Mind If We Drill Through?

Hughes Christensen EZCase Bit

By any measure — safety, schedule, or ultimate cost — there's no substitute for the only steel casing bit system in the industry: Hughes Christensen EZCase. Casing-while-drilling accomplishes two objectives in a single run, saving days of drilling time and associated costs. With its exclusive steel crown and full PDC cutting structure, EZCase does both jobs without compromising on performance. Any formation, any application — there's no better choice than EZCase for taking your liner or casing all the way to TD in record time.

www.bakerhughes.com/ezcase

The only STEEL casing bit on the market.

BAKER HUGHES

Advancing Reservoir Performance

Comprehensive Energy Industry Directories

Electronic Directories that Always Remain Current

Energy industry Directories that provide valuable company location and contact information for thousands of companies in the worldwide and US energy industry. The most comprehensive and current directories now available for the energy industry. An annual subscription provides the user with frequent updates so that the directories always remain current.

These are electronic directories that reside on your PC desktop for easy access and use (sorry no Macs). The directory information is searchable and printable, and there are links available to company web sites. The directories use unique software that enable the information to be displayed much like a print directory. Contact information at your fingerprints, but not exportable to spreadsheet or database.

For most companies the

ELECTRONIC DIGITAL DIRECTORIES INCLUDE:

Company locations, phone and fax,
Key personnel with phone and email
Company operating & finance descriptions
Company Links to websites

Operating Companies
Engineers, Contractors & Service Co's
Equipment Manufacturers & Suppliers
Trade Associations & Regulatory Agencies

- Gas Utility Industry – Worldwide
- Electric Utility Industry - Worldwide
- Pipeline Industry - Worldwide
- Refining & Gas Processing Industry - Worldwide
- Petrochemical Industry - Worldwide
- Liquid Terminals Industry - Worldwide
- Drilling & Well Servicing Industry - Worldwide

- United States & Canada E&P
- Texas E&P
- Houston & Gulf Coast E&P
- Mid Continent & Eastern US E&P
- Rocky Mountain & Western US E&P
- Offshore E&P
- International E&P (outside North America)

Directory Numbers (latest counts)

Directory	Listings	HQ Offices	Personnel	Emails	Phone	Fax	Website
Pipeline	22,584	7,955	67,162	52,951	46,409	21,868	6,328
Refining & Gas Processing	20,873	8,726	58,369	45,344	39,455	20,031	6,462
Petrochemical	18,882	8,264	50,755	38,598	35,863	19,268	5,911
Liquid Terminals	8,457	2,983	28,325	22,693	19,142	8,933	2,637
Gas Utility	13,768	6,645	47,288	37,118	31,035	15,903	4,873
Electric Utility	27,586	13,117	81,906	62,193	49,642	25,432	9,160
Drilling & Well Servicing	15,275	6,745	37,279	28,303	23,639	12,974	3,691
Offshore E&P	9,197	3,842	30,382	25,032	16,240	8,518	3,313
International E&P	10,796	4,647	25,495	16,684	16,869	7,459	2,818
United States & Canada E&P	38,595	23,500	81,713	51,098	54,145	27,242	6,758
Texas E&P	11,760	7,820	31,857	22,614	19,578	9,921	3,101
Houston & Gulf Coast E&P	10,403	6,307	32,722	24,387	18,347	9,409	3,626
Mid Continent & Eastern US E&P	12,370	8,407	29,854	18,954	20,142	8,900	2,576
Rocky MTN & Western US E&P	9,539	6,256	21,603	13,119	13,860	6,710	1,647

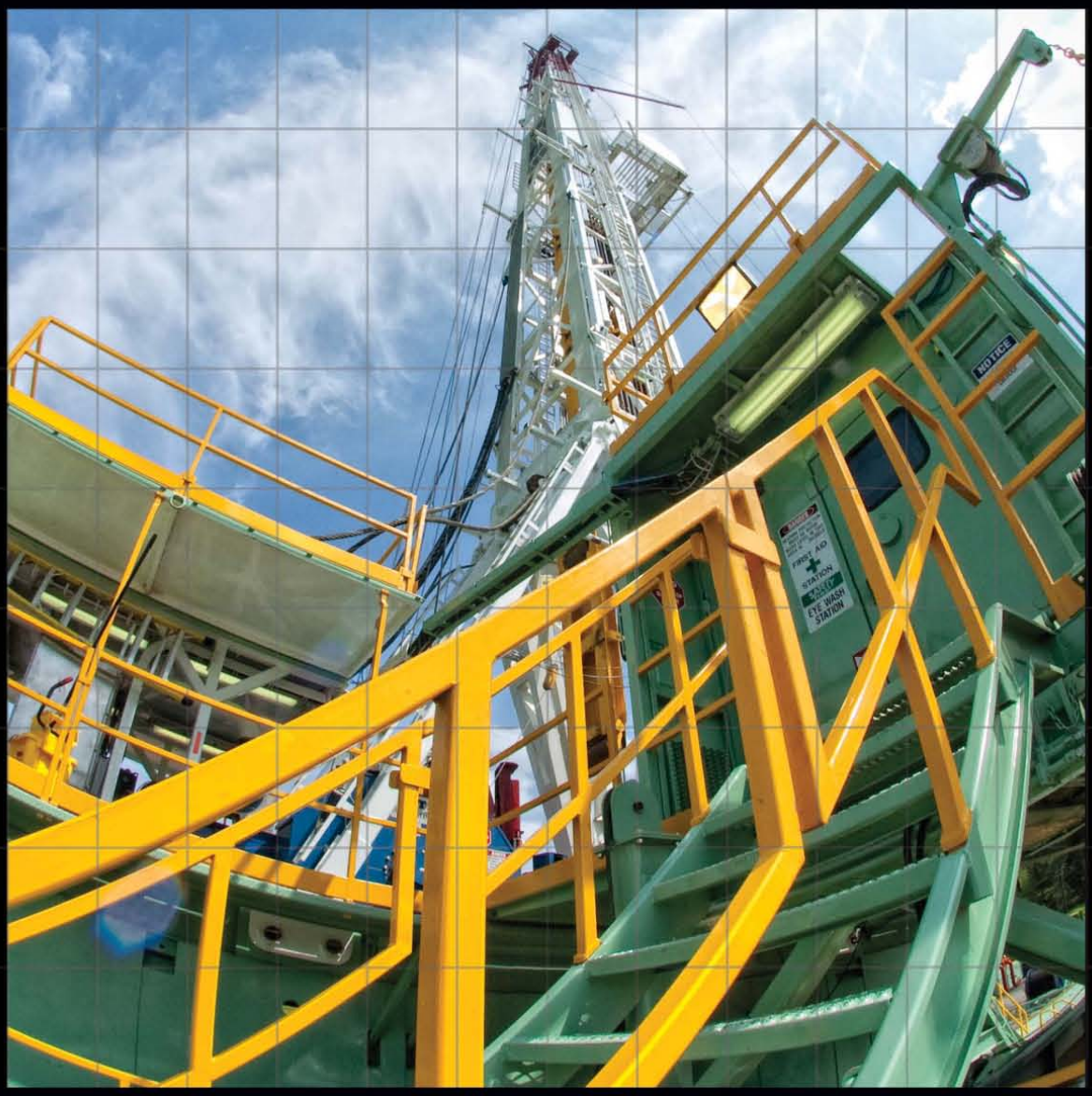
www.ogjresearch.com * To order: 1-918-752-9764 * Or email ORCInfo@pennwell.com

Week of Nov. 9, 2009/US$10.00

PennWell®

OIL&GAS JOURNAL®

International Petroleum News and Technology / www.ogjonline.com



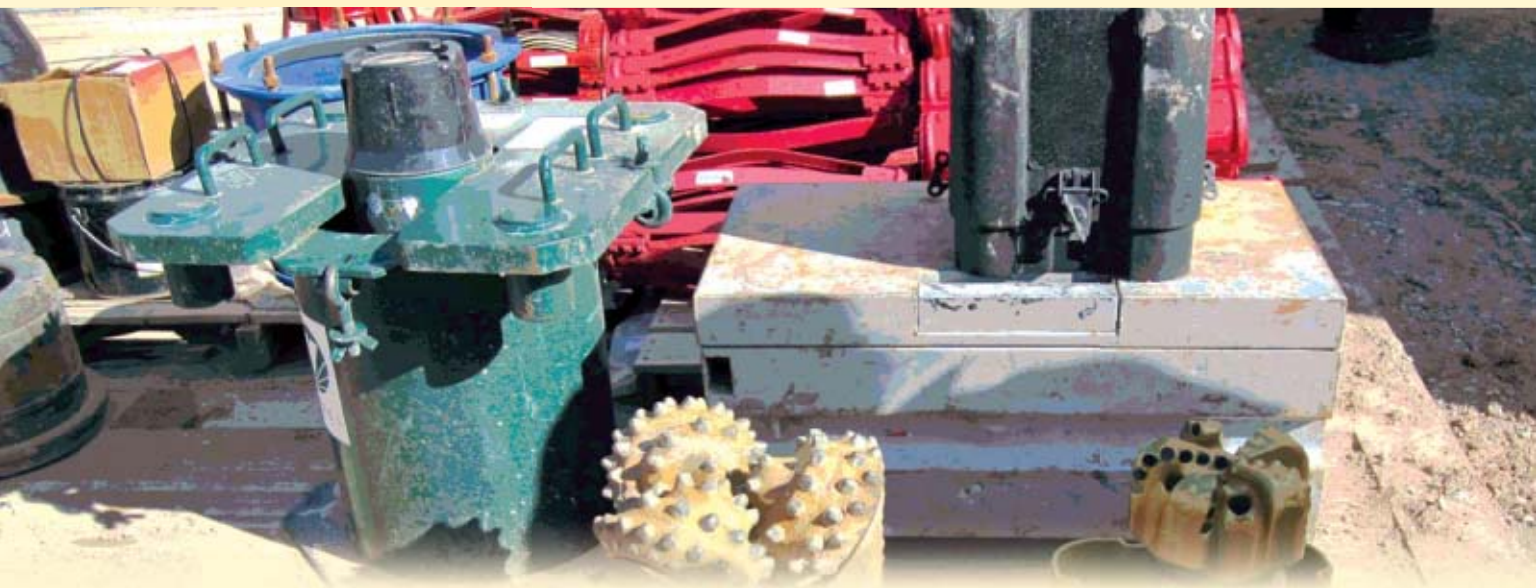
Drilling Report

COMMENT: Brazil aims to avoid long-term oil 'curse'
Dickinson area seen as tip of giant Lodgepole expanse
Revamp of HF alkylation unit uses solid-acid catalyst
API, AOPL working to standardize GPS system

OIL&GAS JOURNAL®

Nov. 9, 2009
Volume 107.42

DRILLING REPORT



REGULAR FEATURES

COVER

The rig is drilling a Marcellus shale well in north-central Pennsylvania. Marcellus shale is one of the more active US unconventional gas plays. The well is on an Anadarko Petroleum Corp. lease, and Precision Drilling Oilfield Services Corp. owns the rig. Although US rig counts are down from a year ago, the count has begun an upward trend, as discussed in OGJ's Drilling Report special, starting on p. 39. Photo from Anadarko.

FLUOR OFFSHORE SOLUTIONS℠

Build Big

When our client wanted conceptual and detailed engineering for the largest FPSO topsides in the world—they called Fluor. However, our involvement on China's largest offshore oil field development project did not end there. Fluor also provided procurement and construction services that aided on-time delivery of first oil at Bohai Bay.

When companies need the expertise and skills to achieve timely first oil & gas, they seek Fluor Offshore Solutions.
To learn more visit our website at **www.fluor.com/offshore.**

FLUOR®

General Interest

Exploration & Development

Drilling & Production

Processing

 Oil & Gas Journal (ISSN 0030-1388) is published 47 times per year by PennWell Corporation, 1421 S. Sheridan Rd., Tulsa, Okla., Box 1260, 74101. Periodicals postage paid at Tulsa, Okla., and at additional mailing offices. Oil & Gas Journal and OGJ are registered trademarks of PennWell Corporation. **POSTMASTER:** send address changes, letters about subscription service, or subscription orders to P.O. Box 3497, Northbrook, IL 60065, or telephone (800) 633-1656. Change of address notices should be sent promptly with old as well as new address and with ZIP code or postal zone. Allow 30 days for change of address. Oil & Gas Journal is available for electronic retrieval on Oil & Gas Journal Online (www.ogjonline.com) or the NEXIS® Service, Box 933, Dayton, Ohio 45401, (937) 865-6800. **SUBSCRIPTION RATES** in the US: 1 yr. $89; Latin America and Canada: 1 yr. $94; Russia and republics of the former USSR, 1 yr. 2,200 rubles; all other countries: 1 yr. $129, 1 yr. premium digital $59 worldwide. These rates apply only to individuals holding responsible positions in the petroleum industry. Single copies are $10 each except for 100th Anniversary issue which is $20. Publisher reserves the right to refuse non-qualified subscriptions. Oil & Gas Journal is available on the Internet at http://www.ogjonline.com. (Vol. 107, No. 42) Printed in the US. GST No. 126813153. Publications Mail Agreement Number 602914. Return Undeliverable Canadian Addresses to: P.O. Box 1632, Windsor, ON N9A 7C9.

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

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

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

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

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

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

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

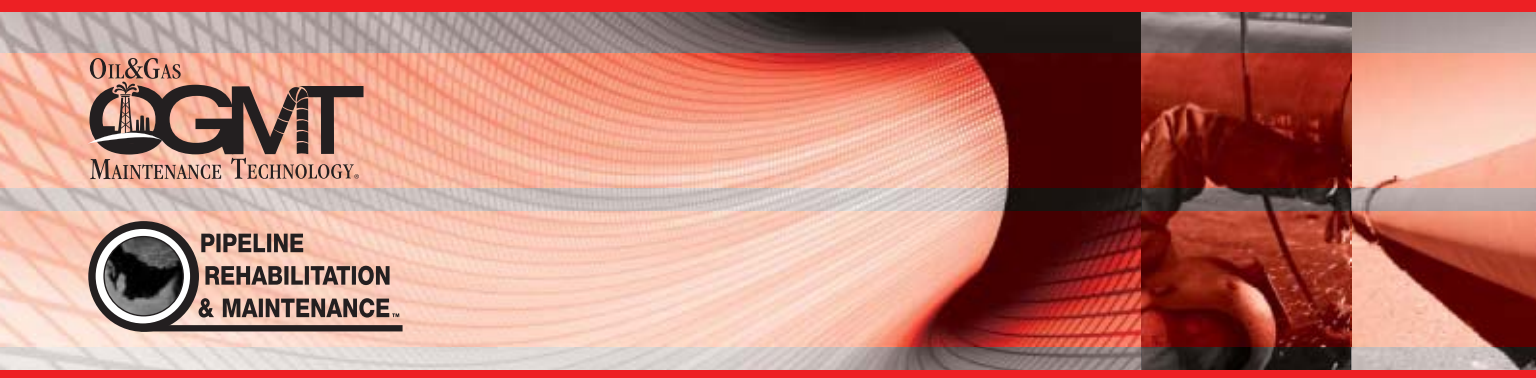
PennWell Corporate Headquarters
1421 S. Sheridan Rd., Tulsa, OK 74112

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

Member Audit Bureau of Circulations & American Business Media

الهيئة الوطنية للنفط والغاز
NATIONAL OIL & GAS AUTHORITY

Held under the Patronage of H.E Dr Abdul Hussain Bin Ali Mirza,
Minister of Oil & Gas Affairs, Chairman-National Oil & Gas Authority, Kingdom of Bahrain



CONNECTING WITH IDEAS 2010

Bahrain International Exhibition Centre, Manama, Bahrain
18 - 20 January 2010 / www.oilandgasmaintenance.com / www.pipeline-rehab.com

REGISTER TO ATTEND TODAY & SAVE $200
www.oilandgasmaintenance.com / www.pipeline-rehab.com

The Gulf's premier forum for oil & gas maintenance, reliability technologies and the latest developments in pipeline rehabilitation and maintenance.

Reasons to Attend

- High quality speakers providing detailed insight into the region's oil and gas maintenance & pipeline rehabilitation industries
- Interactive panels and sessions
- Networking receptions providing opportunities to meet key industry players and leading industry exhibition

Don't miss the opportunity to update your knowledge, skills and see the latest industry developments and technology for the oil and gas industries.

Use promotion code ADPEN-01 for an extra $50 saving & free entrance to exhibition

Sponsored by: Bapco, TC Gulf, NDT

Supported by: الهيئة الوطنية للنفط والغاز NATIONAL OIL & GAS AUTHORITY, ASM International Saudi Arabia Chapter

Owned & Produced by: PennWell

Flagship Media Sponsors: Oil&Gas Journal, Offshore, Oil, Gas & Petrochem Equipment

OGJ Newsletter

Nov. 9, 2009

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

General Interest — Quick Takes

CERI updates oil sands production, cost outlook

The realistic scenario in the latest Canadian Energy Research Institute outlook expects Alberta oil sand production to increase to 1.7 million b/d by 2015, 2.5 million b/d by 2020, 4.5 million b/d by 2030 before reaching a peak of 5.3 million b/d in 2041. Oil sand production was 1.3 million b/d in 2008.

The scenario assumes crude oil demand starting to increase in 2010 as the world recession ends and crude prices reaching $200/bbl for West Texas Intermediate in 2043.

CERI's outlook notes that during the past year oil sands projects have seen construction costs decline by 15% and operating costs decline by 13%.

It estimates that oil sands projects will have a rate of return of 23% for steam-assisted gravity drainage, 11% for mining and upgrading, and 18% for mining without upgrading. Total capital required during its 35-year realistic scenario period is $309 billion.

CERI points out, assuming no technology changes, that by 2043 oil sands natural gas requirements will be three to four times more than current levels, leading to US gas exports into Canada.

In addition, greenhouse gas compliance may cost the industry $130 billion during the next 35 years, CERI says.

API issues new hydraulic fracturing guidelines

The American Petroleum Institute published a new guidance document outlining industry best-practices for properly drilling and cementing wells that are being hydraulically fractured.

The well construction and integrity guideline is designed to ensure that shallow groundwater aquifers and the environment are protected through a well's drilling, completion, and production phases, API said on Nov. 2. It was the second of four documents that API's standards and practices department has been developing to address hydraulic fracing's increasing role in US energy options.

API published a guidance document on hydraulic fracing environmental and reclamation practices in August, it noted. The final two documents that are being developed will address cradle-to-grave water-handling practices and surface environmental considerations.

The newest guidance document is intended to provide producers and state regulators a framework for well construction that will supplement state regulations already in place or being developed, API said. The trade association has published industry standards since the 1920s and continually updates them to provide guidance and highlight industry-recommended best practices on a number of topics, it pointed out.

More than 1 million wells have been drilled in the US using hydraulic fracing over the past 60 years, according to API. As geographical formations being drilled become more complicated, hydraulic fracing will be used even more, especially for natural gas, it said, citing a 2006 government-industry report that found 60-80% of gas wells drilled in the next decade will require the technology.

"Natural gas has the potential to serve as an important bridge to our nation's energy future, but we need hydraulic fracturing to develop this gas," said Doug Morris, API upstream director. "Hydraulic fracturing is a safe and proven technology that is critical to developing the natural gas needed to heat homes, generate electricity, and create basic materials for fertilizers and plastics. This guidance document helps supplement and support existing state regulations to ensure that development of our nation's abundant natural gas resources is safe and effective."

Chesapeake decides not to drill in NYC watershed

Chesapeake Energy Corp. does not plan to drill natural gas wells within the New York City watershed.

Aubrey K. McClendon, Chesapeake's chief executive officer, said, "...it has become increasingly clear to us over the past few months that the concern for drilling in the watershed has become a needless distraction from the larger issues of how we can safely and effectively develop the natural gas reserves that underlie various counties in the Southern Tier of New York."

Chesapeake is the only leaseholder in the New York City watershed, holding fewer than 5,000 acres there. "This leasehold is immaterial to Chesapeake and also does not appear prospective for the Marcellus shale," McClendon said.

Chesapeake notes that it is the largest leaseholder in the Marcellus shale play, with 1.5 million net acres under lease. The leases lie in northern West Virginia, across much of Pennsylvania, and across portions of the Southern Tier of New York.

McClendon also said, "Chesapeake supports the [New York] Department of Environmental Conservation's decision to have all hydraulic fracturing vendors register their products and reveal the chemicals used in them."

Chesapeake discloses the frac chemicals it uses on its web site www.chk.com and also on www.hydraulicfracturing.com. ✦

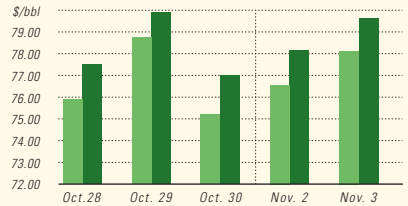
Exploration & Development — Quick Takes

Talisman hikes Marcellus, Montney positions

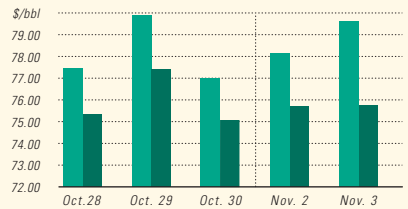
Talisman Energy Inc., Calgary, said it has more than doubled its acreage position to a combined 350,000 acres in the Pennsylvania Marcellus and British Columbia Montney shales and is restructuring its North American operations into shale and conventional business units.

Industry Scoreboard

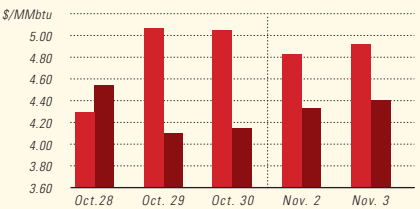
IPE BRENT / NYMEX LIGHT SWEET CRUDE



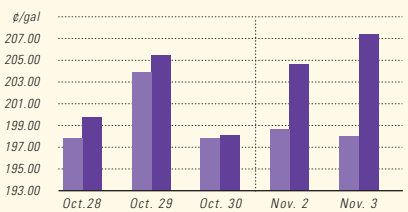
WTI CUSHING / BRENT SPOT



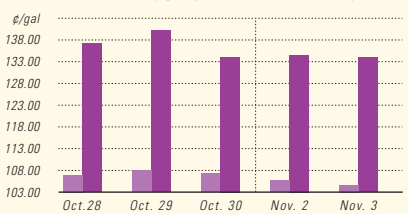
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



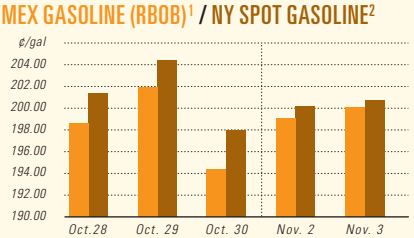
IPE GAS OIL / NYMEX HEATING OIL



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.

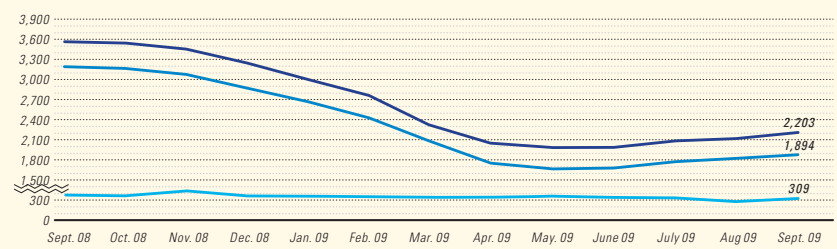
US INDUSTRY SCOREBOARD — 11/9

Latest week 10/23	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	9,083	8,911	1.9	9,024	9,003	0.2
Distillate	3,552	4,087	–13.1	3,598	3,963	–9.2
Jet fuel	1,359	1,430	–5.0	1,409	1,567	–10.1
Residual	573	581	–1.4	549	620	–11.5
Other products	4,148	4,291	–3.3	4,138	4,421	–6.4
TOTAL DEMAND	18,715	19,300	–3.0	18,718	19,574	–4.4
Supply, 1,000 b/d						
Crude production	5,366	4,511	19.0	5,250	4,940	6.3
NGL production[2]	1,940	1,882	3.1	1,993	2,102	–5.2
Crude imports	8,855	9,735	–9.0	9,208	9,772	–5.8
Product imports	2,593	3,116	–16.8	2,768	3,146	–12.0
Other supply[3]	1,576	1,767	–10.8	1,678	1,571	6.8
TOTAL SUPPLY	20,330	21,011	–3.2	20,897	21,531	–2.9
Refining, 1,000 b/d						
Crude runs to stills	14,341	14,557	–1.5	14,485	14,683	–1.3
Input to crude stills	14,641	14,697	–0.4	14,835	15,038	–1.3
% utilization	82.9	83.4	—	84.0	85.4	—

Latest week 10/23	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	339,850	339,072	778	311,873	27,977	9.0
Motor gasoline	208,564	206,945	1,619	194,990	13,574	7.0
Distillate	167,754	169,888	–2,134	126,629	41,125	32.5
Jet fuel–kerosine	45,852	45,139	713	35,991	9,861	27.4
Residual	34,318	34,182	136	38,622	–4,304	–11.1
Stock cover (days)[4]			Change, %		Change, %	
Crude	23.9	23.6	1.3	21.7	10.1	
Motor gasoline	23.0	22.6	1.8	21.8	5.5	
Distillate	47.2	48.6	–2.9	31.8	48.4	
Propane	58.8	62.5	–5.9	58.1	1.2	
Futures prices[5] **10/30**			Change		Change	%
Light sweet crude ($/bbl)	78.51	80.35	–1.84	68.78	9.73	14.1
Natural gas, $/MMbtu	4.69	4.97	–0.27	6.60	–1.91	–28.9

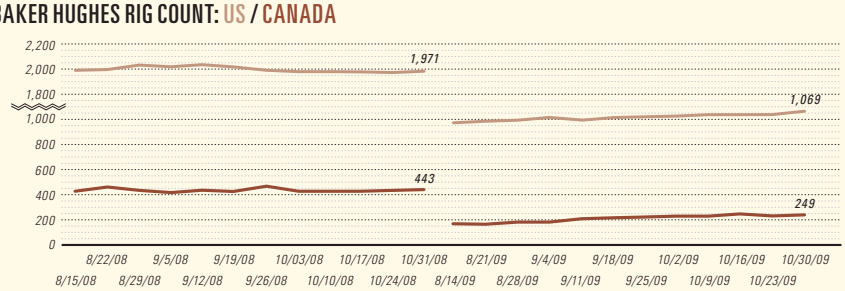
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

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



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

Build better boreholes.

Weatherford's *Revolution* Rotary-Steerable Service helped BP Indonesia achieve better than anticipated production, incident-free, from a multi-well, shallow-gas, extended-reach project while saving more than $1.25 million.

Better boreholes mean better wells. Weatherford's Revolution® Rotary-Steerable Service integrates point-the-bit rotary-steerable technology with the industry's most robust MWD and LWD tools, global real-time operations and drilling optimization support. So, you can steer precisely and efficiently to target and leave a borehole that is smoother, cleaner and easier to case and complete. That means you can get production on line faster, with fewer problems. And, the *Revolution* system's compactness and design simplicity reduce cost and ease logistics – all to help you build better recovery, better profit and better value for your asset.

Start building better boreholes, better wells and better value today. E-mail us at routinetoextreme@weatherford.com.

The Revolution *Rotary-Steerable System provides the industry's highest build angles (10° per 100 ft), pressure (30,000 psi) and temperature (175°C/347°F) ratings and is unsurpassed for reliability.*

Weatherford®

Build....

Drilling | Evaluation | Completion | Production | Intervention

Talisman said it is positioned for a major increase in Marcellus drilling in 2010 and plans to move parts of its Montney shale play to commercial development at the beginning of the year.

The company defines Tier 1 as top quality acreage with an expected full cycle breakeven of $4/Mcf. It has added 170,000 acres in the last few months through a combination of acquisitions and swaps for $570 million (Can.).

In the Marcellus, Talisman expects to end 2009 at 70 MMcfd. Production exceeds 50 MMcfd, compared with 5 MMcfd at the start of 2009 after commercial development began in late 2008.

The company's last five Marcellus wells have estimated ultimate recoveries of 6 bcf/well, and it has hiked its average assumption for EUR over all Tier 1 acreage 17% to 3.5 bcf/well. The 2009 wells have average 30-day initial production rates of 4.5 MMcfd, and the last six wells flowed 5 MMcfd or more.

Marcellus drilling and completion costs are down to (US) $4.3 million/well.

The company's 214,000 highly contiguous net acres in the Pennsylvania Marcellus are centered on Bradford and Tioga counties. Its 180,000 Tier 1 acres have 1,800 net well locations and a full-cycle breakeven of (US) $4/MMBtu. Land acquisition costs averaged (US) $3,250/acre.

Meanwhile, the company has 270,000 net acres in the Montney shale, of which 166,000 acres are considered Tier 1 with 3,000 net well locations. Land acquisition costs averaged $3,500/acre (Can.).

The 2009 focus has been in the Greater Groundbirch, Greater Farrell, and Greater Cyprus areas. Talisman expects to complete 20 pilot wells this year, including 11 horizontal wells. The company expects a full-cycle breakeven of $4/Mcf (Can.) but is not providing guidance yet on drilling and completion costs, initial potential rates, or EURs.

Barrett may give one Uinta shale another try

Bill Barrett Corp., Denver, expensed as a dry hole in the quarter ended Sept. 30 its first horizontal well on the deep Hook shale gas prospect in eastern Utah.

The State 16H-32 well flowed natural gas at a subcommercial rate from Upper Mississippian Manning Canyon shale at about 8,000 ft.

Although the well wasn't commercial, the company will conduct further analysis of a longer horizontal section and improved completion techniques, building on the knowledge gained from this initial well, and will consider a second horizontal well in the area.

The prospect lies in northern Emery County southeast of Price, Utah, along the San Rafael swell on the Uinta basin southwestern flank (OGJ Online, May 6, 2009).

The Manning Canyon shale in the Uinta basin is 2,000 ft thick, 7,000-11,000 ft deep, with attractive 1-4% total organic carbon and a 1.2-1.5% Ro. A hard limestone that may provide a frac barrier underlies it. Shell Exploration & Production Co. has also tested the play (OGJ, Oct. 19, 2009, p. 41).

Bill Barrett also expensed the costs associated with a second shallower well into the fractured Juana Lopez member of the Upper Cretaceous Mancos formation and the Woodside well previously drilled.

The company has a 50% working interest in Hook with ConocoPhillips holding the other 50%. Barrett has 100% working interest in the shallower formation. The prospect covers 74,500 net undeveloped acres.

South Africa shales, sandstones evaluation set

Falcon Oil & Gas Ltd., Denver, plans to evaluate the natural gas content of fractured shales and sandstones of Permian age in the Karoo basin 120 miles northeast of Cape Town, South Africa.

Under a technical cooperation permit, Falcon has up to 1 year to perform a technical appraisal of 7.5 million acres in the basin. The appraisal will include a review of the South African Petroleum Data Base.

The permit does not require Falcon to drill any wells and establishes the company in a priority position for exercising future exploration rights on lands covered by the permit, Falcon said.

Nine wells drilled in the area in the late 1960s and early 1970s encountered gas shows. One well, drilled in 1968, flowed at the rate of 1.84 MMcfd of gas from fractures without stimulation, according to a Soekor Inc. geological well completion report.

Shales due look in New Zealand's East Coast basin

Trans-Orient Petroleum Ltd., Vancouver, BC, plans to deepen to 5,250 ft the Boar Hill-1 wildcat it has drilled to 1,600 ft in New Zealand's nonproducing East Coast basin.

The well's shallow section provided some encouragement as drill cuttings "head gas" readings were progressively more oil-rich as the well cut Oligocene strata, reaching full depth in Oligocene Weber. The drillsite is at the crest of the Boar Hill structure in the 100% controlled, 1.6 million-acre PEP 38349.

Deepening will take the well into the Paleocene and Upper Cretaceous Waipawa black shale and Whangai fractured oil shale source rocks.

Trans-Orient also plans to drill and core three shallow stratigraphic wells in its 100% owned, 530,000-acre PEP 38348 around the Waitangi Hill discovery, where a 1912 well recovered 50° gravity oil at 650 ft. Recent field work indicates that the Whangai formation generated the oil.

Trans-Orient will become a fully owned subsidiary of Tag Oil Ltd. in mid-December. ✦

Drilling & Production — *Quick Takes*

Longhorn gas field starts in Gulf of Mexico

Eni SPA has started production from Longhorn gas field in 2,500 ft of water on Mississippi Canyon Blocks 502/546 in the Gulf of Mexico off Louisiana.

The field is producing 200 MMscfd through four subsea wells connected to the Corral platform, previously called Crystal, on Mississippi Canyon Block 365, 20 miles to the northwest.

Corral is a conventional jacket structure in 620 ft of water. Eni

operates the new field and the platform.

On the Corral platform, Eni has added production and compression equipment able to process 250 MMscfd of gas and 6,000 b/d of oil.

Longhorn was discovered in July 2006.

Eni holds a 75% working interest, and Nexen Inc. holds 25%.

BPTT starts production from Savonette off Trinidad

BP Trinidad & Tobago (BPTT) has started its first natural gas production from Savonette field off Trinidad and Tobago.

Savonette lies in 290 ft of water about 50 miles southeast of Trinidad and Tobago in the prolific Columbus basin. BPTT holds a 100% interest in the field.

Production from the platform is tied into BPTT's Mahogany B platform via a 26-in., 5.3-mile subsea pipeline, where the gas is processed and then exported into BPTT's existing system. Gas from Savonette will supply Atlantic LNG's liquefaction plant for export as LNG to international markets, as well as the domestic market.

With Savonette, BPTT now has production from 12 offshore platforms.

Production from Savonette is expected to average 600 MMscfd of gas, plus associated condensate, from four wells. Savonette production will contribute to maintaining BPTT's total production level at more than 450,000 boe/d.

The Savonette platform was installed in February and is the fourth in a series of normally unmanned installations designed and constructed in Trinidad using a standardized 'clone' concept. The 1,898-tonne jacket and the 871-tonne topsides were built at the Trinidad Offshore Fabricators yard in La Brea, South Trinidad.

BPTT Chairman and Chief Executive Robert Riley said, "Since completing the Cannonball platform in 2005, in just four years, BPTT has designed and constructed three further platforms right here in Trinidad and commenced production from each—Mango, Cashima, and now Savonette."

The Savonette platform project was sanctioned on Apr. 4, 2008, and is a clone of the Cannonball, Mango, and Cashima platforms.

It has a designed capacity to accommodate as much as 1 bcfd of gas, but will produce 600 MMscfd.

BHP Billiton shuts in Griffin oil field

BHP Billiton has shut in the Griffin oil field off Western Australia in licence WA-10-L since it has come to the end of its economic life after 15 years of production.

Production reached a peak flow of 80,000 boe/d in the early stages of the development, but the field is now down to an average of only 4,000 boe/d due to natural depletion. The field was originally estimated to have a life of just 7 years. Total production from the field has been 178 million boe.

Production has been processed on the Griffin Venture floating production, storage, and offloading vessel—one of the first such vessels off Australia. Gas was piped ashore near Onslow for addition to the domestic gas grid. There is no word on the future of Griffin Venture at this stage.

Griffin and nearby associated Scindian and Chinook fields, in the Carnarvon basin about 62 km off Onslow, were found during an exploration program in 1989-90. The fields came on stream in 1994 through subsea wells connected to flowlines leading to the FPSO.

Joint venture partners are BHP, operator, with 45%, ExxonMobil Corp., 35%, and Inpex of Japan, 20%. ✦

Processing — *Quick Takes*

PDVSA closes purchase of Dominican refiner stake

After several months of delays, Venezuela's state-owned Petroleos de Venezuela SA (PDVSA) has completed its purchase of a 49% stake in the Dominican Republic's state refiner Refineria Dominicana de Petroleo SA (Refidomsa), which owns a 34,000-b/d facility in Haina.

The Dominican Republic's Treasury Minister Vicente Bengoa said the sale, worth $131.5 million according to Venezuelan media, would allow his country to become an oil distribution center for the Caribbean and possibly Central America.

As part of the agreement, the Dominican Republic will buy 30,000 b/d of oil from Venezuela in addition to the 50,000 b/d it already receives under the Caracas-sponsored PetroCaribe accord, which provides Venezuelan oil and gas at preferential prices.

Analyst BMI said, "The deal will further integrate the Caribbean island into Venezuela's PetroCaribe petroleum trading scheme, touted by President Hugo Chavez as an alternative to the region's dependence on the US for its energy needs."

Chavez showed interest in the agreement in June, but PDVSA did not obtain a purchase memorandum of understanding from the Dominican government due to a regional crisis involving the ouster of Honduran President Manuel Zelaya, a close political ally of Chavez.

A further delay arose in August after California legislator Loretta Sanchez suggested the agreement would violate the terms of the free trade agreement between the US and the Dominican Republic. Under the FTA's terms, oil refined by Refidomsa could be exported to any market while under the new agreement with PDVSA refined oil could be sold only to Venezuela.

Purchase of the refiner was reported in July, when PDVSA said it agreed to acquire a 49% interest in Refimdosa as partial payment of oil debts. The Dominican Republic owed $1 billion to Venezuela for oil supplied under the PetroCaribe program (OGJ, July 20, 2009, Newsletter).

In December 2008, Royal Dutch Shell PLC sold its 50% stake in Refidomsa to the Dominican government for $110 million, making the government sole owner of the Haina refinery.

Shell said its decision to sell the shareholding was part of its active portfolio management to realize value for shareholders and to refocus the downstream portfolio.

Venezuela, Brazil sign accord on refinery

Brazil's state-run Petroleo Brazileiro SA (Petrobras) and Venezuela's Petroleos de Venezuela SA (PDVSA) completed negotiations

for joint construction and operation of the Abreu e Lima refinery, in Brazil's Pernambuco state.

The two firms said the Abreu e Lima refinery will be able to process 230,000 b/d of heavy oil, supplied equally by Petrobras and PDVSA. The refinery's main product will be low-sulfur diesel.

Petrobras and PDVSA will incorporate the company in Brazil. They did not say when the procedures would be completed or when the refinery would begin operating.

The refinery was conceived to process crude from a PDVSA-Petrobras joint venture in the Carabobo region of Venezuela's Orinoco belt, but it has taken years for the two sides to agree on the terms of their partnership.

Last month, Petrobras said it had resolved all outstanding issues with PDVSA over development of the Abreu e Lima refinery, but that the Venezuelan firm would have to pay Petrobras at least $400 million when it signs the final agreement (OGJ Online, Oct. 8, 2009)

Petrobras will hold a 60% stake in the joint-venture firm, while PDVSA will hold the remaining 40%.

Construction on Aramco's Karan project under way

Saudi Aramco's Karan gas project swung into full speed last month as all four contract packages began construction, according to a company announcement.

Following the awarding of program contracts in March, the offshore platforms and subsea pipeline package began fabrication in September. The units involved 30,000 tonnes of steel for 38 structures, said an announcement from the company in mid October.

The three onshore packages—Karan gas facilities, pipeline utilities and cogeneration, and the Karan sulfur recovery and Manifa gas facilities—have all begun initial construction at Khursaniyah (OGJ, June 22, 2009, p. 50).

Project teams consist of members from Aramco and contractors J. Ray McDermott, Hyundai Engineering & Construction Co., Petrofac, and GS Engineering.

Karan is the first nonassociated offshore gas field Aramco has developed, the announcement reiterated. The onshore facility, about 160 km north of Dhahran, will be able to process 1.8 bscfd of Karan Khuff gas.

The gas will move in a 110-km subsea pipeline from field to onshore processing at the Khursaniyah gas plant. The offshore facilities at Karan consist of four production platforms connected to a main tie-in platform that will feed sour gas to the subsea pipeline.

The Khursaniyah plant will process gas through three trains, each with an inlet capacity of 600 MMscfd. The trains will include gas sweetening, acid-gas enrichment, gas dehydration, and supplementary propane refrigeration. The facilities also will include a cogeneration plant with boiler, a sulfur-recovery unit with storage tank, substations, and a transmission pipeline linked to the country's master gas system. ✦

Transportation — *Quick Takes*

BP, Eni need more gas for Egyptian LNG train

Egypt's state-owned Egyptian Natural Gas Holding Co. (Egas), clarifying earlier comments, reported that BP PLC and Eni SPA have found just 2 tcf of gas, or half the amount needed to start up an LNG train at Damietta.

For the proposed second train to start up, said Abdallah Abdelhady, Egas assistant vice-chairman for production, the two firms have to find a total of 4 tcf of gas. Once they have done so, he said, the second train will start.

An Egas official said last week that the firm had shelved plans for the construction of a second LNG train at Damietta until enough reserves are found.

"If the Egyptian government is given proven gas reserve certificates then it will deal with the project in a more positive manner because we have a lot of commitments with domestic demand," said Hassan Sabry, an Egas projects and planning official.

Shamil Hamdy, undersecretary at the oil ministry, was earlier quoted as saying that Eni had delayed the project because it lacked the necessary financing due to the global economic downturn (OGJ Online, Oct. 30, 2009).

Construction begins on Chinese LNG terminal

Construction on another LNG terminal in China began earlier last month, according to press reports from the country.

The Ningbo LNG terminal is south of Shanghai, in Zhejiang Province, and will be the fifth Chinese terminal, the fourth owned by China National Offshore Oil Co. Ltd. China's National Development and Reform Commission approved the project earlier this year.

When completed in 2012, Phase 1 of construction at Ningbo will have installed 3 million tonnes/year of regasification capacity. Press reports put construction costs of Phase 1 at more than $1 billion. CNOOC envisions a matching second phase but has announced no completion date.

Ownership of CNOOC Zhejiang Ningbo Liquefied Natural Gas Co. Ltd. is among CNOOC Natural Gas & Power Co. Ltd. (51%), Zhejiang Provincial Energy Group Co. Ltd. (29%), and Ningbo City Power Developing Corp. (20%).

CNOOC's 3-million-tpy terminal at Shanghai received its first LNG cargo earlier this month (OGJ, Oct. 26, 2009, p. 11).

Floating Florida LNG terminal approved

A Gulf of Mexico offshore LNG terminal took a major step towards reality Nov. 2 when acting Maritime Administrator David T. Matsuda approved its construction off western Florida.

The approval was expected after Port Dolphin Energy LLC announced last week it had signed a "record of decision" in its application for a license to build the deepwater LNG port.

The signing, according to the announcement by the company, "paves the way to the awarding of a deepwater port license" to be issued by the US Maritime Administration. It marked the "successful completion of a comprehensive environmental impact statement" directed by the US Coast Guard and formal approval [in September] by Florida Gov. Charlie Crist. ✦

Letters

Carbon-eating trees

Your editorial entitled "Mitigating climate change" was right on target (OGJ, Oct. 19, 2009, p. 18). The idea of spending $10.5 trillion on projects with essentially no potential return on investment is ludicrous.

A much better approach for reducing greenhouse gases (carbon dioxide) would be to plant billions of carbon-eating trees. Such a program would benefit all of the agricultural schools in the world and would provide employment for low-skilled workers everywhere.

Additionally, it could put ACORN to work on something worthwhile.

William H. Barlow
Houston

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.

2009

NOVEMBER

IADC Annual Meeting, Miami, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 9-10.

Multiphase User Roundtable-South America, Rio de Janeiro, (979) 268-8959, (979) 268-8718 (fax), e-mail: Heather@petroleumetc.com, website: www.mur-sa.org. 9-10.

API Fall Refining and Equipment Standards Meeting, Dallas, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 9-11.

Digital E&P Event, Houston, (646) 200-7444, (212) 885-2733 (fax), e-mail: cambrosio@wbresearch.com, website: www.digitaleandp.com. 9-11.

NPRA/API Operating Practices Symposium, Dallas, (202) 457-0480, (202) 457-0486 (fax), website: www.npra.org. 10.

Petroleum Association of Wyoming (PAW) Annual Oil & Gas Statewide Reclamation Conference, Casper, (307) 234-5333, (307) 266-2189 (fax), e-mail: cheryl@pawyo.org, website: www.pawyo.org. 10.

Deepwater Operations Conference & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepwateroperations.com. 10-12.

Calendar

SPE International Oil and Gas China Conference & Exhibition, Beijing, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 10-12.

NPRA International Lubricants & Waxes Meeting, Houston, (202) 457-0480, (202) 457-0486 (fax), website: www.npra.org. 12-13.

ASME International Mechanical Engineering Congress and Exposition (IMECE), Lake Buena Vista, Fla., (973) 882-1170, (973) 882-1717 (fax), e-mail: infocentral@asme.org, website: www.asme.org. 13-19.

Latin America LPG Seminar, Miami, (713) 331-4000, (713) 236-8490 (fax), e-mail: ts@purvingertz.com, website: www.purvingertz.com. 16-19.

IADC Completions Conference, Houston, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 17.

Houston Energy Financial Forum, Houston, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.accessanalyst.net. 17-19.

IADC Well Control Asia Pacific Conference & Exhibition, Bangkok, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 18-19.

Energise Your Future Forum, Paris, +33 0 1 47 96 91 68, e-mail: claude.leonard@bostik.com, website: www.energiseyourfuture.com. 18-20..

DECEMBER

Advanced Contract Risk Management Europe for Oil & Gas, Aberdeen, +44 0 207 368 9300, e-mail: enquire@iqpc.co.uk, website: www.contractriskmanagement.MAC=11579.003EDIARY. 1-2.

Refining and Petrochemicals in Russia and the CIS Countries Annual Meeting, Amsterdam, +44 (0) 20 7067 1800, +44 (0) 20 7242 2673 (fax), website: www.theenergyexchange.co.uk. 1-3.

World LNG Summit, Barcelona, +44 (0)20 7978 0000, +44 (0)20 7978 0099 (fax), e-mail: info@thecwcgroup.com, website: www.thecwcgroup.com. 1-4.

European Drilling Engineering Association Expandables, Multilaterals and Technologies Meeting, Vienna, +44 (0) 1483-598000, e-mail: Dukes@otmnet.com, website: www.dea-europe.com. 3-4.

International Petroleum Technology Conference (IPTC), Doha, +971 4 390 3540, e-mail: iptc@iptcnet.org, website: www.iptcnet.org/2009. 7-9.

Nuclear Power International Conference, Las Vegas, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.nuclearpowerinternational.com. 8.

Power-Gen International Conference, Las Vegas, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.power-gen.com. 8-10.

PIRA Natural Gas Markets Conference, New York, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 14-15.

PIRA Understanding Natural Gas and LNG Markets Seminar, New York, (212) 686-6808, (212) 686-6628 (fax), website: www.pira.com. 14-15.

PIRA Understanding Global Oil Markets Seminar, New York, (212) 686-6808, (212) 686-6628 (fax), website: www.pira.com. 16-17.

2010

JANUARY

Plant Maintenance in the Middle East & Annual Meeting, Abu Dhabi, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 10-13.

Oil & Gas Maintenance Technology Conference & Exhibition Co-located with Pipeline Rehabilitation and Maintenance, Manama, Bahrain, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilandgasmaintenance.com. 18-20.

Oil shale adds to energy mix

Guntis Moritis
Production Editor

Oil shale has potential for supplying fuels for many decades, although numerous attempts during the last 100 years have led to only a few commercial projects.

But with projections for a steady rise in world energy needs, fuel production from oil shale can add to the mix of energy sources that the world will require.

Estimates are that the world has about 2.8 trillion bbl of shale oil in place with about 1.5 trillion bbl in the Green River formation of Colorado, Utah, and Wyoming. Green River recoverable resource estimates range from 0.5 to 1.1 trillion bbl, based on a 15 gal/ton cut off.

Oil shale is a general term for sedimentary rock containing a solid organic matter (kerogen) that yields liquid oil, gas, and water when heated either in situ or in surface retorts.

Estonia, China, and Brazil have commercial oil shale projects that have operated for many years. These projects produce about 14,000 bo/d.

The recent 29th Oil Shale Symposium at the Colorado School of Mines in Golden, Colo., updated some of the ongoing projects and technologies.

Utah

Two projects in Utah could move into a production phase in this decade.

Gary Aho, vice-president of operations, Oil Shale Exploration Co. (OSEC), told the symposium that if all partners approve the project by earlier 2010, OSEC could begin producing shale oil from three retorts in 7 years and reach 50,000 bo/d from 12 retorts by 2027.

Aho said after partner approval, OSEC would need 4 years to receive all permits required and another 3 years for building and installing the first three retorts. Petroleo Brasileiro SA (Petrobras) and Mitsui & Co. Ltd. are OSEC's partners.

The project will use both underground and surface mining for feeding Petrosix retorts. Petrobras developed and has operated since 1992 a Petrosix retort in Sao Mateus do Sul, Brazil.

The OSEC project also includes installing two hydrotreaters so that the company can move premium product to market.

Aho said OSEC's leases cover 46,000 acres and hold 4.5 billion bbl in place with an estimated 2.7 billion bbl recoverable.

Red Leaf Resources Inc. operates a 16,800-acre leasehold in Utah with an estimated 1.5 billion bbl in place and may begin a 8,000 bo/d commercial demonstration project in the next 2 years. James Patten, chairman, president, and chief executive officer of Red Leaf, related to the symposium the success of its EcoShale technology pilot.

The technology involves placing oil shale in an excavated quarry lined with impermeable layers and sealed with a bentonitic clay. Pipes transfer dry, low-emission heat from natural gas burners to the oil shale. Red Leaf notes that no rock burns so that the process avoids typical retort emissions.

The process produces a 39° gravity kerogen oil. After recovering the oil, the process includes removing the pipes and moving to a new site, while reclaiming the initial site.

Colorado

Roger Day, vice-president of operations, American Shale Oil LLC (Amso), noted that in 2010, Amso would begin a pilot of its in situ technology on one of the US Bureau of Land Management research, development, and demonstration leases.

Amso is one of four companies granted leases by BLM for demonstrating proprietary processes of commercial shale oil production. Except for the Utah lease granted to OSEC, all the BLM leases are in Colorado's Piceance basin. Shell Exploration & Production Co. and Chevron Corp. are the other companies holding BLM RD&D leases.

Amso technology involves heaters for recovering shale oil initially from a zone below a freshwater aquifer. The pilot test will involve a single heater-producer well traversing the zone at 60°. During last year, Amso completed numerous exploration and hydrology wells for evaluating the site.

Shell continues tests of its freeze-wall technology for developing oil shale in zones in contact with an aquifer. Shell expects the freeze wall to keep water out of the heated zone and keep hydrocarbons from entering the aquifer. Shell's tests are on private lands and not on its BLM RD&D leases.

ExxonMobil Corp. has started to test its Electrofrac method in horizontal wells drilled and hydraulically fractured from its Colony oil shale mine. The technology fills the hydraulic factures with electrically conductive material for distributing heat to the oil shale. ✦

Four 58-MW Rolls-Royce Trent GTGs Available for Immediate Delivery

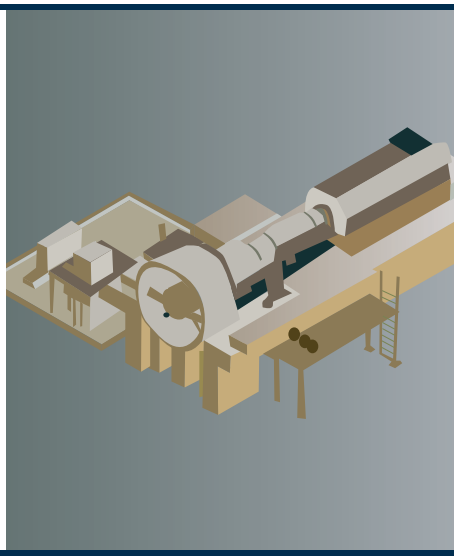
The Rolls-Royce Trent 60 is an advanced aeroderivative gas turbine that delivers up to 58 MW of electric power in simple cycle service. At 42% efficiency, the Trent 60 is highly fuel efficient. It offers operators fast delivery and installation times, and beneficial environmental performance. All or part of the following is available for immediate sale:

- Four Trent 60 Dual WLE GTGs rated at 58 MW with a gross heat rate of 8,592 BTU/kWe.hr (LHV)
- Dual fuel – natural gas and liquid
- Two left-handed units; two right-handed units
- Four generators rated at 13.8 kV, 3 phase, 60 Hz, 0.85 power factor
- Water injection system included
- SCR and carbon monoxide conversion systems with 80-ft stacks
- Acoustic abatement for SCR cladding and silencer
- Water wash system
- Special tools
- GSUs
- Two transformers able to handle two 58-MW units
- GE Prolec 90/120/150 MVA (2 units), with a low voltage 13.8 kV Delta, and a 115 kV Wye HV winding
- Price includes new transformer oil

Two New Alstom 50-Hz Combined Cycle 140-MW Steam Turbine Generators Available for Immediate Shipment

These steam turbine generators (STGs) are new, 140-MW Alstom two-cylinder (HP and IP/LP) reheat condensing steam turbine generator sets suitable for combined cycle outdoor operation with axial exhaust and air-cooled (TEWAC) generator. Initial steam conditions 1900 psia/1050°F/1050°F reheat. Units include manufacturer's performance guarantees and warranties. Units may be shipped directly to your site from Alstom's European manufacturing facility.

- Units come complete with all normally supplied auxiliaries and include factory warranties covering manufacturing defects and performance guarantees.
- Configured as a two-cylinder machine with an HP turbine and a combined IP/LP turbine with an axial exhaust.
- Steam inlet conditions are 1900 psia (nominal)/1050°F/1050°F.
- Air-cooled TEWAC generator rated 165 MVA, 15.75 kV, 3 phase, 50 Hz, 3000 rpm.



Unused GE D11 HP/IP Turbine Assembly Available for Immediate Sale

All parts professionally stored in Pensacola, Florida

Unused GE D11 HP/IP turbine assembly and other miscellaneous parts including LP casings and 304-MW generator stator now available for immediate sale.

Solar Centaur 40 T4701S Turbine Generator Package Now Available

Offered by Williams Field Services Company exclusively through PennEnergy

Solar Centaur 40 T4701S Turbine Generator Package with approximately 60,000 accumulated hours at 50% load. Package was in service from 1999 until August 2007. Engine is BACT compliant with OEM 25 ppm Nox/50 ppm CO guarantee. Operates off SAB-type Ideal generator rated at 3500 kW, 4375 kVA and 13,800 volts at 60 Hz. Miscellaneous equipment includes inlet air filtration and simple exhaust systems, and auxiliary control console with start/stop/sync/control.

Williams

For Info or Pricing Contact

Randy Hall rhall@pennenergy.com P: 713-499-6330 | Bart Zaino bzaino@thomassenamcot.com P: 817-263-3273

Editorial

Carbon price volatility

While Republican senators deserve applause for demanding to know what climate-change legislation would cost before voting on it, the illumination they seek has large shadows. Cost projections have no way to account for a crucial and largely unheeded disadvantage of the cap-and-trade approach to moderation of greenhouse gas emissions.

Cost studies, of course, are essential to political deliberation. And in this case they're alarming. Whether the Environmental Protection Agency captures all hazards in the study Republican senators want to see is anyone's guess. But it still will be a study. It can't see all costs.

Pattern of uncertainty

Recent studies now raising alarm among US refiners contain an illuminating pattern that shows why this is so. The latest of them comes from Energy Policy Research Foundation Inc., Washington, DC. and will be covered in an article in the Nov. 23 issue of Oil & Gas Journal. The study predicts that US refining capacity losses resulting from stationary emission costs alone would be 750,000-2.25 million b/d in 2015-30 if the price of emission allowances were $15/tonne of carbon dioxide equivalent (CO_2e). If the price were twice that level, capacity losses would rise to 2.1-6.3 million b/d. Further capacity losses would result from the inability to pass through the new costs, again depending greatly on the allowance price.

An earlier study by EnSys Energy for the American Petroleum Institute also sees capacity losses: as much as 4.4 million b/d by 2030 if allowances cost $65/tonne, the high end of its range of assumptions (OGJ, Sept. 7, 2009, p. 26). Yet another study, by Alan Gelder of Wood Mackenzie, asserts an allowance price of $50/tonne and estimates the cost disadvantage of US refiners relative to imported product at $18/bbl.

These costs arise because the House and Senate bills would squeeze refining more than other affected industries. They would assign refiners caps covering emissions not only from their facilities but also from combustion of their products. At the same time, it would shortchange them, relative to other industries, in the distribution of allocated allowances and wouldn't hit overseas refiners nearly as hard.

Under either cap-and-trade bill, then, US refiners would have to become extra-heavy buyers of emission allowances. The assumed price of allowances thus affects their industry more than it does others. It's extremely important, however, to any business covered by the legislation and unable to meet emission caps after allocated allowances run out.

So what would the allowance price be? It's obvious from the range of assumed prices in studies cited here that no one knows. Indeed, an August study of the House bill by the Energy Information Administration examined a range of cases producing a range of allowance prices in 2030 of $41-191/tonne of CO_2e.

With so much apparent uncertainty, all study authors can do is to assume a value for allowance prices or a trajectory of values over time, consider other variables, and model results. Although helpful, that's not reality.

The largely ignored disadvantage of cap-and-trade schemes results from what is supposed to be the main appeal: specificity of the declining targets for emission reductions, manifest in the cap. The specificity would keep the market for emission allowances from working freely. A crucial dimension, supply, would be fixed by the cap. As demand for emission allowances varied in response to innumerable forces, beginning with economic activity and weather, allowance prices would fluctuate by amounts exaggerated by the imposed inflexibility of supply.

Certain volatility

A certain characteristic of the market for emission allowances thus would be price volatility. The volatility would aggravate energy consumers and make investments more difficult than they otherwise would be to plan. It would benefit only traders of emission allowances. And the efficiency cap-and-trade planners thought they were giving the effort to cut emissions of greenhouse gases would become massive inefficiency, and consequent cost, in the broader economy.

Studies can't predict these effects. But lawmakers can consider them before supporting an overhaul of energy markets that would have little meaningful effect on the climate. At least they should. ✦

DEEP OFFSHORE TECHNOLOGY™ INTERNATIONAL

February 2–4, 2010

Houston, Texas USA » George R. Brown Convention Center

www.dotinternational.net

Exclusively Offshore

Deep Offshore Technology International Conference & Exhibition networking opportunities puts your company in front of senior level decision makers within operating and engineering companies which focus exclusively on deepwater exploration and production.

These attendees are an extremely knowledgeable and highly targeted audience who concentrate on the perplexities of moving into deep and ultra-deep waters. When every marketing dollar counts, leading companies rely on DOT for the most extensive reach of senior level management responsible for buying decisions.

Plan today to get in front of a targeted group of these industry professionals.

Exhibitor and Sponsorship Sales:

Jane Bailey
UK & Northern Europe
Phone: +44 (0) 1992 656 651
Fax: +44 (0) 1992 656 700
janeb@pennwell.com

Sue Neighbors
Americas
Phone: +1 713 963 6256
Fax: +1 713 963 6212
sneighbors@pennwell.com

Ana Monteiro
Southern Europe
Phone: +44 (0) 1992 656 658
Fax: +44 (0) 1992 656 700
anam@pennwell.com

Michael Yee
Asia Pacific
Phone: +65 9616 8080
Fax: +65 6734 0655
yfyee@singnet.com.sg

Advisory Board – 2010

2H Offshore - David Walters
Anadarko Petroleum Corp. - Matt Lamey
Baker Hughes - David Bilberry
BP E&P Inc. - Kevin Kennelley
Chevron - Jen-hwa Chen
Consultant - Bob Lewis
ExxonMobil - Todd Stevens
FloaTEC - John Murray
HESS Corporation - James Britch
INTECSEA - WhorleyParsons Group - Bob Kipp
INTECSEA - WhorleyParsons Group - Uri Nooteboom
KBR - Derek Disney
KBR/Granherne Americas - Richard D'Souza
MCS - Kieran Kavanagh
Offshore - Gene Kliewer
PennWell Corporation - Eldon Ball
Schlumberger - Mark Alden
SES Subsea Engineering Solutions, Inc. - Steve Bledsoe
Shell E&P Company - Bill Henry
Spitzer Industries, Inc. - Mike McEvilly
SPT Group - Lee Norris
SSP Offshore Inc. - Nico Vandenworm
Subsea 7 - Ian Cobban
TOTAL E&P USA - Ronny Hanssen

Owned & Produced by: PennWell

Flagship Media Sponsors: Offshore | Oil&Gas Journal | Oil&Gas Financial Journal | Oil, Gas & Petrochem Equipment

Supporting Organization: GEP

Sponsored By: ABS | Bennett & Associates | DNV | INTECSEA WorleyParsons Group

Reserve Your Booth Space Today!

COMMENT

Brazil aims to avoid long-term oil 'curse'

Dilma Rousseff
Government of Brazil

Blessed with the world's largest oil discovery in 30 years, Brazil has recently proposed a new development model designed to turn this unexpected windfall towards the public good rather than the curse it has become for other nations, which have found their discovery a short-lived path to prosperity because of the damage it can wreak on the overall economy. Brazil is determined to forge its own way to best manage the exploration and development of these vast oil reserves as well as their ultimate revenues.

To ward off the future oil curse, Brazil is taking bold steps today along a tightrope. On one side of our balancing pole is the commitment to remain a reliable development partner to foreign governments and energy companies. On the other is our country's desire to control its own resources and use their revenues to fuel our fight against poverty and improve social equality.

What's proposed is a New Social Fund that not only would keep these efforts on track for generations to come but also would help shield the economy from the potentially destructive impact of a resource windfall. Also helping to fend off the "curse" is the hard-earned fact that the oil bonanza arrives in a diverse economy and a land rich in many natural resources.

Brazil's booming economy, expected to grow about 4% next year, was attractive to foreign investors well before the discovery of the massive presalt oil reserves. The new legal and regulatory framework submitted to the National Congress aims to preserve this allure.

New system

In the newly outlined production-sharing system, foreigners will remain welcome to bid for contracts to explore and develop oil in association with Petrobras. Last year's global financial crisis–from which Brazil was one of the first countries to recover–has shown us that government involvement can be essential to protect public interest.

The new system would impose stringent oversight onto the contract process to fight corruption and ensure scrutiny. It would rest on a foundation of Brazil's already strict banking transparency regulations, which have helped turn Brazil from a debtor into a creditor nation and produced the clear, real-time metrics that enabled the central banks to take quick measures to counter the global financial crisis.

The existing development contracts already held by foreign companies for 26% of the presalt territory will be unaffected by the new regulations. These agreements will be honored and cover what Petrobras estimates as 5-8 billion bbl of oil and natural gas equivalent. In addition, the current concession model will remain in effect for Brazilian onshore sites.

In the 72% of unlicensed presalt reserves, Petrobras will operate all exploration contracts and partner with all parties while keeping a minimum of 30% of costs incurred and profits realized. That formula leaves plenty of profitability for investors, and Brazil still needs these foreign partners to bid on development rights. A competitive market is a stronger one, both financially and technologically. International investors viewing involvement alongside Petrobras face a tremendous opportunity, as Petrobras has established global benchmarks developing technologies for deep-sea oil exploration. Furthermore, presalt oil exploitation is high reward, low risk.

Social fund

With the creation of the New Social Fund, Brazil will create a public savings account that funnels presalt revenue into education, science, and technology as part of our fight against poverty. Countries that have successfully managed wealth from their newly found

BRAZIL'S NEW LICENSING SYSTEM

Cost recovery mechanisms	• Contractors will recoup costs of exploration, development, operation, and abandonment through "cost oil," limited per period by a ceiling established in their contract. • Costs above ceiling can be carried and recovered in succeeding years.
Production shares before and after cost recovery	• Petrobras will be the operator of all production-sharing contracts, with a minimum participation of 30% of the costs incurred and profits obtained. • "Cost oil" will be shared by contractors, and "profit oil" will be shared among government and contractors according to the auction result.
Royalties	• Royalties are still under consideration by the Brazilian Congress. • The model is expected to follow that of most other fiscal systems, with royalties taken as a percentage of gross revenues (calculated from the percentage of production).
Taxes	Taxes applied will depend on existing legislation.
Uplifts	A portion of capital costs can be recovered through cost recovery, determined on a case-by-case basis by regulation or by contract.
Adjustments to price changes	• Adjustments on "profit oil" shares between the government and contractors can be previewed in contracts to protect against future price fluctuations. • Adjustments will be approved by the national energy council.
Terms of contract auctions	• The winner of auctions for exploration and production-sharing contracts will be the company or group of companies whose proposal offers the greatest percentage of "profit oil" to the Brazilian government. • Upon assigning a contract, the contractor must pay a bonus.
Existing concession contracts	• Concession contracts already established in the presalt region will be fully honored by the Brazilian government. • The new sharing model will be effective only for those areas which have not yet been auctioned, representing about 72% of the whole presalt area, or 107,000 sq km.

Source: Brazil's Energy Research Corp. (EPE)

natural resources, such as Norway, earmarked those funds as investments in human capital and development.

The New Social Fund would draw income from different facets of presalt exploration and production revenues to fuel Brazil's commitment to socially inclusive development. Core to President Luiz Inacio Lula da Silva's priority of sustainable growth to reduce poverty and inequality, this would further brighten a social landscape, which during 2004-08 saw a 10-point rise in the proportion of Brazilians belonging to the middle class—currently 52%.

Brazil continues to take a long-term view of managing these natural resources, including a commitment to renewable and alternative energy. We are self-sufficient in oil, and the presalt discoveries will not impact our clean and renewable energy network. For example, last year, 160 hydroelectric plants produced 74% of all electricity generated, and only 27% of the country's hydroelectric potential has been explored. By 2017, the expanding Brazilian economy is projected to demand approximately 155,000 Mw of installed energy capacity. Despite the presalt bequest, 80% of that energy will continue to come from renewable sources. We also boast the world's largest flex-fuel fleet.

Given the magnitude of expected reserves, many issues surround the development of what international geologists estimate could be tens of billions of barrels of recoverable oil. But the country's fundamental objective is to exploit this resource in a way that bolsters Brazil's economy and its progress in fighting poverty while remaining a reliable international business partner, rewarding the investments of the countries and international oil developers that join Petrobras in exploiting the presalt layer.

Like Brazil's actions to shield its economy from the global financial crisis, the new plan is another step on our unique path as full participants of the world economy while remaining responsible for stewarding our own resources and destiny. For the oft-described country of the future, the future is now. ✦

The author
Minister Dilma Rousseff is chief of staff to President Luiz Inacio Lula da Silva of Brazil and chairman of the board of Petrobras, Brazil's state-controlled oil company.

CSIS: unconventional resources altering global gas outlook

Nick Snow
Washington Editor

Production potential from tight shales and other unconventional resources has significantly altered the world's natural gas outlook, experts said Oct. 28 at a seminar on the evolution of global gas markets at the Center for Strategic and International Studies in Washington, DC.

"Unconventional sources are likely to play a role in other parts of the world," observed Glen Sweetnam, director of the US Energy Information Administration's international, economic, and greenhouse gases division.

By 2035, shale gas could represent 62% of the total gas produced in China, 50% in Australia, and 42% in the US, Sweetnam. "They also have shale gas in Europe, but there's increasing disagreement over whether it will be developed" because so few of the resources

are on private property, officials must contend with a "not-in-my-backyard" (NIMBY) attitude, and the region does not have a particularly robust oilfield service industry to support it, he said.

Sweetnam said EIA is in the process of "tuning up" its first international gas outlook model, which will be included in the next annual energy outlook. Gas provided 26% of the world's consumed energy in 2006 and should continue to supply a similar share, he said, adding, "In end uses, gas will compete against other fuels in stationary markets."

When it released its initial estimate of yearend 2008 US oil and gas reserves on Oct. 29, EIA noted that gas reserves rose enough not only to replace production during the year, "but also to grow by almost 3% over [their level at the end of] 2007, largely due to continued development of unconventional gas from shales."

Sweetnam said, "Low-cost US conventional gas has been depleted. We're left with high-cost conventional gas deep onshore and in small pockets offshore. The unconventional resource is larger, but its costs will have to come down to about $4/MMbtu to be competitive."

Local factors

Local conditions will determine the time and extent of shale gas development, other seminar panelists noted. The lack of existing infrastructure and water-handling issues will likely make Marcellus shale development move more slowly than other US gas-bearing shales, according to Jen Snyder, head of Wood Mackenzie's North American gas practice in Houston. Europe could be "a game-changer" but only after 2019, she added.

Jim Jensen, president of Jensen Associates in Weston, Mass., warned against shale gas over-optimism. "Natural gas is the manic-depressive of energy, swinging from dwindling to abundant supply prospects," he said, adding that shale gas development could be affected by cost questions as well as water disposal and NIMBY issues.

Snyder said the arrival of an economic recession toward the end of 2008 and a recovery that looks increasingly gradual influences the gas demand and price outlooks. "Demand retrenchment occurred as global liquefaction capacity grew, creating a complete mismatch," she observed.

Through last year, Pacific Basin customers called on Atlantic Basin suppliers for around 1.8 bcfd of gas, Snyder said. Now, it's around 400 MMcfd. New North American shale gas production growth through 2015 could negate its pull on Atlantic Basin LNG, she suggested.

"What we're seeing over the next few years is that even though European supplies are under take-or-pay contracts, volumes will contract to protect the price through periods of excess supply," Snyder said. LNG prices in Europe and the US could stay close through 2013, but may climb in 2013 in Europe but not in the US because of its shale gas production. "Essentially, a wide gap could open when more LNG supplies are delivered into Europe. We also see Qatar continuing to deliver baseline supplies to the US to protect prices," she said.

'Upstream very blurred'

Investment costs for developing new global gas supplies vary, the panelists noted. "A lot depends on the size, distance, and location," said Jensen. "The upstream is very blurred. In places like Qatar, some of the opportunity costs are negative because all the money is in liquids and the gas might be flared to save reinjection costs."

Snyder noted that long transportation costs also raise some questions. Jensen added that new gas development is increasingly occurring away from coasts, while customers avoiding some potential producers for political reasons also could affect costs.

Panalists also questioned whether a gas cartel could emerge. "We see individual incentives with producers like Russia," said Snyder, adding, "Going forward, with European shale gas development and a wider supply base, there could be a movement away from oil price-based contracts."

Jensen said, "I've always been skeptical that a gas cartel could work. [The General Agreement on Tariffs and Trade] stipulates that countries can't exercise export controls, which is why [the Organization of Petroleum Exporting Countries] sets production quotas. Because the major gas exporters export only 36% of their total production, controls would affect their domestic markets."

He said Russia could continue to be a leader gas exporter, once it resolves whether OAO Gazprom, its national gas company, is a commercial or political entity. Iran also could be significant because it has the world's second-largest reserves, but its growing domestic demand and need to reinject gas into oil-bearing formations could limit exports, Jensen said. Caspian Basin gas producers face significant pipeline transportation issues while China, which has substantial gas resources, may find them more expensive to produce and consume than coal, he added.

Sweetnam said, "It's difficult to increase market control if you're facing competition from other stationary sources such as nuclear and coal."

US exporting LNG?

Panelists also were skeptical of US prospects to become an LNG exporter if its shale gas resources are aggressively developed. Jensen said liquefaction plants require substantial customer commitments, and that US exporters would be competing in a global market with suppliers with lower overhead.

"I think North America is much likelier to export LNG technology than product," added Snyder. "We also might see some revival of the domestic petrochemical industry."

One audience member disagreed. "With enormous pipeline capacity between the Marcellus shale in the Northeast and the Gulf Coast, LNG exports don't sound so far-fetched, particularly to Europe," said Benjamin Schlesinger, president of Benjamin Schlesinger & Associates LLC in Bethesda, Md. ✦

Senate panel's climate-change markup under protest

Nick Snow
Washington Editor

As other Republicans boycotted the US Senate Environment and Public Works Committee's markup of global climate-change legislation on Nov. 3, George V. Voinovich (Ohio) showed up to work with what he said was still incomplete information.

"I agree with you that climate change and how our nation addresses it is of incredible importance," he told Barbara Boxer (D-Calif.), the committee's chairwoman, in his opening statement. "But, in my 44 years in public service, I have learned that tackling significant problems requires the best information available and the most rigorous analysis from unbiased sources. I don't recall ever finding meaningful solutions with incomplete information and partisanship."

Republicans have complained that the US Environmental Protection Agency's analysis of S. 1733, which Boxer and John F. Kerry (D-Mass.) introduced on Sept. 30, was not adequate for the committee to work knowledgably on the bill.

In her opening statement, Boxer said she and the committee's majority staff took steps to provide more information sooner than usual as the markup approached. The committee held 3 days' of hearings and heard from 54 witnesses on nine panels Oct. 27-29 in addition to 28 earlier global warming hearings during 2009, she said. "To ensure that members had all the information required for this markup, we made the chairman's mark public a full 10 days prior to this meeting, rather than the 3 days required," she added.

The committee's majority also released EPA's analysis of the bill, which she said was built on 5 weeks of analysis by the agency of HR 2454, the measure cosponsored by Reps. Henry A. Waxman (D-Calif.) and Edward J. Markey (D-Mass.) which the House approved by 7 votes on June 26, and another 2 weeks of analysis of changes in S. 1733 which Boxer said modified the House bill by only about 10%.

Boxer also reportedly is feeling pressure from other Democrats on the com-

WATCHING GOVERNMENT

Nick Snow, Washington Editor

Blog at www.ogjonline.com

Chesapeake's NYC decision

So exactly what did Chesapeake Energy Corp.'s decision not to drill any Marcellus shale natural gas wells in New York City's watershed mean? It depends on who you ask.

"One company's voluntary moratorium is no substitute for analyses by the state's Department of Environmental Conservation and Department of Health to determine the potential of natural gas drilling failures in the New York City watershed, and of damage to critical infrastructure in adjacent communities," a spokesman for the city's Department of Environmental Protection told OGJ Nov. 2.

Gwen Lachelt, director of Earthworks' oil and gas accountability project in Durango, Colo., said the same day that the environmental organization welcomed Chesapeake's "recognition that drilling is inherently risky, and that people don't want their drinking water at risk. Welcome and unenforceable declarations aside, the greater issues of permanent protection for the watershed and an underregulated polluting technology remain."

Chesapeake CEO Aubrey K. McClendon took a different view when he reported the Oklahoma City independent producer's decision.

'Needless distraction'

McClendon said, "It has become increasingly clear to us over the past few months that the concern for drilling in the watershed has become a needless distraction from the larger issues of how we can safely and effectively develop the natural gas reserves that underlie various counties in the southern tier of New York and create high-quality green jobs."

Chesapeake's research showed that it was the only leaseholder within the city's watershed, which put it in a unique position to take the matter off the table so the area's gas development discussion can proceed constructively, McClendon said.

"The small amount of acreage Chesapeake had acquired within the watershed region—fewer than 5,000 acres—was largely obtained as a result of leasing land outside the watershed from property owners who also had tracts within the watershed. This leasehold is immaterial to Chesapeake and also does not appear prospective for the Marcellus shale," he said.

Refocusing efforts

Chesapeake believes it can drill safely in any watershed, including NYC's, McClendon said, but the company has chosen to focus its efforts on more promising areas in the state.

The company supports the state DEC's decision to have all fracturing vendors register their products and reveal ingredients in them, and has already made such disclosures at its own web site.

Chesapeake has 1.5 million net acres leased in the Marcellus, making it the single-largest leaseholder in the formation, which begins in New York and crosses Pennsylvania into West Virginia, the company said.

On Nov. 2, the American Petroleum Institute released the second of four hydraulic fracturing guidance documents it has been developing. The well construction and integrity guideline aims to protect shallow groundwater aquifers during a well's drilling, completion, and production phases. ✦

mittee such as Max Baucus (Mont.) and Ben Nelson (Neb.) to modify the bill. She said that she expects the committee to resume its markup on Nov. 4.

More than typical

"That's 7 weeks of analysis, involving tens of thousands of pages of documentation. There is no reason to do additional analysis and spend more taxpayer dollars when the work has been done," she said. "EPA has made it clear they stand behind the economic analysis and that it is more analysis than is typically provided before a markup."

Voinovich responded that he appreciated Boxer's delaying the markup and pushing back the deadline by which Republicans can offer amendments, as well as her inviting EPA to explain its analysis to the committee later that afternoon. "However, while I respect your intent, the issue before us is not whether we understand EPA's 38-page discussion paper on S. 1733 and its current analysis of Waxman-Markey," he continued. "Rather, the issue is that the committee lacks a full analysis, with modeling runs, of S. 1733. Having an EPA briefing does nothing to change that."

Voinovich said the EPA briefing also was unnecessary because it has already agreed to analyze the bill using modeling inputs and assumptions which he requested. "So we should be able to reach a bipartisan agreement to get it done. My staff worked together with EPA's modelers over several weeks to reach this agreement, and I appreciate their hard work. No more negotiation is needed. Chairman Boxer, all you need to do is give your consent, and EPA can begin its work immediately," Voinovich said.

"There is no doubt that, based on the make-up of the committee, S. 1733 will move forward. The majority has the votes, five more on the committee than the minority," he continued. "While I believe that S. 1733 will likely move forward with policies

that I oppose, I can't imagine why we would move ahead without the best information possible from the agency that will be charged with implementing the legislation."

Boxer also reportedly is feeling pressure from other Democrats on the committee such as Max Baucus (Mont.) and Ben Nelson (Neb.) to modify the bill. She said that she expects the committee to resume its markup on Nov. 4. ✦

CFTC chair calls for regulation of emissions markets

Nick Snow
Washington Editor

Comprehensive regulation of financial derivatives will also need to be a critical component of a well-functioning domestic emissions trading market, US Commodity Futures Trading Commission Chairman Gary G. Gensler said on Nov. 3.

"As Congress moves forward with potential cap-and-trade legislation, I believe it should fully regulate the expanded carbon trading markets—including the futures market, the OTC market, and the cash market—without exception," Gensler said in an address to the International Emissions Trading Association's 2009 fall trading symposium.

"Ensuring transparency, protecting the price discovery function, and addressing financial risk are every bit as critical for emissions markets as for other markets," Gensler said, adding, "It is crucial to ensure that carbon markets function smoothly, efficiently, and transparently. Effective regulation of carbon allowance trading will require cooperation on the parts of several regulators."

Gensler said six regulatory components will need to be considered, including standard setting and allocation, compliance with emissions caps and offset requirements, record-keeping and registry maintenance, trade execution system oversight, clearing of trades oversight, and protection against fraud, manipulation, and other abuses.

The first three components, which Gensler said represent the "cap" portion of cap-and-trade, fall within other regulatory agencies' expertise. CFTC is best equipped to handle the remaining components since it already fills this role in existing emissions trading programs, he indicated.

Lists examples

For example, the US Environmental Protection Agency issues sulfur dioxide and nitrogen oxide allowances under the federal acid rain, NOx budget trading, and clean air market programs, he said. On a smaller scale, 10 states from Maine to Maryland form the Regional Greenhouse Gas Initiative and issue GHG allowances, Gensler added.

"In each case, other entities issue allowances, ensure compliance, and maintain the registry. The constant, however, is that the CFTC regulates the emissions futures trading markets," he explained. "In other words, the CFTC has a great deal of experience regulating the 'trade' part of cap-and-trade." It already oversees contracts based on sulfur dioxide, NOx, and carbon dioxide allowances and offsets listed on the New York Mercantile Exchange and Chicago Climate Futures Exchange, Gensler said.

"In most respects, emissions contract markets operate similarly to other commodity markets the CFTC regulates," he said, adding, "While each contract—such as SO_2, wheat, treasury bills, or natural gas—presents its own unique challenges, the regulatory scheme is essentially the same." He said CFTC has thorough processes to ensure that exchanges have procedures in place to protect market participants and ensure fair and orderly trading, that products are designed to minimize potential manipulation, and that exchanges comply with the law and regulations.

Additional oversight

Its compliance staff monitors operations to ensure that exchanges are enforcing their rules and customers are protected from abusive practices. Its surveillance staff watches for signs of manipulation or congestion and determines how to best address market threats. "We have the authority to set and enforce position limits, and our enforcement staff is actively prosecuting cases," Gensler said.

If Congress passes cap-and-trade legislation, CFTC would work with other regulators to implement appropriate additional safeguards, he noted. "There may be specific facets of carbon markets that require particular protections, and I look forward to working with Congress, market participants, and the public to offer the commission's expertise in considering those," he said.

"As a foundation, the markets should benefit from the protections that we currently have against fraud, manipulation, and other abuses as directed by the Commodity Exchange Act coupled with any new protections Congress is considering for the OTC derivatives markets," said Gensler.

"We also must ensure that all transactions in both the carbon futures and cash markets are promptly reported and that a central registry is updated at least on a daily basis," he said, adding, "With immediate registry of trades, it will be easier for regulators to identify manipulation in the markets."

Gensler said he considers it important for companies to be able to make long-term capital commitments and hedge their carbon emissions allowances' long-term price risk. "That is why it is critical to get the regulatory oversight right of both the futures markets and the over-the-counter markets that may develop out of a cap-and-trade program," he maintained. ✦

Study takes midstream look at long-term gas supply

Nick Snow
Washington Editor

Projected growth in North American natural gas supplies and markets will require billions of dollars of additional investments in pipelines, storage, and other midstream infrastructure through 2030, a recent INGAA Foundation Inc. study concluded.

The study, which the Interstate Natural Gas Association of America's research division released on Oct. 20, projected that investments of $133-210 billion—or $6-10 billion/year—would be needed in the next 20 years under various market scenarios.

The outlays would be needed primarily to join increased gas production from unconventional shale basins and tight sands to the existing pipeline network, it said. Anticipated electric power generation and industrial demand growth as well as the potential to connect massive Arctic gas resources and LNG imports to the grid also will be key drivers, it indicated.

Insufficient midstream gas infrastructure investment could lead to volatile prices, reduced economic growth, and diminished deliveries to consumers who need the gas most, the study warned.

"The domestic supply picture for natural gas has been redrawn and experts agree we now have more than 100 years of technically recoverable gas in the US and Canada," said INGAA Foundation Chairman Gary Sypolt. "This study spotlights what this sea change in domestic supplies will mean for investment in additional pipeline, storage, and midstream infrastructure."

Other experts agree that hydraulic fracturing and other technologies are opening up significant gas resources that would have been ignored 20 years ago. "We have an unconventional gas revolution in the US. I expect it to be the default fuel in electric power," Daniel Yergin, chairman of IHS Cambridge Energy Research Associates, said during an Oct. 21 forum cosponsored by the US Chamber of Commerce and Foreign Policy magazine.

Anticipated needs

The study projected that the US and Canada would need 29,000-62,000 miles of gas pipelines and 370-600 bcf of additional storage capacity to meet anticipated market requirements. Most of the new storage would be in high-deliverability salt caverns, which would essentially double current storage capacity, it said.

Other estimated midstream gas infrastructure needs through 2030 include 6.6-11.6 million hp of transmission pipeline compression, 15,000-26,000 miles of gathering pipelines, 20-38 bcfd of processing capacity, and 3.5 bcfd of LNG import terminal capacity, the study said.

Under its base case scenario, it projected that US and Canadian gas consumption will grow to 31.8 tcf in 2030 from 26.8 tcf in 2008, or about 0.8%/year.

The study anticipates that 75% of the market growth will come from power generation. Areas of uncertainty include electric load growth; timing and development of wind, solar, and other renewable technologies; clean coal technology development with carbon capture and sequestration; and expansion of nuclear generation, it added.

Interregional transmission pipeline capacity between major US and Canadian areas is currently about 130 bcfd, the study said, with another 21-37 bcfd potentially needed in the next 20 years. More interregional gas transportation capacity would be needed even without a growing North American gas market due to shifts in production location, it noted. Laterals to reach new production and deliver gas to gas-fired power plants and other new customers also will be needed, it said. ✦

Gas supply potential linked to corporate strategies

Bob Tippee
Editor

The potential of natural gas to reshape energy markets should exert parallel influence on corporate strategies, speakers said at the RMI Oilfield Breakfast Forum in Houston.

Current and prospective gas supply is leaping from development of unconventional resources, especially shales, noted Doug Pferdehirt, president of the Schlumberger Reservoir Production Group.

While the US and Canada dominate current activity, shale gas development is "very much in the early stages of growth in most countries," Pferdehirt pointed out.

He cited a Schlumberger study that found 680 shales in 142 basins and identified 48 basins with shales outside the US as "high-graded" for gas potential.

Of the high-graded basins with shale potential, 32 have existing conventional oil and gas development and therefore equipment and services needed to support shale plays.

Those basins represent "huge

potential" for shale gas development, Pferdehirt said.

North American shale plays, meanwhile, have not nearly run their course. A large inventory of North American shale gas wells that have been producing for more than 10 years offers "huge potential for reentry, redrilling, and refracing," he said.

Another speaker, T. Don Stacy, retired chairman and president of Amoco Eurasia Petroleum Co., encouraged companies to emphasize natural gas as "an ideal stop-gap energy source" that is "least environmentally harmful."

He also said companies should focus on technologies that improve recovery through reservoir optimization and characterization, that cut emissions of greenhouse gases, and that reduce costs over the full life cycle of activities.

A third tactic Stacy suggested is to enhance or establish presence in member-countries of the Organization of Petroleum of Exporting Countries, which he pointed out represents 74% of global oil reserves but only 45% of current production.

US gas emphasis

An emphasis on unconventional gas is evident in the US exploratory strategy of Anadarko Petroleum Corp., which Frank J. Patterson, vice-president, international exploration, said concentrates on finding "the next big resource play.

Outside the US, however, Anadarko's exploration targets "predominantly oil, predominantly really big," Patterson said.

The company dedicates 45% of its capital budget to maintaining its production base, 20% to megaprojects, 25% to exploration, and 10% to midstream and other work.

At a time of tight capital markets, Patterson said, "if you're not financially disciplined, you're not here anymore."

Terry Newendorp, chairman and chief executive officer of international financial firm Taylor-DeJongh, highlighted challenges of raising capital for oil and gas projects.

In credit markets, he said, "It's a very tough time out there unless you're one of the supermajors."

And the equity market "for smaller companies has disappeared."

A growing option for raising capital, Newendorp said, is the formation of joint ventures. He cited ventures Chesapeake Energy Corp. has entered with Statoil for work in the Marcellus shale, BP America in the Fayetteville shale, and Plains Exploration & Production in

the Haynesville shale.

Similarly, he said, North American operators needing capital can form joint ventures with overseas investors that want to enter the region "but need a name to invest in." Such investors, he said, can open new markets for operators and have money. ✦

Slower desulfurization growth seen in US, Canada

Refinery desulfurization capacities for gas oil and naphtha in US and Canada will continue to grow through 2013 but more slowly than they did in 2000-08, says a study by GlobalData, London.

Among 134 active refineries in the US and Canada covered by the study, gas oil desulfurization increased from 2.8348 million b/d in 2000 to 3.8216 million b/d in 2008. The total is expected to reach 3.979 million b/d in 2013.

The average growth rate thus will decline from 3.7%/year in 2000-08 to 0.8%/year in the forecast period, the study says.

Naphtha desulfurization capacity in the US and Canada will increase to 4.6379 million b/d in 2013 from 4.5983 million b/d in 2008 and 4.3418 million b/d in 2000, GlobalData predicts.

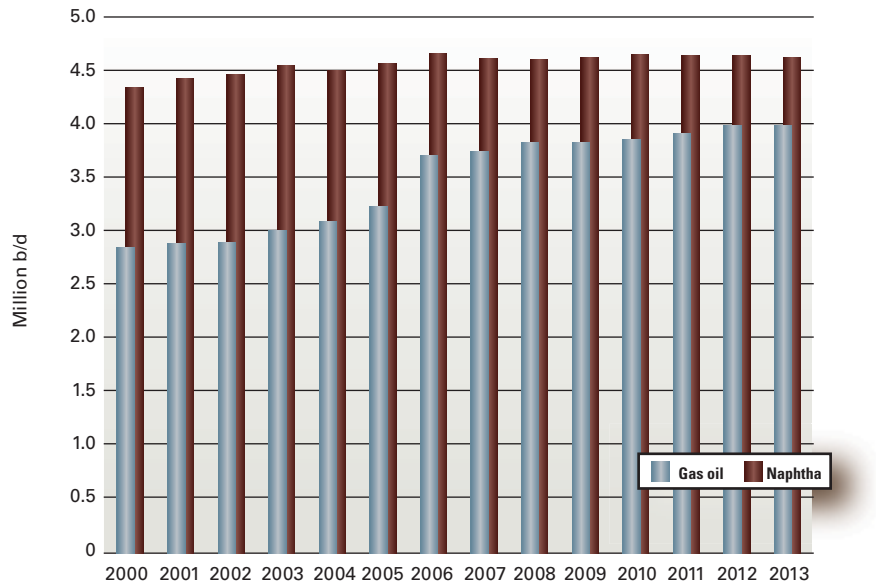
The average growth rate for naphtha desulfurization capacity will decline from 0.7%/year in 2000-08 to 0.2%/year in 2008-13.

The US and Canada have a combined 22% of the world's refinery distillation capacity but 36% of its gas oil desulfurization capacity, the study notes. Their combined naphtha desulfurization capacity is 40% of the global total.

The US share of global gas oil desulfurization capacity is 32.8% and Canada's, 3.1%, GlobalData says.

Refiners have been adding desulfurization capacity to meet requirements for ultralow-sulfur diesel and gasoline. ✦

NORTH AMERICAN GAS OIL, NAPHTHA DESULFURIZATION CAPACITY



Source: GlobalData

Denbury-Encore merger to test CO_2-oil synergies

The production-sequestration synergies of crude oil and carbon dioxide will receive a new test under a $4.5 billion acquisition by Denbury Resources Inc. of Encore Acquisition Co.

Both companies have strategies geared to enhanced oil recovery via CO_2 injection. On Nov. 1 they announced signing of a definitive merger agreement that will leave Denbury, of Plano, Tex., the surviving entity.

Both companies also are pursuing supplies of CO_2 from industrial sources needing to reduce emissions of greenhouse gas through capture and sequestration in the subsurface.

The companies

Denbury has 212.4 million boe of reserves, 59% developed and 82% oil, in mature fields of Mississippi, Louisiana, Alabama, and Texas.

At Jackson Dome in Mississippi it has CO_2 reserves estimated at 5.6 tcf proved, 3 tcf probable, and 2 tcf possible connected to mature oil fields by 750 miles of existing and planned pipelines. Denbury hopes to supplement Jackson Dome supply with CO_2 from Gulf Coast emitters and planned projects to gasify solid carbon.

In this year's second quarter it produced an average of 44,240 boe/d after adjustments for the acquisition late last year of Hastings oil field south of Houston and sale of properties this year

in the Barnett shale gas play.

Among other projects, Denbury is laying a 320-mile, 24-in. pipeline to carry CO_2 from Donaldsonville, La., near the termination of an existing line, to Hastings field.

Encore, Fort Worth, recently reported 186 million boe of reserves, 72% oil and 80% proved developed, in the Williston basin, Rocky Mountains, Midcontinent, and Permian basin. Its interests include 300,000 net acres in the Bakken shale oil play.

In this year's first half Encore produced an average 41,652 boe/d.

Before the merger announcement, Encore said its CO_2 plans centered on Bell Creek field in southeastern Montana. Now on waterflood, the field has an estimated 350 million bbl of oil originally in place with 221 million bbl remaining.

Encore said it expects the field to produce an additional 30.1 million bbl through miscible CO_2 injection. It will deliver the gas through new 206-mile, 8-in. or 10-in. pipeline from the Lost Cabin gas plant operated by ConocoPhillips in central Wyoming.

Encore entered a deal in July to buy about 50 MMcfd of CO_2 from the plant during an initial term of 15 years. In addition to laying the pipeline, it plans to install compression at the plant.

The Bell Creek project includes reactivation of 275 wells and drilling of as many as 75 wells to establish a five-spot injection pattern.

Encore estimated the production response from 100% utilization of the available CO_2 at more than 6,500 b/d by 2015, with output remaining at that level for 10 years.

The Bell Creek project would bring CO_2 to within 120 miles of the Cedar Creek anticline in eastern Montana, where Encore has 40% of its total reserves and estimates oil potentially recoverable via CO_2 injection at 200 million bbl.

It has identified the U4 zone of the Upper Ordovician Red River formation in South Pine oil field as the first target of CO_2 injection enabled by a northward extension of Log Cabin-Bell Creek pipeline.

Shell Oil, the original South Pine operator, conducted a pilot CO_2 flood in the field in the 1980s after the pilot area stopped producing oil via waterflood. Encore estimates potential recovery through CO_2 injection in the target zone at 19 million boe and in other South Pine strata at 42 million boe.

Larger projects

After the merger, the combined company will be able to pursue "significantly larger" CO_2 projects in the Gulf Coast and Rockies, said Denbury Chief Executive Officer Phil Rykhoek.

"This combination will also further enhance Denbury's position as the natural buyer and owner of mature oil properties in our core regions and the partner of choice for CO_2 emitters looking to reduce their carbon footprint," he said.

Rykhoek said the acquisition would provide for production growth in 2015 and beyond, "about the time when we anticipate nearing the production peak of our existing EOR field inventory."

Although the companies have reported financial losses in recent quarters, mainly because of decreased prices of oil and gas, both were profitable last year, during the first half of which prices set record highs.

For 2008, Denbury reported net income of $388.4 million on revenue of $1.366 billion. Encore earned $438.8 million on $1.125 billion of revenue. ✦

OSHA fines BP $87.4 million in Texas City aftermath

Paula Dittrick
Senior Staff Writer

The US Department of Labor's Occupational Safety and Health Administration announced a proposed fine of $87.4 million against BP Products North America Inc., saying the company failed to correct safety problems at its Texas City, Tex., refinery following a March 2005 explosion.

The fine is the largest in its history, OSHA said. Previously, the largest total penalty, $21 million, was issued in 2005, also against BP.

The 2005 explosion killed 15 people and injured 170 others at the 446,500-b/cd Texas City, Tex., refinery, just southeast of Houston in Galveston County. The US Chemical Safety and Hazard Investigation Board issued a series of recommendations during a 2-year period. The recommendations were made to BP, the American Petroleum Institute, OSHA, and others (OGJ, Sept. 8, 2008, p. 20).

CSB concluded that noncompliance with procedures, inadequate equipment maintenance, and personnel mistakes were contributing factors to the accident.

In September 2005, BP entered into a settlement agreement with OSHA under which the company agreed to corrective actions to eliminate potential hazards similar to those that caused the explosion.

"Instead of living up to that commitment, BP has allowed hundreds of potential hazards to continue unabated," Secretary of Labor Hilda L. Solis said Oct. 30. "An $87 million fine won't restore those lives, but we can't let this happen again. Workplace safety is more than a slogan. It's the law."

BP contested all of the citations, saying the matter is before the Occupational Health and Safety Review Com-

mission, which is independent from OSHA. BP suggested the OSHA citations will expedite the process of referring the contested case to an administrative law judge.

OSHA outlines citations

OSHA issued 270 notifications of failure to abate with fines totaling $56.7 million. The agency also identified 439 new willful violations for failures to follow industry-accepted controls on the pressure relief safety systems and other process safety management violations with penalties totaling $30.7 million.

"BP was given 4 years to correct the safety issues identified pursuant to the settlement agreement, yet OSHA has found hundreds of violations of the agreement and hundreds of new violations," said Jordan Barab, acting assistant secretary of labor for OSHA, adding, "BP still has a great deal of work to do."

OSHA can issue a notification of failure to abate if an employer fails to correct a cited condition and the citation is a final order before the Occupational Health and Safety Review Commission. A willful violation exists where an employer knows of a violation and demonstrates "either an intentional disregard for the requirements of the OSHA Act of 1970 or shows plain indifference to employee safety and health," OSHA said.

BP responds

"We are disappointed that OSHA took this action in advance of the full consideration of the review commission," said Keith Casey, manager of the Texas City refinery. "We continue to believe we are in full compliance with the settlement agreement, and we look forward to demonstrating this before the review commission."

BP will continue to work with OSHA to resolve the differences, Casey said. "We believe our efforts at the Texas City refinery to improve process safety performance have been among the most strenuous and comprehensive that the refining industry has ever seen," he said, adding, "We remain committed to further enhancing our safety and compliance systems and achieving our goal of becoming an industry leader in process safety." ✦

SEG: Energy R&D demands wider funds, collaboration

Alan Petzet
Chief Editor-Exploration

Energy research and development challenges are becoming more complex, demand integrated and individual approaches, and are in need of wider funding sources, concluded a forum at the Society of Exploration Geophysicists annual meeting in Houston.

The scale of the energy system is enormous, and energy technologies average 15 years from the start of research to commercial application, said Donald Paul, executive director, University of Southern California Energy Institute and retired Chevron Corp. chief technology officer.

For example, Paul noted, it takes $200 billion in exploration and production spending to add 1% of global oil and gas reserves. US ethanol output is 1% of global liquids production. And 10 Gw of solar would add 1% to US electricity capacity.

Conventional oil production will be inadequate to meet demand, enormous quantities of new feedstock are available, and low carbon fuel standards are coming, he said.

Hopefully, the world is coming out of the worst economic downturn in our lifetimes, and 2010 liquid fuels demand is forecast to be similar to that in 2006-07, he said. Every form of energy will get bigger, and oil, gas, and coal will dominate.

Making money is the whole basis of industrial technology, Paul said, and energy R&D is capital intensive. The US Department of Energy spent $180 billion on energy research in 1961-2008, and US government spending on clean energy technologies totaled $18 billion in 2006-08.

Energy R&D

DOE has allocated fewer federal dollars to energy R&D funding yearly since 2001, said C. Michael Ming, president, Research Partnership to Secure Energy for America.

But the National Petroleum Council 2007 study said that accelerating technology requires three to five times the funding level of accepting an incremental advancement pace, and to attain a breakthrough demands a 10 to 100 times funding hike, Ming noted.

Federal stimulus funds mostly haven't gone into oil and gas. Private industry's share is much larger than government's in the US, with oil and gas company R&D investment falling and the service company share rising in recent years.

Ming pointed to successful programs in countries such as Norway and Brazil with gross domestic products much smaller than that of the US.

Ming listed several successful US R&D projects. He noted that 24 participants have joined the SEG Advanced Modeling Initiative (SEAM), recommended in 2005 by the SEG Research Committee. Modeled partly after DeepStar, SEAM is focused on generating a realistic synthetic salt model of a 60-block area of the US Gulf of Mexico. SEAM was created in 2007.

Trends apparent

Two major trends are apparent in energy R&D, said Bob Peebler, chief executive officer, ION. They are the need

for more rapid diffusion of technology and the need for a more integrated approach.

Peebler said his company conducted mostly internal R&D in 1999. While internal work has continued, the company has now expanded into E&P operator partnerships, corporate venturing with seed capital, academic partnerships, and a joint venture with China National Petroleum Co.'s BGP, the world's largest seismic contractor.

Industry typically does experimental prototypes with such small tests that problems don't surface until full-size tests are performed later, Peebler lamented.

For example, his company wanted to run a geophysical test with 10,000 cableless nodes but could not afford the cost of fielding such an ambitious venture. It has partnered with several oil companies, and however long it takes to learn how to commercially deploy 10,000 to 30,000 cableless nodes over perhaps 80 sq miles, the time will have been cut in half because ION went the partnership route, Peebler said.

John McDonald, Chevron vice-president and chief technology officer, reminded SEG delegates that the world took 125 years to consume the first trillion barrels of oil and is using the second trillion in 25 years. It is estimated that another trillion barrels remain to be discovered, ostensibly at a cost of $20 trillion over the next two decades.

Sustainable R&D

Research and development has to deliver energy, environment, and economic benefits, especially an economic return if it is to be sustainable, McDonald said. Industry will derive benefits from independent and collaborative research and development.

Areas of applied R&D include how to get biomass to work at commercial scale, how to use lower grade heat in geothermal processes, how to eliminate natural gas use in oil and gas operations, how to make steamflooding work in carbonate reservoirs, and converting heavier products into lighter fuels, McDonald said.

The successful pursuit of carbon sequestration will "sustain a prosperous future for fossil fuels," said Raymond Orbach, director of the energy institute, University of Texas at Austin.

The processes of capturing, compressing, and storing carbon dioxide are highly energy intensive, and the industry needs to reduce the cost of capturing CO_2 from flue gas, which is extremely high, said Orbach, a former DOE official.

Public acceptance of the risks associated with CO_2 storage cannot be taken for granted, as demonstrated by protests in Germany this year against a project to sequester CO_2 at 2,600 ft in a saline aquifer.

Bob Pavey, partner, Morganthaler Ventures and past chairman of the National Venture Capital Association, said energy research projects have become a new destination for venture capital only in the past 2 years or so.

Previously most venture capital went to health care, information technology, and consumer and business services companies.

Great uncertainty revolves around who ultimately will buy the developing energy companies that venture capitalists are supporting with seed funds if those companies' research results in commercially viable technologies, Pavey said. ✦

SEC rules might have meant US oil reserves hike

Alan Petzet
Chief Editor-Exploration

Proved US crude oil reserves fell by more than 10% in 2008, but there would likely have been a smaller drop or perhaps even an increase under new Securities and Exchange Commission rules.

Proved natural gas reserves grew by almost 3%, largely due to continued development of unconventional gas from shales, said the US Energy Information Administration.

Gas reserves additions replaced production of 20.5 tcf during 2008, and operators added 6.9 tcf on top of that. The new figure is 244.7 tcf, the highest since EIA began reporting in 1977.

Gas discoveries of 29.5 tcf in 2008 were the sixth consecutive yearly increase and the highest level of discoveries in 32 years of reporting. Ninety percent of the discoveries came from extensions of existing fields.

Natural gas liquids reserves rose 1.4% to 9.3 billion bbl.

Texas accounted for about two thirds of US proved shale gas reserves, primarily in the Barnett play, although other shale plays have emerged.

EIA said shale reserves rose by 5.3 tcf in Texas, 2.4 tcf in Arkansas due to the Fayetteville play, 2.6 tcf in Oklahoma due to the Woodford play, and 800 bcf in Louisiana with the Haynesville play. Marcellus shale development is too recent to have led to a major reserves increase in 2008, EIA added.

WATCHING THE WORLD

Eric Watkins, Oil Diplomacy Editor

Blog at www.ogjonline.com

Khodorkovsky fights back

Russia's oil and gas industry has had its share of drama over former OAO Yukos head Mikhail Khodorkovsky, who was convicted and sentenced to 8 years in jail in 2005 for major fraud and tax evasion.

Khodorkovsky has been on trial again before a Moscow court since Mar. 3 and faces more than 20 years in prison over embezzlement allegations. But the oilman has now opened a new front in his battle with Moscow.

The European Court of Human Rights recently announced that Yukos is suing the Russian government for a record $98 billion. Talk about a counter attack. The former Yukos boss thinks big, and knows the case will serve as a foil to the trial in Moscow.

The European Court of Human Rights initially said the case would be heard in November, but it has since postponed the hearing in order to allow the recently appointed judge to become familiar with the file—doubtlessly a thick one.

Yukos's claims

In its bid for a hearing, Yukos claimed that Russia's tax authorities engineered the company's bankruptcy by handing out disproportionately high fines for financial irregularities.

In its application, Yukos said there was a "lack of proper legal basis" for handing out the fines as well as a "selective and arbitrary prosecution" of its business.

Between 2000 and 2003, Russian judges found Yukos guilty of tax fraud on several occasions, with Yukos eventually forking over €13 billion in unpaid taxes and another €6 billion in penalty charges.

Along the way, Khodorkovsky was convicted and sentenced to jail. His supporters have condemned the trial as politically motivated to keep Khodorkovsky—a critic of Prime Minister Vladimir Putin—out of politics altogether.

Analyst BMI grants that Yukos former shareholders achieved a moral victory in getting the European Court of Human Rights to hear the case, but says it is "doubtful that Yukos will come away victorious in the end."

Moscow worried

That may be, but Moscow is clearly worried as evidenced by its recent efforts to manipulate the outcome of the hearing.

That much became clear in August when the court announced that a Russian judge on the panel, Valery Mussin, had resigned—after having been named a director at Russia's state-owned OAO Gazprom—in order to avoid a conflict of interest in the Yukos matter.

Russian President Dimitry Medvedev then named another judge, Andrei Bushev, as a replacement. That's the very same judge who now needs more time to study the file. It is not clear how much time the newly appointed judge will require, but the hearing will be delayed for as long as he—or Moscow—needs.

As for Khodorkovsky, he seems to have accepted his fate for the moment: "Today I am a prisoner, no more, no less."

Tomorrow, of course, is another day. ✦

Proved reserves of coalbed methane fell 5% to 20.8 tcf.

The SEC accounting change would also have affected 2008 gas reserves. Under existing SEC rules, the price at Henry Hub, La., used to estimate reserves dropped 21% to $5.63/MMbtu at yearend 2008. The price would have increased 32% to $8.93/MMbtu under the new rules.

As to crude oil, the SEC rules change will allow producers starting in 2009 to calculate reserves on an average of first-day-of-the-month prices throughout the year rather than the single price in effect on the year's last trading day. This should reduce sensitivity to price troughs that often occur near the end of a year, EIA noted.

Under the old system, oil reserves fell to 19.1 billion bbl, largely due to the misleading effect that arises almost entirely from negative net revisions, EIA said.

The spot price of West Texas Intermediate fell to $44.60/bbl on Dec. 31, 2008, compared with $99.64/bbl on Jan. 1 and $145.31/bbl in early July.

The yearend price was close to the market low of $30.28/bbl on Dec. 23. Net negative revisions were about the same as the 1.7 billion bbl produced in 2008 and were nearly 1.5 times what was discovered.

"Using the new (SEC) approach, the WTI price would have been $71.79/bbl for 2007 and $101.63 for 2008, an increase of 42%," EIA said.

It said the effect of the new pricing methodology can't be estimated precisely for past years, but "it seems certain that net revisions for 2008 would have been substantially less negative, or perhaps even positive, under the new reporting method."

Oil reserves added in 2008 include 375 million bbl in the Gulf of Mexico Outer Continental Shelf, 250 million bbl in Texas, and 167 million bbl in North Dakota. ✦

OFFSHORE West Africa

23 - 25 March 2010
March 9-11, 2010
Ghana, Accra
International Conference Centre

Early Bird Offer

register before 2 February 2010 and save $220*

The 14th Annual Offshore West Africa (OWA) Conference & Exhibition will be held in the new location of Ghana, Accra at the International Conference Centre on March 9 - 11, 2010. Offshore West Africa is the premier technical forum focused exclusively on West Africa offshore exploration and production.The conference delivers the latest technological innovations, solutions and lessons learned from leading industry professionals.

Why Attend Offshore West Africa?

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

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

BOOK SPACE NOW FOR PRIME PLACEMENT!

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

Use promotion code ADOFFS-02 for an extra $50 saving & free entrance to exhibiton

Register now at :
www.offshorewestafrica.com

www.offshorewestafrica.com

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

Owned & Managed by: PennWell

Flagship Media Sponsors: Offshore, OIL&GAS JOURNAL

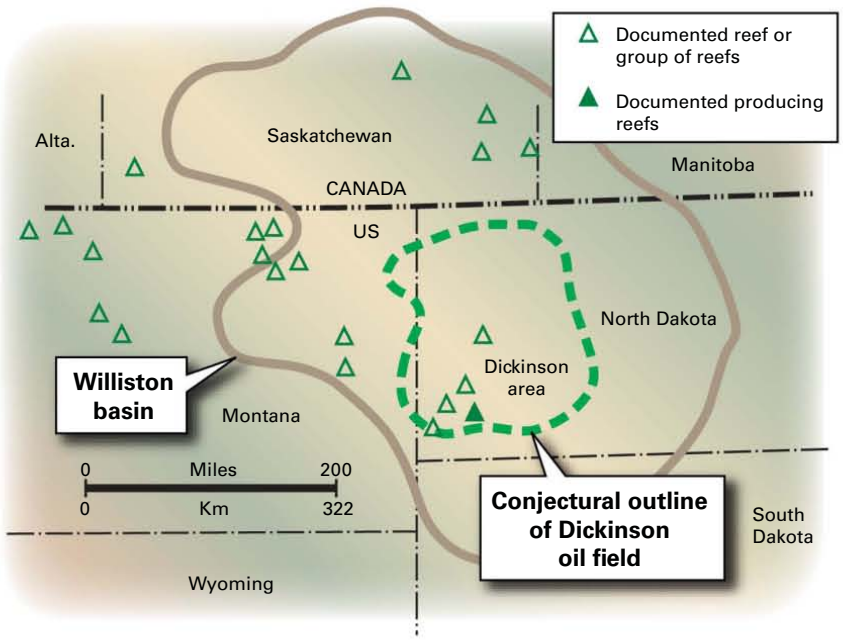
WILLISTON WAULSORTIAN MOUNDS—1

Dickinson area seen as tip of giant Lodgepole expanse

Jamil Azad
Oil For America
Calgary

POSTULATED LODGEPOLE EXPANSE

Fig. 1

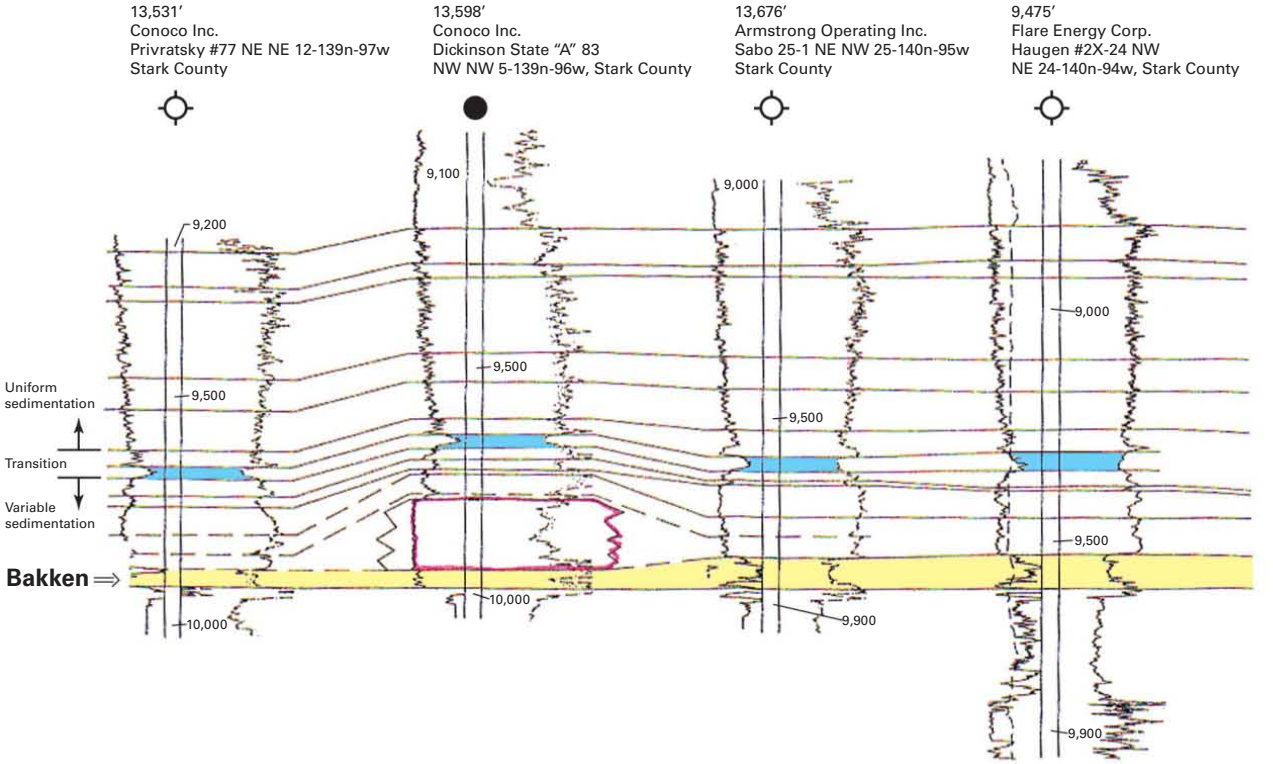


The cluster of Mississippian Lodgepole reef oil fields around Dickinson, ND, could be an indication of a supergiant Williston basin oil field which, although accidentally tapped in 1993, has remained unrecognized.

In time, the technologies that successfully culled a basin's larger oil

LODGEPOLE WAULSORTIAN MOUNDS ON DICKINSON SECTION

Fig. 2



fields pick up the smaller and then the smallest ones, thus exhausting their own potential, although not that of the basin. At this mature stage, new oil discoveries require the introduction of new technologies.

Over the years the author and partner Robert J. Angerer have developed four new technologies. We call them A I, A II, A III, and A V; we have used them to find Lodgepole oil in the Williston basin, construct an entirely new model of the production, and provide means to find reliably the otherwise elusive Lodgepole reefs across a broad expanse of the basin.

Reigniting the 1993-98 Lodgepole play in North Dakota in the decade starting in 2000 have been:

• Our discovery, with our partner Petrosearch Energy Corp. in November 2003, of the Gruman 18-1 Lodgepole producer near Dickinson with an 1,800 b/d initial potential;

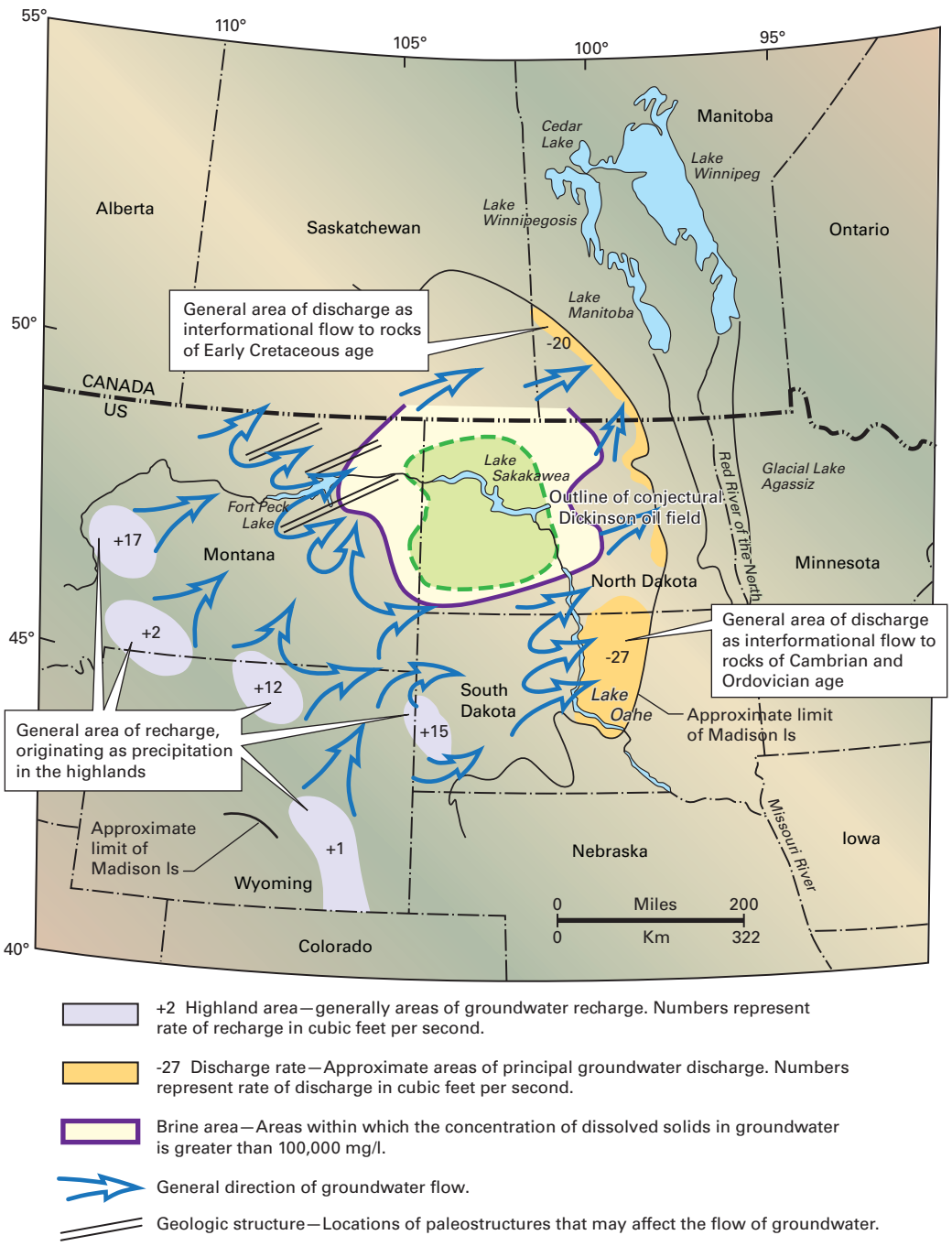
• Marathon Oil Co.'s Darwin 14-35H Lodgepole discovery in January 2009, IP 160 b/d, as a third producing formation (in addition to the Bakken and Three Forks/Sanish) as a part of the Bakken shale play in North Dakota; and

• The Laurine Engel-1 discovery, IP 463 b/d, by Armstrong Operating Inc. and Continental Resources Inc. near Dickinson in September 2009.

In this two-part article, we describe new technologies that reveal that these discoveries may be part of a supergiant oil field that extends far beyond the Dickinson area.

How flushed brines skirted postulated Dickinson oil field

Fig. 3

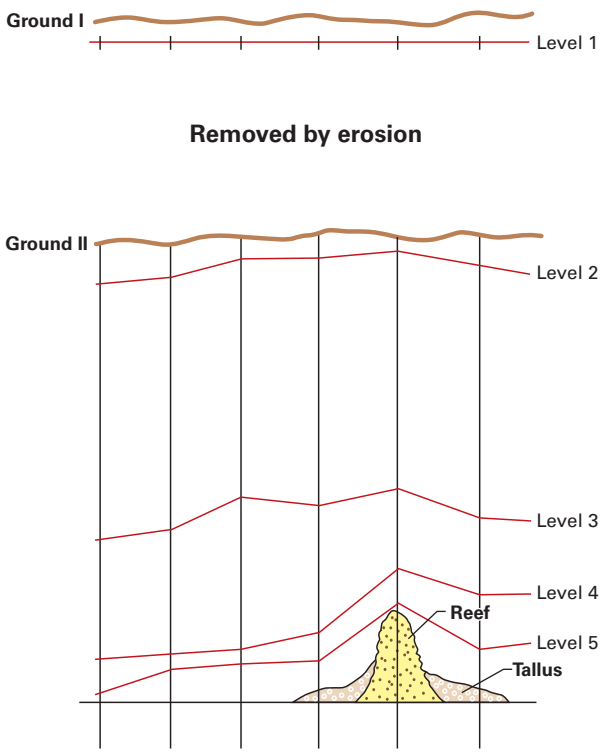


Lodgepole supergiant

We have delineated a conservative conjectural 25,000 sq mile area for the postulated Dickinson supergiant oil field and have shown the documented

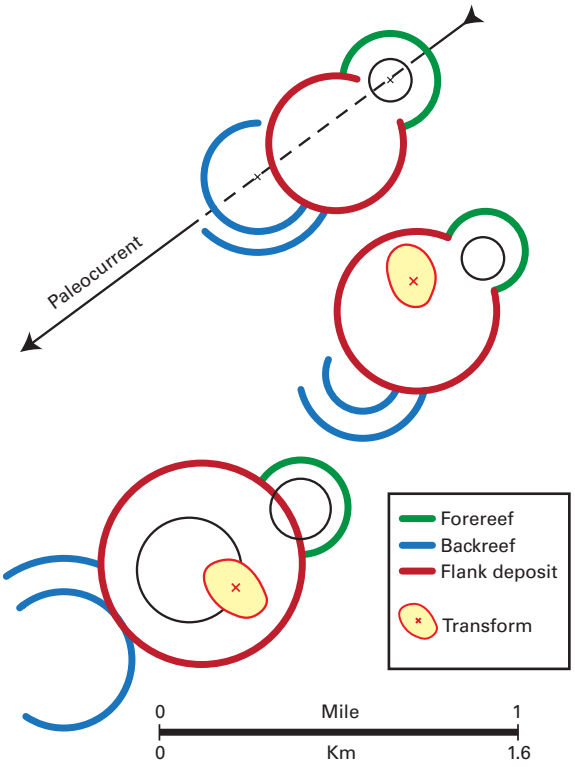
DIFFERENTIAL COMPACTION

Fig. 4



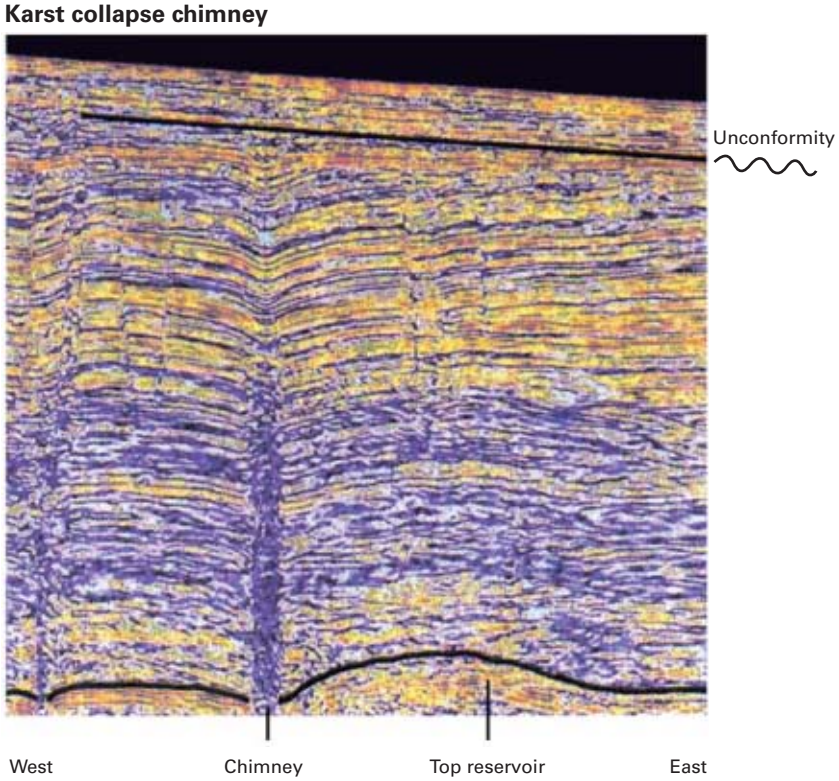
A I/A II MAP

Fig. 5



REFLECTION STRENGTH SEISMIC OVER CHIMNEY

Fig. 6



reefs and productive reefs in the basin (Fig. 1).

Estimated ultimate recoveries of the Dickinson area Lodgepole formation wells average 800,000 bbl/well when dry holes are included and 1.4 million bbl/well considering only producing wells.

Optimally located and completed wells should have a higher yield still, as much as 4 million bbl. The author knows of no better prospects in North America.

Williston geology

The stratigraphy of the Madison Group is composed of hundreds of feet of limestone including the Lodgepole formation. Evaporites that cap Dickinson oil field prevent the upward escape of its hydrocarbons.

Logs show the stratigraphic position of the basin's Waulsortian mounds that grew to be about 330 ft tall (Fig. 2).

Dickinson field lies in the deepest synclinal part of the Williston basin,

which it shares with heavy brines.

Geochemistry demonstrates that the Bakken shale (Fig. 2) did not source Dickinson oil field but that the Lodgepole formation with 13% average total organic carbon did.[1]

Madison aquifer

The deepest part of the Williston basin retains heavy saturated brines, and the fresh waters that flushed brines and oil out of the Madison aquifer in Montana and North Dakota skirted around postulated Dickinson supergiant oil field, thereby preserving it (Fig. 3).[2,3]

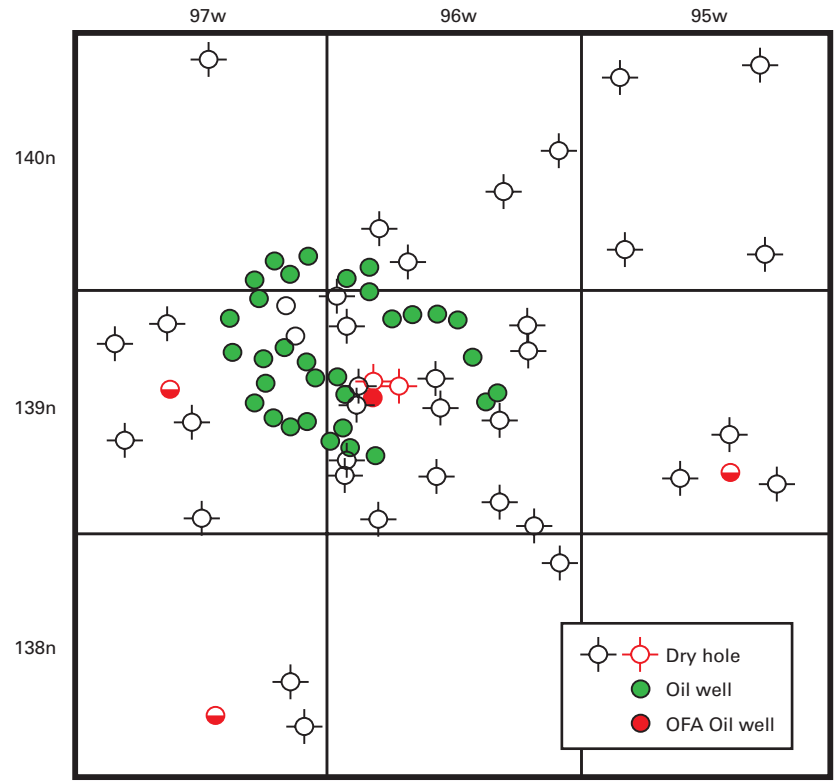
Ineffectual seismic

Every producer hit a reef, and no dry hole did. Practically all wells were sited on the evidence of seismic.

The industry's discoveries dwindled between 1993 and 1998, after which only dry holes followed (a rumored 130 in the Williston basin away from Dickinson). Clearly, here, seismic is not the answer.

DICKINSON AREA DRILLING

Fig. 7



A I analysis

Building on our experience in Texas, as earlier reported here,[3] we focused on the Waulsortian mounds in the Williston basin, the Lodgepole reefs.

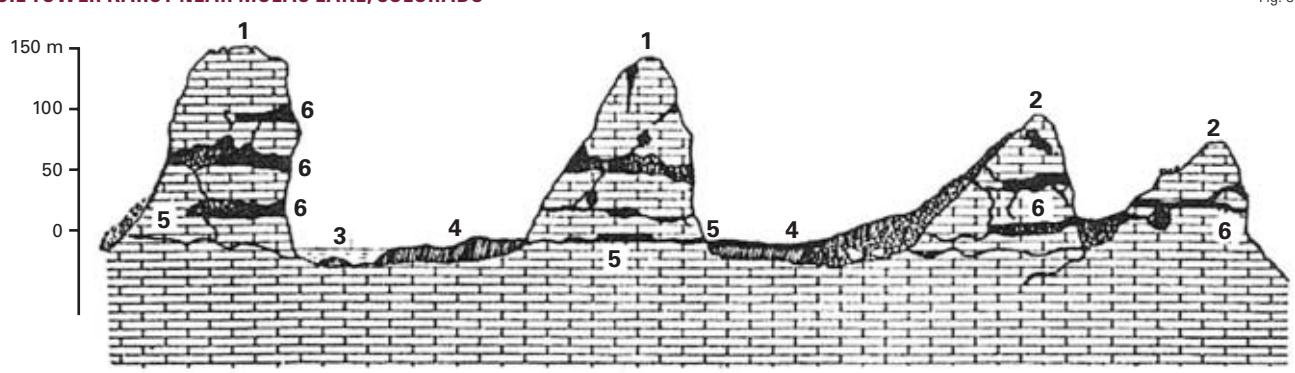
The rationale of the A I photogeomorphological analysis is that the weight of the overburden compacts the off-reef argillaceous sediments more than it does the reef core; this drapes strata over the buildup.

The differential compaction drape increases upward (Fig. 4) and has disappeared at Level 1; this is why the A I analysis requires uplift and erosion to remove enough of the top section (say, from Ground I down to Ground II) to expose the extremely subtle drape etched in the bedrock down to a level where it may be reliably detected.

Of course, A I is only an innovation in aerial photogeomorphology. The outcome Fig. 5, a scientific epiphany published here for the first time, maps the Waulsortian buildups as if stripped

FOSSIL TOWER KARST NEAR MOLAS LAKE, COLORADO

Fig. 8

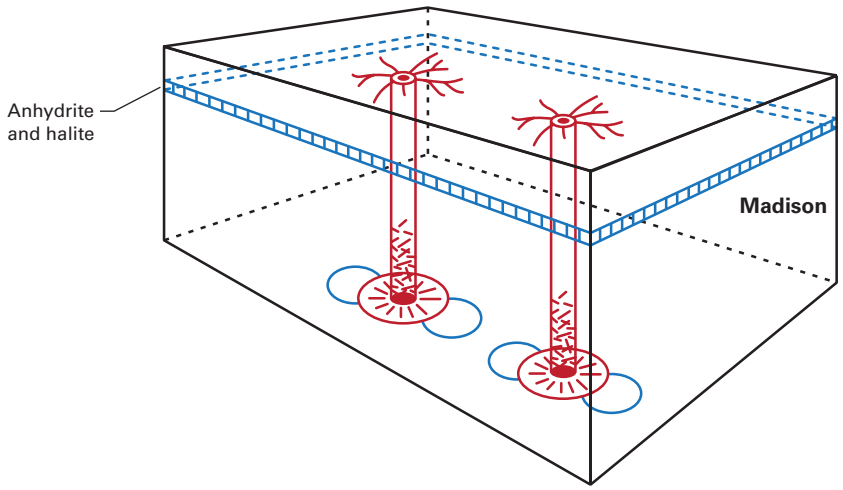


1. Tower karst hills trimmed by lateral fluvial erosion
2. Typical kegelkarst hills
3. River
4. Karst border plain
5. Active foot cave
6. Inactive (fossil) foot cave

Source: After Balazs, 1962 (view at http://www.carbonatecreek.com/paleokarst/molaslake/molaslake.html)

RESERVOIR MODEL OF 'WILLISTON OIL FIELD'

Fig. 9



off overburden! Obviously, with such a map in hand, no one should ever miss a reef.

The vector that runs through the centers of forereef and backreef defines the paleocurrent; it varies little locally but swings widely from basin to basin and between various sections of the same basin; Fig. 5 was compiled in Illinois and properly rotated to reflect different paleocurrent directions, and it works for north-central Texas, the Williston, and other basins.

Wherever studied, the Williston basin is found carpeted with mounds (Fig. 1). The mounds mapped by A I in a typical township of Dickinson occur at a density of about 2.5 mounds/sq mile, which explains the likelihood of random hits.

A I constitutes a formidable advance in reef location, but two more technologies are required to properly exploit the postulated supergiant oil field.

A II analysis

Fig. 5 shows two A IIs (gold ellipse with red X), but the two ellipses are not reef cores but rather their "transforms." This raises the question of how does a reef "project" itself vertically some 3 km to the surface and what is its "X"?

Fig. 6 offers a first clue: solution karst of an oil-bearing limestone in the South China Sea[2] creates caverns that later collapse under the weight of overlying sediments, causing a chimney.

The change from high velocities at the top of the chimney (gold) to low velocities (blue) in the lower part reflects increasing fracturing.

Collapse chimneys that result from underground nuclear tests further elucidate the anatomy of the phenomenon (Fig. 7).

The spherical detonation cavity quickly collapses under the weight of the overburden, creating a chimney topped by a surface crater.

The regression that tops the Lodgepole caused the Waulsortian mounds to emerge and become karsted by meteoric waters as in the towers of Fig. 8.

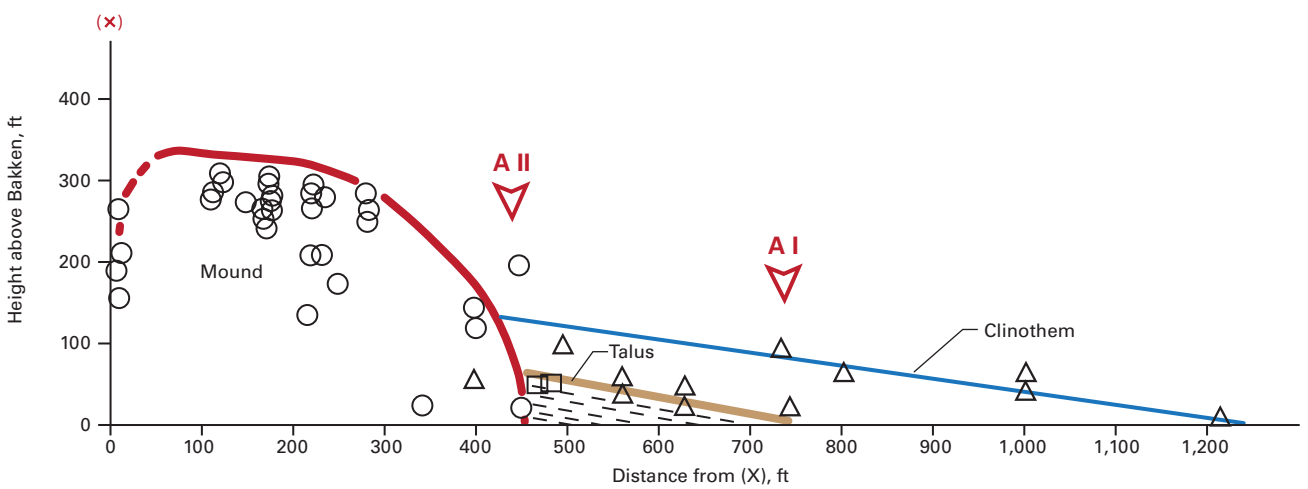
After subsidence resumed, the karsted mounds first collapsed, creating chimneys after 1,500-2,500 ft of new strata had been heaped upon them.

Although the stratigraphic correlations between dry holes work perfectly in Dickinson, correlations between dry holes (drilled outside collapse chimneys) and producers (drilled inside collapse chimneys) or between producers drilled in different collapse chimneys are chaotic and invalidate predictions based on formation.

The new reservoir model of Dickinson oil field has fractures surrounding a collapse chimney that drain the encasing rocks—here competent Madison

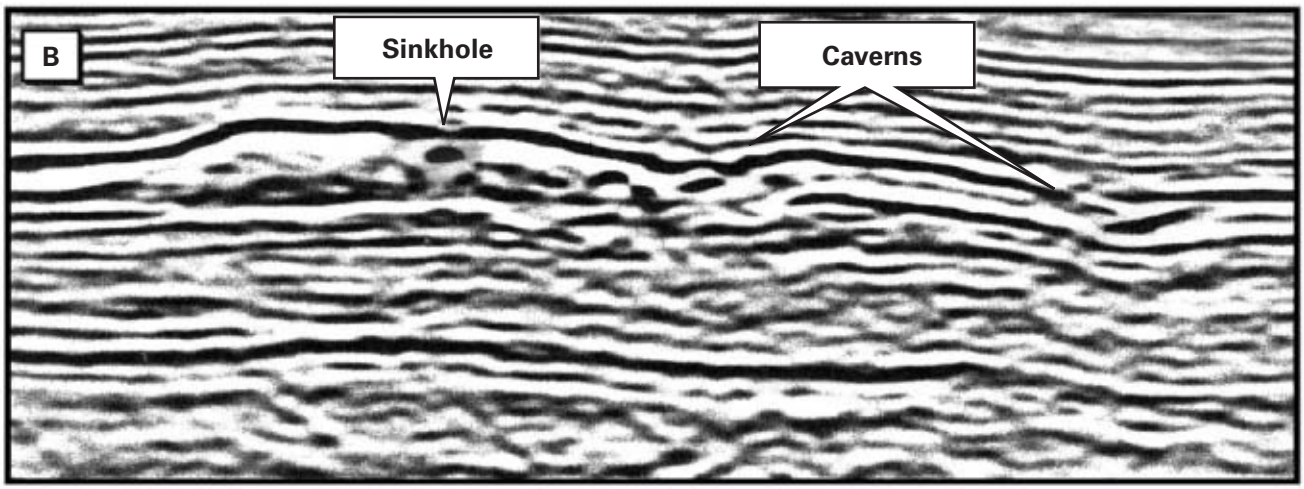
DICKINSON WELLS VS. DISTANCE TO (X)

Fig. 10



SINKHOLE PHENOMENON

Fig. 11



carbonates (Fig. 9). This explains how the puny Waulsortian mounds with 3-5% porosity, negligible nonfracture permeability, and holding a maximum of, say, 120,000 bbl of producible oil, in fact may yield more than 4 million bbl of oil.

The mounds and their collapse chimneys are the outlets of the real reservoir.

Unlike the Bakken shale play in the Williston basin that requires hydraulic fracturing, the collapse of the Lodgepole mounds created a natural vertical fracturing across the entire area that can effectively drain the Madison carbonates if wells are placed within the collapses.

A scaled composite structural profile of all Dickinson wells plotted with (X) as origin shows the reconstructed profile of precollapse mounds and the different amounts of collapse (Fig. 10). Critically, it documents the existence of a central collapse cavity, filled with reef rubble.

The only four wells that found the "central collapse cavity" were sited on the evidence of A II. This central "sinkhole" has been corroborated by seismic elsewhere (Fig. 11).

Next week: Geochemical innovations point to vast Lodgepole oil expanse. ✦

The author

Jamil Azad (jamilazad@ndsupernet.com) worked on various international petroleum exploration assignments for Burmah Oil Co. until 1971, when he took up consulting in geoscience in Calgary. He has been a partner in Oil For America since its inception. He obtained a degree of geologist from Ecole Polytechique Federale in Lausanne, Switzerland.

British Columbia

Husky Energy Inc., Calgary, gauged encouraging flow rates at two vertical exploratory wells in Northeast British Columbia's Montney and Doig shales and plans to drill its first horizontal well there in 2010.

The company said it expanded its land position to 24,000 net acres from 11,500 acres in the play.

The Graham b-10-D/94-B-9 well flowed at a rate of 2.9 MMcfd of gas from the Doig formation. The Cypress a-31-B/94-B-15 well flowed 5.4 MMcfd from the Montney and 2.9 MMcfd from the Doig.

Recovery potential from the wells is among the best vertical tests from the Doig/Montney play, Husky said without giving figures.

New Mexico

The Cave Pool Unit in the Eddy County portion of New Mexico's giant Grayburg-Jackson field could be redeveloped under an agreement between Doral Energy Corp., Midland, Tex., and Blugrass Energy Inc.

Doral Energy acquired from Blugrass a 40% working interest in and is operator of the 2,800-acre Cave Pool Unit 5 miles northwest of Loco Hills. Blugrass Energy owns the other 60%.

The unit is adjacent to three leases owned and operated by Doral that produce from six wells in the Grayburg and San Andres formations and contains nine proved undeveloped drilling locations in Square Lake field.

Cave Pool Unit produces 10 boe/d from 39 Grayburg wells drilled on 40-acre spacing. Doral Energy will rework 10 of the wells.

Redevelopment of the unit as a 20-acre five-spot Grayburg waterflood could add 100 development drilling locations and more than 3 million boe of potential gross reserves.

With the acquisition, Doral Energy owns 8,920 net acres in Eddy County and 186 existing wells in the Artesia-Vacuum Trend.

Improved oil, gas demand, price forecasts raise drilling rig trend

Guntis Moritis
Production Editor

The US working drilling rig count has started to reverse its steep drop as expectations for crude and gas prices and demand have become more bullish.

The Baker Hughes Inc. US rig count for the week ending Oct. 23 was 1,048, up 8 rigs from the previous week. Although this is down considerably from the 2,031 rigs working in September 2008, the count was up 172 rigs from the 2009 low point of 876 rigs in June.

Recent oil prices have been above $70/bbl since reaching a low of about $32/bbl in December 2008 (Fig. 1). Spot gas prices at the Henry Hub have remained below $4/MMbtu, although gas future prices and the large MMbtu spread between oil and gas prices seem to indicate that gas prices will rise (Fig. 2).

Fig. 3 shows the fall in the Baker Hughes working rig count in the world from a high of 3,557 rigs in October 2008 to a low of 1,983 rigs in June 2009 and an increase to 2,203 working rigs in September 2009.

In its world rig count, Baker Hughes does not include land rigs drilling in China and Russian as well as activity in Iran, Iraq, Kuwait, Sudan, and elsewhere.

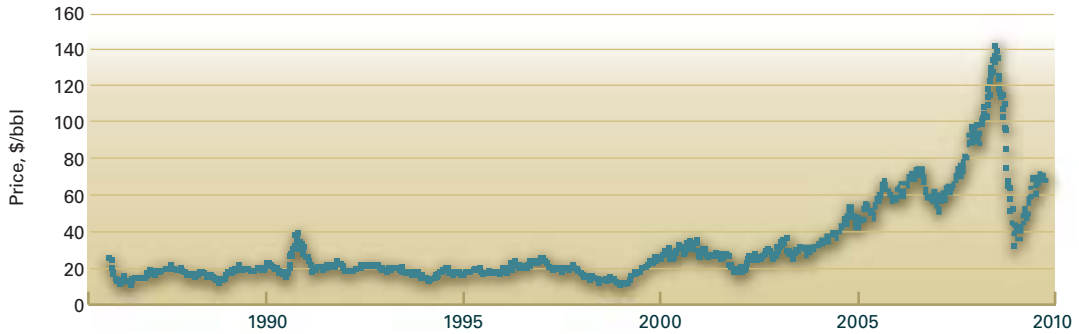
Smith International shows some rig counts unavailable in the Baker Hughes statistics. For some countries, the two counts are very different. This article mainly uses the Baker Hughes rigs counts although it also presents some Smith International numbers. The Smith International rig count of total rigs operating worldwide for September 2009 of 3,444 is considerably more than the 2,203 in the Baker Hughes statistics.

The Baker Hughes count outside of the US and Canada was 986 for September, up 39 from August but down 22 from September 2008. The number of working rigs outside the US and Canada shows much less variance than the rig count for the US and Canada (Fig. 4).

Each week, the OGJ Industry Scoreboard (for example, OGJ, Oct. 26, 2009, p. 6) includes a graph showing the last 2 years of the Baker Hughes working rig count for total world, total onshore, and total offshore rigs. Also shown is a graph that compares the working rig count for the last 3 months with the rig count in the previous year for activity in the US and Canada.

WEEKLY CUSHING WTI SPOT PRICE FOB

Fig. 1



Source: US Energy Information Administration

Another feature in each OGJ is the weekly Baker Hughes rig count table for the US and Canada that is in the Statistics section (for example, OGJ, Oct. 26, 2009, p. 59). The table breaks out the US count by state and offshore and includes total rigs drilling for gas or oil, as well as a comparison of the activity for the same week in the previous year.

The Statistics section each week also contains a table with the weekly Smith International US rig count broken out by proposed depth.

US drilling

The US is the country with the most rigs running. Of the 1,048 in operation during the week ending Oct. 26, Baker Hughes lists 312 drilling for oil, 725 drilling for gas, and 11 drilling miscellaneous wells. A year ago, the breakdown was 423 oil, 1,529 gas, and 12 miscellaneous.

Regarding the type of drilling, Baker Hughes lists 179 rigs drilling directional wells, down 202 from last year; 472 rigs drilling horizontal wells, down 171 from last year; and 397 rigs drilling vertical wells, down 543 from last year.

Fig. 5 shows the rig activity in various basins in the US. Five main basins

US WELLS SPUD BY OPERATOR (JAN.-SEPT. 2009)*

Rank	Operator	Wells spud	% of total	Footage drilled	% of total	Average footage
1	Chesapeake Operating Inc.	809	5.67	7,228,360	6.10	8,935
2	XTO Energy Inc.	644	4.51	6,735,247	5.60	10,458
3	EOG Resources Inc.	541	3.79	5,031,771	4.20	9,301
4	Kerr-McGee Oil & Gas Onshore LP	379	2.65	3,155,885	2.60	8,327
5	EnCana Oil & Gas (USA) Inc.	357	2.50	4,002,393	3.40	11,211
6	SEECO Inc.	347	2.43	1,431,175	1.20	4,124
7	Noble Energy Inc.	329	2.30	2,508,168	2.10	7,624
8	Devon Energy Production Co. LP	318	2.23	3,140,972	2.60	9,877
9	BP America Production Co.	265	1.86	2,374,969	2.00	8,962
10	ConocoPhillips Co.	234	1.64	1,760,624	1.50	7,524
11	COG Operating LLC	187	1.31	1,416,492	1.20	7,575
12	Burlington Resources Oil & Gas Co. LP	185	1.30	1,617,093	1.40	8,741
13	Williams Production RMT Co.	185	1.30	1,484,624	1.20	8,025
14	Questar Exploration & Production Co.	159	1.11	2,058,664	1.70	12,948
15	Energen Resources Corp.	134	0.94	632,519	0.50	4,720
16	Newfield Production Co.	128	0.90	836,045	0.70	6,532
17	ExxonMobil Development Co.	109	0.76	1,367,687	1.10	12,548
18	Atlas Resources Inc.	104	0.73	833,970	0.70	8,019
19	Bill Barrett Corp.	102	0.71	771,209	0.60	7,561
20	Ultra Resources Inc.	101	0.71	1,356,450	1.10	13,430
21	OK Arena Operating Co.	101	0.71	494,900	0.40	4,900
22	BP Exploration (Alaska) Inc.	99	0.69	871,773	0.70	8,806
23	Dominion Exploration & Production Inc.	98	0.69	461,792	0.40	4,712
24	Anadarko E&P Co. LP	98	0.69	1,142,077	1.00	11,654
25	Texas Keystone Inc.	96	0.67	537,720	0.50	5,601
26	Swepi LP	95	0.67	1,271,552	1.10	13,385
27	Marathon Oil Co.	93	0.65	1,067,766	0.90	11,481
28	Apache Corp.	93	0.65	845,620	0.70	9,093
29	Equitable Production Co.	92	0.64	373,103	0.30	4,055
30	Quicksilver Resources Inc.	87	0.61	787,500	0.70	9,052
31	Newfield Exploration Mid-Continent Inc.	85	0.60	799,115	0.70	9,401
32	Chesapeake Appalachia LLC	84	0.59	572,349	0.50	6,814
33	HighMount Expl. & Prod. Texas LLC	84	0.59	670,475	0.60	7,982
34	Cabot Oil & Gas Production Corp.	83	0.58	797,500	0.70	9,608
35	Mewbourne Oil Co.	81	0.57	715,755	0.60	8,836
36	Range Production Co.	78	0.55	763,423	0.60	9,787
37	Chevron USA Inc.	74	0.52	487,481	0.40	6,588
38	EQT Production Co.	70	0.49	310,708	0.30	4,439
39	Petrohawk Operating Co.	69	0.48	921,405	0.80	13,354
40	Range Resources-Appalachia LLC	68	0.48	490,756	0.40	7,217
41	Laredo Petroleum Inc.	66	0.46	891,575	0.70	13,509
42	Range Resources-Pine Mountain Inc.	62	0.43	414,098	0.30	6,679
43	Murfin Drilling Co. Inc.	62	0.43	279,550	0.20	4,509
44	Samson Lone Star LLC	61	0.43	738,531	0.60	12,107
45	Wexpro Co.	61	0.43	775,396	0.60	12,711
46	Venoco Inc.	59	0.41	410,258	0.30	6,954
47	New Dominion LLC	59	0.41	283,500	0.20	4,805
48	Legend Natural Gas III LP	58	0.41	508,000	0.40	8,759
49	Endeavor Energy Resources LP	53	0.37	640,250	0.50	12,080
50	St. Mary Land & Exploration Co.	52	0.36	582,195	0.50	11,196
51	El Paso Exploration & Production Co. LP	49	0.34	612,952	0.50	12,509
52	ConocoPhillips Alaska Inc.	47	0.33	316,717	0.30	6,739
53	SandRidge Exploration & Production LLC	46	0.32	518,646	0.40	11,275

are seeing an increase in working rigs. The western gulf for the week ending Oct. 2 has 127 rigs working compared to low of 93 in for the week ending June 5. Other comparisons for the working rig count ending Oct. 2 with recent lows are: Permian with 146 rigs (Oct. 2) up from 76 rigs (May 15), Louisiana-Mississippi salt basin with 112 rigs (Oct. 2) up from 81 (Mar. 27), Appalachian basin with 102 rigs (Oct. 2) up from 71 (May 1), and Williston basin with 51 rigs (Oct. 2) up from 34 (May 22). For the remaining basins the aggregate count of 486 working rigs (Oct. 2) is still at a low point.

Other trends also show a pickup in activity. Pritchard Capital Partners LLC in an Oct. 12 industry update said that horizontal well permits for drilling in the Marcellus shale in Pennsylvania have soared to 184 in September, compared with 91 in August. It notes much activity in seven counties: Bradford County (36 horizontal permits), Tioga (31), Washington (23), Clinton, (15), Lycoming (14), Greene (14), Lackawanna (11), and Susquehanna (6).

It indicated that environment issues might have decreased the permit applications in Susquehanna County from the 13 in August.

Pritchard said that the most active companies in September based on horizontal permits recieved were Fortuna Energy Inc. (26), Anadarko Petroleum Corp. (25), Range Resources Corp. (24), Chesapeake Energy Corp. (19), EXCO Resources Inc. (11), and Ultra Petroleum Corp (8).

Pritchard noted that three operators in 2009 have permitted more than 95 horizontal wells in the Marcellus play. These are Fortuna (99), Chesapeake (178), and Range Resources (120).

Table 1 shows the 100 operators of record with the most wells spud in the US during January-September 2009. The table from RigData lists operator of record

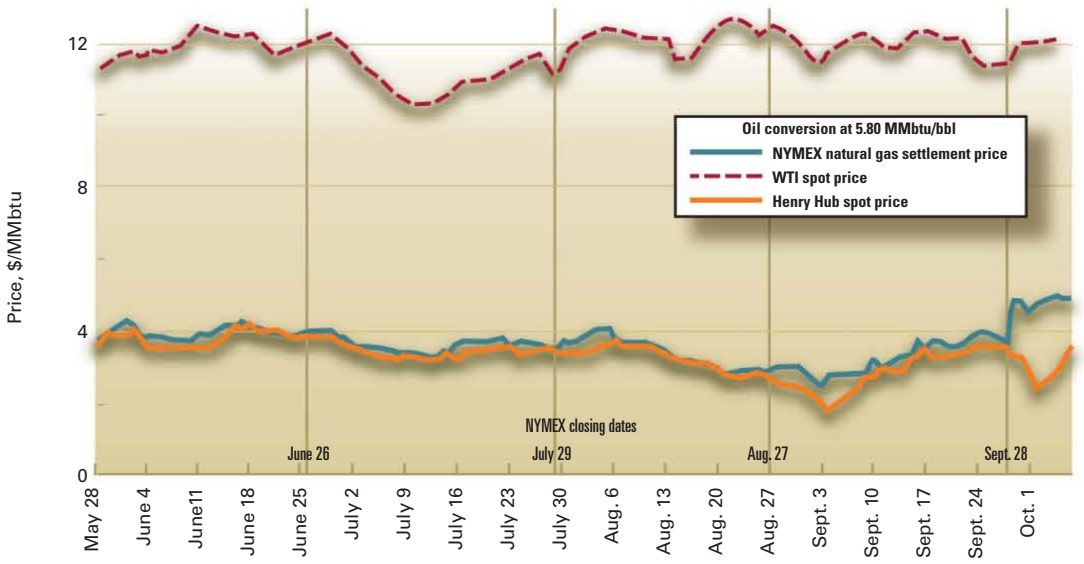
Table 1

Rank	Operator	Wells spud	% of total	Footage drilled	% of total	Average footage
54	Henry Resources LLC	45	0.32	496,000	0.40	11,022
55	Fortuna Energy Inc.	44	0.31	292,471	0.20	6,647
56	OXY USA WTP LP	44	0.31	464,320	0.40	10,553
57	Whiting Oil & Gas Corp.	43	0.30	440,183	0.40	10,237
58	Hilcorp Energy Co.	41	0.29	483,551	0.40	11,794
59	Summit Petroleum LLC	38	0.27	412,200	0.30	10,847
60	Petro-Canada Resources (USA) Inc.	37	0.26	290,939	0.20	7,863
61	Williams Production Mid-Continent Co.	36	0.25	284,516	0.20	7,903
62	Broad Oak Energy Inc.	35	0.25	338,453	0.30	9,670
63	EXCO Production Co. LP	35	0.25	418,252	0.40	11,953
64	American Warrior Inc.	33	0.23	146,930	0.10	4,452
65	Texas Energy Operations LC	33	0.23	266,000	0.20	8,061
66	Hess Corp.	32	0.22	305,122	0.30	9,535
67	Shell Western E&P	32	0.22	443,737	0.40	13,867
68	Fasken Oil and Ranch Ltd.	32	0.22	355,400	0.30	11,106
69	SandRidge Energy Inc.	32	0.22	415,200	0.30	12,975
70	Kriebel Minerals Inc.	31	0.22	165,000	0.10	5,323
71	East Resources Inc.	31	0.22	167,707	0.10	5,410
72	Rosetta Resources Operating LP	31	0.22	288,804	0.20	9,316
73	Comstock Oil & Gas LP	30	0.21	349,772	0.30	11,659
74	Presco Western LLC	30	0.21	178,800	0.10	5,960
75	Unioil	29	0.20	224,171	0.20	7,730
76	Mariner Energy Inc.	28	0.20	291,722	0.20	10,419
77	U.S. Energy Development Corp.	28	0.20	79,134	0.10	2,826
78	Lewis Petro Properties Inc.	28	0.20	238,900	0.20	8,532
79	Petroleum Development Corp.	28	0.20	224,291	0.20	8,010
80	Continental Resources Inc.	27	0.19	283,106	0.20	10,485
81	Carrizo Oil & Gas Inc.	27	0.19	241,200	0.20	8,933
82	Southwestern Energy Production Co.	26	0.18	207,250	0.20	7,971
83	Williams Production Gulf Coast LP	26	0.18	209,289	0.20	8,050
84	Anadarko Petroleum Corp.	25	0.18	379,421	0.30	15,177
85	Pioneer Natural Resources USA Inc.	25	0.18	261,884	0.20	10,475
86	Forest Oil Corp.	25	0.18	311,655	0.30	12,466
87	Unit Petroleum Co.	24	0.17	261,750	0.20	10,906
88	KEBO Oil & Gas Inc.	24	0.17	175,475	0.10	7,311
89	Linn Operating Inc.	24	0.17	218,760	0.20	9,115
90	NFR Energy LLC	24	0.17	298,500	0.30	12,438
91	Stephens Production Co.	24	0.17	158,175	0.10	6,591
92	Chaparral Energy LLC	23	0.16	105,195	0.10	4,574
93	Aruba Petroleum Inc.	23	0.16	207,000	0.20	9,000
94	Clean Gas Inc.	23	0.16	105,100	0.10	4,570
95	VAL Energy Inc.	23	0.16	112,450	0.10	4,889
96	Cholla Petroleum Inc.	22	0.15	136,578	0.10	6,208
97	Cimarex Energy Co.	22	0.15	294,691	0.20	13,395
98	Daugherty Petroleum Inc.	22	0.15	100,957	0.10	4,589
99	Henry Petroleum LP	22	0.15	237,400	0.20	10,791
100	Key Oil Co.	22	0.15	115,490	0.10	5,250
Total for top 100 operators		**9,469**		**83,581,656**		**2,278**
Total for all operators		**14,277**		**119,319,265**		**2,812**

*The list only includes wells deeper than 2,500 ft.
Source: RigData

GAS PRICE, MAY-OCT. 2009

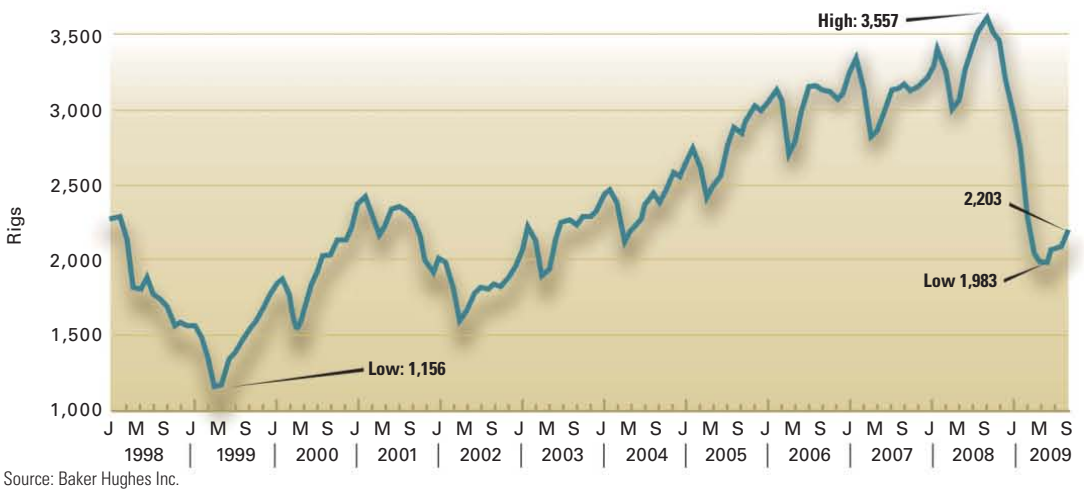
Fig. 2



Source: US Energy Information Administration

WORLD RIG COUNT

Fig. 3



Source: Baker Hughes Inc.

not parent companies. The aggregation of the subsidiary spuds would change a parent company's rank in the table. For instance, the table shows 809 wells spud by Chesapeake Operating Inc. (No. 1 in the table) and 84 wells spud by Chesapeake Appalachia LLC (No. 32).

Southwestern Energy Co. units included in the list are SEECO Inc. (No. 6) with 347 wells spud and Southwestern Energy Production Co. (No. 82) with 26 wells spud.

Of the major companies, BP PLC has two subsidiaries listed: BP America Production Co. (No. 9) with 265 wells spud and BP Exploration (Alaska) Inc. (No. 22) with 99 wells spud.

Another major, ConocoPhillips, has three subsidiaries listed: Conoco Phillips Co. (No. 10) with 234 wells spud, Burlington Resources Oil & Gas Co. LP (No. 12) with 185 wells spud, and ConocoPhillips Alaska Inc. (No. 52) with 47 wells spud.

Royal Dutch Shell PLC has two units listed: Swepi LP (No. 26) with 95 wells spud and Shell Western E&P (No. 67) with 32 wells spud.

Anadarko Petroleum Corp. (No. 84) spud 25 wells while its units Kerr-McGee Oil & Gas Onshore LP (No. 4) spud 379 wells and Anadarko E&P Co. LP (No. 24) spud 98 wells

Several other companies have more than one subsidiaries listed.

The total wells spud from January to September for the 100 operators of record is 9,469 compared with 14,277 for all operators of record.

Table 2 shows that the 2009 active drilling rig fleet for the top 25 drilling contractors in the US has increased to 2,050 rigs compared with 1,849 rigs in 2008, although working rigs have declined from 1,213 in January to 757 in September. The list includes some well servicing rigs. Nabors Drilling USA LP operator has the most active land rigs with 332. Precision Drilling Oil Field Svcs. Corp. had the largest increase in its rig fleet from the previous year because of its purchase of Grey Wolf Drilling Co. LP.

Canada

The number of oil and gas wells expected to be drilled in Canada this year is 8,787, almost a 50% decline from the 16,000 completed in 2008, according to the Canadian Association of Oilwell Drilling Contractors.

The decline is partly attributed to Alberta's new resource royalty framework that came into effect in January 2009, although since then Alberta has put in place some incentive programs for reducing oil and gas royalties for small and mid-size producers to spur drilling of wells that otherwise would be uneconomical.

Most drilling in Canada is the western provinces of Alberta, British Columbia, and Saskatchewan. Because of drilling rules, Western Canadian drilling usually peaks in February and declines in the summer months before starting to climb again.

In 2009, the low point was 70 working rigs in May compared with the 2008 low point of 120 working rigs in April (Fig. 6).

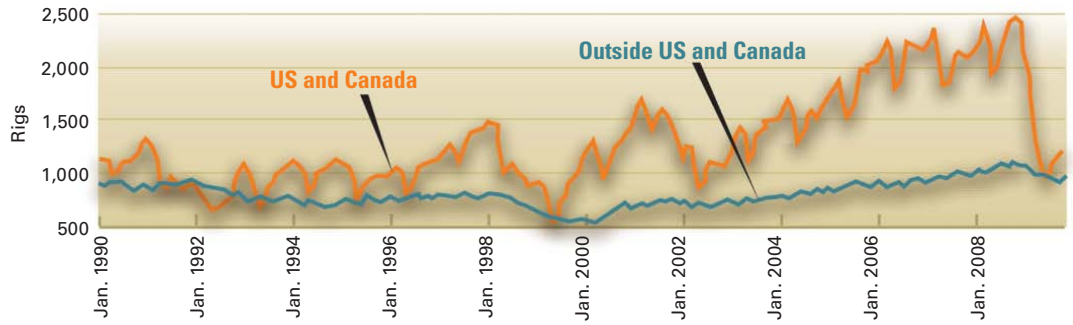
Outside US, Canada

Outside of the US and Canada the working rig count in September was 986 up from 947 in August according to Baker Hughes. In September and August 2008, the rig counts were 1,087 and 1,108. By area, the rig count was 355 Latin America, 83 Europe, 57 Africa, 245 Middle East, and 246 Asia-Pacific (Fig. 7).

In Latin America, countries with the most rigs running in September were Argentina with 39 (21 oil, 18 gas), Brazil with 63 (57 oil, 6 gas), Colombia with 27 (all oil), Mexico 127 (120 oil, 25 gas), and Venezuela 56 (51 oil, 5 gas). The September 2009 working rig count in Mexico is much higher than

Rig count trend

Fig. 4



Source: Baker Hughes Inc.

Top 25 US drilling contractors—onshore and offshore (Jan.-Sept. 2009)*

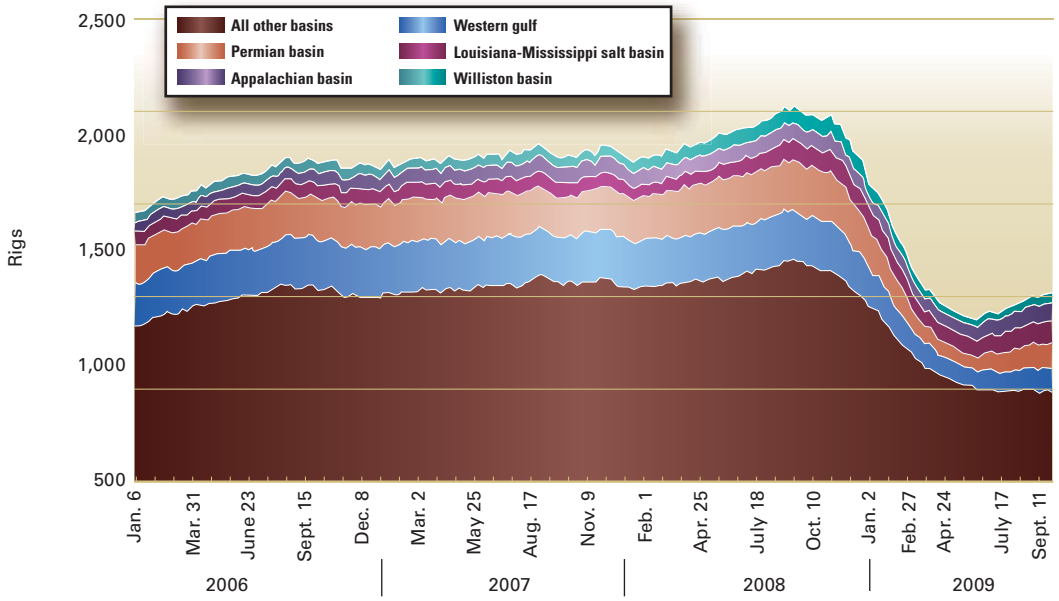
Table 2

Rank	Company	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Average monthly rig use	2009 fleet	2008 fleet
1	Nabors Drilling USA LP	198	176	146	126	110	98	99	103	116	130	332	334
2	Helmerich & Payne IDC	172	156	135	115	105	103	101	101	103	121	214	194
3	Patterson-UTI Drilling Co. LLC	146	107	77	59	57	59	69	74	85	81	334	331
4	Precision Drilling Oilfield Svcs. Corp.	99	81	76	61	56	49	51	58	64	66	162	27
5	Nomac Drilling LLC	76	72	75	68	67	71	76	76	82	74	98	64
6	Unit Drilling Co.	50	38	29	26	25	20	21	24	25	29	87	88
7	Ensign United States Drilling Inc.	48	32	28	22	22	21	22	24	23	27	60	56
8	Trinidad Drilling LP	32	26	31	30	29	36	36	37	36	33	56	46
9	Pioneer Drilling Co.	41	36	31	22	19	20	18	21	19	25	66	64
10	Union Drilling Inc.	33	31	25	23	22	24	21	20	24	25	54	57
11	Cactus Drilling Co. LLC	37	29	25	21	20	20	20	21	22	24	46	43
12	Bronco Drilling Co. Inc.	32	27	17	15	11	11	9	8	12	16	52	54
13	Goober Drilling LLC	27	22	18	17	14	13	13	14	14	17	38	37
14	Unit Texas Drilling LLC	23	17	16	11	9	9	15	14	14	14	46	35
15	Hercules Drilling Co. LLC	24	14	11	10	12	9	12	10	9	12	40	56
16	Rowan Drilling Co. Inc.	23	21	18	15	13	12	14	15	14	16	32	31
17	Nabors Well Services Co.	16	16	15	14	13	12	13	15	15	14	82	76
18	Nabors Offshore Corp.	18	14	15	10	12	9	7	3	3	10	44	44
19	Big Dog Drilling Co.	19	11	9	6	6	5	6	10	11	9	25	25
20	Key Energy Services Inc.	13	11	9	12	7	5	9	14	12	10	47	44
21	Scandrill Inc.	20	18	18	17	14	14	14	15	15	16	20	19
22	Capstar Drilling LP	16	11	8	5	5	7	11	12	14	10	27	27
23	Cyclone Drilling Inc.	15	8	5	4	4	4	4	6	7	6	33	27
24	Felderhoff Bros. Drilling LLC	17	12	10	10	11	10	10	10	10	11	21	23
25	Lariat Services Inc.	18	15	10	8	5	6	6	7	8	9	34	47
	Active rigs	**1,213**	**1,001**	**857**	**727**	**668**	**647**	**677**	**712**	**757**	**807**	**2,050**	**1,849**

*Some rigs that worked earlier in the year may no longer be marketed.
Source: RigData

US RIG COUNTS BY BASIN

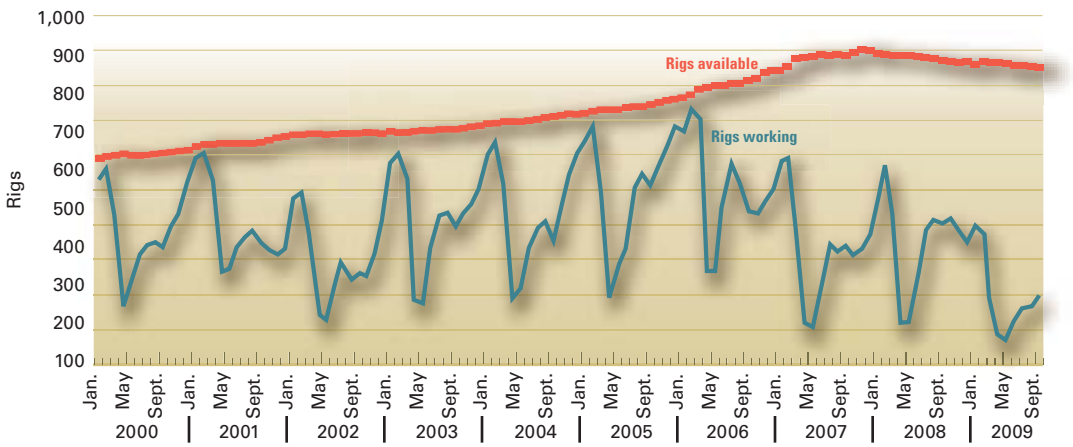
Fig. 5



Source: Baker Hughes Inc.

WESTERN CANADA RIG COUNT

Fig. 6



Source: Canadian Association of Oilwell Drilling Contractors

the September 2008 rig count of 99 (72 oil and 27).

Much of Mexico's new rig activity is in the Chicontepec oil region that contains low permeability reservoirs. Media reports have said that Petroleos Mexicanos (Pemex) is reviewing performance in the region but is not suspending work there (OGJ Online, Oct. 9, 2009).

In coming years, the working rig count will pick up in Brazil as Petroleo Brasileiro SA (Petrobras) begins receiving the 28 new offshore drilling rigs it plans to have built (OGJ Online, Oct. 9, 2009) for use in the ultradeep subsalt horizons in the Santos basin off Brazil. It expects the rigs to start becoming available in 2013-17.

In the Middle East, countries with the most rigs running in September were Abu Dhabi with 12 (all oil), Oman with 46 (39 oil, 7 gas), Pakistan 20 (3 oil, 17 gas), Saudi Arabia 65 (40 oil, 25 gas), and Syria 24 (all oil).

For the same area, Smith International reports Kuwait with 31 rigs, Iran with 65 rigs (54 land, 11 offshore) and Abu Dhabi with 30 (18 land, 12 offshore). Baker Hughes count does not include the activity in Kuwait and Iran and the working land rigs in Abu Dhabi.

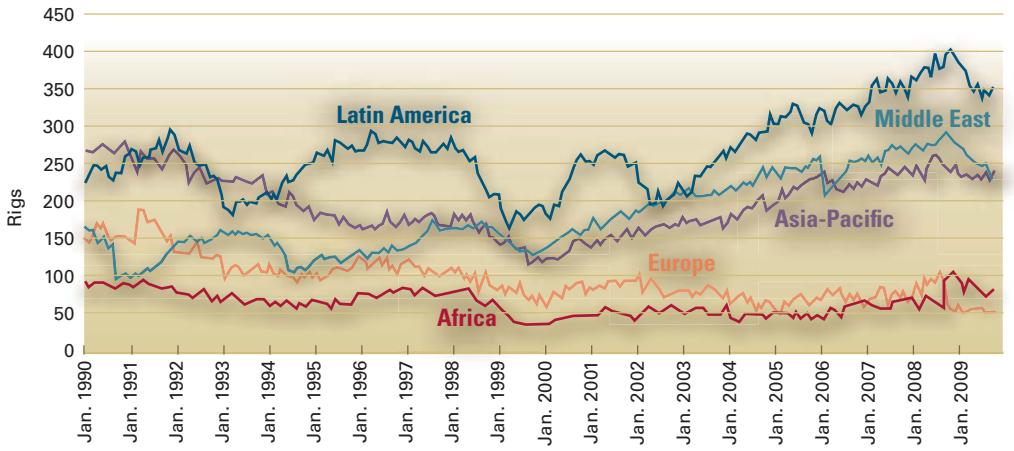
Countries with the highest rig count in the Asia-Pacific region were India with 94 (79 oil, 15 gas), Indonesia with 58 (37 oil, 18 gas, 3 miscellaneous), Malaysia with 17 (16 oil, 1 gas), and offshore China with 21 (20 oil, 1 gas).

Baker Hughes does not report land rigs in China, but for September Smith International counts China with 41 (7 land, 34 offshore).

Norway and the UK are the two European countries with the most working rigs included in Baker Hughes's statistics. These show Norway with 22 (20 oil, 2 gas) and the UK with 19 (13 oil, 6 gas).

Rig count outside US, Canada

Fig. 7



Source: Baker Hughes Inc.

Smith International has a breakout of the Russia and Caspian region. The countries with the main active rigs in this region are Azerbaijan with 13 (1 land, 12 offshore), Kazakhstan with 64 (60 land, 4 offshore), Russia with 312 (307 land, 5 offshore), and Turkmenistan with 9 (6 land, 3 offshore).

In Africa the countries with the most active rigs according to Baker Hughes are Algeria with 25 (21 oil, 4 gas), Angola with 4 (all oil), Libya with 14 (all oil), and Nigeria with 6 (all oil).

Smith International shows a rig count of 311 in Africa for September 2009 compared with the 57 in the Baker Hughes statistics. Countries with the most active rigs in the Smith International count are Algeria with 101 (all land), Angola 16 (2 land, 14 offshore), Congo 14 (6 land, 8 offshore), Egypt 56 (44 land, 12 offshore) Libya 49 (45 land, 4 offshore), Nigeria 23 (11 land, 12 offshore), and Sudan 20 (all land). ✦

Revamp of HF alkylation unit employs solid-acid catalyst

Mitrajit Mukherjee
James Nehlsen
Exelus Inc.
Livingston, NJ

Adolf Ezeribe
John Ibe
NNPC Warri Refining & Petrochemical Co. Ltd.
Ekpan-Warri, Nigeria

Alkylate is in short supply in the US. The renewable fuels standard (RFS) mandates the use of ethanol in gasoline. The high vapor pressure of ethanol requires a reduction in other light gasoline components such as butanes and pentanes in order to meet federal Reid vapor pressure standards. The butane and pentane loss will be about 0.4 gal/1 gal of ethanol added to the gasoline pool.

Octane-based alkylate is a thus a key alternative to compensating for the loss of these light components without adding to the aromatic or olefinic content of the gasoline. A severe alkylate shortage contributed to a spike in gasoline prices in summer 2008.[1]

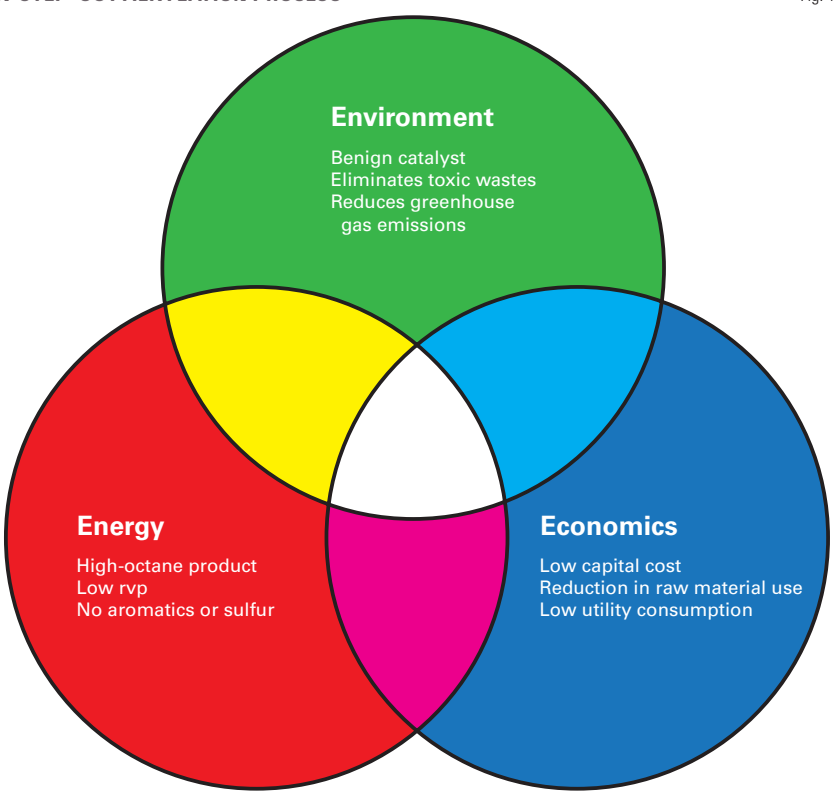
Making matters worse, several hydrogen fluoride alkylation units have been shut down over the last decade.

HF alkylation units require extremely high levels of maintenance to ensure safe operation. Accidents have, in some cases, convinced the refinery management to moth ball these units. Three separate accidents involving HF releases at US refineries occurred in a 5-month span during 2009, leading to prolonged shutdowns and investigations by the US Chemical Safety and Hazard Investigation Board, Washington.[2]

Solid acid-catalyzed alkylation eliminates the hazard and costs associated with using and regenerating corrosive liquid acids such as HF. Solid acids have for many years promised safer and cleaner alkylation.[3] The short lifetimes of most solid acids, however, have resulted in expensive processes with complex reactors and large catalyst inventories, making them uncompetitive with liquid acid technology. Competing with liquid acids requires new solid acids that are engineered for optimum performance, rather than selected from

NEW STEP-OUT ALKYLATION PROCESS

Fig. 1

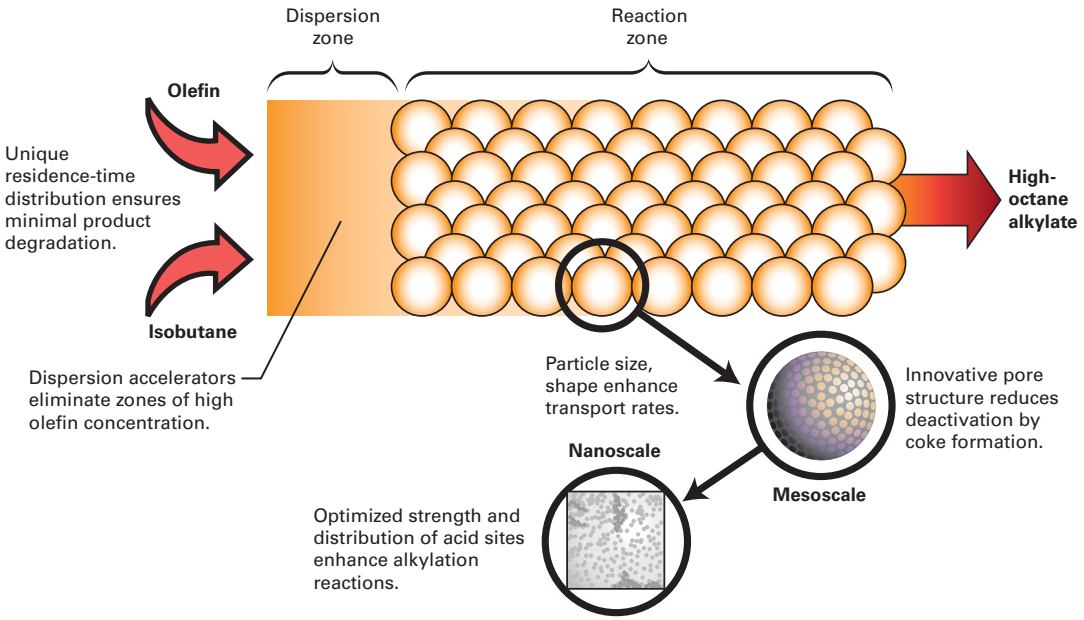


existing materials.[4]

A new engineered solid-acid catalyst has been developed with significantly higher stability, which makes solid-acid alkylation finally competitive with conventional liquid acid technologies. Presented here are the results of a recently concluded study that shows an alkylation process using this new engineered solid-acid catalyst can effectively revamp a mothballed HF unit. According to the results of the study, capital costs for the revamp were minimal while the operating costs were unchanged.

Innovations in engineered SAC system

Fig. 2



Solid-acid catalyst

The new solid-acid catalyst (SAC) has been engineered on multiple levels,[5] as shown in Fig. 2. The catalyst particle shape and size are controlled to provide the proper reaction environment by manipulating the rate of mass transport into and out of the catalyst pellet. In this way, the catalyst reduces the constraints on the reactor design, simplifying the process and reducing overall cost.

The catalyst pore structure has been optimized on both the macro and microscale to enhance the diffusion of large coke molecules out of the catalyst pores, reducing catalyst deactivation that results from pore blockage. The strength and distribution of the active catalyst sites have been tuned to promote alkylation over coke formation. The active sites are adjusted to facilitate formation of 2,3,3- and 2,3,4-trimethylpentane, both of which have octane ratings greater than 100. Cracking and isomerization to dimethylhexanes (DMH) are minimized to maintain high total alkylate octane.

The SAC also has the ability to isomerize 1-butene to 2-butene, leading to higher alkylate octane rating than produced by HF units when using olefin feeds rich in 1-butene. Carefully tuning the catalyst properties at multiple levels achieves all of the desired attributes: long life, high product octane, and simple process design.

Typical operating conditions, SAC-based alkylation

Table 1

Reaction temp., °C.	50-100
Reactor pressure, barg	20
Feed isobutane/olefin ratio, mol/mol	10-15
Olefin space velocity, 1/hr	0.2-0.5

Process

Fig. 3 shows the new alkylation process using the engineered SAC process.[6] Unique to solid acid-based processes are the two multistaged fixed-bed reactors used in the reaction section. One is used for reaction, while the other is being regenerated.

The olefin stream is mixed with isobutane returning from the distillation section and with the reactor effluent recirculation stream before being fed to the reactor. The alkylation reaction is mildly exothermic.

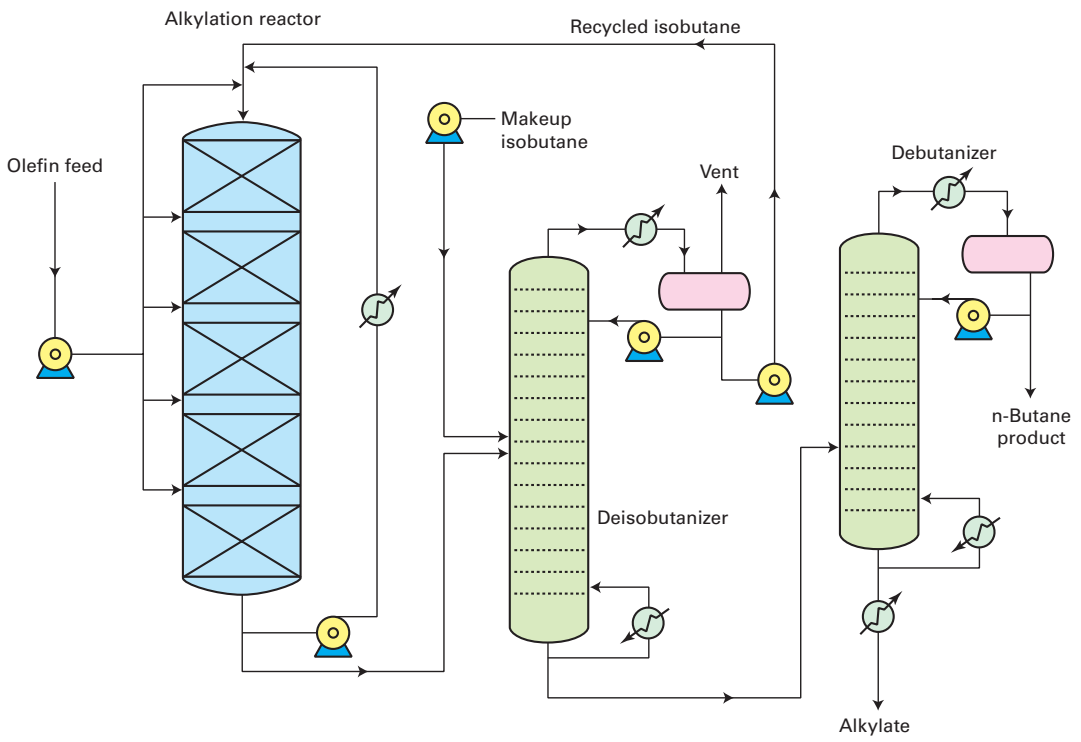
The robust catalyst is insensitive to small changes in temperature and hence the heat of reaction is removed by a heat-exchanger located on the recycle loop outside the reactor. Table 1 gives typical process conditions for the solid-acid catalyst process.

The remaining portion of the process replicates the function of the fractionation section in the HF unit but with reduced complexity. Because the catalyst is a true solid acid, the acid cannot migrate to other parts of the process. As a result, acid neutralization steps are not required. Maintenance requirements are also reduced because corrosion of critical devices, such as emergency pressure-relief valves, is no longer a concern.

The SAC process operates at temperatures greater than that of HF, reducing the need for extensive cooling of the reaction mixture. Consequently, the reaction pressure must be elevated

ALKYLATION OPERATION

Fig. 3



slightly to maintain the reaction in a liquid state. Feed ratio of isobutane to olefin is the same or lower than HF unit designs.

All alkylation catalysts, solid and liquid, must be continuously regenerated. HF units perform the regeneration through a combination of intense heating to decompose alkyl fluorides and distillation to separate acid from heavy hydrocarbons (coke).

For the SAC unit, catalyst regeneration is performed with a circulating loop of hydrogen-hydrocarbon mixture at an elevated temperature of 250° C. This simple flow scheme (Fig. 4) results in low capital costs and the ability to retrofit existing plants readily.[7]

Alkylation cycle lengths are designed to be between 12-24 hr to simplify reactor operation. After the alkylation cycle, the reactor is taken off stream and the solid-acid catalyst is regenerated. During this time, the second reactor maintains the constant alkylate production. Due to the small amount of coke build-up on the catalyst surface, hydrogen consumption is kept to a minimum.

HF alkylation retrofit

A study was commissioned by a refiner to determine the feasibility of converting a 3,000-b/sd HF alkylation unit (Fig. 5) into a solid-acid alkylation unit. The goals of the study included developing a workable, low-capital cost design for the revamped unit while maintaining capacity. The study was dedicated to looking at each major equipment item in the current HF unit to identify equipment that can be retained in either its current service or looking for innovative ways of reusing it.

Based on a preliminary evaluation of the unit data provided by the refiner, Exelus Inc. has developed a design for the HF unit revamp. Each section of the existing unit was analyzed and compared with the requirements of the SAC process. The new SAC-based alkylation is fundamentally the same as HF alkylation with the notable difference of using an inherently safer catalyst technology.

Consequently, a revamp of an existing HF unit to use a SAC allows much of the equipment to continue in its current service. The most cost-effective revamp option is to retain the existing distillation configuration and replace the HF reactor with new fixed-bed alkylation reactors. Many other sections of the existing unit would be retained in their current capacity in order to achieve minimal capital cost.

- *Feed zone.* The feed section of the HF unit included a butane splitter, feed driers, and feed storage tanks and pumps. The revamp design retains these units in their entirety under their current service. The revamped unit utilizes the same feed rates and conditions as the HF unit, allowing these units to continue their operation unchanged.
- *Reaction zone.* The SAC fixed-bed reactors differ in design from conventional HF mixer settlers; so there is no easy way of retrofitting the HF reactors for use in SAC systems. The SAC process therefore requires two new fixed-bed reactors and their associated recirculation pumps.

The SAC reactors, however, require an effluent surge vessel to hold the liquid contents of a reactor while it is being regenerated. The HF settler tank

OIL&GAS JOURNAL online research center™

OGJ Surveys in Excel!

Your Industry Analysis Made Cost Effective and Efficient

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

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

FOR INFORMATION

E-mail:
orcinfo@pennwell.com

Phone:
1.918.831.9488 or 1.918.832.9267

TO ORDER

Web site:
www.ogjresearch.com

Phone:
1.800.752.9764 or 1.918.831.9421

Numbers You Can Count On Every Time!

OIL & GAS JOURNAL SURVEYS

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

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

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

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

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

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

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

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

LNG Worldwide — Facilities, Construction Projects, Statistics
LNGINFO

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

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

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

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

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

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

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

See website for prices

www.ogjresearch.com

is suitable for this service and is reused. The surge vessel is simply a holding tank and requires no particular internals. The settler can be used without modification for this purpose, which is not significantly different from its current service.

• *Separation zone.* The distillation sections of the two units are identical and operate at the same isobutane-to-olefin ratio. Therefore, the existing isostripper (main fractionator) and depropanizer columns continue in their present services while unit capacity is maintained.

Column operation and maintenance are simplified by eliminating the presence of HF in the columns. Product purity specifications are maintained because the column's feed composition and flow are unchanged by the revamp. Smaller operations related to HF capture, such as the HF stripper, are idled.

• *Product finishing zone.* No leaching of acid is possible from the SAC. Therefore, product washing and neutralization steps, including the defluorinator and caustic (KOH) treaters are idled. The solid waste generated from the neutralization steps is also eliminated, reducing operating cost and complexity. Product coolers and storage tanks are retained in their current service.

• *Regeneration zone.* The equipment needed for regenerating the SAC differs from that used to regenerate HF. Many pieces of equipment available in an HF plant, however, can be modified for use in the SAC regeneration cycle.

For example, the fired heater can be used to raise the regeneration gas stream to 250° C. The HF unit uses a fired heater as a reboiler for the main fractionator in order to achieve temperatures high enough to decompose alkyl fluorides formed in the reactor. Such high temperatures are no longer required in the SAC process.

This fired heater can be reserviced for the SAC regeneration and a new reboiler installed in place of the fired heater. The new reboiler can be steam heated in order to reduce maintenance and safety concerns.

The following list summarizes the breakdown of new and retained equipment for the revamp.

Systems retained without modification:

- Feed driers.
- Feed drums and pumps.
- Distillation columns.
- Distillation column supporting equipment (drums, reboilers, condensers).
- Product coolers and storage tanks.
- Energy optimizing heat exchangers in distillation train.

Systems retained in new service:

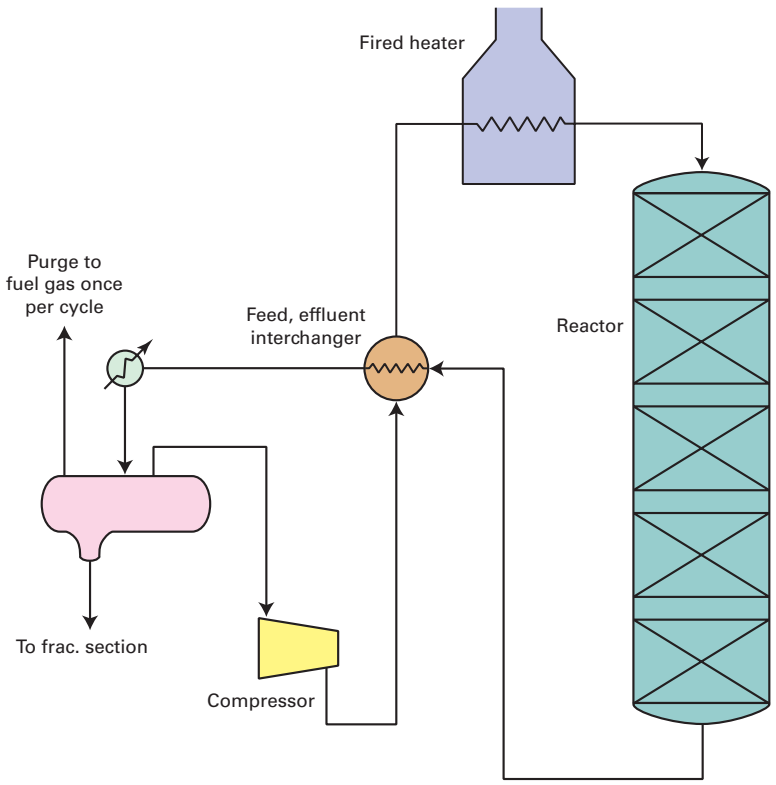
- Reactor-settler becomes surge vessel.
- Main fractionator's fired heater reboiler becomes regeneration fired heater.

New equipment:

- Alkylation reactors (two).
- Reactor recirculation pumps (three).
- Regeneration compressor.
- Regeneration separator vessel.
- Regeneration heat interchanger.
- Main fractionator's steam reboiler.

REGENERATION OPERATION

Fig. 4



Revamp cost

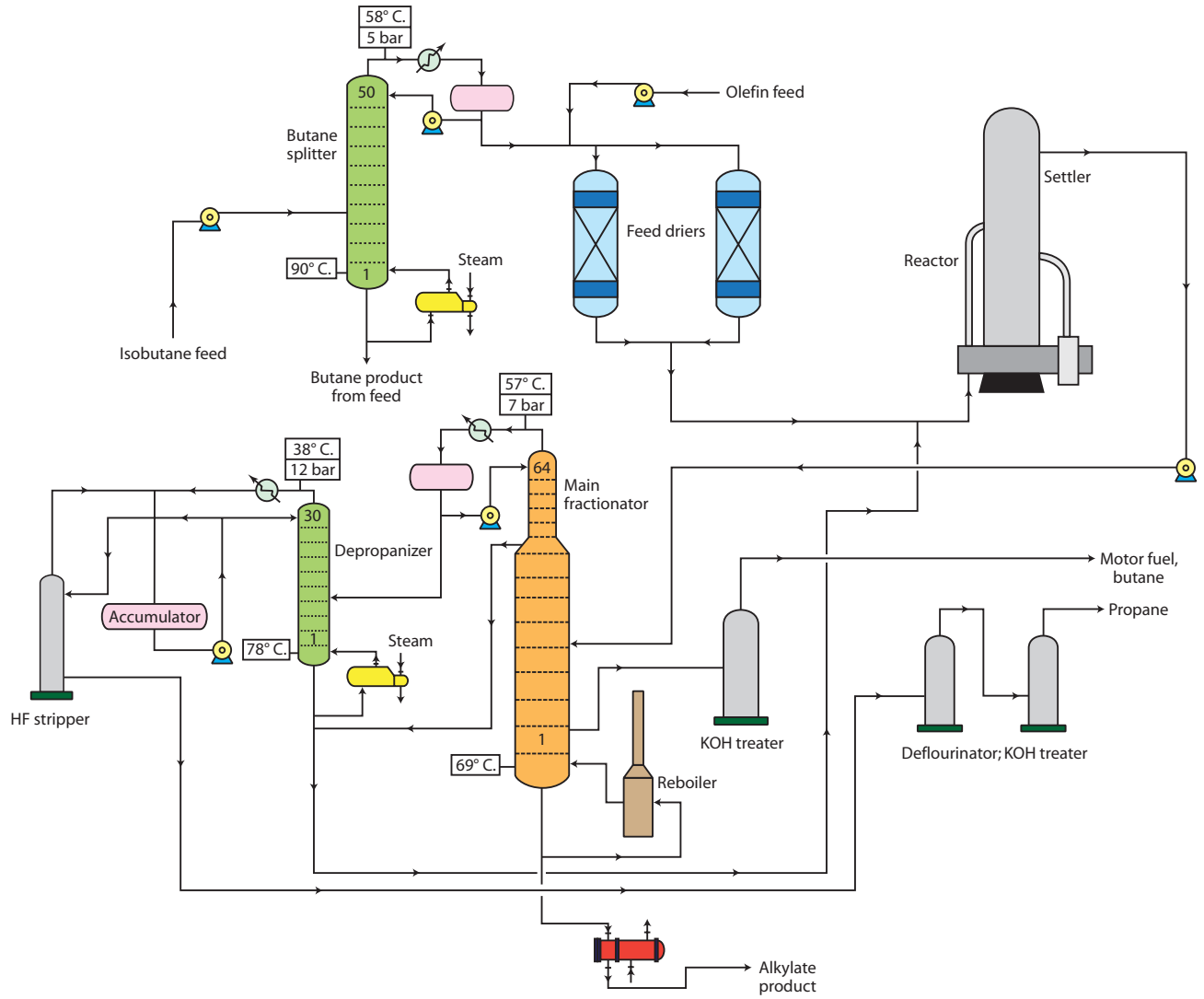
Table 2 gives equipment costs for revamping a 3,000-b/d HF unit to a SAC system. These costs were developed with in-house correlations and algorithms, updated to second-quarter 2008 US Gulf Coast prices. Reactors and supporting vessels are priced according to a power-law dependence of the vessel mass. Heat exchangers are priced by a scaled heat duty.

Compressor and pumps are fixed price based on vendor estimates. Installation costs are calculated from typical scale factors for each equipment type and are summed at the bottom of the table to provide an estimate for total installed cost.

Table 2 shows that the single largest expense, as expected, is for the new reactor vessels. These reactors are the heart of the new alkylation process. The remaining cost is distributed evenly

HF ALKYLATION PROCESS

Fig. 5



among the remaining equipment. Identifying additional idle equipment that can be used for one of the required services will further reduce costs.

The cost for the revamp is less than $3,000/b/d of capacity, which is less than 20% of the cost of a grassroots sulfuric acid plant (including acid-regeneration facility). The SAC-based alkylation revamp is lower in cost than any other revamp option.

The SAC revamp also requires only minor modifications of existing equipment; most is used without any modification. In the case of revamping an operational alkylation unit, the majority of the construction (reactors, recirculation cooler and pumps, and regeneration equipment) can be installed without shutting down the existing unit. This option minimizes downtime and maximizes the profitability of the unit.

Revamp benefits

Most HF revamp projects are driven by safety concerns, either due to an accident or near miss internally at the refinery, or externally, from newly adopted legal requirements. A solid acid catalyst is an Inherently Safer Technology (IST) than liquid acids because it is noncorrosive and nonhazardous.

Conversion of an HF unit to an SAC system eliminates the risks of storing, transporting, and using large quantities of HF.

There are, however, financial rewards for such a revamp as well. Reducing the operational risks of a refinery unit also reduces the associated costs. Spill-mitigation equipment such as water curtains are no longer needed, reducing maintenance and testing. Overhead costs related to emergency planning, personal protective regimens and equipment, and liability are also eliminated.

Solid-waste disposal and the purchasing, transport, and storage of

HF and caustic are both removed as operating costs. Frequent metallurgical inspections and part replacement to compensate for HF-induced corrosion are also rendered unnecessary.

Conversion of an HF unit to a SAC-based one reduces these costs without sacrificing profitability. In this case study, the unit capacity and alkylate octane are maintained. Operating costs are also largely unchanged. Feedstock consumption is similar in each.

The primary utility consumer in both an HF and an SAC alkylation unit is the fractionation section, which is identical for the two units. Additional power consumption in the reactor's recirculation pumps and regeneration compressor is offset by a reduced number of pumps in the product-finishing area and lower reaction cooling-water requirements. The SAC system consumes additional fuel gas and a small quantity of reformer-grade hydrogen in the regeneration loop compared to HF but eliminates caustic, fresh HF, and waste water treatment costs.

The SAC-based revamp considered here also showed significant benefits over other revamp possibilities. Conversion of an HF unit to sulfuric acid requires a significant capital expenditure and does not adequately address the risks of using liquid acids in refinery applications. The transport, storage, and use of sulfuric acid for alkylation have led to numerous accidents and fatalities and it complicates fire fighting efforts.

A revamp to sulfuric acid requires new reactors (contactors), a large refrigeration system, plus infrastructure to handle, store, and transport large quantities of fresh and spent acid, owing to the high acid consumption. Unlike with HF, sulfuric acid is not regenerated within the alkylation unit but instead requires a large, external, dedicated regeneration facility. The capital cost for such a revamp is substantial and in some cases unfeasible due to the refinery's location.

The engineered SAC considered for use in this revamp is designed to provide long catalyst cycle time and low catalyst inventory compared with other available SACs. These technological benefits further minimize the cost of the revamp by reducing the size, complexity, and number of reactors as well as minimizing catalyst cost.

REVAMP OF 3,000 B/SD HF ALKYLATION UNIT TO SAC PROCESS Table 2

Equipment	Qty.	Unit cost, $	Total plant, $
Alkylation reactors	2	430,102	860,204
Reboiler	1	254,322	254,322
Reactor cooler	1	61,764	61,764
Regeneration interchanger	1	216,170	216,170
Compressor	1	500,000	500,000
Recirculation pumps	3	150,000	450,000
Other pumps	2	90,000	180,000
Total equipment cost	**11**	**1,702,358**	**2,522,460**
Commodities			2,562,401
Direct labor			1,201,323
Engineering			1,156,129
Field indirects			1,386,305
Total installed cost			**8,828,618**

Meeting IST directives

SAC-based alkylation technology affords the ability to convert one of the most dangerous refinery operations into one of the safest without sacrificing profit or performance.[8] Such a catalyst forms the core of a safe and efficient process that generates high-octane alkylate without the dangers and costs associated with liquid acid technology.[9]

Revamping an HF alkylation unit to use a solid-acid catalyst is a cost-effective means to comply with new

The authors

Mitrajit Mukherjee (mmukherjee@exelusinc.com) is the founder and president of Exelus, Livingston, NJ. He has spent most of his 17-year career developing viable solid-acid catalyst solutions for isoparaffin alkylation process. Before starting Exelus, he held positions at Catalytica and ABB Lummus Global. Mukherjee holds a BS in chemical engineering from Indian Institute of Technology and an MS from Southern Illinois University.

James Nehlsen (jpnehlsen@exelusinc.com) is a process development manager at Exelus where he has developed new catalytic processes for isoparaffin alkylation, styrene monomer, and biofuel processing. He previously worked as a senior process development engineer at Exelus, investigating technologies related to hydrogen production and Fischer-Tropsch synthesis. Nehlsen holds a PhD in chemical engineering from Princeton University where he developed new desulfurization technologies.

Adolph C. Ezeribe (chinedu.ezeribe@nnpcgroup.com) is currently manager of production at Nigerian National Petroleum Corp. Warri Refining & Petrochemicals Co. Ltd. For 2 years he was the deputy manager in charge of the FCCU and HF alkylation plant. He has also served for 10 years as the chief planning officer at WRPC, and for 5 years as panel operator of the FCCU. He has also been the chief operator-in-training of the polypropylene plant for 5 years. Ezeribe holds a Higher Diploma, a Postgraduate Diploma, and master's degree, all in chemical engineering, from the Rivers State University of Science and Technology.

John Ibe (ibez.john207@gmail.com) is plant superintendent of HF alkylation at Nigerian National Petroleum Corp. Warri Refining & Petrochemicals Co. He has 25 years of refining operations experience. He holds a Higher Diploma in chemical engineering in petroleum refining, and an MBA in project management from the Federal University of Science & Technology, Owerri.

Inherently Safer Technology legislation, restart an HF unit idled after an accident or near-miss, or simply to improve overall plant safety. ✦

References

1. "Analysts See Possible Alkylate Shortage," Octane Week, February 2008.
2. Dittrick, P., "USW seeks phaseout of HF alkylation units," OGJ Online, Aug. 31, 2009.
3. D'Aquino, R., and Mavridis, L., "Solid-Acid Catalysts Shape Up for Alkylation," Chemical Engineering Progress, Vol. 103, No. 1 (2007), pp. 8-9.
4. Mukherjee, M., and Nehlsen, J., "Consider catalyst developments for alkylation production," Hydrocarbon Processing, Vol. 85, No. 9 (2006), pp. 85-96.
5. Mukherjee, M., and Nehlsen, J., "Reduce alkylate costs with solid-acid catalysts," Hydrocarbon Processing, Vol. 86, No. 10 (2007), pp. 110-114.
6. Mukherjee, M., et al., Developments in Alkylation. Hydrocarbon Engineering, Vol. 12, No. 7 (2007), pp. 25-28.
7. Mukherjee, M., et al., "Step-Out Paraffin Alkylation Process using Engineered Solid-Acid Catalyst," Hydrocarbon World, Vol. 3, No. 1.
8. Verbitsky, D., Mukherjee, M., and Nehlsen, J., "Upgrading an olefin polymerization unit," Petroleum Technology Quarterly, Vol. 12, No. 4 (2007), pp. 83-89.
9. Mukherjee, M., et al., "Scale-up strategy applied to solid-acid alkylation process," OGJ, July 10, 2006, p. 48.

API, AOPL working to standardize GPS system

Bill Byrd
RCP Inc.
Houston

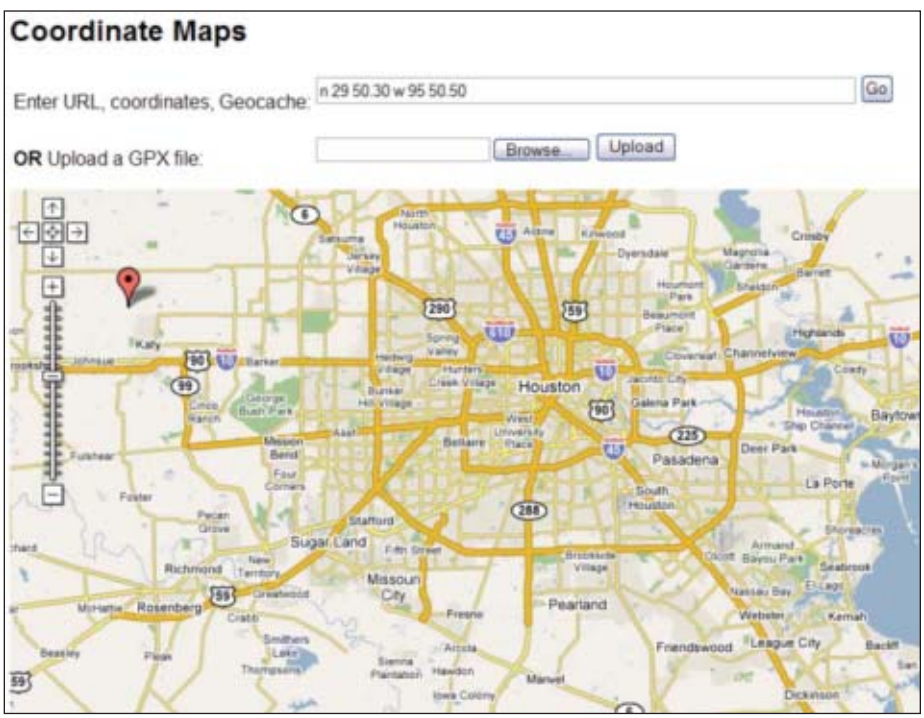
A joint American Petroleum Institute-Association of Oil Pipe Lines team is working to develop standard global positioning system coordinate submittal guidelines in an effort to reduce potential errors in locating oil and gas pipelines.

One-call centers throughout the US increasingly include GPS coordinates as part of a one-call notification by an excavator. GPS coordinates can help accurately locate proposed excavations. Reliance on GPS readings without a clear understanding by all parties concerning important settings and nomenclature options, however, can lead to a false sense of security and actually introduce new errors into the one-call notice process.

An excavator should avoid simply reading numbers off the screen of whatever equipment he or she picked up at the local sporting goods store to the one-call center operator. One-call centers, similarly, should avoid accepting at face value whatever coordinates are given over the phone and simply entering them into the computer system, and line locators should avoid assuming the GPS information they receive is in a certain format or uses a certain datum.

This article addresses three potential sources of GPS error: coordinate nomenclature, datum selection, and accuracy, in the hope its use will further understanding of these issues by all parties involved in the one-call process.

A number of factors affect the accuracy of GPS readings, including the number of satellites, the sophistication of the GPS unit, etc. The accuracy of particular information (i.e., ±29 ft, 58 ft, etc.), is obtained from typical GPS units and frequently is shown on the main screen along with latitude and longitude coordinates. Users widely hold accuracy information to be the only source of error when using GPS coordinates, resulting in a false sense of security. This article shows accuracy to be only one source of error, with other less understood sources perhaps having a much larger effect on absolute accuracy of a depicted location.



This GPS screen shot shows results obtained by plotting a particular coordinate with degrees and decimal minutes (Fig. 1).

Coordinate nomenclature

One common nomenclature uses degrees, minutes, and seconds, dividing the world into 360 degrees with each degree composed of 60 min, each minute composed of 60 sec, and each second recorded in decimal format. Degrees, minutes, and seconds are denoted by °, ', and ", respective-

ly, such as: –30° 53' 27.95".

Another, equally accurate nomenclature uses degrees and decimal minutes, without seconds (30 seconds being equal to 0.5 decimal minutes). A third popular nomenclature simply uses decimal degrees (30 min being equal to 0.5 decimal degrees, and 30 sec being equal to 0.008333 decimal degrees).

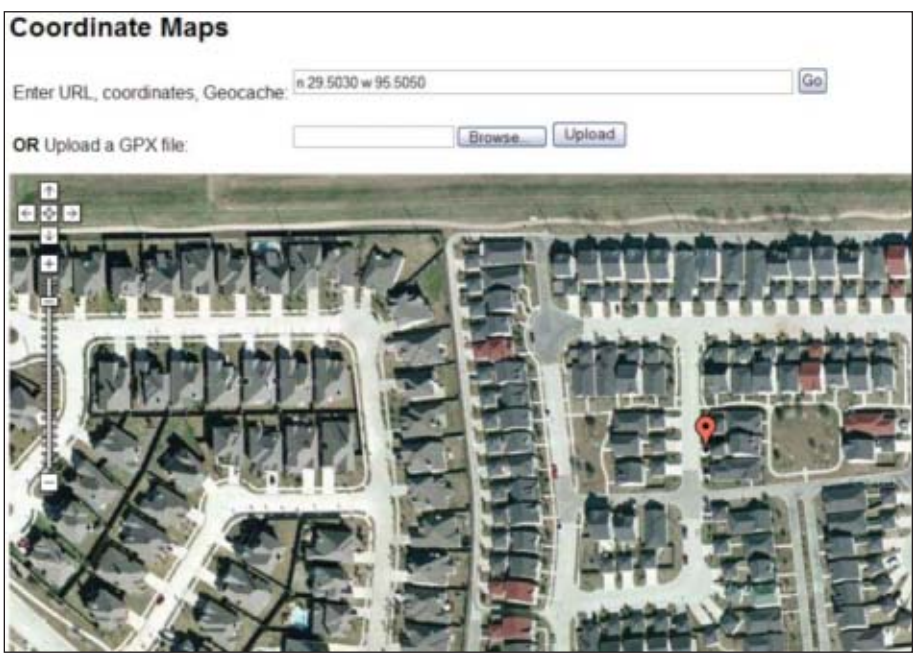
A GPS coordinate submitted in degrees, minutes, seconds is much different than one submitted in degrees, decimal minutes, which is much different than one submitted in decimal degrees. The numbers may look the same, however, and many times a set of coordinate numbers could be feasible in several different nomenclatures.

Fig. 1 plots the GPS coordinate N 29 50.30 W 95 50.50 (with degrees, decimal minutes).

Fig. 2 plots a similar-looking coordinate (N 29.5030 W 95.5050, with decimal degrees).

These plots use the same series of digits (295030 and 955050) and both lie within the greater Houston area, regardless of nomenclature used, but are more than 30 miles apart. The fact that many GPS units fail to show on their main screen which nomenclature is being used can confuse one format with another or create difficulties in determining which a particular GPS unit is using, leading to potentially huge mapping errors.

The same values used in Fig. 1, but placed in a GPS system with decimal degrees, produce a much different result (Fig. 2).

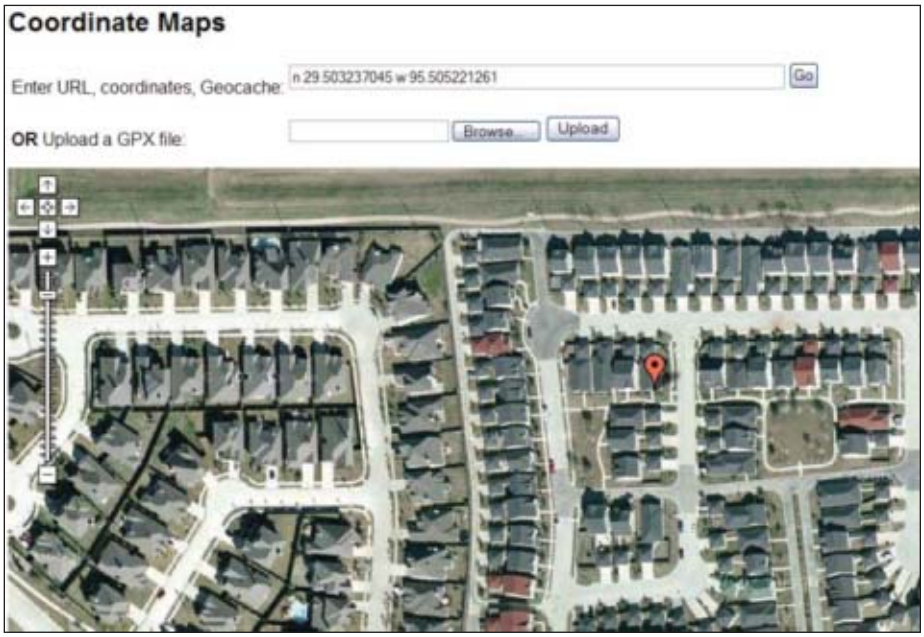


Even with the same nomenclature, differences in the underlying GPS datum can still lead to differences in location. The NAD 83 datum produces the location result shown here for the given coordinates (Fig. 3).

Datum selection

A separate but related issue is the selection of datum in the GPS unit. In this context, a datum is a theoretical model of the earth's surface the GPS coordinates reference against. A typical Garmin GPS unit can be set to more than 100 different datums, 11 starting with NAD 27. Each of these datums is different from the rest, reflecting different models of the earth's surface, ovality, etc.

Few people are familiar with what datum selection means or how to select the correct one. They simply use the default datum to which their unit was set when purchased (or however the previous user left it). Datum selection on a GPS unit usually requires the user to drill down through several menus of settings, and the correct datum to select is far from obvious. The same GPS coordinates, however, will actually lie



With the same coordinates and nomenclature as Fig. 3, but the NAD 27 datum, a different location appears (Fig. 4).

on different points on the earth when using different datums.

The National Imagery and Mapping Agency has published a document (NIMA TR8350.2) listing parameters for many geodetic datums. Some have exotic sounding names like Astro Tern Island (FRIG) 1961 or Pico de las Nieves, while others carry more mundane names like Geodetic Datum 1949 or Arc 1950. Setting the GPS receiver to one of these datums shifts the measured coordinates anywhere from a few meters to as much as 1,000 m from the nominal WGS 84 datum of the GPS system

Plots of the center of the Texas State Capitol dome, for example, with the WGS 84 datum at longitude 97:44:25.19 West, and latitude 30:16:28.82 North as the reference, often vary by more than 500 m from the intended location even with the same coordinates.

The difference between common datums in North America is usually rather small (on the order of dozens of feet, not miles), but even this degree of error could be important for one-call purposes. Both NAD 27 and NAD 83 datums are widely used in North America. The NAD 83 datum is newer, but many companies and government agencies (such as the US Department of Interior, and the US Geological Survey) still use NAD 27, and many maps use that datum.

If someone submitted GPS data with the coordinates shown in Fig. 3 and plotted it with the NAD 83 datum (virtually identical to the WGS 84 datum, the default for most GPS units), the results would be as shown.

But the NAD 27 datum (the default for USGS topographic maps) with the same data represents a point on the other side of the street in a different back yard (Fig. 4). This difference, though small in absolute terms, could lead a utility operator to mistakenly clear a one-call which in the belief the proposed excavation would not affect its facility.

Path forward

All parties involved in the one-call process should understand the importance of GPS accuracy, nomenclature, and datum selection, and establish procedures to avoid confusion concerning these items. A recent API-AOPL Damage Prevention Workshop recommends considering development of standard GPS coordinate submittal guidelines to increase the confidence in and reliability of GPS coordinates submitted by excavators to one-call centers, and transmitted from one-call centers to locators.

Training all one-call centers on this issue with a standardized coordinate submittal criteria, and using a help guide to talk people through how to verify or change the datum and coordinate system settings on common GPS equipment, would also eliminate much of this confusion. An industry group intends to work with the Common Ground Alliance to modify existing CGA best practices and establish new best practices as necessary to address these issues for all involved parties.

The Virginia Pilot Project for using GPS coordinates in damage prevention activities used NAD 83 as the datum and decimal degrees as the format. The National Pipeline Mapping System also prefers NAD 83 and decimal degrees.

To maintain consistency with these previous initiatives, the API-AOPL work group specifically recommends one-call systems adopt NAD 83 and decimal degrees (with a minimum of six decimal place digits) as the standard GPS nomenclature for one-call use. The WGS 84 datum (the default setting for most GPS units) is virtually identical to the NAD 83 datum throughout North America and should also be accepted. The work group also recommends one-call centers obtain and share the stated accuracy of the GPS readings when taking information from excavators. ✦

The author

W.R. Byrd (wrb@rcp.com) is president of RCP Inc., an engineering and regulatory consulting firm, and is a consultant to the API-AOPL Pipeline Performance Excellence Team working to resolve this issue. He holds a BS and MS in mechanical engineering from the Georgia Institute of Technology (1981, 1982) and is a registered professional engineer in Texas, Louisiana, Mississippi, and Alabama.

Imports of crude and products

	Districts 1-4		District 5		Total US		
	10-23 2009	10-16 2009	10-23 2009	10-16 2009	10-23 2009	10-16 2009	*10-24 2008
	1,000 b/d						
Total motor gasoline	693	639	63	10	756	649	831
Mo. gas. blending comp.	603	568	7	4	610	572	625
Distillate	168	86	16	34	184	120	273
Residual	437	103	52	115	489	218	345
Jet fuel-kerosine	27	25	80	49	107	74	38
Propane-propylene	157	100	8	10	165	110	137
Other	181	598	51	51	232	649	734
Total products	**2,266**	**2,119**	**277**	**273**	**2,543**	**2,392**	**2,983**
Total crude	**7,351**	**7,830**	**1,539**	**869**	**8,890**	**8,699**	**10,337**
Total imports	**9,617**	**9,949**	**1,816**	**1,142**	**11,433**	**11,091**	**13,320**

*Revised.
Source: US Energy Information Administration
Data available in OGJ Online Research Center.

Purvin & Gertz LNG netbacks—Oct. 30, 2009

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	6.13	4.63	5.31	4.52	4.64	5.24
Everett	3.69	2.30	3.45	2.38	2.84	3.97
Isle of Grain	3.99	2.75	3.72	2.65	3.30	3.68
Lake Charles	2.40	0.77	2.29	0.93	1.16	2.73
Sodegaura	5.32	7.02	5.57	6.72	6.01	4.65
Zeebrugge	5.71	3.97	5.27	3.86	4.58	5.31

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	14,826	55,788	39,125	12,863	73,765	13,890	4,854
PADD 2	77,512	49,454	25,502	8,577	31,270	1,017	29,523
PADD 3	177,302	69,504	40,752	14,759	47,360	15,542	34,301
PADD 4	15,396	5,821	1,811	523	3,118	238	[1]2,152
PADD 5	54,814	27,997	23,852	9,130	12,241	3,631	—
Oct. 23, 2009	**339,850**	**208,564**	**131,042**	**45,852**	**167,754**	**34,318**	**70,830**
Oct. 16, 2009	**339,072**	**206,945**	**129,244**	**45,139**	**169,888**	**34,182**	**71,634**
Oct. 24, 2009[2]	**311,873**	**194,990**	**100,517**	**35,991**	**126,629**	**38,622**	**60,404**

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

Refinery report—Oct. 23, 2009

District	REFINERY OPERATIONS		REFINERY OUTPUT				
	Gross inputs	Crude oil inputs	Total motor gasoline	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual	Propane–propylene
	1,000 b/d						
PADD 1	1,363	1,364	2,401	90	380	77	57
PADD 2	3,048	3,033	2,264	185	827	35	265
PADD 3	7,105	6,988	2,409	662	1,928	328	692
PADD 4	533	531	286	26	181	10	[1]60
PADD 5	2,399	2,287	1,474	364	470	120	—
Oct. 23, 2009	**14,448**	**14,203**	**8,834**	**1,327**	**3,786**	**570**	**1,074**
Oct. 16, 2009	**14,329**	**14,070**	**8,457**	**1,262**	**3,893**	**673**	**1,062**
Oct. 24, 2008[2]	**15,029**	**14,851**	**8,848**	**1,290**	**4,432**	**600**	**989**
	17,672 Operable capacity		**81.8% utilization rate**				

[1]Includes PADD 5. [2]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

	*10-30-09	*10-31-08	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	85.25	72.37	12.88	17.8
Brent crude	76.25	60.65	15.60	25.7
Crack spread	9.00	11.72	–2.72	–23.2
FUTURES MARKET PRICES				
One month				
Product value	84.67	70.15	14.52	20.7
Light sweet crude	78.51	65.44	13.07	20.0
Crack spread	6.16	4.71	1.45	30.9
Six month				
Product value	90.74	77.96	12.78	16.4
Light sweet crude	81.17	68.31	12.86	18.8
Crack spread	9.56	9.65	–0.08	–0.9

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

OGJ GASOLINE PRICES

	Price ex tax 10-28-09	Pump price* 10-28-09	Pump price 10-29-08
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	224.0	255.4	267.8
Baltimore	216.1	258.0	272.6
Boston	217.1	259.0	266.4
Buffalo	207.2	270.4	251.7
Miami	222.1	275.0	264.2
Newark	216.8	249.7	256.3
New York	204.8	268.0	270.8
Norfolk	210.7	248.4	251.8
Philadelphia	215.3	266.0	268.4
Pittsburgh	214.3	265.0	269.8
Wash., DC	226.2	268.1	270.7
PAD I avg	215.9	262.1	264.6
Chicago	238.8	293.9	270.6
Cleveland	237.2	283.6	254.4
Des Moines	220.5	260.9	250.7
Detroit	235.7	287.3	265.3
Indianapolis	228.8	278.9	260.3
Kansas City	211.6	247.3	240.7
Louisville	230.0	270.9	260.7
Memphis	211.8	251.6	244.7
Milwaukee	224.7	276.0	265.3
Minn.-St. Paul	225.7	271.3	254.6
Oklahoma City	200.2	235.6	220.8
Omaha	207.3	253.0	233.5
St. Louis	209.2	244.9	247.5
Tulsa	195.0	230.4	224.5
Wichita	205.2	248.6	240.8
PAD II avg	218.8	262.3	249.0
Albuquerque	212.0	249.2	250.9
Birmingham	215.8	255.1	232.7
Dallas-Fort Worth	208.6	247.0	240.1
Houston	210.2	248.6	227.1
Little Rock	203.8	244.0	238.6
New Orleans	217.8	256.2	253.9
San Antonio	213.8	252.2	246.1
PAD III avg	211.7	250.3	241.3
Cheyenne	218.8	251.2	264.5
Denver	217.9	258.3	289.8
Salt Lake City	210.4	253.3	274.5
PAD IV avg	215.7	254.3	276.3
Los Angeles	232.4	298.2	306.0
Phoenix	220.9	258.3	293.0
Portland	237.7	281.1	304.7
San Diego	233.5	299.3	313.0
San Francisco	239.6	305.4	318.1
Seattle	239.2	295.1	303.0
PAD V avg	233.9	289.6	306.3
Week's avg.	**218.8**	**263.6**	**261.9**
Oct. avg.	**208.4**	**253.6**	**317.6**
Sept. avg.	**211.0**	**256.6**	**367.2**
2009 to date	**181.5**	**227.1**	—
2008 to date	**306.1**	**350.2**	—

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

REFINED PRODUCT PRICES

	10-23-09 ¢/gal		10-23-09 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	205.60	New York Harbor	204.12
Gulf Coast	200.02	Gulf Coast	202.53
Los Angeles	200.60	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	199.00	ARA	203.21
Singapore	200.02	Singapore	205.24
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	202.85	New York Harbor	173.14
Gulf Coast	199.60	Gulf Coast	173.52
Los Angeles	212.60	Los Angeles	184.69
		ARA	175.67
		Singapore	176.28

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

BAKER HUGHES RIG COUNT

	10-30-09	10-31-08
Alabama	5	5
Alaska	6	8
Arkansas	38	57
California	22	45
Land	21	45
Offshore	1	0
Colorado	39	124
Florida	0	1
Illinois	1	1
Indiana	3	2
Kansas	21	13
Kentucky	11	12
Louisiana	164	190
N. Land	107	88
S. Inland waters	13	19
S. Land	13	29
Offshore	31	54
Maryland	0	0
Michigan	0	2
Mississippi	5	16
Montana	3	9
Nebraska	1	0
New Mexico	48	91
New York	3	4
North Dakota	55	85
Ohio	8	10
Oklahoma	77	197
Pennsylvania	59	29
South Dakota	0	1
Texas	411	911
Offshore	3	6
Inland waters	0	0
Dist. 1	23	27
Dist. 2	14	34
Dist. 3	26	61
Dist. 4	30	89
Dist. 5	67	186
Dist. 6	46	132
Dist. 7B	10	29
Dist. 7C	35	62
Dist. 8	75	125
Dist. 8A	18	26
Dist. 9	27	41
Dist. 10	37	93
Utah	19	36
West Virginia	22	30
Wyoming	39	78
Others—HI-1; NV-3; OR-1; TN-1; VA-3	9	14
Total US	**1,069**	**1,971**
Total Canada	**249**	**443**
Grand total	**1,318**	**2,414**
US Oil rigs	330	408
US Gas rigs	728	1,552
Total US offshore	35	65
Total US cum. avg. YTD	**1,079**	**1,881**

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

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

SMITH RIG COUNT

Proposed depth, ft	Rig count	10-30-09 Percent footage*	Rig count	10-31-08 Percent footage*
0-2,500	60	3.3	86	3.4
2,501-5,000	63	69.8	143	51.0
5,001-7,500	110	20.0	273	14.6
7,501-10,000	237	7.1	458	2.4
10,001-12,500	203	13.3	444	1.1
12,501-15,000	155	1.2	383	—
15,001-17,500	142	—	165	—
17,501-20,000	59	—	77	—
20,001-over	37	—	31	—
Total	**1,066**	**10.6**	**2,060**	**6.4**
INLAND	18		31	
LAND	1,011		1,972	
OFFSHORE	37		57	

*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]10-30-09	[2]10-31-08
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	21	22
Alaska	689	702
California	648	653
Colorado	66	67
Florida	5	6
Illinois	26	26
Kansas	109	113
Louisiana	1,401	612
Michigan	17	18
Mississippi	63	62
Montana	85	86
New Mexico	166	164
North Dakota	202	198
Oklahoma	176	178
Texas	1,389	1,185
Utah	63	63
Wyoming	145	145
All others	66	74
Total	**5,337**	**4,374**

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

US CRUDE PRICES

	10-30-09 $/bbl*
Alaska-North Slope 27°	65.67
South Louisiana Sweet	77.00
California-Kern River 13°	68.20
Lost Hills 30°	76.80
Wyoming Sweet	68.75
East Texas Sweet	73.00
West Texas Sour 34°	68.50
West Texas Intermediate	73.50
Oklahoma Sweet	73.50
Texas Upper Gulf Coast	66.50
Michigan Sour	65.50
Kansas Common	72.50
North Dakota Sweet	63.25

*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]	10-23-09
United Kingdom-Brent 38°	76.76
Russia-Urals 32°	76.27
Saudi Light 34°	75.68
Dubai Fateh 32°	76.22
Algeria Saharan 44°	77.06
Nigeria-Bonny Light 37°	78.02
Indonesia-Minas 34°	79.82
Venezuela-Tia Juana Light 31°	76.95
Mexico-Isthmus 33°	76.84
OPEC basket	76.79
Total OPEC[2]	76.36
Total non-OPEC[2]	75.78
Total world[2]	76.11
US imports[3]	74.80

[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]

	10-23-09	10-16-09	10-23-08	Change, %
	bcf			
Producing region	1,188	1,187	935	27.1
Consuming region east	2,058	2,041	2,001	2.8
Consuming region west	513	506	450	14.0
Total US	**3,759**	**3,734**	**3,386**	**11.0**
	Aug. 09	**Aug. 08**	**Change, %**	
Total US[2]	**3,352**	**2,867**	**16.9**	

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

WORLDWIDE CRUDE OIL AND GAS PRODUCTION

	Aug. 2009	July 2009	8 month average production 2009	8 month average production 2008	Change vs. previous year Volume	Change vs. previous year %	Aug. 2009	July 2009	Cum. 2009
	Crude, 1,000 b/d						Gas, bcf		
Argentina	529	602	605	601	4	0.6	119.7	127.4	956.90
Bolivia	40	40	40	40	—	–0.7	40.0	40.0	325.00
Brazil	1,960	1,919	1,929	1,801	129	7.1	29.0	28.0	232.00
Canada	2,520	2,597	2,551	2,576	–25	–1.0	401.6	414.4	3,445.10
Colombia	670	657	650	573	77	13.3	30.0	30.0	240.00
Ecuador	460	470	476	500	–24	–4.8	2.0	2.0	16.00
Mexico	2,542	2,561	2,609	2,835	–226	–8.0	220.8	218.7	1,710.69
Peru	110	109	104	72	32	45.2	11.4	11.3	78.70
Trinidad	106	103	109	113	–4	–3.4	120.8	112.5	914.99
United States	5,200	5,233	5,229	5,090	140	2.7	1,869.0	1,857.0	14,693.00
Venezuela[1]	2,210	2,160	2,139	2,358	–219	–9.3	72.0	72.0	550.00
Other Latin America	83	83	83	83	—	–0.2	5.5	5.5	43.73
Western Hemisphere	**16,431**	**16,535**	**16,524**	**16,641**	**–117**	**–0.7**	**2,921.7**	**2,918.8**	**23,206.10**
Austria	19	18	19	17	2	10.2	4.4	3.7	36.26
Denmark	250	256	266	290	–24	–8.2	23.0	23.1	177.78
France	18	18	18	20	–2	–8.7	2.5	2.6	21.50
Germany	54	55	57	61	–4	–6.7	39.2	40.8	342.87
Italy	80	69	81	102	–20	–20.0	20.0	20.0	177.50
Netherlands	25	25	27	35	–9	–24.6	130.0	130.0	1,690.00
Norway	1,970	2,147	2,078	2,163	–85	–3.9	262.6	286.2	2,446.76
Turkey	48	48	45	41	4	9.6	—	—	—
United Kingdom	998	1,338	1,368	1,410	–42	–2.9	122.3	161.0	1,511.15
Other Western Europe	5	4	3	4	–1	–16.2	0.2	0.2	8.71
Western Europe	**3,467**	**3,979**	**3,961**	**4,141**	**–180**	**–4.3**	**604.2**	**667.5**	**6,412.53**
Azerbaijan	1,050	1,050	1,034	937	97	10.3	40.0	40.0	285.00
Croatia	14	14	14	15	–1	–7.5	4.6	5.4	41.27
Hungary	14	14	14	15	–1	–5.0	7.2	7.0	56.92
Kazakhstan	1,350	1,400	1,273	1,175	98	8.3	100.0	100.0	800.00
Romania	90	90	90	94	–4	–4.0	19.0	19.0	148.00
Russia	9,940	9,880	9,825	9,739	86	0.9	1,350.0	1,300.0	11,750.00
Other FSU	450	450	450	400	50	12.5	300.0	300.0	2,550.00
Other Eastern Europe	39	39	43	49	–5	–11.3	17.9	17.9	152.12
Eastern Europe and FSU	**12,946**	**12,937**	**12,742**	**12,423**	**320**	**2.6**	**1,838.7**	**1,789.3**	**15,783.30**
Algeria[1]	1,220	1,220	1,241	1,380	–139	–10.1	245.0	245.0	1,975.00
Angola[1]	1,800	1,790	1,746	1,920	–174	–9.1	6.0	6.0	40.00
Cameroon	72	72	74	86	–12	–13.8	—	—	—
Congo (former Zaire)	25	25	25	25	—	—	—	—	—
Congo (Brazzaville)	240	240	240	240	—	—	—	—	—
Egypt	630	630	644	670	–26	–3.9	120.0	120.0	975.00
Equatorial Guinea	320	320	320	320	—	—	0.1	0.1	0.48
Gabon	240	230	224	233	–9	–3.8	0.3	0.3	2.43
Libya[1]	1,550	1,540	1,555	1,729	–174	–10.1	38.0	38.0	297.00
Nigeria[1]	1,740	1,680	1,770	1,950	–180	–9.2	90.0	85.0	691.00
Sudan	500	500	500	485	15	3.1	—	—	—
Tunisia	78	81	84	84	—	–0.1	8.6	7.3	64.89
Other Africa	221	221	221	221	—	—	9.1	9.1	70.40
Africa	**8,637**	**8,549**	**8,644**	**9,342**	**–698**	**–7.5**	**517.1**	**510.8**	**4,116.20**
Bahrain	30	30	29	30	—	–1.0	30.0	27.0	206.82
Iran[1]	3,800	3,820	3,754	3,936	–183	–4.6	290.0	290.0	2,295.00
Iraq[1]	2,480	2,480	2,378	2,451	–73	–3.0	22.0	22.0	159.00
Kuwait[1,2]	2,240	2,240	2,279	2,609	–330	–12.6	36.0	36.0	292.00
Oman	780	820	793	723	70	9.7	55.0	55.0	451.00
Qatar[1]	770	770	766	856	–90	–10.5	220.0	220.0	1,772.00
Saudi Arabia[1,2]	8,200	8,240	8,174	9,273	–1,099	–11.8	220.0	220.0	1,718.00
Syria	360	360	374	386	–13	–3.2	18.0	18.0	140.00
United Arab Emirates[1]	2,270	2,270	2,269	2,636	–368	–13.9	135.0	135.0	1,045.00
Yemen	260	270	274	310	–36	–11.5	—	—	—
Other Middle East	—	—	—	—	—	1.6	12.0	12.1	73.11
Middle East	**21,190**	**21,300**	**21,089**	**23,209**	**–2,120**	**–9.1**	**1,038.0**	**1,035.1**	**8,151.94**
Australia	482	478	468	443	24	5.5	138.1	141.4	1,000.90
Brunei	145	160	149	161	–12	–7.3	35.0	37.0	276.36
China	3,854	3,812	3,740	3,799	–59	–1.5	251.2	249.5	1,963.99
India	666	670	657	675	–18	–2.6	120.3	116.8	789.85
Indonesia[1]	870	880	861	861	—	—	200.0	210.0	1,600.00
Japan	13	14	16	17	–1	–8.1	9.0	9.3	81.04
Malaysia	720	740	734	761	–28	–3.6	140.0	140.0	1,100.00
New Zealand	52	49	47	59	–13	–21.3	13.0	13.0	97.90
Pakistan	63	62	64	67	–3	–4.7	124.6	121.6	982.12
Papua New Guinea	35	35	38	42	–4	–10.4	1.0	1.0	7.70
Thailand	239	236	242	227	16	6.9	37.0	34.0	269.34
Vietnam	330	330	308	285	23	7.9	15.0	15.0	117.50
Other Asia-Pacific	35	35	35	40	–5	–12.5	94.5	94.5	745.00
Asia-Pacific	**7,503**	**7,502**	**7,357**	**7,437**	**–79**	**–1.1**	**1,178.7**	**1,183.1**	**9,031.70**
TOTAL WORLD	**70,174**	**70,801**	**70,317**	**73,193**	**–2,875**	**–3.9**	**8,098.4**	**8,104.6**	**66,701.77**
OPEC	28,740	28,680	28,546	32,458	–3,912	–12.1	1,376.0	1,371.0	12,950.00
North Sea	3,237	3,761	3,732	3,880	–148	–3.8	446.7	509.1	4,641.41

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

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 918-832-9201, email: glendah@pennwell.com.

- *DISPLAY CLASSIFIED: $390 per column inch, one issue. 10% discount three or more CONSECUTIVE issues. No extra charge for blind box in care. Subject to agency commission. No 2% cash discount.*
- *UNDISPLAYED 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 $56.00 No agency commission, no 2% cash discount. Centered/Bold heading, $9.00 extra.*
- *COMPANY LOGO: Available with undisplayed ad for $83.00. 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

Paradigm Geophysical Corporation in Houston, TX seeks Software Developer II. Qualified applicants will possess a Master's degree in Computer Science or related field plus one year experience in Linux/UNIX development. Fax resume to Rebecca King at (713) 393-4806. Resume must include job code PAR664.

Cementing and Stimulation Specialist – Midland, TX. Seeking BS/MS in Mech. or Chem. Eng. And exc. acad. record. 5 yrs. exp. in oil gas industry, 3 yrs. exp. in design and execution of well cementing and reservoir stimulation and 1 yr. exp. in lab testing of cement slurries and stimulation fluids req'd. Employer will accept any suitable combination of edu., train., or exp. Mail CV to ExL Petroleum, LP., 6 Desta Dr. #2800, Midland, TX 79705, Attn: HR.

Colt Energy, Inc. seeks a thermal oil recovery project field manager in Central Western Missouri to manage the development of shallow heavy oil reserves through steam flooding. Candidate must have 5 years experience in the development of shallow heavy oil reserves through steam flooding, knowledge of heavy oil & thermal reservoir & production engineering with drilling, completion and operations experience, including management of field personnel. A minimum of a Bachelor's Degree in a related Engineering discipline (Petroleum, Chemical, Mechanical or Electrical), experience with heavy oil and thermal reservoir engineering practices and the ability to relocate to asset area. Mail or email resume to John Amerman, Colt Energy, Inc., 4330 Shawnee Mission Parkway, Suite 233, Fairway, KS 66205 - johnamerman@hotmail.com

STRUCTURES

Hiring?

Selling Equipment?

Need Equipment?

New Business Opportunity?

Contact: Glenda Harp

+1-918-832-9301 or

1-800-331-4463, ext. 6301

Fax: +1-918-832-9201

EMPLOYMENT

OIL/GAS INTERESTS

Oil/Gas rights/interests for sale or lease in Tioga/Potter Counties, PA. Excellent geology available with the rights or with lease. Paul Cizek, 5 Center Street, Watsontown, PA 17777. Fax/Phone 570-538-1818.

BUSINESS OPPORTUNITY

Want to purchase minerals and other oil/gas interests. Send details to: P.O. Box 13557, Denver, CO 80201.

CONSULTANT

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

Read OGJ Classifieds

LEGAL NOTICE

NOTICE TO BIDDERS
OIL AND GAS LEASE SALE

The Commonwealth of Pennsylvania, Department of Conservation and Natural Resources, Harrisburg, Pennsylvania, will receive sealed bids for Oil and Gas Leases until 2 P.M., prevailing local time (EST), **TUESDAY, JANUARY 12, 2010,** at which time bids will be publicly opened and read for the leasing of six (6) tracts of State Forest lands comprising a total of 31,967 acres located in Clinton, Tioga, Potter, Cameron, and Clearfield Counties, Pennsylvania.

The minimum bid is Two Thousand Dollars ($2,000.00) per acre; bids of less than this minimum per acre will not be accepted. The royalty rate has been established at eighteen percent (18%).

All prospective bidders must be pre-qualified by the Department no later than 5:00 p.m. EST Wednesday, December 9, 2009 to participate in the lease sale. To pre-qualify, prospective corporate bidders must be registered to do business within Pennsylvania and must be in good standing with the PA Department of State's Corporation Bureau.

Pre-qualified bidders must comply with all requirements established by the Department for the submission of bids as set forth on the Department's website at www.dcnr.state.pa.us/forestry/oil_gas.aspx. Bids must be submitted by January 12, 2010 (2 p.m. EST) on the Department's forms and must be accompanied by two executed lease signature pages and an irrevocable letter of credit for ten percent (10%) of the amount of the initial bonus rental payment. The winning bidder shall pay to the Department the full bonus rental payment by no later than 5:00 p.m. EST, Friday, March 12, 2010.

Information available on the Department website includes: pre-qualification and bid instructions; bid form; lease agreement; sample letter of credit; information about the lease sale tracts being offered, including a complete set of tract maps in both .pdf and GIS shape file format; and the complete Environmental Review performed by the Department for the lease sale tracts.

A hard-copy of the bid documents found on the website can be obtained from the Department for a pre-paid cost of $100.00 per requested bid packet, or on CD ROM in digital form for $50.00 per bid packet, or in both paper and CD ROM combined for $150.00 per bid packet. Requests for hard copy or CD ROM bid packets should be mailed to PA Department of Conservation and Natural Resources, Bureau of Forestry, Minerals Section, P.O. Box 8552, Harrisburg, PA 17105-8552. Payment of bid packet fees must accompany a bid packet order request. Checks or money orders must be made out to "Commonwealth of Pennsylvania".

Award decisions will be made public within 24 hours of the completed bid opening on the Department's website at **www.dcnr.state.pa.us/forestry/oil_gas.aspx**.

The following Department representatives are available to answer questions regarding the lease sale: Ted Borawski at 717-772-0269, Nathan Bennett at 717-783-7940, or Amy Randolph at 717-783-7948.

JOHN QUIGLEY, ACTING SECRETARY
DEPARTMENT OF CONSERVATION AND NATURAL RESOURCES

EQUIPMENT FOR SALE

AUCTION

Classified Advertising

EQUIPMENT FOR SALE

Advertising Sales / Advertisers Index

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

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

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

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

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
Stephen Wilding, 188 Gordon Avenue, Camberley, GU15 2NT United Kingdom Tel: +44.7545.829.891, Fax: +44 7545.829.891; E-mail: stephenw@pennwell.com

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

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

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

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

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

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

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

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

Companies move toward disclosure in frac-fluid issue

In a simmering US political challenge to the main method for completing gas wells in shale, a secondary issue over proprietary information is starting to dissipate.

The larger threat is federal regulation of hydraulic fracturing, refinements of which have combined with horizontal drilling to unlock the enormous potential of shales.

The oil and gas industry has used hydraulic fracing for 60 years. Regulation

The Editor's Perspective

by Bob Tippee, Editor

of the practice has occurred effectively at lower levels of government.

But activist lawmakers and regulators want to impose federal regulation. The producing industry, wary of new delays and costs, says that level of oversight isn't necessary.

In support of a new layer of regulation, environmental groups and their friends in government are planting fear in a public mostly unaware of the technique before overblown warnings emerged that it dooms drinking water.

Their regulatory push includes an effort to require disclosure of frac-fluid composition.

At first, the industry opposed the idea. An important element of competition among frac service providers is fluid performance, which depends greatly on ingredients. Disclosing fluid composition would be like giving away company secrets.

At the end of September, however, Schlumberger Ltd. said it was asking suppliers for permission to report chemicals used in its frac fluids. A month later, Chesapeake Energy Corp. supported disclosure and posted on its web site a list of chemicals in fluids used to frac its wells.

In rapidly developing US shale plays, both companies are heavyweights.

They also worked together on a Louisiana well near where 17 cattle died last April after drinking water thought to contain spilled frac fluid. So they have first-hand experience with the readiness of opponents to use an incident like that to incite alarm.

Because fear of fracing is largely fear of the unknown, information should be a prime antidote. Against determined opposition, however, it's never guaranteed to work.

Understandably, many companies abhor the idea of tipping their proprietary hands on frac fluids.

Given recent events, however, and in view of the broader effort to regulate if not stifle hydraulic fracing, it's an idea whose time already may have arrived.

(Online Oct. 30, 2009; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Aramco switches from WTI benchmark

Starting with its January sales program, Saudi Aramco, national oil company of Saudi Arabia, will switch from West Texas Intermediate to an index of Gulf Coast sour crudes as the benchmark for pricing its oil for sale in the US market.

Aramco will use Argus Media Ltd.'s Argus Sour Crude Index (ASCI) in pricing its Extra Light, Arab Light, Arab Medium, and Arab Heavy crudes, which are heavier and have higher sulfur content than WTI. That index, launched in May, uses the volume-weighted average of daily spot sales of the Mars, Poseidon, and Southern Green Canyon crudes.

Aramco's move is "more of an evolutionary smoothing out of distortions, rather than...a dramatic change in the dynamics of the US crude market," said Paul Horsnell at Barclays Capital in London. He sees it as "a form of insurance" against volatility caused by WTI price dislocations. Usually, Gulf crudes and WTI prices move "pretty much in line." However, distortions caused by logistical or inventory constraints at its pricing point in Cushing, Okla., can dislocate WTI prices away from North Sea Brent and US gulf crude prices.

Aramco's switch to ASCI sparked speculation other exporters of sour crude to the US may change over. But the move should not be interpreted as a rejection of WTI's general role as market leader, Horsnell said.

"US gulf crudes tend to be assessed in terms of differentials to WTI, rather than as separate centers of independent price discovery, and we expect that to continue," he said, adding, "Should an active OTC or futures market based on ASCI eventually arise, then the dynamics could change. However, establishing futures contracts based on delivered US gulf sours has proved very problematic in the past and is still very far from an inevitable development. Indeed, the current regulatory climate is not exactly ideal for any innovative development of new OTC or formal exchange based oil derivatives."

The New York Mercantile Exchange has tried to establish a benchmark US gulf sour crude contract for trade since the early 1990s. Now NYMEX officials say they will launch a futures contract based on the Argus index before Aramco makes its change.

Saudi pricing formulas

For more than 20 years, Saudi crudes imported into the US on term contracts have been priced against a benchmark averaged 50 days after the time of loading and adjusted by a differential declared in advance for the month plus freight cost adjustments. "Until the January 1994 sales program, the marker used was Alaskan North Slope (ANS) as delivered into the US gulf. After a period in which holders of term contracts grew dissatisfied with the dynamics of ANS prices, WTI forward prices were introduced instead," Horsnell said. "Given that past changes in the mechanics of the formula have primarily been the result of representations from term contract holders, it seems safe to see the change as reflecting a wide discontent within the US oil industry about the performance of WTI during those periods of dislocation."

At its inception, ASCI said it will use WTI as a basis for its price assessments, with the WTI basis following the NYMEX light sweet crude contract.

Bloomberg News reported Mars Blend crude for December trading at a $3.10/bbl discount to WTI at Cushing in late October. Discounts for Poseidon and Southern Green Canyon crudes were $3.05 and $3.95, respectively. On the US spot market, WTI at Cushing was down $2.87 to $77/bbl Oct. 30 in lock-step with the December futures contract on NYMEX. Brent for the same month lost $2.84 to $75.20/bbl. The average price for the Organization of Petroleum Exporting Countries' basket of 12 reference crudes, including Saudi Arabia's Arab Light, was down 38¢ to $75.56/bbl that day.

"To some extent the growth in prominence of ASCI is as much a challenge to Brent as it is to WTI," Horsnell said. "Before, Brent was the only benchmark that had a claim to being the best gauge for Atlantic crude pricing during periods when the US Midcontinent pricing decoupled. Now there is another potential claimant, albeit one that so far lacks the panoply of OTC and derivative markets and liquidity that are necessary to lay a claim to being a center of price discovery rather than one of price reflection."

In Europe and the Mediterranean, Aramco prices its crude against the Brent-weighted average posted by the International Petroleum Exchange in London. In Asia, it relies on the average of two Persian Gulf benchmarks of Oman and Dubai grades of crude.

(Online Nov. 2, 2009; author's e-mail: samf@ogjonline.com)

OIL SANDS™ HEAVY OIL TECHNOLOGIES

www.OilSandsTechnologies.com

Exhibit Today

Expanding Sustainably

Growth requires the oil sands and heavy oil industry to make steady, long-term progress along a narrow road for which no map exists.

On one side loom the high costs of extracting, processing, and transporting unconventional hydrocarbons.

On the other side are environmental performance standards that toughen with time and that the industry never must fail to meet.

Each step along this road requires innovation. Each must withstand unpredictable economic changes. Each must uphold eternal values of nature and society.

On this road, the beacon for progress is technology, advances in which will control the costs, improve the environmental performance, and assure the sustainability of an industry crucial to oil supplies – now and in the future.

The Oil Sands and Heavy Oil Technologies Conference & Exhibition is the premier showcase for the knowledge and methods of this fascinating business.

Take this opportunity to present your product or service to a powerful, influential audience. Join PennWell Petroleum Events in this fourth year conference and exhibition.

Reserving Exhibit Space and Sponsorship Information is Available by contacting our Sales Professionals

Exhibitor and Sponsorship Sales:

Peter D. Cantu
(Petroleum Companies M - Z)
Phone: +1 713 963 6283
Fax: +1 713 963 6212
Email: peterc@pennwell.com

Kristin Stavinoha
(Petroleum Companies A - L)
Phone: +1 713 963 6283
Fax: +1 713 963 6212
Email: kristins@pennwell.com

Bob Lewis
(Power Companies)
Phone: +1 918 832 9225
Fax: +1 918 831 9875
Email: blewis@pennwell.com

Oil Sands and Heavy Oil Technologies Conference & Exhibition | July 20–22, 2010 | Calgary TELUS Convention | Centre, Calgary, Canada

Owned & Produced by: PennWell

Flagship Media Sponsors: Oil&Gas Journal, Power Engineering, Oil&Gas Financial Journal, Oil, Gas & Petrochem Equipment, Offshore

Media Partners: oilsands review, oilweek

Mind If We Drill Through?

Hughes Christensen EZCase Bit

By any measure — safety, schedule, or ultimate cost — there's no substitute for the only steel casing bit system in the industry: Hughes Christensen EZCase. Casing-while-drilling accomplishes two objectives in a single run, saving days of drilling time and associated costs. With its exclusive steel crown and full PDC cutting structure, EZCase does both jobs without compromising on performance. Any formation, any application — there's no better choice than EZCase for taking your liner or casing all the way to TD in record time.

www.bakerhughes.com/ezcase

The only STEEL casing bit on the market.

BAKER HUGHES

Advancing Reservoir Performance