2015, up from 2.854 trillion cu m in 2005, always subject to timely investment. The biggest regional increase in absolute terms is in the Middle East, but there is also a marked increase in Africa and Latin America. All told, production is expected to increase in all major regions except OECD Europe, where North Sea output is declining. North American production growth should slow after 2015.

Natural gas supplies will continue to come mainly from conventional sources but coalbed methane and other nonconventional supplies, such as shale gas, should be playing a growing role in some regions, notably North America.

The great uncertainty, however, is how major resource holders will meet increasing demand, rapidly rising costs, and development of more-remote gas.

Pipeline delays

Looking at the needed infrastructure to deal with increasing gas flows, both regional and global, Tanaka was concerned that "progress on major pipelines, outside the United States is slow." Improvements to market functioning are especially urgent in Europe, he noted, because of the region's growing demand for gas. Also needed in Europe are greater cross-border gasline connections.

Noted, also, were the many delays in pipeline infrastructure development last year globally as well as increased costs. Particularly mentioned were Nabucco and Nord Stream in Europe and the Alaska pipeline in North America.

In LNG there are similar trends, as many projects are planned but not all are going ahead. In this area, the review notes the unprecedented and major expansion in regasification capacity worldwide, which risks being underutilized for it greatly exceeds liquefaction capacity. On the other hand, concedes the review, this could be a source of flexibility.

The review is prolific and detailed on all these developments. It also includes data and forecasts on OECD and non-OECD regions to 2015 and in-depth reviews of five OECD countries and regions, including the European Union. ✦

Pertamina under increased parliamentary scrutiny

Eric Watkins
Oil Diplomacy Editor

Indonesia's state-owned PT Pertamina has come under increased parliamentary scrutiny for further alleged irregularities in its importation of foreign oil products.

"The inquiry committee has found some other irregularities concerning Pertamina's other crude and fuel imports," said legislator Zulkfili Hassan, who heads the House of Representatives committee charged with investigating management of the country's oil and gas industry.

"The committee findings cannot be published to the public, but we will definitely report them to law enforcers," said Zulkifli, who added that his committee would summon Pertamina officials for further questioning on Oct. 23.

As police continue investigating Pertamina over earlier allegations that it imported a sub-standard oil type called Zatapi last year, one industry observer agreed with Zulkifli in thinking that that case may be just one of many against the firm.

Pri Agung Rakhmanto, executive director of the Reforminer Institute said it was quite possible other such incidences had occurred because "Pertamina has more than 50 partners for importing crude and fuel products."

Pri Agung noted that, "only five of them repeatedly win the import tenders" and that "it's very possible that a case like Zatapi also occurred in other import deals." In particular, Pri Agung noted that PT Gold Manor International, Singapore, which won a Pertamina-sponsored tender to provide 600,000 bbl of Zatapi crude oil to Indonesia, is one of the few companies that consistently wins oil supply tenders.

Gold Manor won the tender to supply Zatapi crude in December 2007, and began shipping the oil to a refinery in Cilacap, Central Java, in February.

However, legislators of the House of Representatives Commission VII overseeing energy and mineral resources revealed that Gold Manor's proposal to compete in the tender was incomplete as it did not include a detailed break-

down of the contents of Zatapi oil.

The Attorney General Office began investigating the case on Mar. 2, and police last month named four Pertamina staff members, including a vice president and a former director, as suspects in the case.

Pertamina president director Ari Soemarno has repeatedly denied there have been irregularities in the makeup of imported Zatapi crude and that the imports have not caused state losses.

"In fact, Pertamina benefits from the lower price of Zatapi. We saved $5.5 on each barrel of Zatapi we imported. Thus, in total, we saved $3 million on 600,000 bbl of Zatapi oil," Ari said.

In July, the Indonesia's Supreme Audit Agency (BPK) began an investigative audit of fuel imports by Pertamina and its subsidiary, Singapore based Petral, a week after experts hinted at irregularities in the imports.

The audit, which has a particular aim, began two days ago at Pertamina to look at the procurement (of crude oil and fuel products)," BPK auditor Widodo H. Mumpuni said on July 24.

At the time, lawmakers said that although Pertamina had 42 brokers for crude imports and 50 for fuel products imports, only 5-7 brokers regularly won tenders for procurement. ✦

Indonesia awards contracts, opens new bidding round

Eric Watkins
Oil Diplomacy Editor

Indonesia's Ministry of Energy and Mineral Resources announced the award of 22 new oil and gas blocks to investors, out of the 25 it offered for bids.

The government awarded the Arafura Sea block to ConocoPhillips, the offshore West Papua I and III blocks to Chevron Corp., and the offshore North Sumbawa II block to Husky Energy Inc.

Malaysia's Ranhill Energy Sdn. Bhd. won the onshore South CPP block, while India's Gujarat State Petroleum Corp. and Essar E&P Ltd. together were awarded the Southeast Tungkal Block.

Australia's Pearl Energy and Australian Worldwide Exploration Ltd. won the East Muriah Block, and China's Sinochem Petroleum E&P won the Madura Block.

The government, which awarded the remaining blocks to lesser-known investors, said companies that won the new blocks plan to invest a total of $330 million during the first 3 years of exploration.

New tenders

Even as it made the awards, the government also opened a new tender for 31 oil and gas blocks onshore and offshore. The new tender document will be provided on Nov. 10, and the deadline for bids will be in January, 2009, for some areas, and in March.

Blocks are available in: Sumatra. One onshore-offshore block and four blocks off northern Sumatra; two onshore

Indonesia expects E&P investment to reach $375 million

Eric Watkins
Oil Diplomacy Editor

Indonesia expects investments to reach $375 million for the 22 oil and gas blocks it awarded on Oct. 17, according to Evita H. Legowo, director general for oil and gas.

Chevron Corp., ConocoPhillips, and Husky Energy Inc., all of which won oil and gas exploration rights for four blocks, have pledged total investment of at least $91.4 million over the next 3 years.

Chevron subsidiary Chevron Indonesia Ventures Ltd., which won the rights to explore the West Papua I and West Papua II blocks in West Papua, will invest $24.5 million in each field.

ConocoPhillips, which was awarded exploration rights for Arafura Sea block, will need to invest $30 million in the first 3 years. Husky Energy is expected to invest $12.4 million for 3 years of exploration activity on North Sumbawa II block.

In addition to the three international oil companies, other companies winning exploration rights (and their respective blocks) include:

Serika East Seruway BV (East Seraway); Ranhil Energy Sdn. Bhd., (South CPP); Consortia PT Radiant Nusa Investama-PC (SKR) International Ltd. (South West Bukit Barisan); PT Karya Inti Petroleum (Lirik II); PT Tiga Musim Mas Jaya, (West Tungkal); Consortian Gujarat State Petroleum Corp. Ltd-Essar E&P Ltd. (South East Tungkal); PT Harpindo Mitra Kharisma (Lampung III); Consortia Pearl Energy Ltd.-Australian Worldwide Exploration Ltd. (East Muriah); PT Sinochem Petroleum E&P (Madura); Consortia Kaizan Oil & Gas LLC (West Sageri, South East); Niko Resources Ltd. (Ganal I, South Matindok); Consortia PT Kutai Timur Resources-Salamander Energy Ltd. (South East Sangatta); Adelphy Energy Ltd. (South Bengara II); PT General Energy Indonesia (North Bone); Consortia Kaizan Oil & Gas LLC-Marathon Indonesia New Ventures Ltd. (Bone Bay); PT Putindo Bintech (Buton I); and Consortia Biak Petroleum LLC-Niko Resources Ltd. (Seram).

blocks in central Sumatra; and two onshore blocks in southern Sumatra.

Kalimantan. Two onshore blocks in southern Kalimantan; and one block onshore and two off eastern Kalimantan;

Papua. One onshore-offshore block in northern Papua, and five off western Papua.

Other offshore blocks include the N. Surumana Block in the Makassar Strait, the Sermata Block in the West Arafura Sea, two blocks off southern Sulawesi, the Karaeng Block off northern Selayar, the SE Halmahera-SW Kofiau Block off South Halmahera, the East Bula Block off Seram, the Penyu block off West Natuna, and the Sokang Block off East Natuna.

Other onshore blocks include the South East Madura onshore-offshore block in East Java; and the Terumbu Block, which is partly onshore-offshore Madura. ✦

Pertamina moves in on Kodeco, CNOOC

Eric Watkins
Oil Diplomacy Editor

Indonesia's state-owned PT Pertamina, in line with the country's developing policy of resource nationalism, is vying with partner Kodeco Energy Ltd. to become the operator of the offshore Madura oil and gas block.

Pertamina holds a 50% stake in the block, with the remaining 50% jointly controlled by Kodeco Energy and China's National Offshore Oil Corp. (CNOOC), each with a 25% stake.

The Indonesian firm's 50% share was deemed insufficient for the company to control the block's management, according to Pertamina corporate vice-president, upstream, Karen Agustiawan.

"It is true that we are the majority shareholder," Karen said. "The problem is the combination of Kodeco and CNOOC is also 50%, creating a possibility of deadlock, which is precisely the thing that we want to avoid."

With a bigger stake, Karen said, Pertamina plans to replace Kodeco as the block's operator. Kodeco had refused Pertamina's proposal for the block, which produces some 6,500 b/d of oil and 45 MMscfd of gas.

Kodeco shareholder representative Sung Sik Min said the South Korean firm is open for negotiation with Pertamina and CNOOC over the operatorship, and that the block's production-

WATCHING THE WORLD

Eric Watkins, Oil Diplomacy Editor

Blog at www.ogjonline.com

Will Russia join OPEC?

Much has been said over recent months about the possibility of Russia joining the Organization of Petroleum Exporting Countries. In the coming months, we'll probably hear more, too.

A week or so ago, Qatar's Oil Minister Abdullah bin Hamad Al-Attiyah expressed the hope of seeing Russia one day become a full member of OPEC as it would "add value" to the organization.

"I wish one day to see Russia as a full member of OPEC," Al-Attiyah said in an interview. "Russia as the second (largest) oil exporting country (after Saudi Arabia) has a strong role in the oil market, so if Russia were to join OPEC, it would add value," he said.

But even Al-Attiyah had to acknowledge that his wish has little chance of being fulfilled—at least for the moment. "So far the Russians support cooperation, but they don't talk about full membership," he said.

Rising speculation

Speculation about Russian membership arose after Russia sent its most senior delegation in a decade to OPEC's Sept. 9 ministerial meeting in Vienna. At the meeting, Russian Vice-Premier Igor Sechin proposed extensive cooperation between Russia and OPEC to meet global energy needs.

Sechin said at the time that "a draft memorandum of understanding will be submitted" on the matter to OPEC's leaders. But even Sechin didn't suggest that Russia would consider becoming an OPEC member.

Sechin said that Russia and OPEC aimed to increase the predictability and transparency of "all factors that affect the market conditions." He said it was "impossible to imagine" how global energy security could be strengthened "without a dialogue between Russia and OPEC."

Cooperation could include joint projects between Russian and OPEC national oil and gas companies, joint investments and the sharing of technology, as well as environmental issues, Sechin said. But again, he said nothing about becoming a member of OPEC.

Russians say 'nyet'

With all due respect to our friend Al-Attiyah and other esteemed OPEC ministers, there is no reason to think that Sechin or any other Russian official ever would want to join the organization.

After all, what is OPEC about except creating and maintaining production quotas on its members to ensure that none of them deliberately—or even accidentally—destabilizes prices by adding too much or too little oil to the market.

Frankly, it's a little hard to imagine Vladimir Putin or any of his minions accepting the idea of limits to production imposed by anyone. And that, of course, is exactly what OPEC would want to do with a Russia that already can seriously undermine international markets.

Between Russia and OPEC there is no great love lost. Each side recognizes that it can undermine the other and both sides want the other to know that. At best, we'll see an uneasy cooperation between OPEC and Russia. On the question of joining OPEC, Russia's answer will remain "Nyet." ✦

sharing contract—set to expire on May 6, 2011—had to be extended in any case.

According to Sung, the South Korean company plans to seek an extension of the West Madura PSC but "every time we invite Pertamina to discuss the issue, they choose not to come."

The looming contract extension date puts Kodeco and CNOOC in a weak bargaining position as Indonesian regulations require investors to return oil and gas blocks to the government after their rights expire.

Under those terms, Indonesia can either extend the Kodeco and CNOOC contracts or simply offer the block to Pertamina. In an effort to secure at least a share of the block, Kodeco and CNOOC might decide to accede to Pertamina's demand.

Pertamina's efforts to assume control of the Madura block follow attempts to obtain a larger interest in other oil and gas concessions, including Total's Mahakam Block in East Kalimantan, Inpex's offshore Masela Block in the Timor Sea, and Chevron Corp.'s deepwater fields off East Kalimantan.

"We want to have 20% stakes in Masela, Mahakam, and the deepwater areas," Karen said. "We have secured an approval from the government through the state-enterprises minister… he understands that we want to be 'the lord' in our own country," Karen said, underlining the resource nationalism behind the move. ✦

Ecuador's giant Pungarayacu to see heavy oil appraisal

Ecuador's state-owned Petroecuador and Petroproduccion have signed a 30-year contract with Ivanhoe Energy Ecuador Inc., a subsidiary of Ivanhoe Latin America, to explore and develop Block 20 on the western edge of Ecuador's Amazon basin.

Block 20 contains the 250-sq-mile Pungarayacu heavy oil accumulation along the Napo uplift.

Ivanhoe said the contract covers project appraisal and the development, including production and upgrading the heavy oil of the 426-sq-mile Block 20, which lies 125 miles southeast of Quito, the Ecuadoran capital.

Pungarayacu field was discovered 30 years ago. During the 1980s, Petroproduccion drilled 26 core holes in the field, which has been studied and evaluated by Petroproduccion, ARCO, and other oil companies.

According to Ivanhoe, "these third-party studies estimated that Pungarayacu contains between 4.5 billion bbl (Petroecuador-ARCO) and 7 billion bbl (Petroecuador) of oil in place." Ultimate development cost will range to several billion dollars.

The Cretaceous Hollin sandstone, one of the principal producing formations in Ecuador's Amazon basin, is the pay zone at Pungarayacu. It is 250 ft to more than 300 ft thick and is topped from surface to deeper than 1,500 ft.

The firm said confirmation of these resources "would make the Pungarayacu field the largest accumulation of heavy oil in Ecuador and one of the largest in Latin America."

Ivanhoe also believes there is potential for deeper exploration for lighter oil.

Ivanhoe said, "This deeper zone in the Pungarayacu field has not yet been drilled with exploration wells, but the field lies on a regional arch that could focus migrating oil into this area."

ECUADOR'S SUPERGIANT HEAVY OIL FIELD

Fig. 1

Production plans

According to project plans, oil production will begin with 30,000 b/d, eventually rising to 120,000 b/d of 9-14° gravity oil.

Ivanhoe plans to use its heavy-to-light (HTL) technology to upgrade the heavy crude into grades of 23° gravity crude. The viscosity-reducing technology is proprietary and patented but unproven at commercial scale in the oil industry. Modules as small as 10,000 b/d are being designed in San Antonio, the company said.

"We look forward to demonstrating the substantial advantages of our HTL process, which include enhanced efficiency, significant environmental benefits, and the economic production of previously stranded petroleum resources," said David Martin, a seasoned Latin American geologist and executive chairman and chief executive officer of Ivanhoe Latin America.

Investment requirements are estimated to be $20 million during the first year of the contract and a total of approximately $110 million for the first 3 years of appraisal.

To recover its investments, costs and expenses, and to provide for a profit, Ivanhoe will receive from Petroproduccion a payment of $37/bbl of oil produced and delivered to Petroproduccion.

The payment will be indexed quarterly for inflation, starting from the contract date, using the weighted average of a basket of three US government-published producer price indexes relating to steel products, refinery products, and upstream oil and gas equipment.

Ivanhoe Energy Ecuador may elect to receive its payment in oil, based on market prices, Ivanhoe said.

The company said it is in detailed discussions about Pungarayacu development partnerships with international oil companies, including Asian companies.

Accruals from the block

Petroecuador said in early October that it expects to obtain more than $40 billion in revenue from Pungarayacu field. That followed a statement in August by Petroecuador Pres. Luis Jaramillo who said that Ivanhoe would start producing about 108,000 b/d of heavy oil at the Pungarayacu field by May 2009.

Such a time line seems highly optimistic, however. Ivanhoe said no field work will begin until after 6 months of environmental studies. The succeeding 3-year appraisal phase would involve seismic surveys, drilling appraisal and production wells, and conducting steam injection tests of the various sands.

Nevertheless, a greatly underutilized 400,000 b/d oil pipeline to the Pacific Coast port of Esmeraldas crosses Block 20, Ivanhoe noted.

New wells are required because the 26 uncased core holes have been plugged.

White et al. wrote in AAPG Memoir 62 that cumulative production from Ecuador's Oriente from 1972 through 1992 was 1.7 billion bbl from Hollin and 1.17 billion bbl from the overlying Cretaceous Napo formation. They estimated remaining recovery in the province at 2 billion bbl in the succeeding 20 years, mainly from existing fields and developments already under way in the early 1990s.

Exploration on the block outside Pungarayacu might raise its estimate of oil in place to 15-20 billion bbl, said Robert Friedland, executive chairman of Ivanhoe.

In 2007, Ecuador rejoined the Organization of the Petroleum Exporting Countries and has an assigned production quota of 520,000 b/d.

The country had a total output of about 511,000 b/d in 2007, including production by Petroecuador and private oil companies operating in the country (OGJ Online, Aug. 22, 2008). ✦

BC's Beaver River field flows gas from shales

The life of Northeast British Columbia's Beaver River field may be extended if initial flows from shale and siltstone formations prove out in the Liard basin field.

Two Canadian independent operators reported an initial flow of 10 MMcfd of sweet, dry gas at 3,000 psi wellhead pressure on a 3-day test at the field's A-5 well.

The gas flow came from a brittle layer, rich in dolomite, at the top of a thick sequence of organic rich shale after a series of minifracs and high-pressure acid stimulations. The goal of the exercise was to identify prospective intervals for a future frac stimulation program.

Pending regulatory approval, the well will go on production by the end of October, said Questerre Energy Corp. and Transeuro Energy Corp.

Questerre Energy said, "While too early to evaluate the full contribution from the Liard shales, these initial results are well above our expectations. With over 30 sq miles of prospective acreage, existing infrastructure and takeaway capacity, this remains an exciting opportunity."

Questerre, which operates the field, said the high flowing pressure associated with this well will likely reduce production from the lower pressure A-2 and A-7 wells, limiting overall production gains.

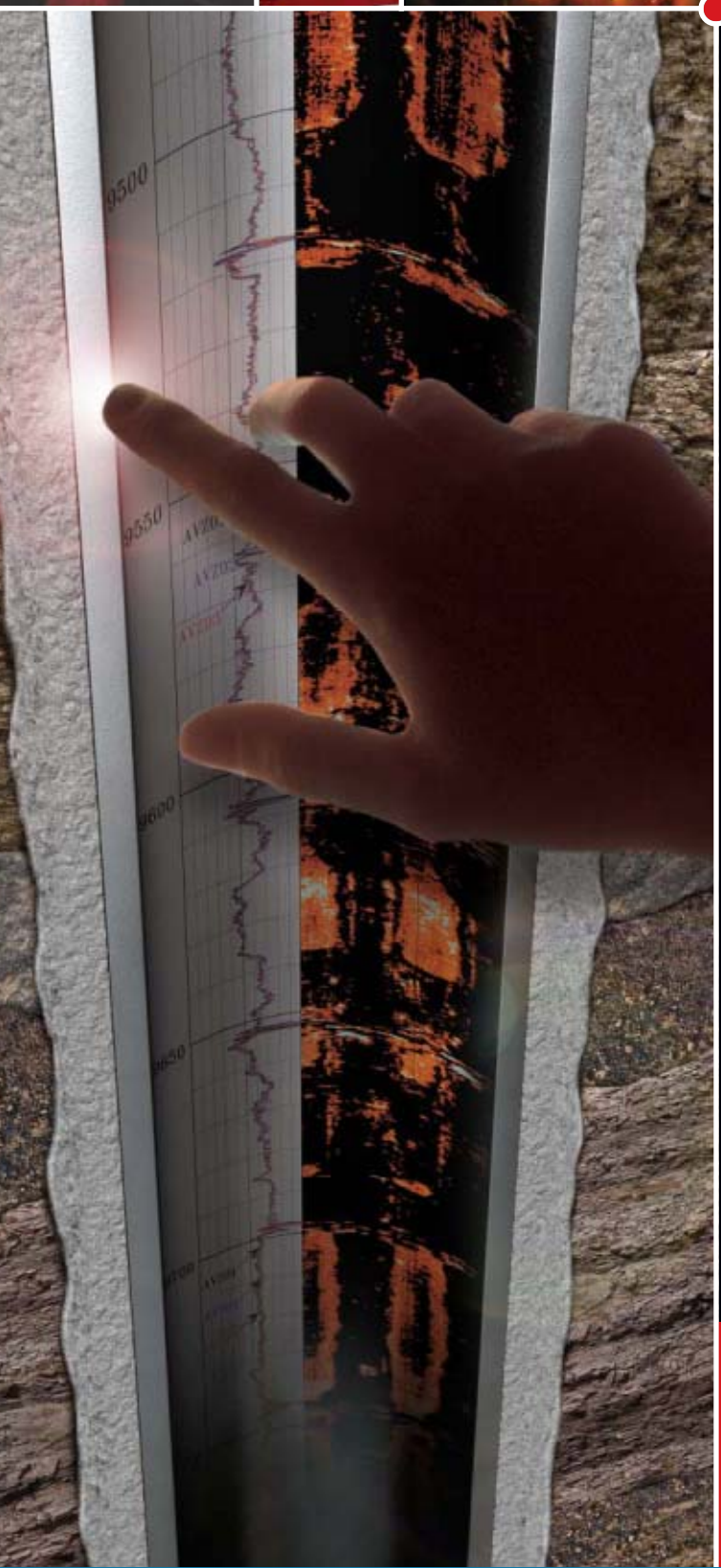
Transeuro said it expects the gas rate to decline initially and is confident it will stabilize at commercial levels.

Beaver River field, 150 km northwest of Fort Nelson, BC, is near the provincial border with Yukon and 100 km east of the Horn River basin, which has an emerging gas play in the Devonian Muskwa and Evie shale.

A-5 is the third well to be put on production from the shale-siltstone intervals at Beaver River field, said Transeuro. The intervals are collectively more than 2,000 m thick and for classification purposes have been separated into three major intervals.

The intervals are the Mississippian Mattson shale at 1,200-2,100 m,

HALLIBURTON WIRELINE AND PERFORATING SERVICES



For rock-solid reliability—miles underground—look into our integrated, cased-hole solutions.

Halliburton Wireline and Perforating Services has one of the widest, most reliable arrays of cased-hole solutions in the world. These solutions include everything from casing and cement evaluation, production and reservoir evaluation to mechanical and perforating services—all of which can be conveyed on electric line or slickline, and which complement our industry-leading, tubing-conveyed perforating.

Before you get in too deep, take a closer look at Halliburton Wireline and Perforating Services. With precision tools and technologies that meet the toughest E&P challenges on earth—just as our people do every day—we've built a reputation for reliability and service excellence throughout the industry. For more information, please visit us at www.halliburton.com/wireline1.

HALLIBURTON

producing in the A-7 well; the Devonian Besa River shale at 2,000-3,000 m, producing in the A-2 well; and the Devonian Golata and Muskwa shales at 3,000-4,000 m. The Muskwa is not yet tested at Beaver River.

Transeuro said, "The appraisal strategy for the shale is to target the more brittle rock intervals that have higher carbonate and silica content and are therefore expected to respond favorably to stimulation. The brittle rocks contain free gas and may serve as a pathway for the shale gas to enter the well. The long-term production test is intended to establish how much gas can be recovered from the surrounding shale through the stimulated layer." ✦

Pluspetrol starts up Pagoreni gas-condensate field

The Peruvian government reported that the six-member Consorcio Camisea has begun production of natural gas at Pagoreni field on Block 56 in the Cuzco region and part of the Camisea gas-condensate project.

The consortium, comprised of Pluspetrol Peru Corp., Hunt Oil, SK Energy, Tecpetrol, Sonatrach, and Repsol YPF SA, said it will initially produce gas at six wells on the block.

The consortium said Pagoreni means an increase in the production of liquids of as much as 45,000 b/d and an increase in gas production from 500 MMcfd to 1.26 bcfd.

Gas is piped to the 450-MMcfd Malvinas gas processing plant near the Camisea fields and is then transported to Pisco, where naphtha, propane, butane, and diesel are extracted.

The consortium said the launch of production from Block 56 marks the exploitation of a new reserve of 3.4 tcf of gas and 227 million bbl of NGL, increasing the Camisea reserves to 14.8 tcf.

Development of Block 56, in which the consortium has invested some $850 million, is also being referred to as the second phase of the Camisea project as it is adjacent to Block 88, which went into production in mid-2004.

Welcomed production

The Block 56 production will be welcome in Peru, which is seeing demand growth for gas. In fact, demand has grown so quickly that the pipeline transporting gas from Camisea to the capital region has reached capacity.

The pipeline is operated by a consortium known as Transportadora de Gas del Peru SA, or TGP. According to the energy and mines ministry, TGP has a contract to increase capacity in the westbound pipeline to 450 MMcfd from the current 290 MMcfd.

Earlier this month, the Peruvian government awarded Conduit Capital Partners LLC subsidiary Kuntur Transportadora de Gas, SAC (Kuntur), a 30-year concession contract to build a southbound 700-km pipeline to carry gas from Camisea to the port of Ilo in southern Peru.

Development and construction cost for the pipeline, known as the Gasoducto Andino del Sur (GAS), is estimated to be $1.4 billion. Construction is due to begin in 2010, with operations expected to begin by yearend 2012.

Conduit said the pipeline will deliver "attractively priced gas that is expected to help spur economic growth in Peru's southern region, which will begin facing power shortages as soon as 2011." ✦

Egypt

Gulf of Suez Petroleum Co., the joint venture of BP PLC and Egyptian General Petroleum Corp., is drilling an appraisal well at the early 2008 Burtocal oil discovery on the North Shadwan block in the southern Gulf of Suez.

The concession has three undeveloped discoveries, said Beach Petroleum Ltd., Adelaide, which is acquiring a 20% interest from Tri-Ocean Energy, private Cairo operator, subject to final ministerial approval.

Two shallow nearshore discoveries each found 8 million bbl proved and probable recoverable, while Burtocal identified 24 million bbl in the Cretaceous Nubia sandstone.

Beach pointed out that the Nubia came on line May 15, 2008, at Gupco's Saqqara field, 7 km west of Morgan field, with four wells producing at the rate of more than 30,000 b/d through a 13-km pipeline to the Ras Shukeir onshore separation and gas processing plant.

Newfoundland

A group led by Chevron Canada Ltd. and Shell Canada Energy is seeking partners to carry part of the costs of an exploratory well in the Orphan basin 350 km east of St. John's, Newf.

The well, to be drilled in 2009, would be only the second well in the basin (see map, OGJ, Aug. 8, 2005, p. 32). The first well, Great Barasway F-66, was drilled in 2006-07 at a cost of $200 million. Results are confidential.

A farmee would assume part of Chevron and Shell's costs to earn up to a 25% interest in the prospect and an option to earn an interest in the balance of two licenses that total 4.2 million acres.

The licenses are in 1,500-3,500 m of water, and the prospect is supported by 3D and 2D seismic. ExxonMobil and Imperial Oil Ltd. each hold 15% interests in the licenses.

Missouri

MegaWest Energy Corp., Calgary, reported production of 50 b/d of heavy oil from shallow Pennsylvanian sands at its Marmaton River steam drive project in Vernon County, Mo.

It is operating 40 producing wells, 13 steam injectors, a water supply well, and a water disposal well in 10 acres. Steam injection is to start in November on an adjacent 10 acres with 24 producing and 10 injection wells.

Steam preheat at the Grassy Creek project with 46 producers and 15 injectors on 19 acres was to begin Oct. 15.

Continuing high oil, gas prices drive world drilling

Nina M. Rach
Drilling Editor

Crude oil prices hovered below $100/bbl in fourth-quarter 2007, keeping drilling crews busy and motivating operators to invest in capital-intensive projects. As the prices rose through 2008, more new rigs were ordered and day rates continued to increase. New yards are under construction in India and China, with nearly 200 newbuilds filling order books.

Oil averaged $123.80/bbl in second-quarter 2008, then fluctuated wildly in third-quarter 2008, from a high of $147.27 on July 11 to $90.51 on Sept. 16, averaging $118.22/bbl.[1] Turmoil in the US financial system has some analysts speculating about a looming recession and slowed demand for energy. On Sept. 29, Deutsche Bank lowered its 2009 New York oil price forecast by 23% to $92.50/bbl because of the economic crisis.[1]

High natural gas prices drive a lot of drilling in North America, where there's a pipeline infrastructure and established markets. Prices have been sufficient to justify the cost of hydraulic fracturing gas-bearing shales, and demand for frac services has increased sharply as operators pursue new shale plays around the US and Canada.

Operators of new pipeline projects in Australia and elsewhere will increase drilling in order to maintain a steady supply of natural gas to feed LNG trains (OGJ, Oct. 13, 2008, p. 45).

Improved technologies affect natural gas drilling by reducing costs and expanding the economically recoverable resource base.

Worldwide activity

Worldwide drilling set a record in August 2008, with 3,523 rigs operating, based on the Baker Hughes Inc. international rig count (Fig. 1).[2]

The North American rig count reached a historic high of 2,436 rigs in August 2008, up 13% from a year earlier and diverging from a pattern set over the last 5 years (Fig. 2, Baker Hughes). The seasonally cyclic trend, in which drilling spikes in February, is driven by Canadian operations.

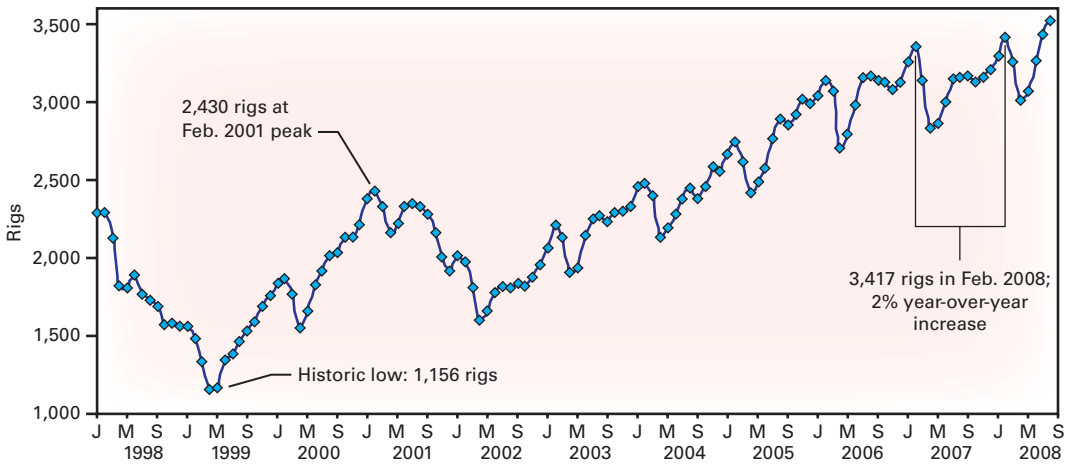
Normally, drilling falls off in March and April, increases over the summer, levels off in August and September, and then rebuilds to a new peak in February. In 2008, however, North American drilling has steadily increased since April, and August drilling surpassed February (Fig. 2).

Baker Hughes Inc.'s international rotary rig count (excluding North America, Iran, and Sudan) reached a record high of 1,102 rigs in June 2008, up 8.6% from 1,015 rigs a year earlier (Fig. 2). For BHI to count an international rig as active, it must have been drilling at least 15 days during the month. A rig is considered drilling if it is "turning to the right" and has not yet reached TD.[2]

The increase in international rig use is mainly driven by gains in Latin America, the Middle East, and Asia Pacific.

WORLD RIG ACTIVITY

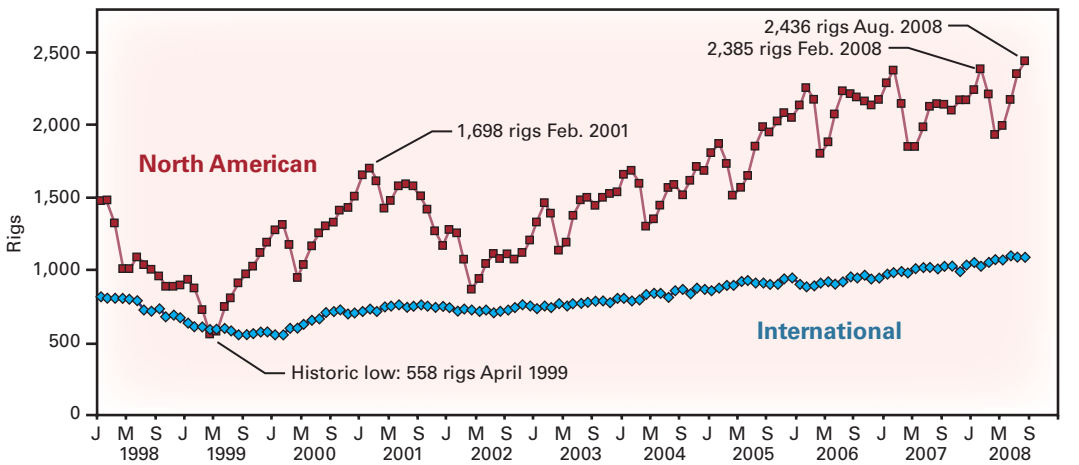
Fig. 1



Source: Baker Hughes Inc.

NORTH AMERICAN, INTERNATIONAL RIG COUNT

Fig. 2



Source: Baker Hughes Inc.

Drilling activity in Europe rose only slightly; activity has decreased about 10% in Africa (Fig. 3).

Drilling in Latin America increased about 9% year-over-year, with a new peak of 398 rigs active in June 2008. Most of this (80%) is land drilling.

Mexico hosted the largest number of active rigs—104 (77 land, 27 offshore) in August 2008, representing 27% of all rigs working in Latin America.

The largest land fleet in South America continues to work in Argentina, where 82 rigs were drilling in August, up from 73 rigs a year earlier. After Argentina and Mexico, land fleets are particularly active in Venezuela (56), Colombia (41), and Brazil (26), and Ecuador (12).

There was only minor land activity in Peru (6 rigs), Bolivia (4), and Trinidad and Chile (1 each).

Offshore Latin America, Brazil dominates with 29 rigs drilling in August, followed closely by Mexico and more distantly by Venezuela (14) and Trinidad (3).

Two rigs were drilling off Peru, which is uncommon. Peru's six offshore basins (from north to south: Tumbes, Talara, Sechura, Trujillo, Salaverry, and Pisco) have been very lightly explored.[3]

In the 1970s and 1980s, operators drilled 18 wells on five structures in the Tumbes basin, discovering oil and gas in five fields: Albacora, Barracuda, Corvina, Delfin, and Piedra Redonda.

BPZ Resources Inc. drilled five wells in Corvina field, the most recent in August 2008, and produces oil to an FPSO, according to company reports. Other operators have drilled four wells (dry holes) in the Trujillo basin, none in the Salaverry.[3]

State-run Petroleo Brasileiro SA (Petrobras) has been signing long-term contracts for many new MODUs, to ensure that it has sufficient capability to drill its increasing offshore portfolio. Brazil will also be the first country in Latin America to start building offshore rigs.

After Brazil's 1997 hydrocarbon law opened the oil sector to competition, independent oil companies enjoyed years of relatively open access to bid rounds and leases. Nevertheless, they were shut out from presalt bidding in the ninth round, November 2007. Brazil's Agencia Nacional de Petroleo (ANP) removed 41 blocks after the Tupi discovery was announced.

New presalt discoveries, such as Anadarko's Wahoo field and Petrobras's Jubarte field in the Campos basin and Tupi and Carioca in the Santos basin,

the digital asset™

speed

cost

Be there without being there.

Halliburton's **Real Time Centers™** (RTC) do more than integrate everything from prospect generation to drilling, logging, evaluation, reservoir modeling and production optimization. They enable you to do it all without having to be at the worksite. Change the way you work: Increase the speed of your operations and reduce costs at the same time.

From exploration to production, the **Digital Asset™** environment's integrated workflows allow you to fully realize the highest asset performance possible. For more information, go to www.halliburton.com/RTC.

Make decisions. Not compromises.™

HALLIBURTON

** North Sea Real Time Center customer*

TOP 50 US OPERATORS IN 2008

Table 1

Rank[1]	Company	Footage, drilled	% of total	Average footage	Well starts[2]	% of total	Dir. wells
1	Chesapeake Operating Inc.	12,653,336	5.4	9,250	1,371	4.0	922
2	XTO Energy Inc.	9,139,878	3.9	9,828	932	2.7	388
3	EOG Resources Inc.	8,985,167	3.8	9,311	970	2.8	549
4	Devon Energy Production Co. LP	7,214,821	3.1	9,121	797	2.3	622
5	EnCana Oil & Gas (USA) Inc.	6,461,157	2.7	10,388	624	1.8	406
6	Pioneer Natural Resources USA Inc.	4,154,350	1.8	9,684	435	1.3	77
7	Noble Energy Inc.	4,103,167	1.7	5,912	697	2.0	147
8	BP America Production Co.	3,935,948	1.7	9,327	436	1.3	298
9	Williams Production RMT Co.	3,748,284	1.6	6,429	585	1.7	418
10	Kerr-McGee Oil & Gas Onshore LP	3,707,453	1.6	8,369	444	1.3	239
11	Apache Corp.	3,245,238	1.4	9,864	370	1.1	56
12	Burlington Resources Oil & Gas Co. LP	3,243,868	1.4	9,951	335	1.0	171
13	SandRidge Energy Inc.	2,850,113	1.2	11,681	244	0.7	42
14	Forest Oil Corp.	2,681,748	1.1	11,036	244	0.7	31
15	Questar E&P Co.	2,637,255	1.1	12,210	218	0.6	101
16	Samson Lone Star LLC	2,571,075	1.1	12,361	209	0.6	54
17	ConocoPhillips Co.	2,544,455	1.1	6,858	383	1.1	97
18	Atlas Resources Inc.	2,441,997	1.0	6,326	397	1.2	9
19	HighMount E&P Texas LLC	2,357,455	1.0	7,938	297	0.9	1
20	Ultra Resources Inc.	1,781,680	0.8	13,498	133	0.4	112
21	Anadarko E&P Co. LP	1,706,947	0.7	8,286	206	0.6	74
22	Quicksilver Resources Inc.	1,582,400	0.7	8,462	187	0.5	182
23	El Paso E&P Co. LP	1,551,868	0.7	5,705	278	0.8	61
24	Cimarex Energy Co.	1,428,592	0.6	11,710	122	0.4	52
25	Cabot Oil & Gas Production Corp.	1,420,500	0.6	8,211	178	0.5	30
26	SEECO Inc.	1,393,796	0.6	4,052	345	1.0	318
27	Range Production Co.	1,388,155	0.6	8,024	173	0.5	66
28	Endeavor Energy Resources LP	1,358,766	0.6	9,119	149	0.4	3
29	Petroleum Development Corp.	1,327,375	0.6	6,412	207	0.6	49
30	St. Mary Land & Exploration Co.	1,316,097	0.6	9,401	142	0.4	40
31	Chevron USA Inc.	1,310,164	0.6	7,799	475	1.4	69
32	Bill Barrett Corp.	1,303,320	0.6	6,062	215	0.6	135
33	Henry Petroleum LP	1,286,258	0.5	10,809	119	0.3	0
34	Berry Petroleum Co.	1,257,522	0.5	3,881	329	1.0	95
35	Newfield Production Co.	1,250,367	0.5	6,946	183	0.5	58
36	Mariner Energy Inc.	1,201,875	0.5	10,926	123	0.4	14
37	Energen Resources Corp.	1,199,199	0.5	4,835	252	0.7	31
38	Whiting Oil & Gas Corp.	1,165,943	0.5	8,511	138	0.4	56
39	Marathon Oil Co.	1,142,143	0.5	12,551	149	0.4	137
40	Swift Energy Operating LLC	1,125,589	0.5	10,327	109	0.3	47
41	Cimarex Energy Co. of Colorado	1,110,088	0.5	8,741	134	0.4	44
42	Unit Petroleum Co.	1,096,770	0.5	9,706	113	0.3	23
43	Newfield Explor. Mid-Continent Inc.	1,080,198	0.5	10,802	101	0.3	91
44	Penn Virginia Oil & Gas LP	1,078,900	0.5	13,157	82	0.2	44
45	Shell Rocky Mountain Prod. LLC	1,056,240	0.4	13,370	79	0.2	76
46	Continental Resources Inc.	1,032,276	0.4	10,120	159	0.5	143
47	ExxonMobil Development Co.	1,025,291	0.4	12,658	83	0.2	63
48	KCS Resources Inc.	1,015,247	0.4	9,146	111	0.3	34
49	BP Exploration (Alaska) Inc.	933,801	0.4	8,413	140	0.4	129
50	Goodrich Petroleum Co.	929,300	0.4	12,069	77	0.2	7
	Total		**54.4**			**44.2**	**6,911**

[1]Rank according to number of wells drilled. [2]Wells deeper than 2,500 ft.
Source: RigData; data from January-September 2008

are likely to usher in a long period of ultradeep drilling (OGJ, Oct. 6, 2008, p. 30). Petrobras has already spent more than $1 billion drilling 15 wells in the ultradeep presalt, announcing 10 discoveries.[4]

Petrobras indicated it would order 28 new rigs to develop the presalt plays, beginning in 2013. If all 28 rigs are delivered on schedule and fully utilized, and each well takes 100 days to drill, Simmons analysts say Petrobras could theoretically drill 700 wells by 2024.[4]

In the Middle East, 289 rigs were drilling in August, up 7% from a year earlier. Most of this (89%) is land drilling. Offshore activity decreased 11% to 32 rigs, but land drilling was up 10%, to 257 rigs. Three countries have particularly active drilling programs: Saudi Arabia, Egypt, and Oman. Saudi Arabia had the largest share (26%) of rigs in the Middle East, split 65 land frigs and 10 offshore. The second largest concentration (21%) was in Egypt (60 rigs, split 49 land, 11 offshore). Oman was running 55 rigs, all but one on land.[2]

Another cluster of countries includes Pakistan, with 25 rigs drilling in August, Syria (20), Yemen (15), Kuwait (13), Abu Dhabi (11), and Qatar (10). There was minor activity in Dubai and Jordan (2 land rigs each). Baker Hughes discontinued counting rigs in Iran and Sudan in January 2006. [2]

Europe had 97 rigs operating in August, split nearly evenly between land (49) and offshore (48). Activity was up 18% from 82 rigs working a year earlier. Four countries accounted for 61% of the European activity: UK (24 rigs), Romania (18), Norway (17) and Germany (10). Smaller fleets were running in Turkey (6 rigs), Hungary (5), Italy (4), Netherlands (3), Denmark (2), France and Poland (1 each), and 6 elsewhere.

Drilling in Asia-Pacific increased

Stimulation Equipment For The Oilfield

Stewart & Stevenson, equipment supplier to the worldwide oil and gas industry, provides stimulation equipment utilized in fracturing applications. Featuring technically advanced controls that improve job quality and simplify operation, our stimulation units work as a fully integrated system to perform fracturing treatments. Included are:

- Fracturing Pumps
- Blenders
- Chemical Additive and Hydration Systems
- Acidizing Equipment
- Support Equipment
- Data Acquisition and Control Centers

Stewart & Stevenson's comprehensive oilfield equipment also includes:

- Drilling and Workover Rigs
- Coiled Tubing Systems
- Power Generation Systems
- Diesel and Natural Gas-Fueled Engines
- Transmissions and Torque Converters

Wherever our equipment is put into service around the globe, we offer customer support that includes equipment training, commissioning and servicing.

Stewart & Stevenson…a trusted name for over 100 years.

U.S. Sales & Service
Houston, Texas: 713-751-2632
Edmond, Oklahoma: 405-562-0025

Canada Sales & Service
Calgary, Alberta: 403-215-5300

International Sales & Service
Houston, Texas: 713-751-2649

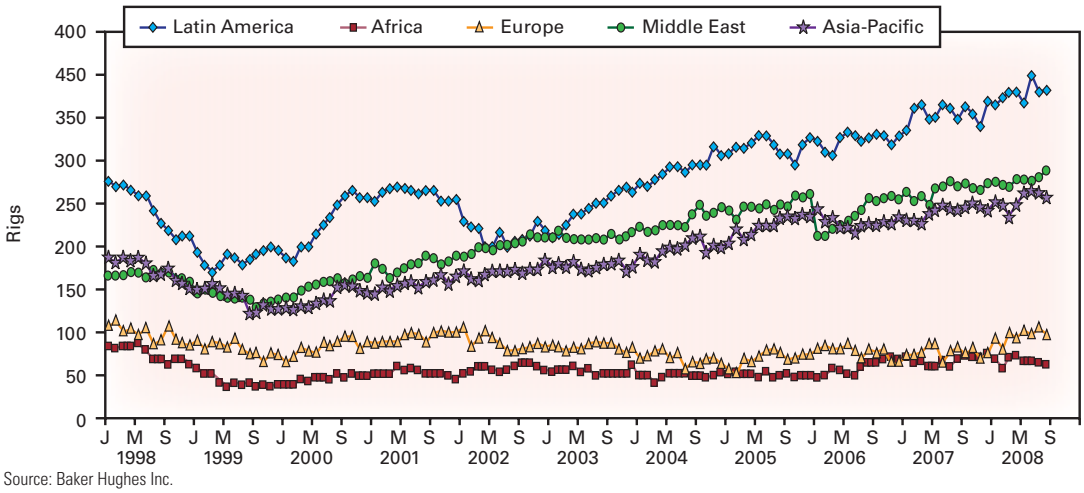
STEWART & STEVENSON

Building For Our Next Century

Visit us on the Web at www.stewartandstevenson.com.

INTERNATIONAL RIG COUNT BY REGION

Fig. 3



Source: Baker Hughes Inc.

about 7% over the year, with 257 rigs working in August 2008, up from 241 in 2007. Land drilling (53%) slightly leads offshore work.[2]

The most drilling activity in August 2008 was in India (80 rigs) and Indonesia (63), accounting for 56% of drilling in the region, according to Baker Hughes.

Cairn India ordered two new super-single AC-powered drilling rigs from Weatherford International; the first arrived in late September. Both will be used in development drilling in Rajasthan, where Cairn has delineated several oil fields (Fig. 4).

Significant fleets are also working in Australia (29 rigs), China offshore (24), Thailand (13), Malaysia (11), and Vietnam offshore (9). Smaller numbers are drilling in New Zealand (6 rigs), Myanmar (5), Brunei and Papua New Guinea (4 each), Japan (3), Phillipines (2), and other places (4).

Drilling activity in Africa has dropped about 9% from a year ago. In August 2008, 62 rigs were drilling in more than eight African countries and about 74% of those were on land.

About 37% were at work in Algeria (23 rigs) and another 24% in Libya (15 rigs). Tunisia and Angola each had 5 rigs, Nigeria 4, Congo 3, Gabon 1, and 6 were working elsewhere.[2]

SCORE ends

After acquiring Global Santa Fe Corp. last year, Transocean Inc. has discontinued the monthly summary of current offshore rig economics (SCORE). This measure was initiated by Houston-based offshore drilling contractor Global Marine and was a useful measure of profitability. The calculations compared the profitability of current mobile offshore drilling rig rates to the profitability of rates at the 1980-81 peak of the offshore drilling cycle, when speculative new rig construction was common. In 1980-81, SCORE averaged 100% and new-contract day rates equaled the sum of daily cash operating costs plus about $700/day profit/$1 million invested.

Transocean is the world's largest offshore drilling contractor, controlling 146 mobile offshore drilling units (MODUs), about 24% of the global fleet.

Cairn drillers work the drill floor in Ravva field, Rajasthan state, India (Fig. 4; photo from Cairn India).

2008 UTILIZATION OF TOP 25 US DRILLING CONTRACTORS—ONSHORE AND OFFSHORE*

Table 2

Rank	Company	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Average monthly rig use	2008 fleet	2007 fleet
1	Patterson-UTI Drilling Co. LP	242	243	247	250	245	251	264	269	251	331	324
2	Nabors Drilling USA LP	234	223	229	234	245	250	254	263	242	334	319
3	Helmerich & Payne IDC	159	160	165	168	173	174	180	185	171	194	164
4	Grey Wolf Drilling Co. LP	101	100	102	101	102	105	110	111	104	119	123
5	Unit Drilling Co.	73	71	69	68	71	71	72	74	71	88	81
6	Nomac Drilling LLC	1	2	3	4	7	18	62	62	20	64	58
7	Pioneer Drilling Co.	57	56	57	61	60	59	63	63	60	64	64
8	Ensign United States Drilling Inc.	53	52	51	51	51	51	51	51	51	56	56
9	Union Drilling Inc.	35	33	35	38	38	42	44	45	39	57	52
10	Trinidad Drilling LP	38	41	44	44	44	44	44	45	43	46	39
11	Bronco Drilling Co. Inc.	35	34	37	39	41	41	39	38	38	54	56
12	Cactus Drilling Co. LLC	39	40	40	40	41	41	41	41	40	43	38
13	Lariat Services Inc.	36	37	38	38	38	39	40	40	38	47	43
14	Hercules Drilling Co. LLC	27	23	29	26	31	34	35	35	30	56	55
15	Goober Drilling LLC	34	33	33	34	35	35	35	36	34	37	31
16	Key Energy Services Inc.	15	15	21	21	25	26	17	19	20	44	16
17	Unit Texas Drilling LLC	28	27	26	28	29	30	30	31	29	35	38
18	Rowan Drilling Co. Inc.	25	25	25	26	27	28	28	29	27	31	28
19	Cyclone Drilling Inc.	19	18	20	21	24	23	24	25	22	27	27
20	Precision Drilling Oilfield Services Inc.	11	13	14	14	17	18	21	25	17	27	7
21	Capstar Drilling LP	24	25	25	26	26	26	26	26	26	27	24
22	Nabors Well Services Co.	13	14	14	16	19	19	17	16	16	26	73
23	Big Dog Drilling Co.	23	23	23	22	23	24	24	25	23	25	23
24	Nabors Offshore Corp.	13	13	14	13	18	17	17	17	15	44	42
25	Felderhoff Brothers Drilling LLC	18	21	20	20	19	20	22	22	20	23	22
	Active rigs	**1,353**	**1,342**	**1,381**	**1,403**	**1,449**	**1,486**	**1,560**	**1,593**	**1,446**	**1,899**	**1,803**

*Some rigs that worked earlier in the year may no longer be marketed.
Source: RigData; based on data Jan. 1-Aug. 31, 2008

US drilling

US drilling continues to increase as operators continue to develop conventional plays and target new shale-gas plays throughout the country.

RigData's list of the top 50 operators, based on footage drilled, shows that they drilled 15,279 wells (including 6,911 directional wells) in the first 9 months this year, all deeper than 2,500 ft (Table 1). This is an 18% increase over the 12,991 wells that the 50 top operators drilled in 2007 (OGJ, Oct. 22, 2007, p. 41). And yet, those 15,279 wells represented only 44.2% of all the wells drilled in the US through September 2008, while the 12,991 well starts in the first 3 quarters of 2007 represented 50.7%.

The number of directional wells, 6,911, represented 45% of all wells drilled. Three operators each drilled more than 500 directional wells: Chesapeake Operating Co. (922), Devon Energy Production Co. LP (622), and EOG Resources Inc. (549).

Five operators drilled 250-499 directional wells: Williams Production RMT Co. (418), EnCana Oil & Gas (USA) Inc. (406), XTO Energy Inc. (388), SEECO Inc. (318), and BP America Production Co. (298).

Fifteen of the top 50 operators drilled wells with an average footage of 10,000 ft or greater. Seven operators drilled wells with an average footage of 12,000 ft or greater: Ultra Resources Inc., Shell Rocky Mountain Production LLC, Penn Virginia Oil & Gas LP, Exxon-Mobil Development Co., Samson Lone Star LLC, Questar E&P Co., and Goodrich Petroleum Co.

RigData ranks Patterson-UTI Drilling Co. first in rig utilization among US drilling contractors, but three Nabors companies are listed separately (Table 2). Taking Nabors Drilling USA LP (ranked second), Nabors Well Services Co. (ranked 22), and Nabors Offshore Corp. (ranked 24) as a single entity, and the overall utilization would be higher, 273 rigs used, on average, each month, compared with Patterson-UTI's average of 251 rigs.

Other top drillers, with an average 50 rigs or more in use each month, are: Helmerich & Payne IDC ,171 rigs in use; Grey Wolf Drilling Co. LP, 104; Unit Drilling Co., 71; Pioneer Drilling Co., 60; and Ensign US Drilling Inc., 51.

US rig counts are considerably higher than a year ago. Table 3 shows the 4-week average for all US rigs in September 2008 was 2,018, up 13% from 1,787 rigs a year earlier.

For the week ending Sept. 26, 2008, the Baker Hughes rig count listed 1,912 rigs drilling in the US, while RigData listed 2,315 working rigs (Table 3). There were also 69 rigs (BHI; 114 RigZone) drilling off Alabama, Alaska, California, Florida, Louisiana, and Texas. Baker Hughes listed 14 rigs working in Louisiana's inland waters; Rigzone reported 35 in Louisiana and 4 in Texas inland waters. Baker Hughes rig counts are more conservative, and only include rigs "turning to the right."

M&A, IPO

According to Forbes, 2008 is "on pace to be the year with the least number of mergers and acquisitions in a decade." Initial public offerings are also scarce, it noted, with only seven venture-backed offerings.[5]

On Sept. 30, Dow Jones VentureSource reported that in third-quarter 2008, returns from venture-backed companies reached a new low, down

66% from a year earlier.

The quivering credit market and instability in the US financial system may leave investors particular risk-adverse, unwilling to bankroll innovative companies in the energy sector. This may delay the introduction of cutting-edge technologies, so badly needed as drilling reaches record levels of activity and presses further into deep water, arctic, and hostile temperature-pressure environments worldwide.

Larger IOCs, NOCs, and service companies may be more insulated from the financial fallout than start-ups, but few companies will be immune to the global credit crunch in their sponsorship of basic R&D activities.

In the not-too-distant past, drilling services were available through short-term contracts, but surging demand for rigs and experienced professionals has led operators to lengthened contracts and advance commitment of capital.

US ONSHORE AND OFFSHORE DRILLING ACTIVITY

Table 3

State, district	Baker Hughes's rig count: 4-week avg. 2007	4-week avg. 2008	Week, as of 9/14/08	Week, as of 9/21/08	RigData's working rigs: 4-week avg. 2007	4-week avg. 2008	Week, as of 9/14/08	Week, as of 9/21/08	Waiting to spud
Alabama	4	5	4	4	4	4	4	3	1
Offshore	1	1	1	1	—	—	—	—	—
Total	**5**	**6**	**5**	**5**	**4**	**4**	**4**	**3**	**1**
Alaska	5	8	8	8	12	14	15	15	1
Offshore	—	3	3	3	—	2	2	2	—
Total	**5**	**11**	**11**	**11**	**12**	**16**	**17**	**17**	**—**
Arkansas	49	59	59	59	52	67	66	64	4
California	34	47	46	46	39	43	42	40	1
Offshore	2	1	1	1	—	—	—	—	—
Total	**36**	**48**	**47**	**47**	**39**	**43**	**42**	**40**	**—**
Colorado	116	115	116	109	117	130	129	126	4
Florida	—	1	1	1	—	1	1	1	—
Offshore	1	2	2	2	—	—	—	—	—
Total	**1**	**3**	**3**	**3**	**—**	**1**	**1**	**1**	**—**
Illinois	1	—	—	1	7	10	10	11	—
Indiana	2	2	2	2	4	2	1	2	—
Kansas	14	11	10	12	50	59	55	59	4
Kentucky	11	12	12	12	11	14	13	17	—
Louisiana									
North, land	62	85	89	85	71	105	102	108	3
South, land	25	26	25	26	42	36	36	34	5
Offshore	56	55	56	51	46	59	61	58	4
Inland waters	25	19	21	14	39	36	37	35	—
Total	**168**	**185**	**191**	**176**	**198**	**236**	**236**	**235**	**12**
Michigan	2	2	2	2	11	11	10	10	—
Mississippi	11	16	17	16	24	20	19	19	1
Montana	13	11	10	10	18	14	15	11	2
Nebraska	—	—	—	—	5	1	—	1	—
Nevada	3	3	3	4	2	1	1	1	—
New Mexico	74	91	91	91	67	93	95	93	—
New York	6	7	7	8	6	9	9	8	—
North Dakota	43	74	73	75	44	88	85	88	4
Ohio	14	10	10	10	12	14	14	14	—
Oklahoma	195	212	211	202	218	246	240	244	12
Oregon	—	1	1	1	—	—	—	—	—
Pennsylvania	16	27	27	27	43	59	63	61	—
South Dakota	2	1	1	2	2	1	1	1	—
Tennessee	5	2	2	2	4	2	1	1	1
Texas	168								
District 1	26	27	27	25	27	28	30	28	3
2	33	36	35	38	42	42	44	44	—
3	56	62	59	61	63	77	76	79	10
4	86	91	93	87	93	98	99	100	12
5	186	187	185	189	186	188	186	186	13
6	122	132	135	141	128	146	148	146	9
7b	37	31	29	30	51	50	46	51	4
7c	59	71	71	69	62	73	69	69	3
8	110	132	130	129	126	150	149	149	9
8a	19	27	29	26	24	32	30	32	4
9	37	42	43	44	44	57	56	58	1
10	60	99	100	100	70	96	96	94	3
Inland waters	1	1	—	—	2	4	4	4	—
Offshore	6	11	11	11	10	12	12	13	—
Total	**831**	**937**	**936**	**939**	**916**	**1037**	**1029**	**1036**	**71**
Utah	42	45	42	43	53	61	62	61	2
Virginia	3	6	6	6	3	4	4	4	—
Washington	1	1	1	1	1	1	1	1	—
West Virginia	33	28	28	28	33	35	33	33	1
Wyoming	78	80	83	80	135	146	142	148	2
US deep water	—	—	—	—	37	42	43	41	1
Total	**1,787**	**2,018**	**2,018**	**1,995**	**2,140**	**2,483**	**2,457**	**2,468**	**124**

Source: RigData; a summary of data presented in the Sept. 26, 2008 edition of "LOCATION & OPERATORS" report

Newbuilds, offshore

Drilling contractors continue to make significant capital investments in their fleets, committing billions to new rigs. According to ODS-Petrodata, about 189 new MODUs are under construction worldwide, including 84 jack ups, 56 semisubs, 43 drillships, and 6 drilling tenders, to be delivered 2008-11 (Table 4).

This backlog is up 36% from the 140 MODUs under construction a year ago (OGJ, Oct. 22, 2007, p. 41). So far, only half (18) of the 35 jack ups scheduled for 2008 completion have been delivered this year, and orders continue to accumulate (Fig. 5).

Adding 189 new rigs to the fleet of 620 MODUs will increase the fleet by 30%, to 809 offshore rigs (Table 5).

On May 30, Petrobras announced board approval for contracts on 12 newbuild, ultradeep drilling rigs. Ten of these will be owned by Brazilian companies, but built overseas.[4]

The 12-rig order strengthened the ultradeep newbuild market and Sim-

MODUs* UNDER CONSTRUCTION

Table 4

	Jack ups	Semisub-mersibles	Drill-ships	Tenders	Total
US Gulf of Mexico	12	—	—	—	12
Latin America	2	2	2	—	6
North Sea	0	2	—	—	2
Europe - other	0	3	—	—	3
Mediterranean	0	1	—	—	1
Middle East	15	3	—	2	20
India	3	—	—	—	3
Southeast Asia	35	25	—	4	64
Far East	16	18	41	—	75
Caspian Sea	—	1	—	—	1
Russian Arctic	1	1	—	—	2
Total	**84**	**56**	**43**	**6**	**189**
MODUs under construction by delivery date					
2008	17	9	1	—	27
2009	39	19	6	2	66
2010	23	13	15	3	31
2011	5	10	17	1	28
Undetermined	—	5	4	—	—
Total	**84**	**56**	**43**	**6**	**189**
MODUs under construction with no drilling contract					
2008	3	—	—	—	3
2009	28	—	—	2	30
2010	19	4	5	2	30
2011	4	5	12	1	22
Undetermined	—	3	—	—	3
Total	**54**	**12**	**17**	**5**	**88**

*MODU - mobile offshore drilling unit.
Source: ODS-Petrodata Inc., Offshore Rig Locator, Sept. 1, 2008

OFFSHORE RIG FLEETS: OCTOBER 2008

Table 5

Rig type	Current fleet size	Units under construction	Future fleet size
Jack ups	379	84	463
Semisubmersibles	160	56	216
Drillships	38	43	81
Tenders	26	6	32
Drill barges	11	—	11
Submersibles	6	—	6
Total	**620**	**189**	**809**

Sources: Rigzone; ODS-Petrodata Inc.; shipyard and operator announcements

Keppel FELS delivered the Discovery I, an enhanced B-class jack up rig, 49 days ahead of schedule to Discovery Drilling, a joint venture of Jindal Drilling & Industries. The rig will go to work off India under a 3-year contract for ONGC (Fig. 5; photo from Keppel FELS Offshore & Marine Ltd.).

mons analysts said drilling contractors will expect 5-7-yr term contracts at or above $550,000/day to justify building new semisubs and drillships.[4]

Petrobras has yet to order an additional 28 deepwater rigs, but will need them delivered 2013-17 to support announced project plans. Will this lead to further cost inflation?

Among recent announcements:

- *Sept. 22:* Noble Corp. announced that subsidiary Noble Drilling Holding LLC is building a new harsh environment Globetrotter-class drillship for $585 million. The hull and propulsion systems will be built by South Korea's STX Heavy Industries Co. Ltd. in a new yard in Dalian, China, and the topsides by Huisman Equipment BV in the Netherlands (Fig. 6). Noble has options for three more drillships expiring end of first-quarter 2009.
- *Sept. 25:* Norwegian rig contractor MPF Corp. Ltd. announced that it filed for insolvency protection under the provisions of both US Chapter 11 and Provisional Liquidation in Bermuda. The company said there were "substantial cost overruns" in the construction of its MPF01 drillship. The hull is under construction at COSCO's shipyard in Dalian. The "Multi-Purpose Floater" was designed to handle early production and will be the world's largest drillship.[6]

Looking ahead

There are no signs that the demand for oil and natural gas will abate, and continuing high prices should promote continued drilling. Most analysts are bullish on the broader energy cycle.

Most of the newbuilds for land fleets and more than half of the MODUs under construction (Table 4) are already committed to contracts, so we may see additional building as new plays require rigs.

One of the most interesting areas to watch will be offshore Brazil, which has 55 MODUs under contract and more on the way. The rapidly expanding fleet of ultradeepwater and harsh environment rigs will require thousand of experienced personnel—how will we get them?

Land drilling will continue to

Noble Drilling Corp. ordered a drillship based on the Huisdrill 10,000 design in late September (Fig. 6; image from Huisman Equipment BV).

increase as long as natural gas prices remain high and newbuilds enter the market and renew the fleets. Operators will need them to pursue unconventional resource plays and explore relatively untapped basins, particularly in North and South America, Australia, and India. ✦

References

1. Habiby, Margot, "Oil Drops Most in 17 Years in Quarter on Economy Woes," Bloomberg.com, Sept. 30, 2008.
2. Baker Hughes Inc. rig counts, http://investor.shareholder.com/bhi/rig_counts/rc_index.cfm.
3. Ghazi, Tarek, "GIS-aided play assessment of several basins in offshore Peru," Apr. 4, 2006, http://gis.esri.com/library/userconf/pug06/papers/peru_basins.pdf.
4. Kessler, Robert A., Mei, Brandon, and Khoja, Kazim, "Petrobras Initiation Report," Simmons & Co. International, Energy Industry Research, Sept. 9, 2008.
5. Corcoran, Elizabeth, "Sucker punch for innovation," Forbes.com, Oct. 1, 2008.
6. MPF Corp., www.mpf-corp.com.

Canadian drilling activity continues to slow

Nina M. Rach
Drilling Editor

Canadian drilling continues its decline, but Canadian drillers are diversifying, sending rigs to the US and abroad, purchasing US rig fleets, and continuing to upgrade equipment.

Although Canada is the world's third-largest producer of natural gas, it is slowly becoming a net importer due to its severe climate and high level of industrialization. Canada usually exports a significant amount of energy output, predominantly to the US, but when the electrical grid is under pressure, provinces buy power back from the US.[1]

Roger Soucy, president of the Petroleum Services Association of Canada (PSAC), told OGJ that the new increased government royalty rates in Alberta will come into effect Jan. 1, 2009, and will "negatively affect future activity." The value of drilling and service companies on the market is also depressed due to the price of oil, which has fallen to less than $100/bbl from $147/bbl earlier this year, and the impending crash of the financial and credit markets, he said.

On the upside, Canada's oil exports increased to nearly $31 billion (Can.) in first-half 2008, although volumes did not increase from 2007. The Weekly Energy Bulletin for Sept. 22-26, published by Nickle's Canadian Oil Register, pondered that "record oil prices and slowly growing export volumes could result in the value of the country's oil exports reaching an all-time high of around $60 billion or more this year, easily smashing the 2007 record of $41.5 billion."

Forecasts

On July 25, PSAC predicted drilling activity will decrease 11% in 2008, in an updated Canadian drilling forecast.[2] The initial release of the 2008 forecast in October 2007 projected 14,500 wells would be drilled in 2008. But in April, PSAC revised this upward to 16,500 wells in 2008.[3] The July update reiterates the prediction of 16,500 wells, noting that this is still 11% fewer than the total number drilled in 2007 (18,557 wells).

On Apr. 23, PSAC's Soucy said, "While all the talk of late is centered on the price of oil, it's actually the price of natural gas that affects the industry in Canada, especially in Alberta." With so much focus placed on the oilsands, he said, many, "including our government, seem to overlook the fact that the conventional—gas-based—industry is still where the vast majority of royalties and other industry revenues to the government and Albertans come from."

Among the provinces, PSAC

PSAC CANADIAN INDEX

Fig. 1

Source: Petroleum Services Assoc. of Canada; Oct. 15, 2008

forecasts:

- 11,815 wells in Alberta, down 15% from 2007.
- 820 wells in British Columbia, down 6% from 2007.
- 3,445 wells in Saskatchewan, up 1% from 2007.
- 360 wells in Manitoba, up 12% from 2007.
- 40 wells in Ontario, down 13% from 2007.
- 14 wells in eastern Canada (Quebec, New Brunswick, Nova Scotia, Prince Edward Island, and Newfoundland-Labrador), down 42% from 2007.

PSAC also predicts that another six wells will be drilled in northern Canada this year (Yukon, Northwest Territories, Nunavut), down 25% from 2007.

Market index

PSAC Index companies

Companies represented in Fig. 1 include:

Bonnett's Energy Services Trust
Cathedral Energy Services Income Trust
Canadian Energy Services LP
CE Franklin Ltd. Co.
Calfrac Well Services Co.
Enerflex Systems I Trust
Ensign Energy Services Co.
Eveready Income Fund
Essential Energy Services Trust
Flint Energy Services Co.
IROC Energy Services Co.
Mullen Group Inc. Fund Trust
Newalta Income Fund Trust
Norex Exploration Co.
Precision Drilling Trust
Peak Energy Services Trust
Phoenix Technology Inc. Trust
Petrowest Energy Services Trust
Pulse Data Inc.
Pason Systems Corp.
Pure Energy Services Co.
Shawcor Ltd.
Saxon Energy Services Co.
Savanna Energy Services Co.
Trican Well Service Co.
Technicoil Corp.
Tesco Corp.
Total Energy Services Trust
Wenzel Downhole Tools Co.
ZCL Composite Inc.

Source: Petroleum Services Association of Canada

PSAC, Canada's national trade association, represents more than 270 companies in the service, supply, and manufacturing sectors of the upstream petroleum industry. The Canadian Index compiles the market performance of the Top 30 (by market cap) Canadian, publicly traded PSAC member companies (Fig. 1).

The data show a drop in the PSAC index to about 140 at the end of September, from a high of 200 in mid-June.[4] The index in mid-September was 30 points below its position a year earlier (170), attributable to change in the taxation regime in Alberta (OGJ, Oct. 22, 2007, p. 50) and to general downturn in the financial markets. This was followed by a precipitous fall in mid-September to a low of about 90 in mid-October. This decline is not limited to Canada; the Philadelphia oil field index of US companies shows a similar decrease.

Companies are added or removed from the PSAC Top 30 list quarterly.

Drilling contractor mergers

Several Canadian drilling contractors have acquired US-based fleets in the past year.

In June, Calgary's Savanna Energy Service Corp. purchased five drilling rigs and equipment from privately held GreyStone Drilling LP for $59 million ($11.8 million/rig).[5] All five of the rigs are working in the Haynesville in Louisiana and Texas.

Precision Drilling Trust is in the final stages of acquiring Houston-based Grey Wolf Inc., one of the largest US drilling contractors. Based on footage drilled in 2007 and the size of its US land drilling fleet (120 units), Grey Wolf is the fifth largest drilling contractor, with a market capitalization of $1.9 billion (OGJ, Sept. 1, 2008, p. 39).

The merger is worth $1.12 billion in stock and cash, working out to $9.3 million/rig. Pro forma ownership of the new company will be 75% Precision Drilling and 25% Grey Wolf.

According to Precision Drilling's presentation at the Peters & Co. Ltd. North American Oil & Gas Conference on Sept. 11, the rationale for its merger with Grey Wolf is to:

- Build high-performance rigs at lower cost.
- Introduce superseries rigs to new customers.
- Drill North American oil and gas shales.
- Grow internationally, targeting global oil.

The fleet of the combined company will include 371 drilling rigs, 19 newbuilds, and 229 service rigs; second only to Nabors Drilling in North America. Most of the new combined fleet is in Canada (221 drilling rigs, all service rigs). Another 147 drilling rigs are in the US, as well as 2 in Mexico and 1 in Chile, as of Aug. 22.

Fleets

Savanna Energy Services offers drilling services through three subsidiaries: Trailblazer Drilling Corp., Lakota Drilling, and Akuna Drilling Inc. The average age of the 104-rig fleet is less than 5 years. Drilling accounts for 80-85% of the company's revenues, and well-servicing 15-20% (through Savanna Well Servicing).

According to Savanna's second-quarter 2008 results, announced Aug. 5, the company has expanded its rig fleets into southern Saskatchewan (6 drilling, 8 well service) and the US (14 drilling). Expecting a strong demand in 2009, the company has also increased its 2008 capital construction program by $54.5 million to a total of $150 million for the year. The new allocation covers four additional heavy-duty double drilling rigs, two double service rigs, drill pipe, and other equipment, expected to be in service by third-quarter 2009.

Savanna is enhancing its capabilities in deep directional and horizontal gas and oil drilling and will have 108 drilling rigs and 72 well service rigs at the end of the construction program. Nearly half of the fleet (46 rigs) consists of hybrid drilling rigs, designed to accommodate both coiled tubing and conventional, jointed, Range 3 pipe

with automated pipe-handling equipment and top drives (Fig. 2).

Savanna drilled 4,586 wells with its hybrid rigs in 2007, dominating the sub 2,000-m market in Canada.[6] Savanna's market share increased to about 25% of all Canadian wells drilled in mid-2007, up from 16% in mid-2005.

Trailblazer Drilling, one of Savanna's subsidiaries, designed the hybrid rigs in 2002, and the hybrid fleet now consists of:

- 38 first-generation rigs (CT1500), capable of drilling to 1,500 m with 2⅞-in. coiled tubing or 1,200 m with 3½-in. drill pipe.
- 8 second-generation rigs (CT2200), capable of drilling to 2,200 m with 3½-in. coiled tubing or drill pipe.

Precision Drilling is building 19 Super Series rigs in its 2008 build program, with long-term contracts for all. The company has the capacity to manufacture 8 rigs/quarter.

Operators drilling

According to Nickle's Rig Locator on Oct. 15 (www.nickles.com/rig), the five busiest operators drilling in Canada were:

- Husky Energy Inc., 32 rigs.
- EnCana Corp., 32 rigs.
- Talisman Energy Inc., 25 rigs.
- ConocoPhillips Canada Ltd., 20 rigs.
- Canadian Natural Resources Ltd., 19 rigs.

Western Canada

Most Canadian drilling is in the Western Canada Sedimentary basin, predominantly Alberta and British Columbia.

According to Nickle's Rig Locator Drilling Summary, companies have drilled and completed 15,715 wells in western and northern Canada during January-September 2008, down slightly from the same period in 2007. Industry reported 1,181 wells completed in August 2008, down 17% from a year earlier.

The western Canadian drilling fleet had an average 846 rigs available to work in the first three quarters of 2008, down slightly from 866 rigs last year, and has operated at 46% average utilization, up from 42% utilization in 2007.

Calgary's Savanna Energy Services Corp. has 46 hybrid drilling rigs in its fleet, capable of running coiled tubing or conventional jointed pipe with top drives and automated pipe-handling equipment (Fig. 2; photo from Savanna Energy).

Based on weekly surveys, Nickle's reported that an average of 394 rigs were active between January and the end of September, up 8% from 365 rigs active a year earlier.

Rig counts were higher in every province except Alberta, which suffered only a 1% decline to an average of 263 rigs working, down from 265.

Saskatchewan kept an average of 63 rigs working, up 37% from last year (46 rigs).

British Columbia kept 61 rigs working, on average, up 22% from last year (50 rigs).

Manitoba oil drilling kept six rigs working this year, up 50% from the four rigs working last year.

On Aug. 12, 2008, the Canadian Association of Oilwell Drilling Contractors forecast that 18,087 wells would be drilled this year in western Canada, down about 5.5% from 19,144 wells drilled in 2007. This revision is a 28% improvement over the dismal 2008 forecast issued in October 2007.

CAODC attributed the positive revision to "increasing activity based on renewed strength in commodity prices and positive drilling results, particularly in the high profile [shale] plays in Saskatchewan (Bakken) and British Columbia (Montney)."

CAODC also predicted that the size of the western Canadian drilling fleet would decrease to 885 rigs by yearend 2008 and that rig utilization in 2008 would increase to 42%, up from 38% in 2007.

Historically, the average Canadian rig utilization over the past 4 years has been 59%:

- 43% in 2007.
- 64% in 2006.
- 64% in 2005.
- 63% in 2004.

The fleet usually reaches peak utilization in February (Fig. 3).

In February 2008, utilization was only 76%, slightly down from 77% a year earlier.

The drilling success rate in western Canada dropped significantly in the first 8 months of 2007 as the percentage of dry holes nearly doubled, increasing to 9.7% from 4.9% in 2007 (Fig. 4).

The percentage of oil drilling, relative to gas drilling, has been increasing since 2004. There were 6,114 gas wells and 3,332 oil wells drilled in the first 8 months of 2008, about 1.8 gas wells/oil wells (Fig. 4). This compares with previous years:

- 2.4 gas/oil wells in 2007.
- 2.7 gas/oil wells in 2006.
- 3.2 gas/oil wells in 2005.
- 3.5 gas/oil wells in 2004.

This 5-year downward trend can be attributed to the overall rise in world oil prices relative to Canadian gas prices. There is no energy parity; natural gas price increases have not kept pace with oil prices and gas subsequently trades at a substantial discount to oil in terms of its energy value.

Canadian Beaufort

On June 6, the Minister of Indian

Affairs and Northern Development gave notice of the bids selected after the 2008 Beaufort Sea/Mackenzie Delta Call for Bids closed on June 2.[7]

BP Exploration Co. Ltd. bid $1.17 billion (Can.) and won three offshore exploration licenses in the Canadian Beaufort Sea: EL449, EL 451, and EL453. The company was already a large landholder in the Canadian arctic through its acquisition of Amoco Canada Petroleum Co. in 1998.

MGM Energy Corp. and Devon Energy Corp. paid $5.5 million (Can.) for EL450, a 41,000 hectare parcel in the Tulita region of the Northwest Territories, southeast of Norman Wells.

ConocoPhillips Canada Resources Corp. won EL452 with a bid of $2.54 million (Can.). This 196,000 hectare parcel abuts the southern edge of the three BP licenses.

The new license holders must drill wells within 5 years in order to hold the blocks for an additional 4 years.

Off Newfoundland

The Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB) released its 2007-08 annual report on June 4, 2008, detailing activities in the province.

C-NLOPB issues land rights in the form of exploration licenses (EL); significant discovery licenses (SDL), and production licenses (PL). As of Mar. 31, 2008, in the Newfoundland and Labrador Offshore Area, there were:

- 37 ELs with total work commitments in excess of $731 million (Can.).

This includes one new EL (1105) issued in January 2008 to Corridor Resources Inc. for a work expenditure bid of $1,521,000 (Can.).

- 48 SDLs.
- 8 PLs, including two new PLs.

The Board also issued 20 operating licenses for offshore activity during the reporting year.

C-NLOPB reviewed applications to drill three delineation, six development, and three exploration wells in 2007-08:

- ExxonMobil plans to drill a second well in the Orphan basin in 2009, following the Great Barasway F-66 exploration well drilled in 2007.
- Shoal Point Energy drilled an onshore to offshore well on EL 1070 near the abandoned Shoal Point K-39 location.
- A consortium of StatoilHydro, Husky Energy Inc., and Petro-Canada announced plans to bring Transocean's Henry Goodrich semisubmersible drilling rig back to the Grand Banks areas in mid-2008 to embark on a multi-well drilling program that will last 2 to 2½ years. The rig is under contract from June 2007 to July 2010 for $358,000/day, according to Transocean's fleet status reports.

The consortium said it would drill the Mizzen exploration well in EL 1049 (Flemish Pass basin, 1,100 m water depth) to kick off the program, followed by exploration wells on the Primrose and North Mara prospects, further delineation of the West Avalon Pool at White Rose, and two development wells in the Terra Nova field.

On Aug. 9, The Henry Goodrich spud the North Amethyst E-17 well, drilled to 2,964 m, and was logging at the end of September, according to C-NLOPB's weekly public status reports.

Transocean's GSF Grand Banks semi-sub is also working in Atlantic Canada, under contract to Husky from January 2008-February 2011 for $353,000/day (US). On Sept. 13, it spud (reentered) the E-18 9 well at White Rose, according to C-NLOPB.

Western Newfoundland

Tekol and Gas Corp. plan to drill an onshore to offshore exploration well near Lark Harbour, Western Newfoundland, C-NLOPB reported in its 2007-08 annual report.

On Feb. 28, Vulcan Minerals Inc. announced that it was transferring interests in petroleum permits onshore the Bay St. George basin in western Newfoundland to Investcan Energy Corp.[8]

Off Nova Scotia

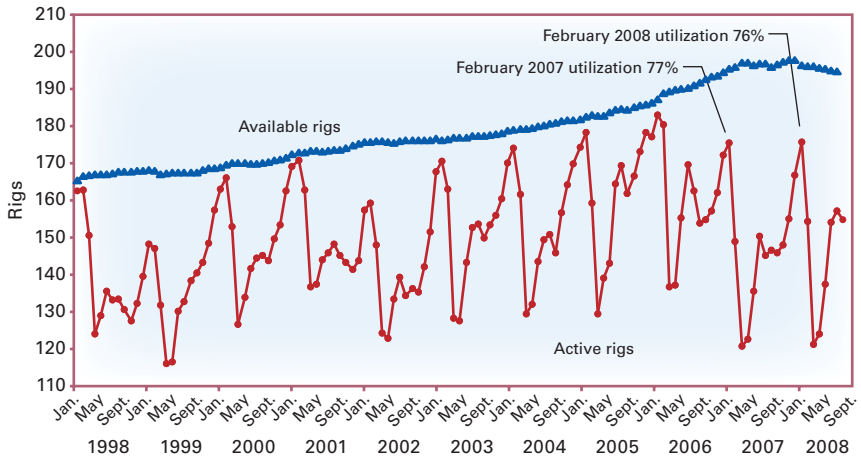
The Canada-Nova Scotia Offshore Petroleum Board (CNSOPB) issued its 2007-08 annual report on July 30. There has been no drilling off Nova Scotia in 2008.

On Sept. 15, CNSOPB announced it has issued two 9-year exploration licenses off Sable Island. CNSOPB issued Exploration Licenses 2417 and 2418 to Ammonite Corp. and Catheart Energy Inc., after having announced the companies as successful bidders on July 10 under Call for Bids NS07-1.

Earlier this month, at the Canadian Offshore Resources Exhibition in Halifax, two operators discussed plans to drill off Nova Scotia in 2009, subject to rig availability. Canadian

WESTERN CANADA DRILLING ACTIVITY

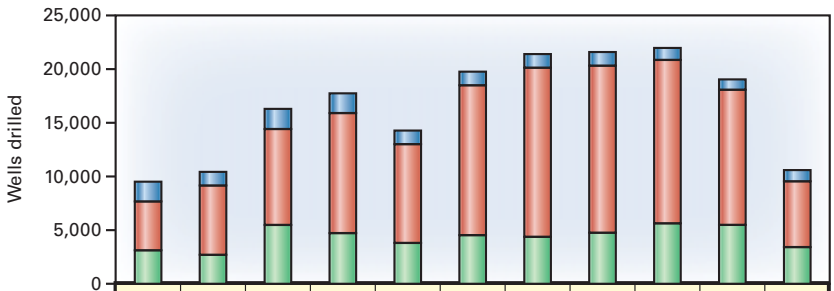
Fig. 3



Source: Nickle's Energy Group, Rig Locator

WESTERN CANADIAN OIL, GAS WELLS

Fig. 4



	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	*2008
% DRY	19.3	13.6	11.7	10	9.1	6.3	5.9	6.5	4.9	4.9	9.7
DRY	1,850	1,427	1,903	1,759	1,289	1,233	1,266	1,414	1,072	935	1,015
GAS	4,585	6,309	8,934	11,177	9,073	13,944	15,645	15,359	15,289	12,621	6,114
OIL	3,142	2,730	5,462	4,689	3,832	4,473	4,427	4,822	5,599	5,429	3,332

*Through September 2008.
Sources: Nickle's Daily Oil Bulletin; Canadian Assoc. of Oilwell Drilling Contractors

Superior Energy Inc. Pres. Mike Coolen said the company intends to drill on its shallow-water Mariner block near Sable Island in fall 2009 and may use a rig from Rowan Cos. Ian Padden, project manager at Bass Enterprises Production Co., told conference delegates that BEP hopes to drill a deepwater prospect in October or November 2009. The Ma Cherie prospect is about 200 km southwest of Halifax.

The Deep Panuke offshore gas development project is under development about 250 km southeast of Halifax. It's operated by EnCana Corp. and partners and will produce first gas in 2010.

In January 2008, EnCana carried out a geophysical survey along the proposed pipeline route using M/V Anticosti.

In September, Joint Oil of Libya and Tunisia announced a swap agreement that gives it an overriding royalty interest and optional participating interest in Canadian Superior's Mariner block off Nova Scotia (OGJ, Sept. 15, 2008, p. 50). Canadian Superior receives a 7-year exploration license for the 7th of November block, 75 miles offshore in the southern Mediterranean.

Onshore Nova Scotia

Triangle Petroleum Corp. is exploring for shale gas in the Maritimes basin (OGJ, Oct. 22, 2007, p. 50) and has drilled two vertical wells (45% working interest) in the 516,000-acre Windsor block in its 2008 drilling program.[9]

Using Nabors Rig 4, Triangle drilled the N-14-A well in July to 8,500 ft and encountered Horton Bluff shale at 3,600 ft, but noted more gas between 4,200-8,200 ft.

The company spud the second well, the O-61-C in August, in a separate fault block about 14 miles west of the first well. The planned TD is 9,900 ft.

In July, Calgary's Forent Energy Ltd. announced it obtained exploration rights to the 466,000-acre Beechhill block near Antigonish, NS (OGJ Online, July 16, 2008). Forent has a 3-year license with an option to renew, and plans to explore for conventional and unconventional resources.

New Brunswick

Halifax-based Corridor Resources plans to drill three widely spaced vertical wells based on 2D seismic, followed by a horizontal well in the Mississippian Frederick Brook shale near Elgin, NB (OGJ, June 16, 2008, p. 39). The $32 million program includes the acquisition of a 65 sq km grid of 3D seismic.

Corridor also plans a $14.4 million program to drill several horizontal wells in Hiram Brook sands.

In August, Calgary's PetroWorth Resources Inc. reported the results of two wells drilled into the Hiram Brook sandstone in eastern New Brunswick (OGJ Online, Aug. 7, 2008). Gas flowed at 1.058 MMcfd from the E-08 (Feenan-2) well, commingled from four zones. The Hiram Brook section in the Feenan-4 well was extremely hard and metamorphosed, and Petroworth said it would drill elsewhere on its 40,846-acre Rosevale license.

Triangle Petroleum has a 70% working interest on 68,000 gross acres in New Brunswick.

Canadian R&D

StatoilHydro is supporting Canadian heavy oil research and bolstering its heavy oil portfolio.

In June 2007, Statoil ASA, through subsidiary Statoil Canada Ltd., acquired North American Oil Sands Corp. for about $2.2 billion (Can.), with access to 257,200 acres in the Athabasca region of Alberta.[10]

StatoilHydro expects first production from the Leismer demonstration project in late 2009-early 2010, reaching a capacity of 10,000 b/d of bitumen. The production will come from 22 horizontal well pairs drilled from 4 pads.

In July 2008, a StatoilHydro ASA executive said crude prices need to be at least $70/bbl to cover capital and operating expenses and provide an acceptable rate of return from producing Canadian oil sand deposits.

Other mergers

Calgary's Zedi Inc. announced on Sept. 24 that it signed a letter of intent to acquire Calgary-based, privately held OAS Oil field Accounting Service Ltd. through its wholly owned subsidiary, Zedi Canada Inc. for $6.235 million (Can.).

Zedi is Canada's leading digital gas measurement firm. OAS provides chart reading and integration services to the oil and gas industry, with 25,000 wells under surveillance. The transaction will close Oct. 31, 2008.

Drilling ahead

Drilling is likely to decrease in the

near future, due to changes in Alberta's taxation, low natural gas prices, reduced share values, and resulting higher spread rates for loans to fund operations.

Reduced access to capital will probably cause a drop in capital budgets, especially at junior producing companies.[11] Peters & Co. Ltd.'s PE Junior Producers Index (Fig. 4) dropped 50% in September, to about 7,000 from nearly 15,000 points.

The energy sector announced 79 merger and acquisition deals worth $6.3 billion (Can.) in first-half 2008, compared with 110 deals worth $23.8 billion (Can.) in first-half 2007, a 72% drop, according to Sayer Energy Advisors.[12]

More mergers may be ahead. Smaller companies without proved, developed, producing reserves may be unable to find financing as lenders get more selective and equity markets dry up, pushing them into mergers or into selling working interests in prospects.

On the upside, new and improved rigs and equipment will deliver more cost-effective results in the field, where it may be a buyer's market. ✦

References

1. Canadian Energy Market Analysis, Energy Business Reports, http://energybusinessreports.com.
2. "Natural Gas Rebound Sustains Activity," Petroleum Services Association of Canada, July 25, 2008, www.psac.ca.
3. "Natural Gas Activity on the Rebound," PSAC, Apr. 23, 2008.
4. www.psac.ca/statistics/ser_index_co.html.
5. "Savanna Energy acquires drilling rigs in the US," June 16, 2008, www.savannaenergy.com.
6. August 2008 corporate update, Savanna Energy Services Corp., www.savannaenergy.com/docs/presentations/savanna%20-%20august%202008.pdf.
7. Results of the 2008 Call for Bids: Beaufort Sea and Mackenzie Delta, Indian and Northern Affairs Canada, www.ainc-inac.gc.ca/oil/act/Cal/beau2008//winbid/06_08_e.html.
8. "$1,000,000 financing announced," Vulcan Minerals news, www.vulcanminerals.ca, April 2008.
9. "Triangle Petroleum Provides Update on Its Maritimes Shale Program," Marketwire news, Aug. 28, 2008.
10. Cattaneo, Claudia, "Statoil can teach us a lesson," Financial Post, May 1, 2007, www.financialpost.com.
11. Mahony, James, "US Credit Crisis Choking Off Access To Capital," Nickle's Daily Oil Bulletin, Sept. 29, 2008, www.nickles.com.
12. Olijnyk, Zena, "Energy M&As are beginning to heat up," National Post, Aug. 30, 2008, www.sayeradvisors.com.

September hurricanes hit gulf rigs

Nina M. Rach
Drilling Editor

Hurricane Gustav moved through the Gulf of Mexico Sept. 1-5, causing rig and platform evacuations. Dozens of platforms were damaged, but no rigs were lost.

Hurricane Ike swept through the gulf Sept. 10-14, damaging and destroying drilling rigs and production platforms.

On Sept. 16, the US Minerals Management Service reported that three jack up rigs were destroyed, one jack up was extensively damaged, and two rigs were set adrift by Hurricane Ike. MMS also reported that the derrick on BP's Mad Dog platform was lost.

MMS reported on Sept. 24 that 52 of the 3,800 offshore oil and gas production platforms in the Gulf of Mexico were destroyed by Hurricane Ike, up from 49 platforms reported on Sept. 18. Dozens of additional platforms suffered moderate to extensive damage from storm surge and wave action.

Lost jack ups

Contractors lost three jack up drilling rigs: Pride Wyoming, Rowan Anchorage, and ENSCO 74.

Pride International had 11 jack ups at work in the Gulf of Mexico and lost one to Hurricane Ike. The Pride Wyoming mat slot jack up is missing and expected to be a total loss. The Bethlehem JU-250-MS rig was built by Bethlehem Steel in Beaumont, Tex., and delivered in 1976. It was working for Apache Corp. in Ship Shoal Block 283, about 90 miles south of Houma, La., for $60,000/day, and was to begin a 3-month contract for Stone Energy at $77,500/day. The Pride Wyoming was insured for $45 million, with $20 million loss retention.

Rowan Cos. had nine rigs operating and nine rigs under construction in the Gulf of Mexico. The Rowan Anchorage, a LeTourneau 52-class slot jackup, is believed to have capsized off Louisiana, where it was drilling in Vermillion Block 201 for Newfield Exploration. It had been operating under a well-to-well contract at $60,000/day and was insured for $60 million, less a $17.5 million windstorm deductible.

Also, Rowan's shore base in Sabine Pass, Tex., was subjected to a significant storm surge and will be out of commission for a while. One of the company's new jack ups, Rowan Mississippi, was apparently struck by another vessel during the storm and will require some repairs.

The derrick of BP's Mad Dog spar snapped and fell to the seafloor during Hurricane Ike (Fig. 1; photo from BP).

On Sept. 15, Dallas-based ENSCO International Inc. reported that ENSCO 74, a MLT Super 116-C jack up, was missing and presumed sunk. It was working in about 230-ft water depth, 92 miles from shore in South Marsh Island Block 149 for Mariner Energy when Hurricane Ike passed over.

The cantilevered jack up with 375-ft legs was insured for $100 million and

ENSCO has a $50 million retention per occurrence for windstorm damage losses.

Missing derricks

Diamond Offshore Drilling Inc. had 8 jack ups and 10 semisubmersible rigs in the gulf in September. One jack up, the Ocean Tower, was extensively damaged during Hurricane Ike. It was drilling in Vermillion Block 245 for Chevron but lost its derrick and drilling package. The LeTourneau Class 53-S jack up was built by Marathon LeTourneau in Vicksburg, Miss., and delivered in 1972.

BP Exploration's Mad Dog spar platform was installed in 4,734 ft water in Green Canyon Block 782 and began production on Jan. 13, 2005. BP operates Mad Dog (60.5% working interest) on behalf of partners BHP Billiton (23.9%) and Unocal (15.6%).

On Sept. 15, BP announced that the derrick had been toppled by Hurricane Ike and fell to the seafloor. Pride manages the Mad Dog drilling rig (Fig.1).

Failed moorings

Sugar Land, Tex.-based Noble Drilling had seven rigs working in the gulf; two semisubmersibles drifted off location after their mooring systems failed during Hurricane Ike. Both the Noble Paul Romano and the Noble Amos Runner had been working for Anadarko. On Sept. 15, Noble said that the mooring system on the Noble Lorris Bouzigard semisub was also damaged but the rig did not drift.

Transocean's Transocean Marianas semisub drifted a few miles off location at Green Canyon Block 516 where it had been drilling for ENI. Transocean said the rig will need some repairs.

With nearly a month lost to delays and damage from the two hurricanes, spud dates will be delayed and drilling programs will probably need to be modified. An uptick in demand for platform decommissioning services is also likely. ✦

Effective risk evaluations prevent refinery shutdowns

Paul F. Schubert
SGS Group
Bartlesville, Okla.

Glen Gannon
SGS Group
Singapore

An Asian refinery instituted an aggressive, comprehensive risk-based asset integrity management program to reduce substantially unplanned releases, shutdowns, and regulatory fines. Since implementation, the Asian refinery eliminated unplanned releases and reduced unplanned shutdowns by 92%.

During a 2-year period, the Asian refinery experienced a series of unplanned releases that cost more than $200 million in lost product, production shut-down losses, and regulatory fines. In addition, the plant experienced frequent upsets and shutdowns.

In a risk-based inspection (RBI) approach to asset integrity management (AIM), the probability of failure and consequence of failure determine a risk ranking for each system and component. The frequency and intensity of monitoring is then adjusted to achieve an acceptable level of risk.

Adoption of risk-based approaches in the petrochemical, refining, and natural gas industries represents a shift from reactive inspection and maintenance methods (Table 1).

In the long-term, an effective risk-based approach should substantially reduce maintenance and inspection costs because inspection focuses instead on those components and systems most likely to fail and most likely to have significant consequences. In the short-term, however, inspection and maintenance costs can actually increase when the current condition and history of the plant's systems are scrutinized.

Risk-based approach

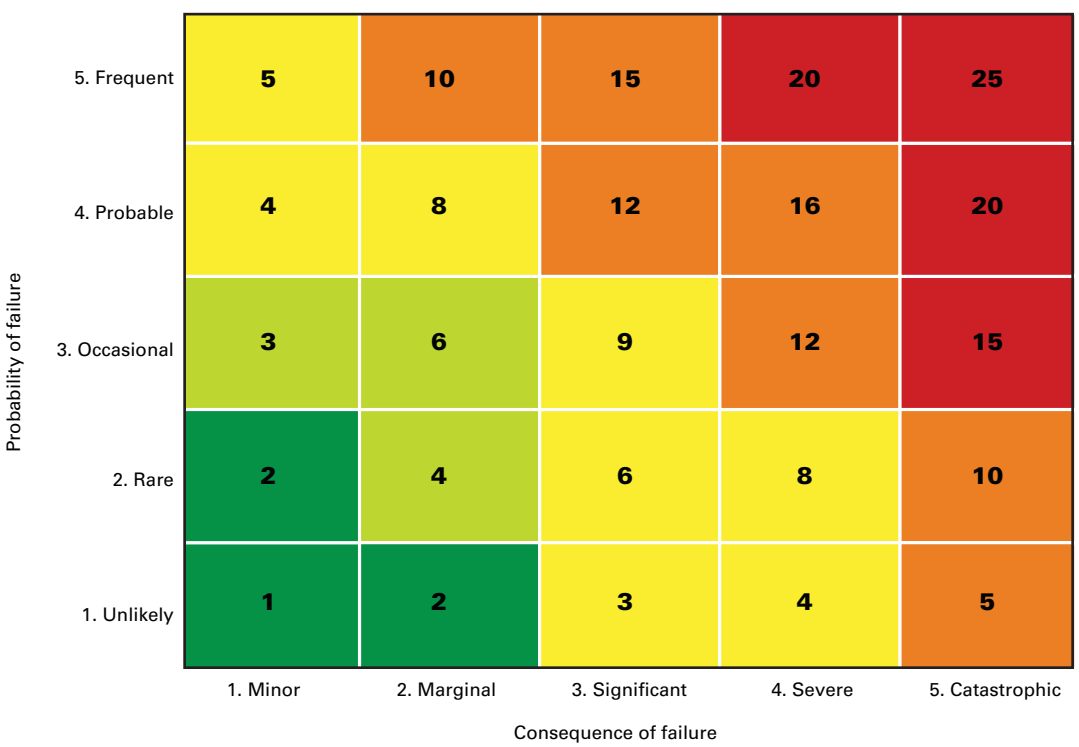
At the core of any risk-based approach is developing risk rankings for process units or individual equipment items such as piping circuits, tanks, or pressure vessels. A simple qualitative approach provides a good framework for understanding the more quantitative methodology used in the Asian refinery.

In a qualitative approach, the refiner assesses each plant unit or item and assigns a position within a risk matrix. A 5x5 risk matrix is most commonly used (Fig. 1).

One axis of the matrix represents the likelihood of failure, and the other represents the consequence of failure. During the first stages of RBI implementation, data are

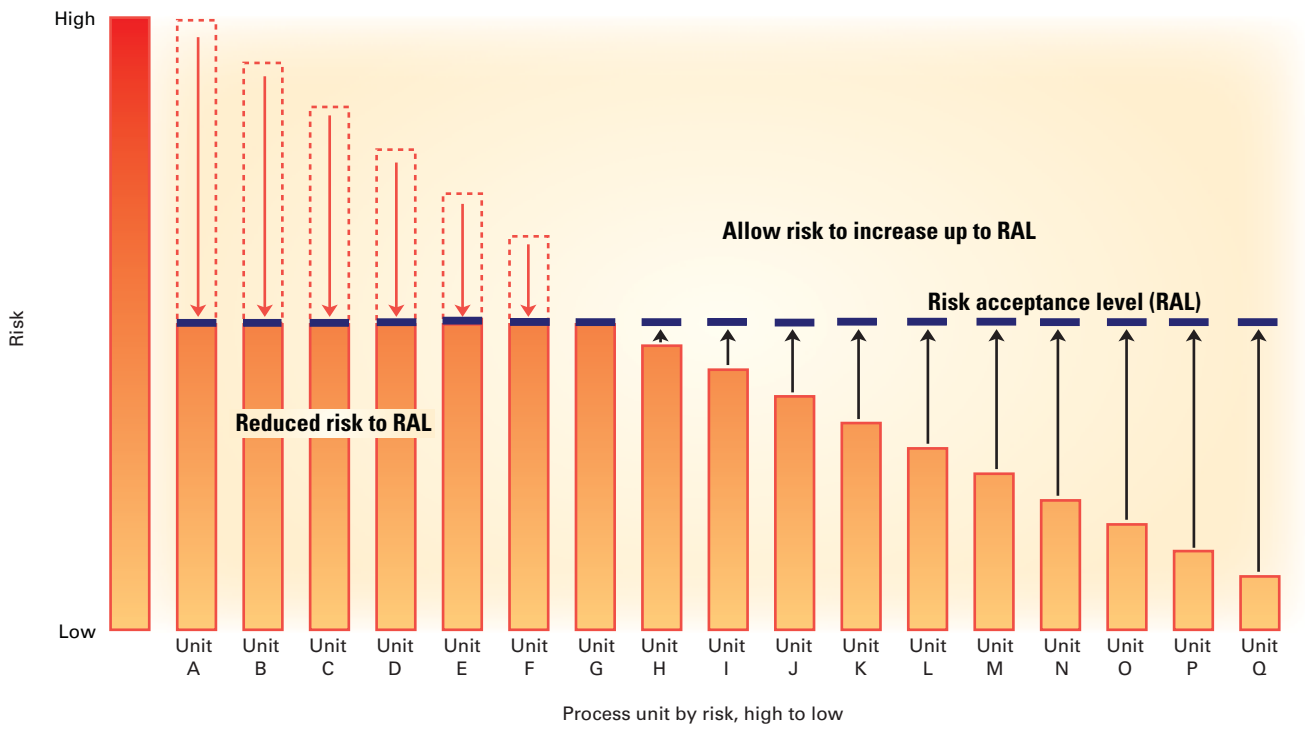
QUALITATIVE RBI MATRIX

Fig. 1



RISK ADJUSTMENT

Fig. 2



collected to rank likelihood and consequence.

Key parameters used to establish the likelihood of failure include:

- The amount and complexity of equipment within the item.
- Damage mechanisms.
- Environmental factors.
- Usefulness of inspection for predicting failure.
- Current equipment condition.
- The nature of the chemical or thermal process.
- Safety design and safeguards.

Key components in evaluating the consequence of failure include the potential for fire or explosion, toxicity, and environmental damages.

For the Asian refinery, we took a more rigorous quantitative approach, collecting corrosion data, damage mechanisms, use histories, process conditions, and other pertinent information for each unit or item.

We then developed possible risk scenarios and calculated a numerical value for each risk scenario RS by multiplying the likelihood LS of failure for each scenario by the consequence CS of failure for each possible scenario. The total risk for an item is then sum of all risks for all of the risk scenarios.

In the quantitative approach, each unit or item has a unique risk value. The inspection program is then designed so that the risk value associated with each process unit or item is adjusted to the same acceptable level of risk (Fig. 2).

For high-risk units or items, the risk acceptance level (RAL) is typically achieved by increasing the frequency of inspection and often the intensity of inspection. Inspection intensity can increase by taking measurements at more locations, or applying additional applicable measurement techniques. For low-risk units or items, the frequency and intensity of inspection are lowered and individual levels or risk associated with the unit or item are increased to the RAL.

INSPECTION STRATEGIES

Table 1

Approach	Type	Description
Reactive	Fire-fight	Fix when equipment fails to perform
Scheduled	Traditional	Fix when manufacturer suggests to do so
Compliance-based	Law	Fix when legislation indicates to do so
Condition-based	Predictive	Fix when condition indicates to do so
Risk-based	Proactive	Fix when risk exceeds a set limit

Understanding the problem

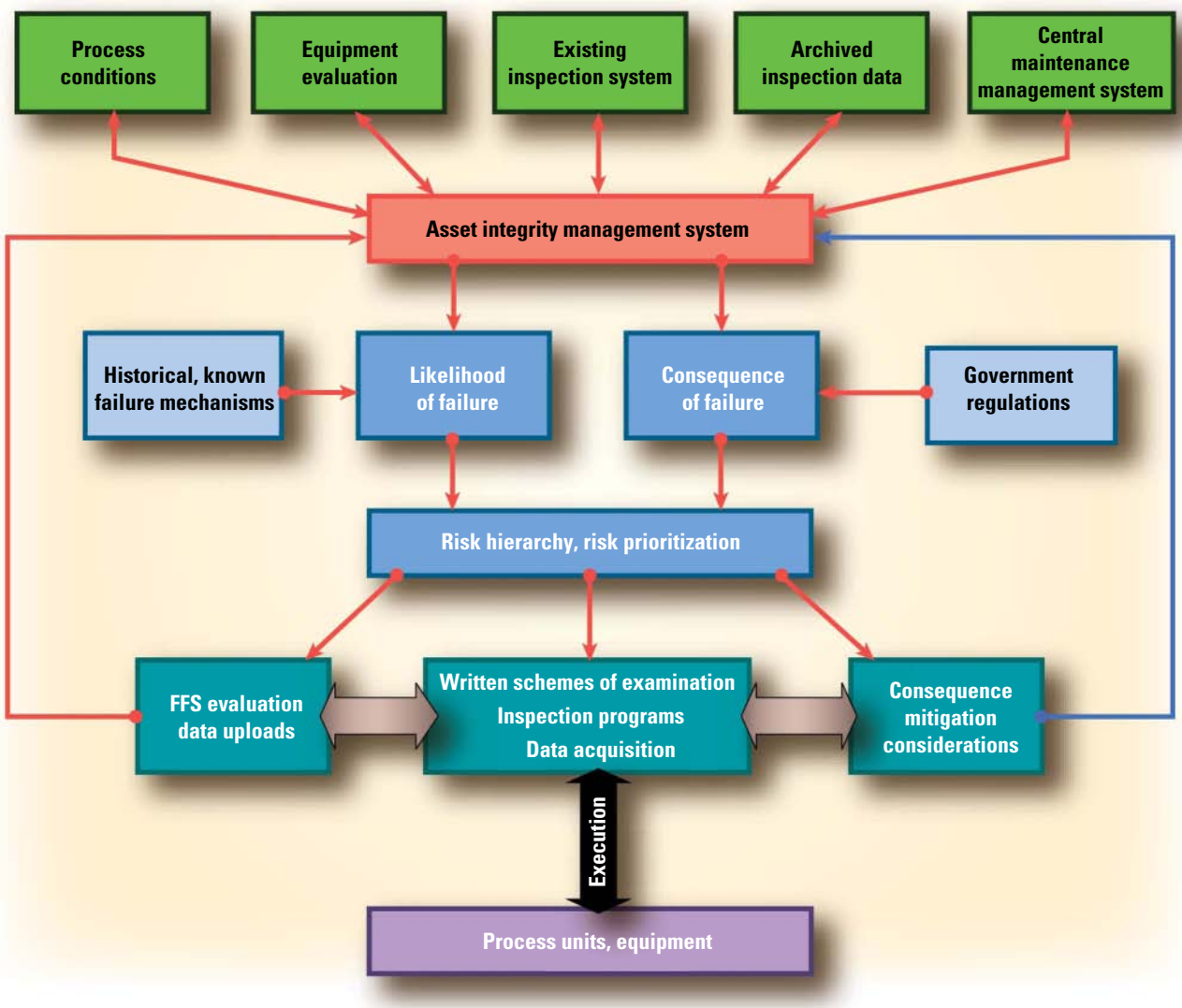
In many cases, the reason for shifting from a time-based or condition-based inspection program to an RBI program is to reduce long-term inspection costs. For this particular refinery, lower costs were a secondary benefit; the primary reason was the need to eliminate unplanned releases.

Our evaluation identified five major factors leading to releases:

- Unclear goals and objectives for

RBI PROCESS OVERVIEW

Fig. 3



the existing AIM program.

- Ineffective AIM management systems (repeatable quantitative processes with remediation tracking).
- Inconsistent inspection data and limited mechanical and process data (record-keeping issues).
- Unplanned and costly integrity-related outages.
- Mechanical and physical risks due to hazardous material transportation and climatic extremes.

These factors showed that the refiner needed a different inspection approach.

Legislative requirements required a time-based inspection approach. Achieving the desired outcome, therefore, required the refiner to work with legislators so that they could understand how the risk-based approach would actually exceed the safety, reliability, and economic objectives of the legislation.

RBI process overview

The refiner's goal was a program that represented an industry best practice RBI program. Because of the refinery's location, this required development of a specific facility inspection scheme that reflected API, British (PSSR), and national protocols, guidelines, practices, and procedures.

Fig. 3 shows the basic components and work flow of RBI implementation for the refinery. We incorporated existing data and programs into the basic AIM system. We evaluated historical and known failure mechanisms for each system and component and established a probability of failure.

We determined the consequences of failure using a combination of factors. Because preventing unplanned releases was the refiner's primary goal, the main factor was the nature of the chemicals that would be released if containment failure occurred.

The process quantified each risk scenario and determined a risk value for each unit. Once these risk profiles were completed, we developed and imple-

mented written schemes of examination, the inspection program, and data acquisition program.

Because the release and outage problems were well documented at the refinery, this historical data helped identify the units subject to the most common upsets. The inspection program then focused on implementation in the highest-risk units first.

Key tasks

Establishment of any RBI program is difficult. For this program's implementation, 12 dedicated plant integrity specialists, including engineers, inspectors, and technicians, were employed in the refinery's inspection organization.

Major specific tasks conducted during implementation of the refinery's RBI program were:

- Identification of factors contributing to likelihood or consequence of failure:

—Local environmental factors. These are degradation mechanisms that could affect the loss of containment or overall performance due to local environmental factors (temperature, humidity, etc.).

—Possible failure mechanisms. Each system component has known failure mechanisms and remediation methods.

—Effects of multiple failure mechanisms due to local conditions, such as seismic stress or brittle failure.

- Evaluation of risk to meet safety, environmental, and economic objectives:

—Calculation and ranking of the total risk at each refinery unit.

—Establishment of the RAL.

- Development of the specific inspection program for each unit to achieve the RAL:

—Determining which items are critical and essential for monitoring.

—Establishing repeatable, credible, and well-documented inspection methods to enable the refiner to predict corrosion rates and evaluate fitness for service (FFS).

—Inspection and maintenance planning. Assessing FFS outcomes (multidisciplinary engineering analysis), remaining life, turnaround data and extent, and next inspection dates.

- Program implementation:

—Installation and entry of all data into a commercially available AIM RBI software system for plant components and systems.

—Training of personnel in objectives, policies, and procedures.

- Management of change process:

—Liaise with national legislators for a shift in time-based inspection constraints.

—Documentation and approval for all inspection process changes.

—Verify that the process is producing the desired results.

Deficiencies

When program implementation began, we identified several key deficiencies within the refinery. Some of these deficiencies were present before the components were initially put into service. These included fabrication defects, segregation, wrong materials of composition, welding flaws, poor fabrication techniques, and incomplete and inaccurate records. We prioritized these deficiencies with respect to risk and developed remediation programs for each.

Deficiencies resulting from the components being on stream were also discovered. Typical of these were generalized corrosion, corrosion under insulation, stress cracking, other metallurgical changes, pressure excursions, and delayed maintenance. As with the other deficiencies, we prioritized these for remediation.

RBI program effects

During a 2-year period in 2004-06, the refinery experienced seven unplanned gas releases. Fortunately, there were no injuries or fatalities associated with these events. The combination of lost product, production shutdown losses, and regulatory fines ranged from almost $100,000 to nearly $100 million. The total cost was more than $200 million.

The 2-year RBI project was initiated at the refinery in 2006. During the first year, we developed the program and started implementing it on the highest-priority units. During the second year, we addressed the refinery's remaining units.

When we addressed the high-risk items, issues within the refinery began to decrease. Once the program reached its second year, unplanned releases stopped and, therefore, the losses associated with them also ceased. In addition, unplanned outages from all sources were reduced by 92%.

One area where the RBI program was most apparent was on the contingency budget for turnarounds. In 2006, the budget and expenditures were $80 million. For 2007, the actual spending was reduced to $26 million, representing a savings of $54 million. ✦

The authors

Paul F. Schubert (paul.schubert@sgs.com) is global sales and marketing manager for SGS Asset Integrity Management Services, Bartlesville, Okla. He has 26 years' experience in the petrochemical and natural gas industry. Before SGS, Schubert held various technical and marketing management positions with Syntroleum Corp., Monitor Labs, Catalytica, Phillips Petroleum, and Engelhard Corp. Schubert holds a BS in chemistry from the University of Arkansas, Fayetteville, and a PhD in inorganic chemistry from the University of Illinois, Champaign-Urbana. He conducted graduate studies in business administration at San Jose State University, Calif.

Glen Gannon (glen.gannon@sgs.com) is operations director for SGS Global Asset Integrity Services, Singapore. He has 28 years' experience in the oil, gas, and maritime industries. Before joining SGS, Gannon worked with major contractors including BSP, Esso BHP, BP-GUPCO, Stena JVs, ExxonMobil, Oceaneering, Subsea International, and Australian Blue Water Shipping Contractors. Gannon holds a degree from the Australian Maritime College.

FRACTURE PROPAGATION—Conclusion

Prediction steel-grade dependent

Robert Eiber
Robert J. Eiber Consultant Inc.
Columbus, Ohio

Battelle's two-curve method (TCM) fracture arrest predictions for X70 grade steels and higher requires a correction factor for the predictions to be accurate and useful for selecting pipe steels. The first part of this article (OGJ, Oct. 20, 2008, p. 52) examined three correction factors: Leis, Wilkowski, and Centro Sviluppo Materiali (CSM). This concluding article will show the appropriate factor to be grade-specific.

Background

Fracture initiation occurs when a flaw exists in a pressurized pipe that is the maximum size flaw for the toughness level of the pipe at the operating stress level in the pipe. A deep enough and short enough flaw will result in a stable leak when it penetrates the pipe's WT. A sufficiently long and shallow flaw penetrating enough of the WT will begin to propagate along the length of the pipe.

If the pipe is operating at less than its transition temperature (i.e., 85% shear area transition temperature, SATT) in the drop-weight tear test (DWTT), the fracture will be brittle and will propagate at high speeds and possibly over long distances (miles). If the pipe is operating at greater than DWTT 85% SATT, it will be ductile and the propagation or arrest will depend on its toughness (Charpy V-Notch impact energy, CVN).

TCM contrasts the fracture speed and pressure curves for a pipe with a given toughness against the gas decompression speed curve and pressure

Equations

$$CVN_{TCM\text{-}Leis} = CVN_{TCM} + 0.002\ CVN_{TCM}^{2.04} - 21.18 \quad (1)$$

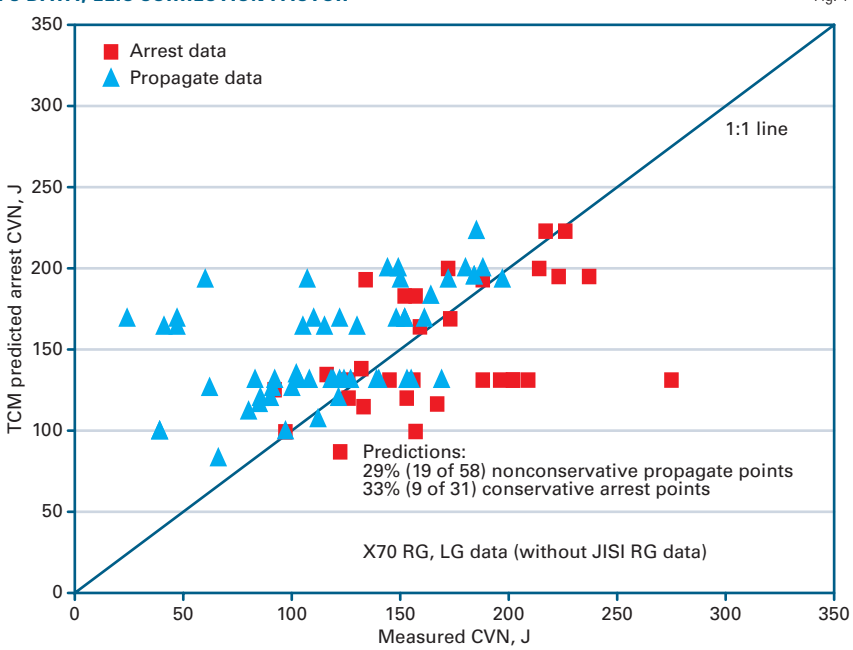
Where: CVN_{TCM} is the Charpy energy predicted for arrest and is greater than 94J. Below 94J $CVN_{TCM\text{-}Leis} = 1.0$. This definition of CVN_{TCM} also applies to Equation 3.

$$CVN_{TCM\text{-}Wilk} = 0.056\ (0.1018\ CVN_{TCM} + 10.29)^{2.957} - 16.8 \quad (2)$$

$$CVN_{TCM\text{-}Leis} = CVN_{TCM} + 0.003\ CVN_{TCM}^{2.04} - 21.18 \quad (3)$$

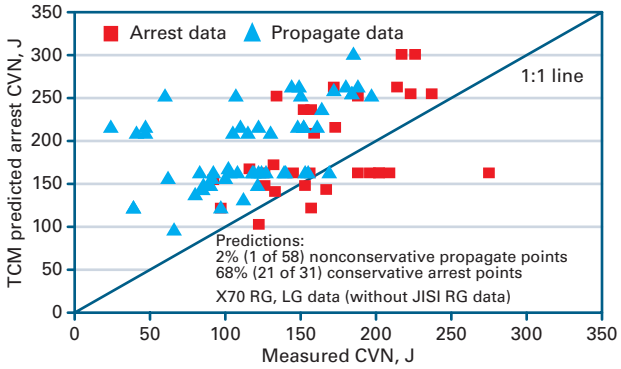
X70 DATA, LEIS CORRECTION FACTOR

Fig. 1



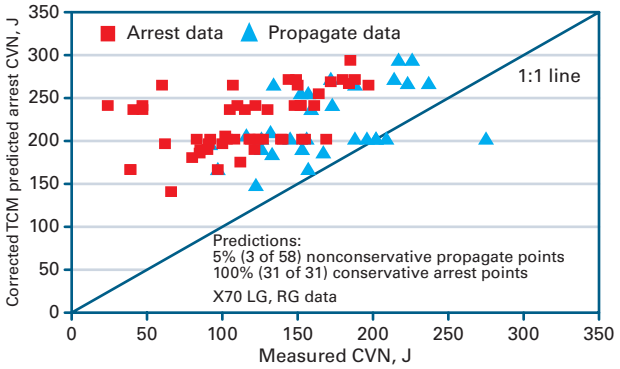
X70 DATA, WILKOWSKI CORRECTION FACTOR

Fig. 2



X70 DATA, CSM CORRECTION FACTOR

Fig. 3



providing the driving force for the fracture.

Testing

Testing the X70 steels showed the Leis factor to be the least conservative and CSM the most conservative for the steels examined, with the Leis factor emerging as a reasonable correction factor to apply. A factor between Leis and Wilkowski appears to be necessary for X80 control-rolled steels, and a modification of the Leis factor is proposed later in this article. The modification increases the conservatism of the Leis equation but leaves it lower than the Wilkowski factor.

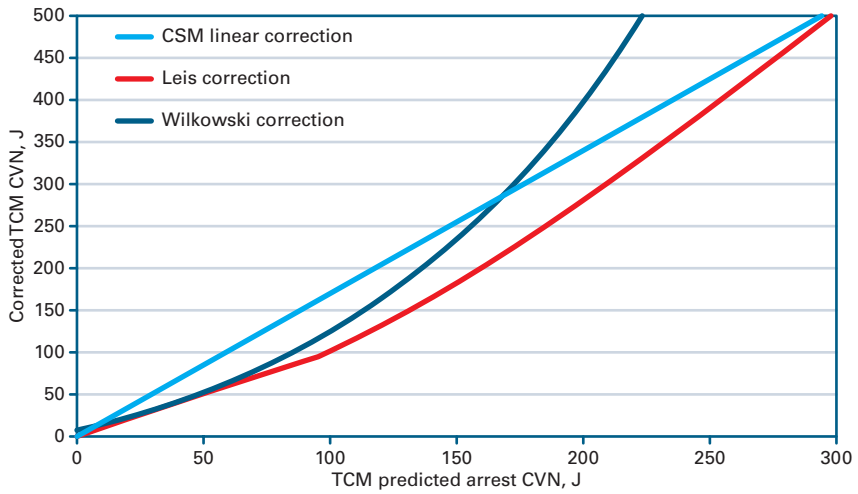
Insufficient data exist to define what factor is needed for X80 quenched and tempered steels.

Figs. 1 and 2 show X70 lean and rich gas test data, including the TCM predictions corrected by Equations 1 and 2, respectively. Fig. 1 shows the Leis correction factor resulted in nonconservative propagate and conservative arrest data points with about the same percentages, creating a usable average correction factor.

Fig. 2 shows the Wilkowski correction factor applied to lean and rich gas X70 data, demonstrating that the Wilkowski correction factor is more conservative than the Leis factor, with only 2% of nonconservative propagate data lying outside the correction. The increase in the conservative arrest point to 68% demonstrates this more conservative status, offering users a more conservative choice than the 1.7 factor proposed by CSM.

CORRECTION FACTORS, TCM CVN PREDICTIONS

Fig. 4



X80 QUENCHED, TEMPERED FRACTURE ARREST PREDICTION

Fig. 5

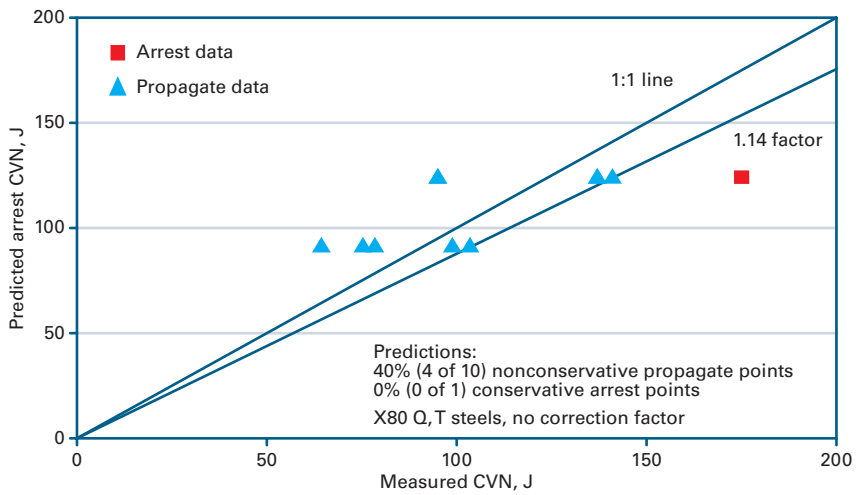
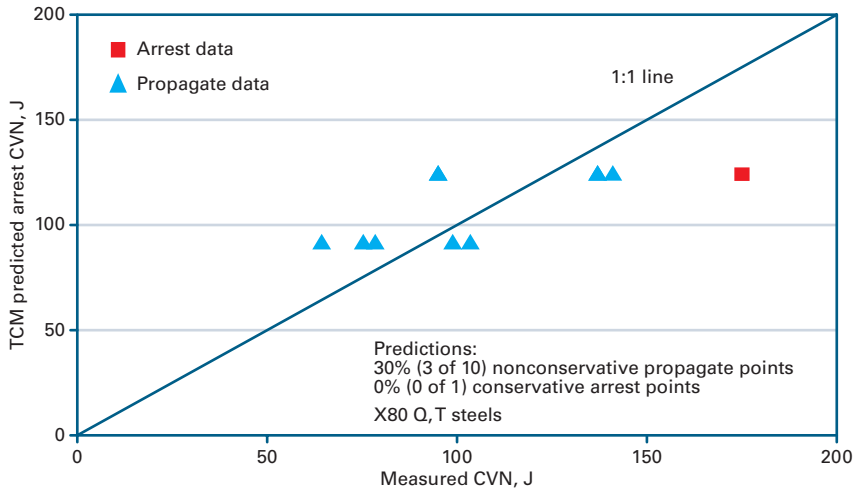


Fig. 3 shows the CSM correction factor applied to the lean and rich gas

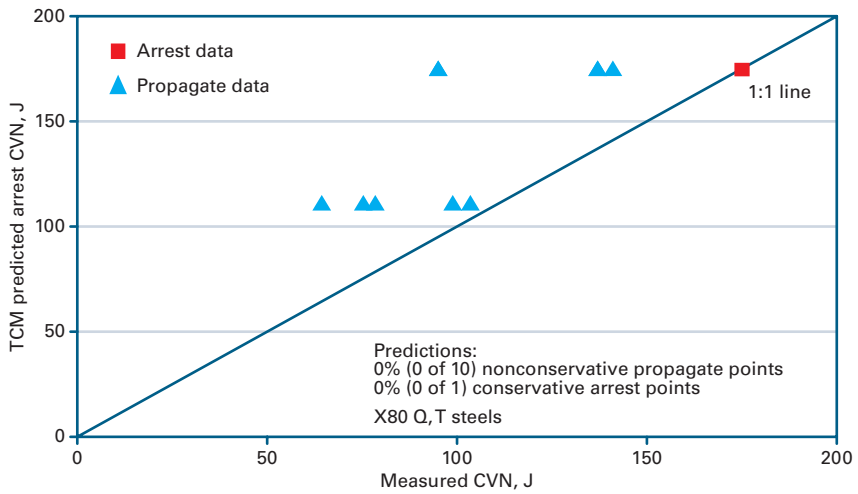
X80 QUENCHED, TEMPERED PREDICTION, LEIS CORRECTION FACTOR

Fig. 6



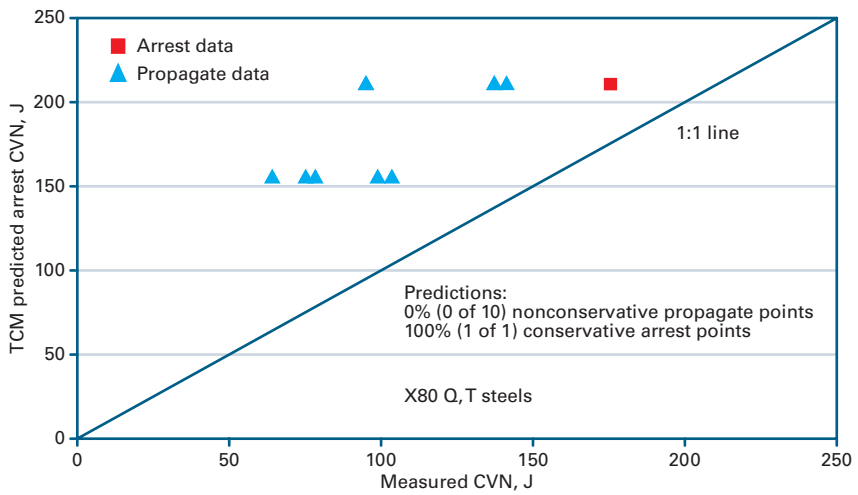
X80 QUENCHED, TEMPERED PREDICTION, WILKOWSKI CORRECTION FACTOR

Fig. 7



X80 QUENCHED, TEMPERED PREDICTION, CSM CORRECTION FACTOR

Fig. 8



SUMMARY OF CORRECTION FACTOR EFFECTS ON X70 STEELS

Table 1

Correction factor	Nonconservative propagate data (%)	Conservative arrest data (%)
Leis	29	33
Wilkowski	2	68
CSM	5	100

X80 CR FULL-SCALE TEST DATA SOURCES

Table 2

Organization	Test numbers
EPRG	III.2, III.3
CSM	15, 26

CORRECTION FACTOR EFFECTS, X80 STEELS

Table 3

Correction factor	Nonconservative propagate data (%)	Conservative arrest data (%)
Leis	27	0
Wilkowski	7	50
CSM	7	90

X70 data, demonstrating it to be the most conservative of the three, with 5% nonconservative propagate data and 0% conservative arrest data. These results seem extremely conservative, so much so that the required pipe toughness may be unavailable from mills.

Fig. 4 compares the correction factors for CSM, Leis, and Wilkowski. The CSM correction starts as the highest until a TCM CVN of 170 J is reached, at which point the Wilkowski correction becomes the highest. The Leis correction is the lowest of the three.

Table 1 summarizes the results of the correction factor effects on the X70 steels for lean and rich gases. The table shows that as the conservativeness of the correction factor increases, the percentage of conservative arrest data increases. The Leis factor appears to be about right for the X70 control-rolled steels examined, based on the observation that it lies between the nonconservative and conservative data.

X80 predictions

The balance of this article will discuss the factors that control fracture arrest for X80 pipe and address application of the existing formulations to predicting the arrest toughness of X80 pipe. Available X80 burst test data all involve lean gas. Applying the following information to rich gas must therefore be done with caution, as data from X70-grade pipes showed the possibility that predicted arrest toughness may have to be higher for rich gas than had been determined for lean gas. The predictions are also only valid for steels exhibiting a relatively flat upper shelf in the CVN curve.

All of the X80 data presented applies to control rolled or thermomechanically processed steels as did all of the X70 steel data presented previously. Table 2 shows the X80 tests performed. Table 3 summarizes the effect of the correction factors on the X80 steels.

Table 3 offers two observations. The various factors have a different effect on the higher-grade pipe, suggesting that a factor should be grade specific. The Leis factor also does not have any conservative arrest data, while the Wilkowski and CSM factors appear too conservative with only 7% nonconservative propagate data points. Equation 3 shows a proposed revision to the Leis correction factor for X80 controlled rolled steels, increasing the multiplier from 0.002 to 0.003.

It would be nice to have zero nonconservative and conservative data points, but the present status of predictive capabilities coupled with the variability in toughness properties leads to scatter in the full-scale test results that cannot be eliminated. This suggests that a correction factor averaging the nonconservative propagate data and the conservative arrest data is about as good as can be expected.

Not every length in a pipeline has to arrest a fracture for fracture control to be achieved. Specifying the predicted TCM arrest level as a minimum value for a pipe order will ensure all pipe has a toughness level that exceeds the minimum specified value.

Quenched, tempered

The final assessment is based on X80 quenched and tempered steels. Having only 11 data points minimized the scatter. Figs. 5-8 show a comparison of the measured CVN energies of the pipes in full-scale tests vs. the TCM predicted CVN arrest energies. With the few data points available, even the uncorrected data are in reasonable agreement. But the X80 control-rolled-steel results demonstrate the need for a correction factor. ✦

Equipment / Software / Literature

Rig activity scheduler software updated

The latest version of rig activity scheduler (RAS) software—Version 3.0—promises to help take the guesswork out of assigning rigs to wells and enables upstream operations to utilize drilling, completion, and workover rigs more efficiently.

With new features that provide decision support, RAS 3.0 incorporates an automated, interactive capability for scheduling complex drilling operations. Rigs are assigned to wells with a drag-and-drop interface that links drilling activities to user-defined key performance metrics, such as production output, rig budgets, and well completion dates. As operating conditions change and revisions are needed, users can develop and evaluate multiple scenarios before selecting the most appropriate course of action. RAS 3.0 features include:

- An advanced rig cost model, allowing multiple contract, availability date, day rate, and transportation cost information to be incorporated into drilling plans and schedules.
- GIS integration, to support rig transportation computations based on multiple factors, including the available road network, transportation speed, and movement restrictions.
- Support for well availability-unavailability intervals, to accommodate restrictions because of weather and wildlife.
- Enhanced auditing and security capabilities.

Source: **Actenum Corp.,** 10th Floor, 675 W. Hastings St., Vancouver, BC V6B 1N2.

New oil field surge protection device

A new, single metal oxide varistor module with a high surge handling capability that absorbs and dissipates the excess energy from lightning strikes and power surges is suited for use in oil field applications.

Designated Strikesorb, the 40 mm and 80 mm surge protection devices (SPDs) met the Underwriters Laboratories Inc. 1449 3rd Edition Safety Standard's intermediate current abnormal overvoltage test by successfully conducting current at 1,000A for 7 hr without disconnecting from the circuit. Featuring a flat slope resistance characteristic, the Strikesorb SPD

modules received a nominal discharge current test (In) rating of 20 kA, the highest possible, without the use of internal fuses.

Strikesorb SPD modules have been designated as Type-4 devices deemed suitable for use in Type-2 applications by UL.

Source: **Raycap Inc.,** 2310 N. Molter Rd., Suite 102, Liberty Lake, WA 99019.

Fugro Gravity & Magnetic Services (FGMS),

Houston, has named Mark Weber president and Dr. Luiz Braga vice-president, global business development. FGMS is the business development arm of Fugro Airborne Surveys and Fugro Ground Geophysics. Weber will oversee the new venture that will provide the oil and gas industry with a full spectrum of gravity and magnetic services—data acquisition and processing, interpretation, software and nonexclusive data—for land, marine, and airborne applications. Weber's experience spans from field quality control manager to interpretation geophysicist to executive. He has a bachelor's from the Colorado School of Mines and has been working in the oil and gas industry for more than 20 years on projects in 30 countries. Weber is a member of the American Association of Petroleum Geologists, Society of Exploration Geophysicists, Houston Geologic Society, and Geophysical Society of Houston. Braga will manage the business development activities on an international basis for a team of experts situated in Houston, Calgary, London, Rio de Janeiro, Dubai, Perth, and Mexico. He was formerly marketing manager and deputy general manager and is credited with developing and enhancing Fugro's airborne geophysical market in South America. Braga received a Ph.D. in geophysics from Oregon State University and has more than 18 years' experience in the petroleum industry and 27 years' experience working in earth sciences. He is a founding member of the Brazilian Society of Geophysicists and a member of SEG.


Weber


Braga

Fugro Gravity & Magnetic Services is a part of Fugro, which interprets and processes data collected at sea, on land, and from the air using advanced surveying, seismic, oceanographic, meteorological, and positioning services.

Honeywell Process Solutions,

Phoenix, has been selected by South Korea-based SK Engineering & Construction (SKE&C) to design the integrated process control system for a major oil and gas expansion project in Kuwait. The agreement calls for Honeywell to provide the main process automation, safety, and operator training systems for the plant and integrate its technology with existing third-party systems. Additionally, Honeywell will provide local technical support at the site. Honeywell will supply its Experion Process Knowledge System, which allows operators to centrally control and more efficiently manage all processes in the facility. It also enables users to monitor information from critical subsystems, such as fire and gas detection and security devices. Additionally, Honeywell's Safety Manager will be used to safely coordinate procedures such as unit start-up and shut-down. For operator training, SKE&C selected Honeywell's UniSim Operations, a process simulation system that helps reduce operator error and improve safety and efficiency by training operators on processes offline.

Honeywell Process Solutions is part of Honeywell International's Automation and Control Solutions group, a global leader in providing product and service solutions that improve efficiency and profitability, support regulatory compliance, and maintain safe, comfortable environments in homes, buildings, and industry. Honeywell International is a diversified technology and manufacturing leader, serving customers worldwide with aerospace products and services; control technologies for buildings, homes and industry; automotive products; turbochargers; and specialty materials.

KBC Advanced Technology PLC,

London, has introduced its new Alternative Fuels and Feedstocks (AFFS) service to serve companies considering building or operating alternative fuel plants or utilizing alternative feedstocks that need to optimize designs and operations to maximize yields of high-value products, minimize energy consumption and CO_2 emissions, ensure reliability, and operate at optimum staffing levels using best practices systems, work processes, procedures, and tools. KBC provides leading CapX (Capital Excellence) services to help companies make sense of the options and make the right decisions for their facilities. KBC's OpX (Operations Excellence) services for AFFS assist companies in effectively operating this type of facility. KBC expertise includes alternative fuels plants fed by crude oil, natural gas, coal, or biomass.

KBC is a leading independent consulting, process engineering, and software group that delivers improved operating performance to the oil refining, petrochemical, and other process industries worldwide.

Pinpoint Drilling & Directional Services LLC,

Dallas, has named Robert J. Stayton CEO. He is a 28-year veteran of the oil and gas industry, most recently having worked for Weatherford. His experience includes work for the Gas Research Institute, and he has authored several articles on horizontal directional drilling. Stayton has a BBA from the University of Oklahoma.


Stayton


Raymond

Pinpoint also named Steve Raymond vice-president, sales and marketing. Raymond has worked alongside Stayton in the past.

Pinpoint is a prominent integrated directional, horizontal, and MWD services provider in targeted US unconventional gas drilling basins.

NCH (UK) Ltd.,

West Bromwich, England, has agreed to acquire Manchester, England-based Waterwell Services, merging the firm with its Chem-Aqua UK water treatment business. Terms of the deal aren't disclosed. Lol Moore, Waterwell's owner and managing director, will join the Chem-Aqua UK management team to lead their engineering/equipment group. NCH UK is a division of NCH Corp., a leading global supplier of industrial and institutional maintenance solutions based in Irving, Tex.

Waterwell designs, builds, and services reverse osmosis, filtration, softener, and similar units.

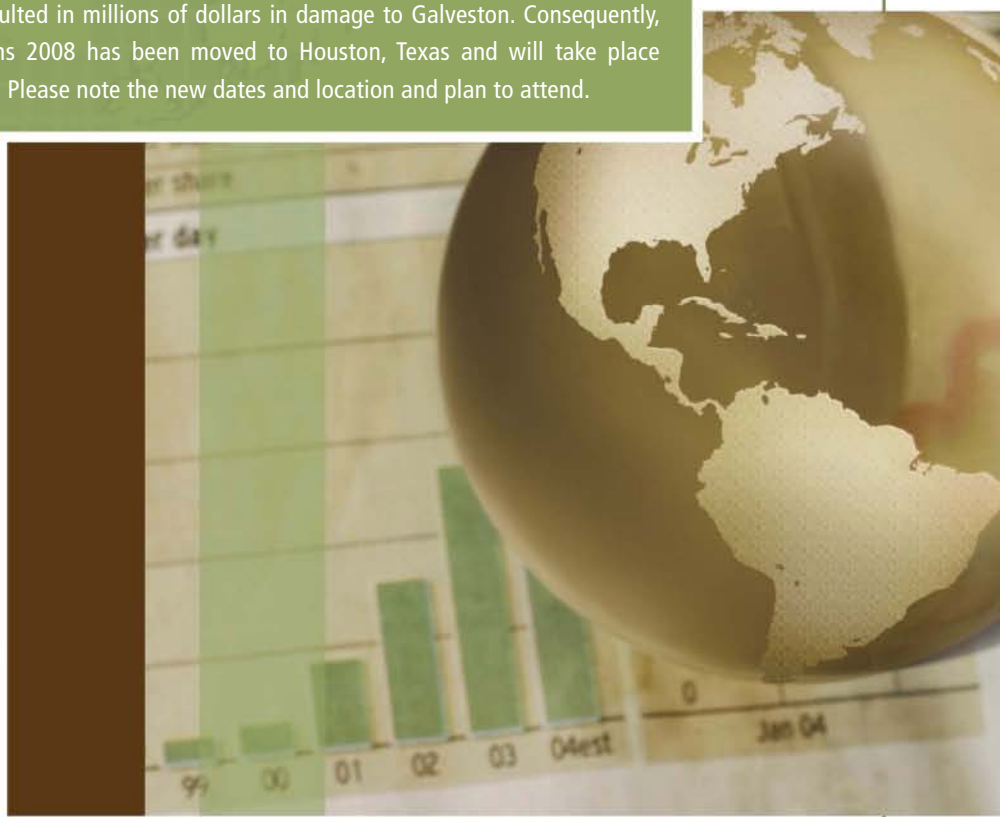
Deepwater Operations

DEEPWATER OPERATIONS CONFERENCE AND EXHIBITION

November 3 – 5, 2008 | George R. Brown Convention Center | Houston, Texas

NEW DATES! NEW LOCATION!

Hurricane Ike has resulted in millions of dollars in damage to Galveston. Consequently, DeepWater Operations 2008 has been moved to Houston, Texas and will take place November 3-5, 2008. Please note the new dates and location and plan to attend.



FOR EVENT INFORMATION:

Eldon Ball
Conference Director
P: +1 713 963 6252
F: +1 713 963 6296
E: eldonb@pennwell.com

Gail Killough
Conference Manager
P: +1 713 963 6251
F: +1 713 963 6201
E: gailk@pennwell.com

FOR INFORMATION ON SPONSORING OR EXHIBITING:

Kristin Stavinoha
Exhibit/Sponsorship
Sales Manager
Phone: +1 713 963 6283
Fax: +1 713 963 6201
Email: kristins@pennwell.com

SUCCEEDING In A Changing Environment

As the industry shifts to deeper water, the environment in which we work becomes more complex, hazardous and expensive. Successful companies recognize early the changing conditions and environmental challenges facing the industry. At the Deepwater Operations Conference & Exhibition in 2008, participants and attendees will discuss how to succeed under these extreme conditions.

Plan to attend, sponsor and exhibit at the 2008 conference and exhibition as the technical focus shifts to "Succeeding in a Changing Environment." As with our past conferences, proceedings will not be published and the press will not be invited to assure confidentiality between the attendees and the speakers allowing the most up–to–date information to be shared.

WWW.DEEPWATEROPERATIONS.COM

Owned & Produced By: PennWell | Flagship Media Sponsors: Offshore, Oil&Gas Journal | Host: bp

Silver Sponsor: NALCO | Bronze Sponsor: Petrofac | High Performance Sponsors: Baker Hughes, FastorQ, MMR

Sponsored By: bp, Champion Technologies, FMC Technologies, Honeywell, Shell

Imports of crude and products

	Districts 1-4		District 5		Total US		
	10-10 2008	10-3 2008	10-10 2008	10-3 2008	10-10 2008	10-3 2008	*10-12 2007
	1,000 b/d						
Total motor gasoline	1,452	1,432	0	2	1,452	1,434	1,093
Mo. gas. blending comp.	991	958	0	0	991	958	579
Distillate	91	122	0	43	91	165	302
Residual	166	270	92	162	258	432	504
Jet fuel-kerosine	67	132	6	19	73	151	191
Propane-propylene	102	64	14	15	116	79	210
Other	397	572	132	54	529	626	957
Total products	**3,266**	**3,550**	**244**	**295**	**3,510**	**3,845**	**3,836**
Total crude	**8,988**	**9,229**	**1,173**	**1,117**	**10,161**	**10,346**	**10,408**
Total imports	**12,254**	**12,779**	**1,417**	**1,412**	**13,671**	**14,191**	**14,244**

*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

	*10-17-08	*10-19-07	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	84.99	94.74	–9.75	–10.3
Brent crude	69.89	84.42	–14.53	–17.2
Crack spread	15.10	10.32	4.78	46.3
FUTURES MARKET PRICES				
One month				
Product value	81.72	93.72	–12.00	–12.8
Light sweet crude	75.21	87.84	–12.63	–14.4
Crack spread	6.50	5.88	0.63	10.7
Six month				
Product value	88.99	97.34	–8.35	–8.6
Light sweet crude	77.30	83.01	–5.71	–6.9
Crack spread	11.69	14.32	–2.63	–18.4

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

Purvin & Gertz LNG netbacks—Oct. 17, 2008

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	10.90	8.61	9.99	8.49	9.25	9.90
Everett	5.81	3.76	5.43	3.86	4.22	6.10
Isle of Grain	11.40	9.36	10.67	9.35	9.63	10.70
Lake Charles	4.06	2.36	3.83	2.51	2.68	4.69
Sodegaura	9.98	12.47	10.24	12.13	11.32	8.24
Zeebrugge	11.56	9.22	10.83	9.12	9.78	10.84

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		Jet fuel, kerosine	Fuel oils		Propane-propylene
		Total	Blending comp.[1]		Distillate	Residual	
	1,000 bbl						
PADD 1	13,708	46,978	26,267	7,797	48,474	14,028	4,342
PADD 2	60,574	48,747	18,622	7,290	27,015	1,427	25,314
PADD 3	167,686	64,722	30,804	10,934	32,204	18,086	28,990
PADD 4	14,738	6,815	2,388	557	2,882	337	[1]2,559
PADD 5	51,492	26,526	20,734	9,680	11,573	4,828	—
Oct. 10, 2008	**308,198**	**193,788**	**98,815**	**36,258**	**122,148**	**38,706**	**61,205**
Oct. 3, 2008	**302,587**	**186,815**	**95,969**	**36,783**	**122,601**	**37,809**	**60,876**
Oct. 12, 2007[2]	**321,865**	**195,768**	**90,360**	**41,654**	**136,318**	**36,425**	**60,374**

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

Refinery report—Oct. 10, 2008

District	REFINERY OPERATIONS		REFINERY OUTPUT				
	Gross inputs	Crude oil inputs	Total motor gasoline	Jet fuel, kerosine	Fuel oils		Propane-propylene
					Distillate	Residual	
	1,000 b/d						
PADD 1	1,547	1,557	2,244	116	460	117	61
PADD 2	3,129	3,109	2,121	228	953	47	223
PADD 3	6,655	6,423	2,901	622	1,997	262	572
PADD 4	554	552	270	18	186	12	[1]156
PADD 5	2,598	2,474	1,628	426	588	122	—
Oct. 10, 2008	**14,483**	**14,115**	**9,164**	**1,410**	**4,184**	**560**	**1,012**
Oct. 3, 2008	**14,251**	**14,024**	**8,936**	**1,435**	**4,029**	**581**	**1,025**
Oct. 12, 2007[2]	**15,239**	**15,123**	**8,864**	**1,469**	**4,172**	**644**	**1,030**
	17,610 Operable capacity		**82.2 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 10-15-08	Pump price* 10-15-08	Pump price 10-17-07
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	288.8	335.3	284.1
Baltimore	292.2	334.1	272.9
Boston	288.1	330.0	268.6
Buffalo	257.4	318.3	283.9
Miami	275.3	326.9	303.2
Newark	287.3	319.9	270.9
New York	269.0	329.9	283.6
Norfolk	280.3	318.7	267.9
Philadelphia	281.3	332.0	279.2
Pittsburgh	270.5	321.2	280.6
Wash., DC	282.4	320.8	286.2
PAD I avg	279.3	326.1	280.1
Chicago	263.7	328.1	294.2
Cleveland	256.3	302.7	279.5
Des Moines	268.3	308.7	273.4
Detroit	261.1	320.5	290.0
Indianapolis	256.1	315.5	289.5
Kansas City	263.4	299.4	274.1
Louisville	278.0	318.9	289.5
Memphis	263.1	302.9	259.4
Milwaukee	269.2	320.5	296.8
Minn.-St. Paul	268.2	312.2	290.7
Oklahoma City	244.7	280.1	267.4
Omaha	248.9	294.2	271.6
St. Louis	272.5	308.5	263.3
Tulsa	250.1	285.5	262.8
Wichita	254.3	297.7	265.9
PAD II avg	261.2	306.4	277.9
Albuquerque	274.5	310.9	280.3
Birmingham	263.5	302.8	271.4
Dallas-Fort Worth	255.1	293.5	264.4
Houston	258.5	296.9	269.4
Little Rock	259.8	300.0	268.1
New Orleans	279.8	318.2	271.4
San Antonio	269.2	307.6	268.0
PAD III avg	265.8	304.3	270.4
Cheyenne	281.1	313.5	279.6
Denver	300.8	341.2	292.6
Salt Lake City	280.8	323.7	287.9
PAD IV avg	287.6	326.1	286.7
Los Angeles	276.0	343.1	304.5
Phoenix	292.6	330.0	279.1
Portland	291.6	335.0	300.1
San Diego	283.1	350.2	315.1
San Francisco	288.3	355.4	322.4
Seattle	284.1	340.0	305.4
PAD V avg	286.0	342.3	304.4
Week's avg.	**272.1**	**317.7**	**281.6**
Sept. avg.	**322.7**	**367.2**	**280.4**
Aug. avg.	**330.8**	**375.3**	**280.8**
2008 to date	**309.7**	**353.7**	—
2007 to date	**229.9**	**273.5**	—

*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

	10-10-08 ¢/gal		10-10-08 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	197.28	New York Harbor	225.61
Gulf Coast	186.90	Gulf Coast	222.86
Los Angeles	235.30	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	191.21	ARA	234.17
Singapore	209.05	Singapore	199.36
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	193.40	New York Harbor	158.57
Gulf Coast	185.30	Gulf Coast	171.36
Los Angeles	241.30	Los Angeles	203.53
		ARA	189.35
		Singapore	163.77

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

BAKER HUGHES RIG COUNT

	10-17-08	10-19-07
Alabama	5	7
Alaska	7	8
Arkansas	57	48
California	45	42
Land	45	41
Offshore	0	1
Colorado	122	112
Florida	2	0
Illinois	1	0
Indiana	2	2
Kansas	11	14
Kentucky	12	10
Louisiana	198	144
N. Land	80	51
S. Inland waters	20	25
S. Land	32	28
Offshore	66	40
Maryland	0	1
Michigan	2	1
Mississippi	17	9
Montana	9	12
Nebraska	0	1
New Mexico	93	70
New York	6	8
North Dakota	74	46
Ohio	10	14
Oklahoma	193	191
Pennsylvania	26	18
South Dakota	1	0
Texas	925	850
Offshore	7	8
Inland waters	0	2
Dist. 1	27	27
Dist. 2	36	30
Dist. 3	64	63
Dist. 4	89	80
Dist. 5	186	180
Dist. 6	135	124
Dist. 7B	25	38
Dist. 7C	63	54
Dist. 8	129	117
Dist. 8A	29	21
Dist. 9	39	40
Dist. 10	96	66
Utah	38	46
West Virginia	30	30
Wyoming	75	69
Others—NV-4; OR-1; TN-4; VA-5; WA-1	15	11
Total US	**1,976**	**1,764**
Total Canada	**437**	**331**
Grand total	**2,413**	**2,095**
Oil rigs	428	320
Gas rigs	1,537	1,438
Total offshore	78	50
Total cum. avg. YTD	**1,879**	**1,760**

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	10-17-08 Rig count	10-17-08 Percent footage*	10-19-07 Rig count	10-19-07 Percent footage*
0-2,500	85	3.5	59	5.0
2,501-5,000	142	49.2	104	59.6
5,001-7,500	272	17.6	220	21.8
7,501-10,000	464	2.5	436	2.5
10,001-12,500	460	0.8	433	1.6
12,501-15,000	382	0.2	280	0.3
15,001-17,500	170	—	111	—
17,501-20,000	79	—	69	—
20,001-over	31	—	33	—
Total	**2,085**	**6.6**	**1,745**	**7.5**
INLAND	31		39	
LAND	2,001		1,658	
OFFSHORE	53		48	

*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]10-17-08	[2]10-19-07
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	20	20
Alaska	665	686
California	649	657
Colorado	60	66
Florida	5	6
Illinois	26	27
Kansas	98	107
Louisiana	920	1,197
Michigan	15	15
Mississippi	58	59
Montana	95	95
New Mexico	162	161
North Dakota	123	128
Oklahoma	174	172
Texas	1,236	1,333
Utah	51	53
Wyoming	149	148
All others	61	75
Total	**4,567**	**5,005**

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

US CRUDE PRICES

	10-17-08 $/bbl*
Alaska-North Slope 27°	110.67
South Louisiana Sweet	75.00
California-Kern River 13°	58.65
Lost Hills 30°	66.95
Wyoming Sweet	56.85
East Texas Sweet	67.75
West Texas Sour 34°	63.75
West Texas Intermediate	68.25
Oklahoma Sweet	68.25
Texas Upper Gulf Coast	64.75
Michigan Sour	61.25
Kansas Common	67.25
North Dakota Sweet	58.00

*Current major refiner's posted prices except North Slope lags 2 months. 40° gravity crude unless differing gravity is shown.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

WORLD CRUDE PRICES

$/bbl[1]	10-10-08
United Kingdom-Brent 38°	83.80
Russia-Urals 32°	81.82
Saudi Light 34°	81.13
Dubai Fateh 32°	78.50
Algeria Saharan 44°	85.18
Nigeria-Bonny Light 37°	88.24
Indonesia-Minas 34°	86.20
Venezuela-Tia Juana Light 31°	85.26
Mexico-Isthmus 33°	85.15
OPEC basket	84.24
Total OPEC[2]	81.78
Total non-OPEC[2]	82.27
Total world[2]	82.00
US imports[3]	80.91

[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]

	10-10-08	10-3-08	10-10-07	Change, %
	bcf			
Producing region	892	867	994	–10.3
Consuming region east	1,945	1,899	1,925	1.0
Consuming region west	440	432	445	–1.1
Total US	**3,277**	**3,198**	**3,364**	**–2.6**
	July 08	**July 07**	**Change, %**	
Total US[2]	**2,516**	**2,894**	**–13.1**	

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

Statistics

World oil balance

	2008 2nd qtr.	2007 1st qtr.	2007 4th qtr.	2007 3rd qtr.	2007 2nd qtr.	2007 1st qtr.
	Million b/d					
DEMAND						
OECD						
US & Territories	19.96	20.15	20.90	21.06	20.95	21.09
Canada	2.26	2.37	2.39	2.43	2.30	2.38
Mexico	2.16	2.10	2.16	2.06	2.14	2.12
Japan	4.59	5.41	5.25	4.70	4.64	5.43
South Korea	2.09	2.33	2.31	2.06	2.12	2.35
France	1.92	1.98	2.02	1.94	1.86	1.98
Italy	1.61	1.62	1.75	1.65	1.69	1.72
United Kingdom	1.72	1.72	1.73	1.75	1.78	1.80
Germany	2.41	2.47	2.54	2.55	2.37	2.37
Other OECD Europe	7.23	7.41	7.60	7.52	7.25	7.35
Australia & New Zealand	1.14	1.13	1.15	1.12	1.10	1.12
Total OECD	**47.09**	**48.69**	**49.80**	**48.84**	**48.20**	**49.71**
NON–OECD						
China	7.94	7.72	7.87	7.59	7.52	7.33
FSU	4.49	4.34	4.32	4.22	4.32	4.25
Non–OECD Europe	0.80	0.86	0.79	0.73	0.78	0.85
Other Asia	8.88	8.81	8.93	8.64	8.83	8.74
Other non–OECD	15.99	15.57	15.25	15.54	15.22	14.93
Total non–OECD	**38.10**	**37.30**	**37.16**	**36.72**	**36.67**	**36.10**
TOTAL DEMAND	**85.19**	**85.99**	**86.96**	**85.56**	**84.87**	**85.81**
SUPPLY						
OECD						
US	8.75	8.64	8.58	8.36	8.50	8.38
Canada	3.31	3.35	3.40	3.48	3.37	3.45
Mexico	3.20	3.30	3.35	3.46	3.61	3.59
North Sea	4.33	4.46	4.57	4.28	4.49	4.80
Other OECD	1.59	1.54	1.57	1.56	1.54	1.50
Total OECD	**21.18**	**21.29**	**21.47**	**21.14**	**21.51**	**21.72**
NON–OECD						
FSU	12.60	12.60	12.66	12.55	12.60	12.61
China	3.99	3.93	3.86	3.87	3.96	3.92
Other non–OECD	11.07	10.83	11.13	11.21	11.04	10.70
Total non–OECD, non–OPEC	**27.66**	**27.36**	**27.65**	**27.63**	**27.60**	**27.23**
OPEC*	**36.94**	**36.69**	**36.18**	**35.44**	**35.07**	**35.98**
TOTAL SUPPLY	**85.78**	**85.34**	**85.30**	**84.21**	**84.18**	**84.93**
Stock change	**0.59**	**–0.65**	**–1.66**	**–1.35**	**–0.69**	**–0.88**

*Includes Angola.
Source: DOE International Petroleum Monthly
Data available in OGJ Online Research Center.

US petroleum imports from source country

	June 2008	May 2008	Average YTD 2008	Average YTD 2007	Chg. vs. previous year Volume	Chg. vs. previous year %
	1,000 b/d					
Algeria	492	620	535	718	–183	–25.5
Angola	649	476	506	580	–74	–12.8
Kuwait	183	263	222	200	22	11.0
Nigeria	1,020	918	1,092	1,080	12	1.1
Saudi Arabia	1,493	1,604	1,538	1,434	104	7.3
Venezuela	1,215	1,171	1,172	1,356	–184	–13.6
Other OPEC	1,032	874	1,015	627	388	61.9
Total OPEC	**6,084**	**5,926**	**6,080**	**5,995**	**85**	**1.4**
Canada	2,359	2,346	2,472	2,470	2	0.1
Mexico	1,254	1,218	1,304	1,590	–286	–18.0
Norway	122	183	118	173	–55	–31.8
United Kingdom	286	237	223	310	–87	–28.1
Virgin Islands	314	340	336	319	17	5.3
Other non–OPEC	2,948	2,612	2,490	2,737	–247	–9.0
Total non–OPEC	**7,283**	**6,936**	**6,943**	**7,599**	**–656**	**–8.6**
TOTAL IMPORTS	**13,367**	**12,862**	**13,023**	**13,594**	**–571**	**–4.2**

Source: DOE Monthly Energy Review
Data available in OGJ Online Research Center.

OECD total net oil imports

	June 2008	May 2008	Apr. 2008	June 2007	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	–1,187	–1,341	–1,277	–993	–194	19.5
US	11,202	11,056	11,498	12,222	–1,020	–8.3
Mexico	–978	–1,120	–1,335	–1,501	523	–34.8
France	1,653	1,720	1,716	1,670	–17	–1.0
Germany	1,980	2,043	2,210	2,059	–79	–3.8
Italy	1,498	1,441	1,528	1,566	–68	–4.3
Netherlands	1,042	1,005	818	903	139	15.4
Spain	1,473	1,496	1,627	1,476	–3	–0.2
Other importers	3,950	3,900	4,100	3,868	82	2.1
Norway	–1,899	–1,960	–2,069	–1,962	63	–3.2
United Kingdom	48	–112	115	–206	254	–123.3
Total OECD Europe	**9,745**	**9,533**	**10,045**	**9,374**	**371**	**4.0**
Japan	4,578	4,681	5,077	4,849	–271	–5.6
South Korea	1,891	2,251	2,055	2,125	–234	–11.0
Other OECD	805	968	1,059	954	–149	–15.6
Total OECD	**26,056**	**26,028**	**27,122**	**27,030**	**–974**	**–3.6**

Source: DOE International Petroleum Monthly
Data available in OGJ Online Research Center.

OECD* total gross imports from OPEC

	June 2008	May 2008	Apr. 2008	June 2007	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million b/d					
Canada	459	375	504	435	24	5.5
US	6,084	5,926	6,262	6,289	–205	–3.3
Mexico	45	20	10	27	18	66.7
France	779	837	650	786	–7	–0.9
Germany	399	471	495	500	–101	–20.2
Italy	1,213	1,212	1,176	1,265	–52	–4.1
Netherlands	661	640	554	491	170	34.6
Spain	788	789	559	770	18	2.3
Other importers	1,349	1,216	1,232	1,002	347	34.6
United Kingdom	391	304	267	247	144	58.3
Total OECD Europe	**5,580**	**5,469**	**4,933**	**5,061**	**519**	**10.3**
Japan	3,606	4,275	4,634	4,035	–429	–10.6
South Korea	2,347	2,354	2,263	2,364	–17	–0.7
Other OECD	691	693	699	736	–45	–6.1
Total OECD	**18,812**	**19,112**	**19,305**	**18,947**	**–135**	**–0.7**

*Organization for Economic Cooperation and Development.
Source: DOE International Petroleum Monthly
Data available in OGJ Online Research Center.

Oil stocks in OECD countries*

	June 2008	May 2008	Apr. 2008	June 2007	Chg. vs. previous year Volume	Chg. vs. previous year %
	Million bbl					
France	177	177	173	174	3	1.7
Germany	273	277	280	283	–10	–3.5
Italy	137	136	134	133	4	3.0
United Kingdom	100	99	98	101	–1	–1.0
Other OECD Europe	681	682	676	662	19	2.9
Total OECD Europe	**1,368**	**1,371**	**1,361**	**1,353**	**15**	**1.1**
Canada	194	194	194	188	6	3.2
US	1,686	1,673	1,665	1,730	–44	–2.5
Japan	619	617	610	622	–3	–0.5
South Korea	147	146	141	158	–11	–7.0
Other OECD	108	104	102	112	–4	–3.6
Total OECD	**4,122**	**4,105**	**4,073**	**4,163**	**–41**	**–1.0**

*End of period.
Source: DOE International Petroleum Monthly Report
Data available in OGJ Online Research Center.

PennEnergy EQUIPMENT
WWW.PENNENERGY.COM

You need rigs. Not risks.

In a tight rig market, you don't have time to second-guess your supplier. That's a good reason to work with LongForza Corporation.

Straight-talking and no-nonsense, LongForza is a direct distributor of oilfield equipment from premium global manufacturers. And now, PennEnergy is pleased to be the exclusive source of LongForza-supplied onshore drilling rigs in 1000-, 1500- and 2000-HP configurations.

With competitive pricing, aggressive timelines and turnkey services from crew leasing to financing, LongForza has what you need in today's market, including the most important thing – integrity.

Standards
Our manufacturers adhere to API, ASTM, ANSI, ISO and MilSpec and others.

Services
On-site rig-up training and testing are included in our competitive pricing.

Transparency
Who we represent and the warranties we offer – it's all on the table for our customers.

Want to know more?
Contact Randy Hall at PennEnergy
Blackberry/Email: rhall@pennenergy.com | P: 713-499-6330

LONGFORZA CORPORATION

Classified Advertising

Your marketplace for the oil and gas industry

DEADLINE for CLASSIFIED ADVERTISING is 10 A.M. Tuesday preceding date of publication. Address advertising inquiries to CLASSIFIED SALES, 1-800-331-4463 ext. 6301, 918-832-9301, fax 918-831-9776, email: glendah@pennwell.com.

- *DISPLAY CLASSIFIED: $375 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 CLASSIFIED: $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 $54.00 No agency commission, no 2% cash discount. Centered/Bold heading, $9.00 extra.*
- *COMPANY LOGO: Available with undisplayed ad for $80.00. Logo will be centered above copy with a maximum height of 3/8 inch.*
- *NO SPECIAL POSITION AVAILABLE IN CLASSIFIED SECTION.*
- *PAYMENT MUST ACCOMPANY ORDER FOR CLASSIFIED AD.*

EMPLOYMENT

PANTHER ENERGY COMPANY, LLC

Degreed Field Geologist
to work in the OK-TX panhandle as geo-steering representative for rapidly growing, Independent Exploration and Production Company, drilling horizontal wells. Previous field experience is advantageous. Excellent opportunity for advancement and experience with current technologies. Competitive salary and generous comprehensive benefit package, commensurate with experience & qualifications. Send cover letter and resume to:
Human Resources
P. O. Box 3105
Tulsa, OK 74101
hr@pantherenergy.us
Fax 866-585-2752

OYO Geospace Corporation in Houston, TX seeks Quality Engineer I. Qualified applicants will possess bachelors in engineering and 1 year experience in a manufacturing environment. Email resumes to Lacey Rice at: recruiter@oyogeospace.com. Must put job code RDX0908-01 on resume.

OYO Geospace Corporation in Houston, TX seeks Project Engineer. Qualified applicants will possess a Bachelor's degree in Mechanical Engineering plus five years experience in designing sensitive electro-mechanical devices. Email resumes to the attention of Lacey Rice at: recruiter@oyogeospace.com. Must put job code RDX0908-01 on resumes.

ConocoPhillips in Trainer, PA has openings for the following positions.
- Reliability Engineer – Job code 0062I
- Senior Instrument Engineer – Job code 0062J

Related degrees and experience required. To submit resume, please visit www.conocophillips.com/careers. Please put job code on resume

---

Weatherford in Houston TX seeks Product Line Mgr./Sr. Stimulation Tech. Advisor for Sand Control Product line. Req's: Bach in Eng., Chem. or Sci. & 5 yrs in-job or as Eng Mgr/Bus Develop Mgr for sand control product line. In lieu of Bach + 5, will accept 10 yrs related exp. in sand control technology. Please fax or e-mail resume to HR at 281-260-5669 or David.Dyer@weatherford.com

---

ConocoPhillips Company in Midland, Texas seeks Data Analyst. Qualified applicants will possess a bachelor's degree in Information Technology or closely related field and at least one (1) or more years of related experience. To submit resume, please visit www.conocophillips.com/careers. Put Job code 0063D on resume.

Senior Petroleum Engineer

At Union Bank of California, our people are our greatest asset. We are one of the largest banks in California with a longstanding reputation for professional training and career development. We invest in a diverse workforce as our employees come from many different backgrounds, bringing with them different experiences and perspectives.

Become part of a team where community, diversity, and exceptional service are part of everyone's job. Invest in you!

POSITION OVERVIEW

The Senior Petroleum Engineer will provide technical support in the analysis of oil and gas properties for loan requests and existing customers who tend to be small, independent oil and gas companies.

This primarily involves critical auditing of independent third party engineering evaluations, in all key areas of technical due diligence including, production, expense, cost estimates and economic assumptions. In addition, the responsibilities will include the analysis of the technical risks associated with the credit requests, as well as monitoring the performance of existing customers through the comparison of forecasted production and financial trends, versus actual production and financial figures.

QUALIFICATIONS

- Minimum 5 years of Petroleum Engineering experience with a major or large independent oil company or bank.
- Familiarity with hydrocarbon reserve evaluation.
- Proficiency with spreadsheets and pc literate.
- Strong analytical ability as well as strong written and verbal communication skills.

Requires moderate level of domestic travel.

Preferred skills include: Familiarity with financial statements, reserve reports, and ARIES software.

Position location will be in either Los Angeles, CA, Houston or Dallas, TX.

Union Bank of California offers a competitive compensation and benefits package including a 401K plan. Pre-employment background screening is required for all positions. Union Bank of California is an equal opportunity employer.

Apply now!
You can apply to the available Senior Petroleum Engineer opportunity (Job requisition #05701) opportunity via the Union Bank of California website at www.uboc.com/careers

BUSINESS OPPORTUNITY

Want to purchase minerals and other oil/gas interests. Send details to: P.O. Box 13557, Denver, CO 80201.

Have investors looking to purchase the following oilfield service companies: workover rigs, water hauling, SWD wells, pumping (nitrogen, acid, etc.), frac tank rentals, coiled tubing, fishing tool rentals. Hebert Properties 337-257-1819.

DRILLING PROSPECTS

WANTED
Oil Drilling prospects. Less than 3,000 ft.
Southwest Minerals, Inc.
Harvey Estes, Pres.
813-376-4075
Harveylv@aol.com

DRILLING PROSPECTS

DRILLING PROSPECT
3,000 acre Arbuckle surface anticline in southern Oklahoma not leased. Potential pay at 5000'. Excellent surface geology. Review geology in my office, sign confidential agreement then evaluate structure in field.
Write PennWell Corporation, Petroleum Classifieds, 1421 S. Sheridan, Tulsa, OK 74112.

FIELD DEVELOPMENT PROSPECT FOR SALE

4,074 contiguous, leased acres, Prospect, where oil & gas has been discovered in Roosevelt County, NM. IP 171 bopd from a 50' thick payzone within the San Andres formation at 4,300'. Accepting only written inquiries addressed to P.O. Box 6874, Santa Rosa, CA 95406. Will respond only to inquiries from established O&G companies capable of immediately entering into an aggressive field development project.

REAL ESTATE

MARCELLUS Service Terminal – Property for Sale – 7 acres with 5000 sq/ft, 2 bay garage; Immediate highway access; Paved parking for 30+ trucks; 3,000 sq/ft office; Ideally located in the center of drilling activity. Space to build to suit. Ready immediately. Call Bill Doyle at 724-368-3900 x15

EQUIPMENT FOR SALE

50,000 BOPD 150 MMCFD OIL AND GAS INITIAL PRODUCTION FACILITY

Components Mfg in 2004, Engineered and Constructed by Expro

FAS, Export Packed, Customs Cleared, Port of Korsakov, Sakhalin Island Russia
Available for Export Mid-December 2008—Mid January 2009

Included:

Two Wauk L7044GSI Ariel JGK-4 Gas Compressor Units
Two Wauk L36GSID Bingham 2x3x6.5A VCR Crude Export Pumps
Two Gas Generator Sets CAT G3516 LE 975 kW 400V Units 50 hertz
Low Temperature Separator Unit
Ethylene Glycol Regenerator Unit
Two Steam Generator Units
Crude Oil Cooler Unit
Gas Inlet Cooler Unit
Crude Oil Train Unit
Heater Exchangers/Transfer Pump Skid
Crude Oil Coalescer & Export Meter Skid
NGL Injection Pumps Skid
Gas Inlet Separator Skid

Offered by Material Management Resources, Inc.
Contact: Dennis K. Burke
Office: (713) 656-5613 Fax: (262) 313-1191
E-Mail: dennis.k.burke@exxonmobil.com
Alternate E-mail: dennisb@materialmg.com

Network INTERNATIONAL GAS TO LIQUIDS PLANT AUCTION

A WORLD OF SURPLUS ENERGY EQUIPMENT. ONE SITE.

NOVEMBER 20, 2008

400 BBL/D GAS TO LIQUIDS PILOT PLANT & PLANT TECHNOLOGY PACKAGE

Trey • (713) 590-1623 • TValentino@Networkintl.com

www.OneSiteForEquipment.com

NATCO

Producing Solutions

Water, Oil and Gas Treatment/Conditioning Equipment

For Sale, Lease, Contract Service

Separators, Hydrocyclones, Float Cells, Filtration, Electrostatic Oil Treaters, Amine Units, Glycol Units, JT-Plants, Refrigeration Units, LACT Units

For Information Call 713.895.1744

www.NATCOGroup.com

E-mail your ad to:
glendah@pennwell.com

REFRIGERATION AND J.T. PLANTS

7.5 MMSCFD, 1000 PSI, NATCO

4.0 MMSCFD, 1000 PSI, NATCO

6.5 MMSCFD, 1250 PSI X 400 PSI, H&H J.T.

2.0 MMSCFD, 1000 PSI, PROCESS EQPT.

OTHERS AVAILABLE

PLEASE CALL 318-425-2533, 318-458-1874

regardres@aol.com

Process Units

Condensate Stabilizer
6,500 BPSD

200 T/D Methanol Plant

FCCU UOP
17,000 – 22,000 BPSD

BASIC Engineering, Inc.
Please Call: 713-674-7171
Tommy Balke
tbalkebasic1@aol.com
www.basicengineeringinc.com

SURPLUS GAS PROCESSING/REFINING EQUIPMENT

NGL/LPG PLANTS: 10 - 600 MMCFD
AMINE PLANTS: 120 – 1,000 GPM
SULFUR PLANTS: 10 - 180 TPD
FRACTIONATION: 1000 – 25,000 BPD
HELIUM RECOVERY: 75 & 80 MMCFD
NITROGEN REJECTION: 25 – 80 MMCFD
ALSO OTHER REFINING UNITS
We offer engineered surplus equipment solutions.
Bexar Energy Holdings, Inc.
Phone 210 342-7106
Fax 210 223-0018
www.bexarenergy.com
Email: info@bexarenergy.com

FCC Unit -- 10,500 bpd
Alkylation Unit -- 6,500 bpd
Both Units Completed 1996
Excellent Condition
Doug Wood
Plant Process Equipment
281-333-7700
dwood@plant-process.com

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

CONSULTANTS

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

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

The Next Generation of Deepwater Challenges

Plan now to join industry colleagues and conference host Woodside Petroleum for the 20th Deep Offshore Technology (DOT) International Conference & Exhibition 3 – 5 December 2008 in Perth, Australia.

E&P operations offshore Australia encounter the full scope of technology challenges – deepwater conditions, remote field locations, deep gas development challenges, hostile environments, seafloor issues, difficult currents, flow assurance issues, long distances from infrastructure, logistical challenges, isolation from heavy lift and installation vessels – you name it and Australia has it all.

This year's DOT addresses virtually every technology issue that any deepwater operator will ever have to face. Plan today to exhibit, sponsor and attend this exciting event, along with the industry's leaders and brightest minds in this unique technology showcase.

For more information, please visit our Web site at www.deepoffshoretechnology.com.

DEEP OFFSHORE TECHNOLOGY INTERNATIONAL ASIA / PACIFIC ™

20 DEEP OFFSHORE TECHNOLOGY CONFERENCE & EXHIBITION

3 - 5 DECEMBER 2008
PERTH, AUSTRALIA
PERTH CONVENTION EXHIBITION CENTRE
www.deepoffshoretechnology.com

Exhibitor & Sponsorship Sales:

Jane Bailey (UK, Europe, Middle East & Africa)
Email: janeb@pennwell.com
Phone: +44 (0) 1992 656 651 • *Fax:* +44 (0) 1992 656 700

Sue Neighbors (The Americas)
Email: sneighbors@pennwell.com
Phone: +1 713 963 6256 • *Fax:* +1 713 963 6212

Michael Yee (Asia Pacific)
Email: yfyee@singnet.com.sg
Phone: +65 9616 8080 • *Fax:* +65 6734 0655

Owned & Produced By: PennWell
Hosted By: Woodside
Flagship Media Sponsors: Offshore, Oil&Gas Journal, Oil&Gas Financial Journal, Oil, Gas & Petrochem Equipment
Supporting Organization: GEP
Media Partner: Oil & Gas Australia

Sponsored By: ABS, Apache Energy, Bennett & Associates, Cameron, Chevron, Clough, Department of Industry and Resources, Marine Contractors, INTEC WorleyParsons Group, States Oil States Industries, Inc.

Advertising Sales / Advertisers Index

Houston
Regional Sales Managers. Marlene Breedlove; Tel: (713) 963-6293, Fax: (713) 963-6228, E-mail: marleneb@pennwell.com. Charlene Burman; Tel: (713) 963-6274, Fax: (713) 963-6228; E-mail: cburman@pennwell.com. Mike Moss; Tel: (713) 963-6221, Fax: (713) 963-6228: E-mail: mikem@pennwell.com. PennWell - Houston, 1455 West Loop South, Suite 400, Houston, TX 77027.

Southwest / South Texas/Western States/ Gulf States/Mid-Atlantic
Marlene Breedlove, 1455 West Loop South, Suite 400, Houston, TX 77027; P.O. Box 1941 Houston, TX 77251; Tel: (713) 963-6293, Fax: (713) 963-6228; E-mail: marleneb@pennwell.com.

Northeast/New England/Midwest/North Texas/ Oklahoma/Alaska/Canada
Charlene Burman, 1455 West Loop South, Suite 400, Houston, TX 77027; Tel: (713) 963-6274, Fax: (713) 963-6228; E-mail: cburman@pennwell.com.

Scandinavia/Denmark/The Netherlands/Middle East/Africa
David Betham-Rogers, 11 Avenue du Marechal Leclerc, 61320 Carrouges, France; Tel: 33 2 33 282584, Fax: 33 2 33 274491; E-mail: davidbr@pennwell.com.

United Kingdom
Linda Fransson, Warlies Park House, Horseshoe Hill Upshire, Essex EN9 3SR, UNITED KINGDOM Tel: +44 (0) 1992 656 665; Fax: +44 (0) 1992 656 700; E-mail: lindaf@pennwell.com.

France/Belgium/Spain/Portugal/Southern Switzerland/Monaco
Daniel Bernard, 8 allee des Herons, 78400 Chatou, France; Tel: 33 (0)1 3071 1224, Fax: 33 (0)1 3071 1119; E-mail: danielb@pennwell.com, France, Belgium, Spain, Portugal, Southern Switzerland, Monaco.

Germany/Austria/Northern/Switzerland/Eastern Europe/Russia
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. Andreas Sicking, Germany, Austria, Northern Switzerland, Eastern Europe, Russia, Former Soviet Union.

Japan
e. x. press Co., Ltd., Hirakawacho TEC Building, 2-11-11, Hirakawa-cho, Chiyoda-ku, Tokyo 102-0093, Japan, Tel: 81 3 3556 1575, Fax: 81 3 3556 1576; E-mail: manami.konishi@ex-press.jp; Manami Konishi.

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) 6 737-2356, Fax: (65) 6 734-0655; E-mail: yfyee@singnet.com.sg. Singapore, Australia, Asia Pacific.

India
Rajan Sharma, Interads Limited, 2, Padmini Enclave, Hauz Khas, New Delhi-110 016, India; Tel: +91-11-6283018/19, Fax: +91-11-6228928; E-mail: rajan@interadsindia.com.

Italy
Vittorio Rossi Prudente, UNIWORLD MARKETING, Via Sorio 47, 35141 PADOVA - Italy; Tel:+39049723548, Fax: +390498560792; E-mail: vrossiprudente@hotmail.com.

Supply cuts key to how far oil prices plunge

With equity markets gyrating and economies in peril, attention gravitates to demand in questions about oil prices. But no one should overlook supply.

That's not to say demand has lost importance. The International Energy Agency now expects global oil demand to average 86.5 million b/d this year, up only 0.5% from last year's level. That's 240,000 b/d less annual average demand than IEA projected last month. At the beginning of this year, IEA was projecting global oil-demand growth for 2008 of 2.3%.

The Editor's Perspective

by Bob Tippee, Editor

As demand unravels, crude oil prices plunge. In New York futures trading, marker crude fell below $70/bbl to a 14-month low Oct. 16. That's half its level of only 3 months ago. The question of the day: How low will crude prices go? The answer depends greatly on supply.

And supply depends first on action by the Organization of Petroleum Exporting Countries. The group's rescheduling of an extraordinary meeting to Oct. 24 from Nov. 18 signals a production cut. The only question, which group members already may have decided, is how much. Beyond OPEC's production response lie supply reductions emanating from the same economic malaise that's slashing demand.

Constrained credit has become a new limit on oil industry investment.

"In the upstream," IEA notes in its October Oil Market Report, "this will intensify the impact already accruing from access restrictions, tightening fiscal barriers, and manufacturing/service capacity constraints. In short, expanding production capacity, even in line with moderating demand growth, becomes more difficult."

Investment difficulties will hit small independent producers and possibly several Russian operators hardest, IEA says. Most large international companies and state producers will survive; those with heavy debt will have trouble. Rig orders may be cancelled. A new phase of industry consolidation is likely.

"A cash liquidity crisis also affects storage, refining, and trading activity," IEA says. "Oil market liquidity itself is already suffering, so underlying price volatility could persist, or even increase, in the months to come, something that further complicates investment planning for the future."

Supply constriction thus looms—from OPEC and from curtailed investment.

Atop those two joists rests the next price floor.

(Online Oct. 17, 2008; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

OPEC regains market attention

Although the faltering economy has been driving down energy prices in recent months, the November US crude contract rebounded $2 to $71.85/bbl Oct. 17 on the New York Mercantile Exchange in anticipation that the Organization of Petroleum Exporting Countries would cut production at its Oct. 24 meeting in Vienna.

Thanks to some of the largest 1-day price losses in NYMEX's history, front-month US crudes have recently traded for less than half of the record $147/bbl that they commanded in July. Olivier Jakob at Petromatrix, Zug, Switzerland, noted US crude fell as low as $68.57/bbl in intraday trade Oct. 13-17, finishing down $5.85/bbl at the end of that business week. Heating oil lost $3.24/bbl in the same period, while the contract for reformulated blend stock for oxygenate blending (RBOB) was down $5.92/bbl. Jakob said, "On the other hand, natural gas gained 3.9%." North Sea Brent crude for December was down $6.22/bbl for the week.

The average price of OPEC's basket of 13 benchmark crudes gained 48¢ to $63.82/bbl Oct. 17 but was still down $8.85/bbl from the Oct. 10 closure. Thus far this year, the OPEC basket had averaged $106.13/bbl, up from $69.08/bbl for all of 2007. Days before the meeting, OPEC Pres. Chakib Khelil said a production cut was "very likely" since global supply exceeded demand by 2 million b/d. OPEC earlier lowered its outlook for world oil consumption by 450,000 b/d to 87 million b/d.

OPEC would not have moved its meeting from mid-November to Oct. 24 "if it had not already decided on a cut," Jakob said. "Everyone these days is getting a rescue plan and OPEC has decided it also wants one."

At Friedman, Billings, Ramsey & Co. Inc. (FBR) in Arlington, Va., analysts were expecting a 1 million b/d reduction going into the meeting. "But we question whether weaker producers will be able to adhere to their quota during a downturn, particularly as additional cuts are likely to be required," they said. They estimated Saudi Arabia alone could reduce production by 1 million b/d "as long as the OPEC barrel fetched an average price of $60/bbl in 2009. By contrast, our estimates suggest Iran must earn $74/bbl in 2009 if exports fall even 100,000 b/d (to 2.4 million b/d)," they said.

Paul Horsnell, Barclays Capital Inc., London, said OPEC is likely to cut more than is necessary for the medium term, if prices are to be stabilized in the short run. "A cut of 1 million b/d with the potential for more cuts to come looks like a feasible starting point for discussions," he said.

Adam Sieminski, chief energy economist, Deutsche Bank, Washington, DC, said, "We believe OPEC production cuts are inevitable in this environment, but the experience of 1998 and 2001 suggests the cartel will struggle to cut production as fast as world growth is slowing." He added, "We now expect global gross domestic product growth to slow to 1.2% in 2009, and that this will translate into flat to declining oil demand. Energy and industrial metals commodities will be major casualties in this environment." As a result, he said, "We expect oil prices will average only $60/bbl and could bottom out at $50/bbl in 2009 or early 2010."

Industry reductions

Having already lowered its 2009 rig count forecast last month, Raymond James & Associates Inc. in Houston cut it again because "the economic situation has severely deteriorated," analysts said. "Additionally, reported US natural gas storage injections remain bearish despite more than 200 bcf of hurricane-related production shut-ins in the Gulf of Mexico." As a result, they said, "We now anticipate the US rig count will fall by more than 10% year-over-year in 2009 with a 40% peak-to-trough decline in the natural gas rig count. We expect the overall domestic rig count to fall 30% from its highs."

Raymond James expects US natural gas prices to remain depressed until late 2009 with the rig count hitting bottom in mid-2010 at an average 1,500, down 12.5% from 2009. "Between the reduced cash flows, the credit crunch, and the simple need to remove excess natural gas supply, we see no real way out of a severe slowdown in natural gas-directed activity in the US," they said.

FBR reduced its 2008 crude price forecasts to $105-110/bbl from an average $115/bbl previously. It lowered its 2009 outlook to $80-95/bbl, from an earlier pick of $110/bbl. Its 2010 projection is now for $70-$85/bbl, a "new downside" from the former estimate of simply $85/bbl. FBR's long-term estimate for 2011 and beyond is at $80-90/bbl.

(Online Oct. 20, 2008; author's e-mail: samf@ogjonline.com)

We've stepped up.

When our customers ask for more, we respond.

Today, we're the world's largest private upstream chemical company. For more than 50 years we've been listening to you.

We've climbed to the summit to ensure when our customers ask for advanced products and services to solve challenging deepwater issues — we deliver!

Through research and development, manufacturing and service operations, we provide proprietary chemicals that enhance productivity and improve well economics – from marginal assets to deepwater investments.

Each job still begins with your problem – not an inventory of standard chemical treatments.

We've stepped up, but we're still focused on you. The same personalized approach-now with a global footprint.

Get in step with the solution for improving your operations and economics. Call us at +1 713-627-3303 to meet with your regional representative or visit us online at www.champ-tech.com to learn more.

Champion Technologies

Drill Faster. Last Longer. Go Further.

QUANTEC

New Technology for Record-Breaking Performance

Superior durability. Superior stability. Superior drilling.
The revolutionary new Quantec premium PDC drill bits from Hughes Christensen set new standards for high-performance drilling, shattering records in challenging environments from hard granite to highly abrasive sandstone and shale. Precision depth of cut and incomparable wear resistance deliver extended operating life and accelerated rates of penetration that can save you days of rig time. Quantec — only from Hughes Christensen.

The Drill Bit Company.

BAKER HUGHES Hughes Christensen

Worldwide Headquarters The Woodlands, Texas Tel: 713 625 6654 Fax: 713 625 6655