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OGJ Focus: Exploration and Development

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Calculating high cetane 300-400° F. cut for diesel
Pressure test succeeds where other measures fail

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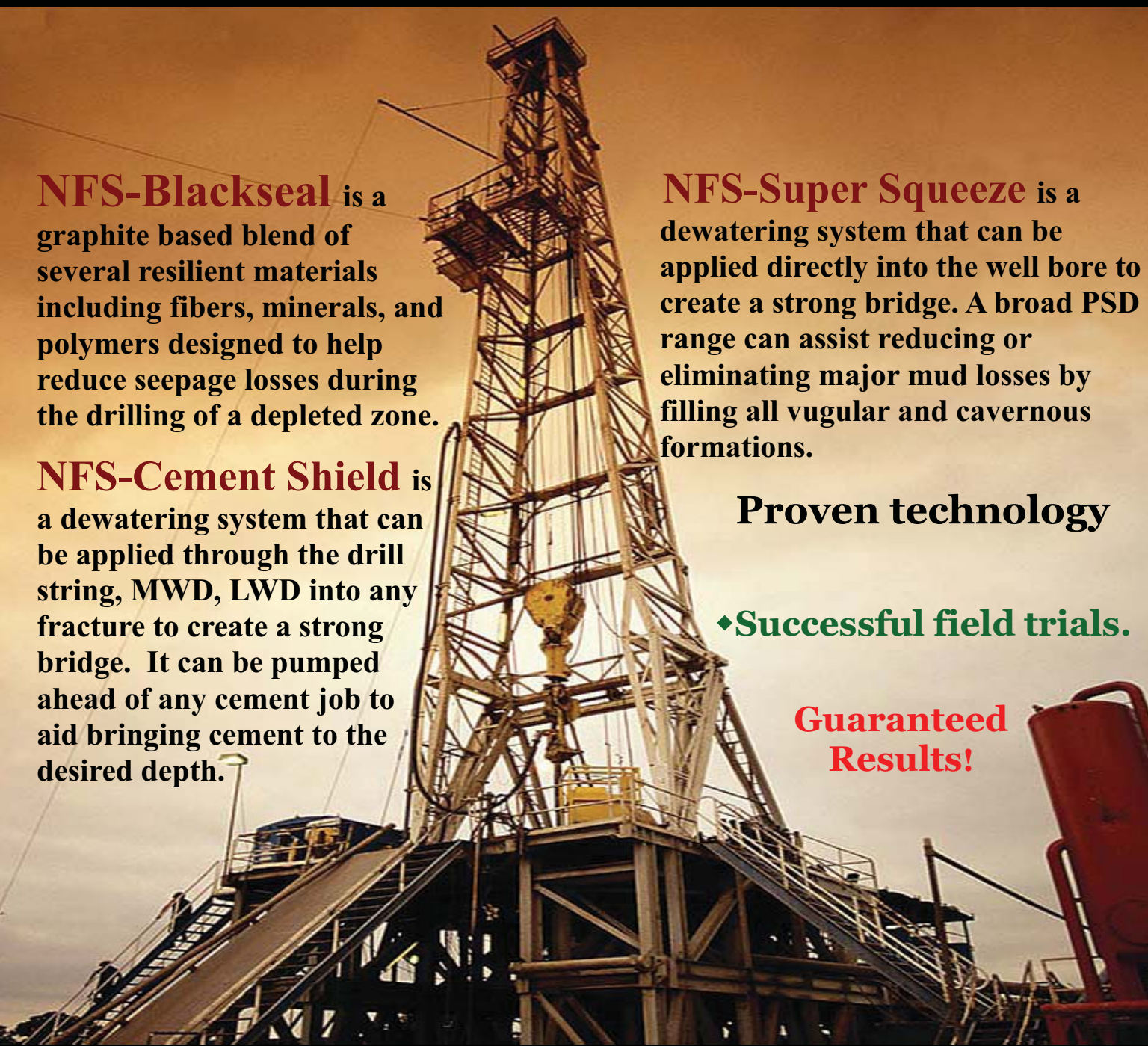

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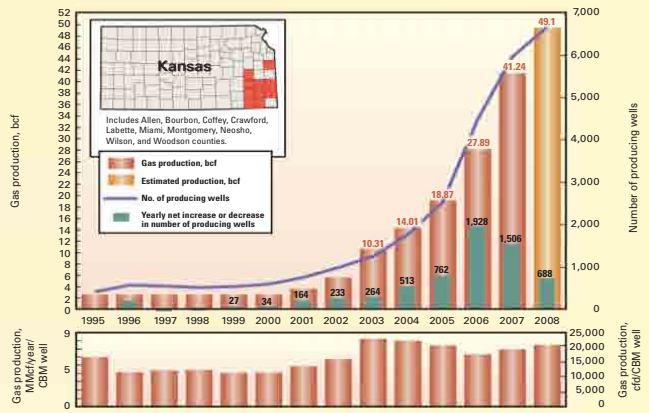
OIL&GAS JOURNAL®

Feb. 8, 2010
Volume 108.5

OGJ Focus: Exploration and Development

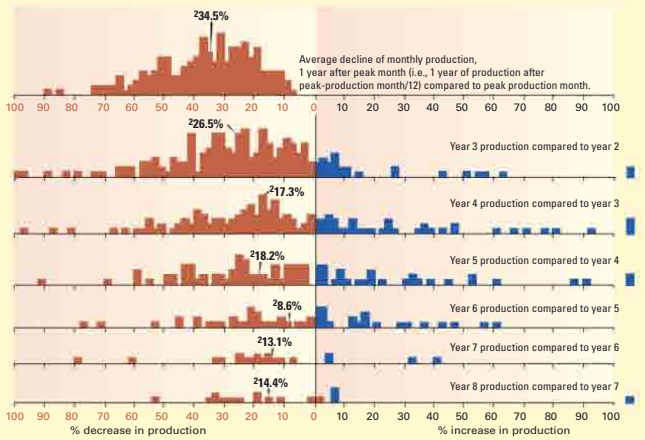
Yearly gas production in southeast Kansas*

Fig. 1



Southeast Kansas coalbed yearly production declines[1]

Fig. 5



[1]Data are for a 200-well representative database. [2]Average decline by total volume of all wells.

Regular Features

Cover

A blizzard doesn't stop a crew at this TXD/Foxxe Energy rig from setting production casing at a coalbed methane well in the Cherokee basin in Wilson County, Kan. An article on the future of eastern Kansas CBM potential starts on p. 33. Cover image by Ken Recoy, senior geologist, Quest Energy, Chanute, Kan.

General Interest

Exploration & Development

Technology

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Feb. 8, 2010

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General Interest — Quick Takes

API, NPRA question EPA's proposed ozone limits

Two witnesses from oil industry trade associations separately questioned the US Environmental Protection Agency's plan to significantly toughen ground-level ozone emission limits as they testified at EPA hearings in Houston and Arlington, Va.

EPA's own science does not even support such a move, according to Ted Steichen, a policy advisor at the American Petroleum Institute, and David Friedman, environmental affairs director at the National Petrochemical & Refiners Association.

Neither EPA's review in 2008 nor more recent studies justify lowering the standard based on the health effects of exposure, Friedman continued in his prepared statement at the hearing in Arlington. "The science…during the 2008 review and the latest studies have not changed the earlier conclusion. In fact, in the current reconsideration, EPA indicates that it will rely only on the previous record and not consider any new evidence," he said.

Testifying in Houston, Steichen emphasized progress that has been made improving the nation's air quality in large part through oil and gas industry efforts. More efforts will follow under the existing ozone standards because of pollution controls which are in place or which soon will be implemented, he said.

Cleaner fuels brought to market now and in the future will result in cleaner air for decades to come as cleaner engines are put in place, Friedman said in his prepared statement. "We will see cars and trucks producing significantly lower emissions. In addition, emissions from power plants will be cut in half by 2015. The current National Ambient Air Quality ozone standard is working," he said.

Moving forward with significantly lower ozone limits if there are no demonstrable benefits could unnecessarily increase energy costs, cut jobs, and reduce domestic energy development and energy security, he continued. "These rules represent a stop sign on the road to economic recovery, and will lead to further loss of American manufacturing jobs and increased reliance on imported gasoline and diesel fuel," Friedman warned.

Sabine Neches Waterway reopens after spill

The Sabine Neches Waterway at Port Arthur, Tex., has been reopened to limited tanker traffic while clean-up continues of crude oil spilled after a tanker-barge collision Jan. 23 (OGJ Online, Jan. 26, 2009).

Closure of the waterway caused minor disruption of refinery operations at Port Arthur and nearby Beaumont.

About 462,000 gal of crude entered the water when a barge being pushed by the Dixie Vengeance towing vessel punctured the hull of the 95,660-dwt Eagle Otome tanker.

Cause of the collision remained unclear after the US Coast Guard raised doubts about earlier reports that the tanker had lost power. USCG said three tugs escorted the damaged tanker to the Sunoco Inc. terminal at Beaumont for discharge of the remaining cargo.

"We are doing everything we can to provide much-needed relief to the region's four large refineries," said USCG Capt. J.J. Plunkett, captain of the port and federal on-scene coordinator for the response.

House bill reintroduced to recover royalties

Two US House members reintroduced legislation that they said could recover as much as $54 billion in federal offshore royalty payments that were mistakenly exempt in the late 1990s.

The measure would require producers that hold such leases to renegotiate terms before being able to bid on newly offered tracts. The leases originally were issued without a requirement to pay federal royalties to stimulate Gulf of Mexico deepwater exploration and development. They were erroneously exempted from royalty payments when price thresholds were omitted from 1996 to 2000.

"Instead of oil companies drilling for free on public land, we should be drilling for deficit dollars by fixing this taxpayer ripoff," said Rep. Edward J. Markey (D-Mass.), who chairs the House Select Committee on Energy Independence and Global Warming. "Half of our trade deficit in 2008 was from buying foreign oil, and $54 billion of our national budget deficit could be solved by keeping oil companies honest."

The bill's cosponsor, Rep. Chris Van Hollen (D-Md.), who co-chairs the bipartisan Renewable Energy and Energy Efficiency Caucus, said that the bill would close what he termed a "costly, special interest loophole." ✦

Exploration & Development — Quick Takes

Group signs Halfaya development contract

A group led by PetroChina Co. Ltd. has signed its service contract for development of supergiant Halfaya oil field in Iraq (OGJ, Dec. 21, 2009, Newsletter).

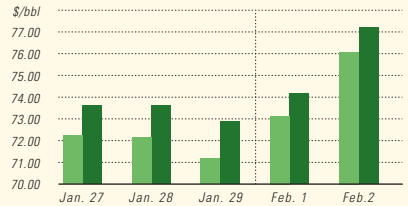
The 20-year contract, with state-owned Missan Oil Co., calls for an increase in production to a plateau of 535,000 b/d from 3,100 b/d at present.

The group will receive a remuneration fee of $1.40/bbl when production exceeds 70,000 b/d and must sustain output at the plateau rate for 13 years. The contract provides for cost recovery.

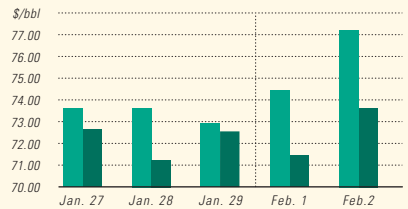
The Iraqi oil ministry said seven wells drilled in Halfaya field have appraised oil in multiple Tertiary and Cretaceous formations

Industry Scoreboard

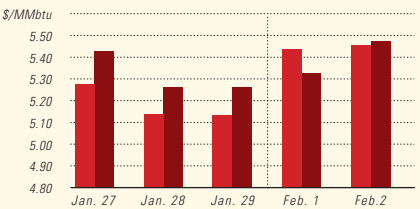
IPE BRENT / NYMEX LIGHT SWEET CRUDE



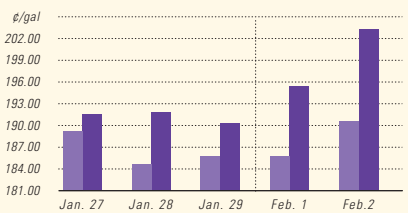
WTI CUSHING / BRENT SPOT



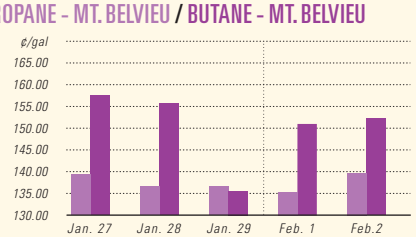
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



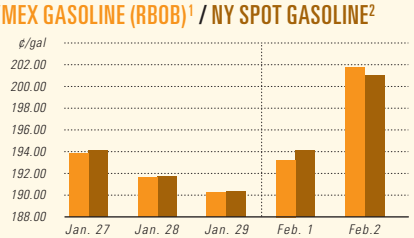
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



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

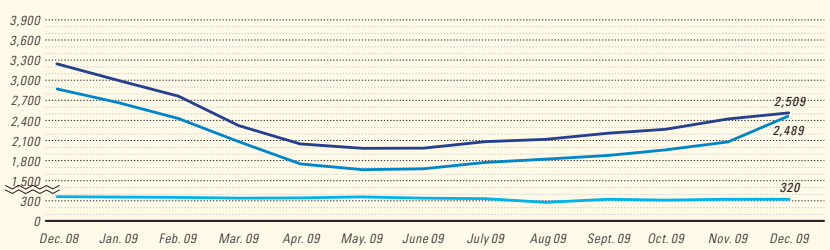
US INDUSTRY SCOREBOARD — 2/8

Latest week 1/22	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	8,676	8,749	–0.8	8,676	8,690	–0.2
Distillate	3,677	4,002	–8.1	3,677	4,075	–9.8
Jet fuel	1,388	1,367	1.5	1,388	1,357	2.2
Residual	490	713	–31.3	490	700	–30.1
Other products	4,522	4,298	5.2	4,524	4,302	5.1
TOTAL DEMAND	18,753	19,129	–2.0	18,753	19,124	–1.9
Supply, 1,000 b/d						
Crude production	5,457	5,199	5.0	5,457	5,246	4.0
NGL production[2]	2,066	1,794	15.2	2,046	1,797	13.9
Crude imports	8,414	9,744	–13.6	8,414	9,852	–14.6
Product imports	2,703	3,288	–178	2,703	3,321	–18.6
Other supply[3]	1,727	1,673	3.2	1,785	1,051	69.8
TOTAL SUPPLY	20,367	21,698	–6.1	20,404	21,266	–4.1
Refining, 1,000 b/d						
Crude runs to stills	13,811	14,533	–5.0	13,811	14,112	–2.1
Input to crude stills	14,056	14,564	–3.5	14,056	14,503	–3.1
% utilization	79.5	82.5	—	79.5	82.1	—

Latest week 1/22	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	326,677	330,565	–3,888	338,881	–12,204	–3.6
Motor gasoline	229,427	227,442	1,985	219,859	9,568	4.4
Distillate	157,496	157,138	358	143,952	13,544	9.4
Jet fuel–kerosine	43,690	43,733	–43	38,401	5,289	13.8
Residual	37,789	38,781	–992	36,045	1,744	4.8
Stock cover (days)[4]			Change, %		Change, %	
Crude	23.7	23.8	–0.4	23.6	0.4	
Motor gasoline	26.4	25.9	1.9	25.1	5.2	
Distillate	42.8	42.9	–0.2	35.3	21.2	
Propane	22.0	25.8	–14.7	30.9	–28.8	
Futures prices[5] 1/29			Change		Change	%
Light sweet crude ($/bbl)	74.03	76.82	–2.79	43.11	30.92	71.7
Natural gas, $/MMbtu	5.35	5.62	–0.27	4.66	0.69	14.9

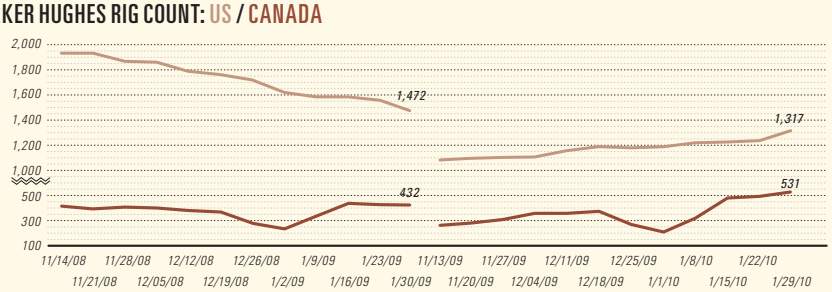
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

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since discovery in 1976. Current production is from four wells completed in Cretaceous Mishrif and Nahr Umr zones.

The field is a northwest-southeast trending anticline about 30 km long and 10 km wide. It's 35 km southeast of Amara.

PetroChina has a 37.5% interest in the consortium. Total E&P Iraq and Petronas Carigali Sdn. Bhd. hold 18.75% each. State partner South Oil Co. has a 25% interest.

European unconventional gas attracts firms

The Ukraine unit of EuroGas Inc., New York, acquired three unconventional gas concessions in eastern Ukraine's Donbas basin and increased activities in the Lublin basin that extends from Poland into western Ukraine.

The acquisition brings to five the number of shale gas and coalbed methane concessions held by EuroGas Ukraine Ltd. in eastern Ukraine under a joint activity agreement with Nadra Luganshchiny Ltd.

The five concessions total 512 sq km, and the largest, Marijewvskogo Poligon, covers 251 sq km. Horizontal drilling is to start this year.

Meanwhile, EuroGas GMBH signed a memorandum of understanding to explore for unconventional gas, such as shale and CBM gas, in the Lublin basin where it was the first foreign company to successfully drill a CBM well in the Ukrainian sector in the late 1990s.

Meanwhile, Realm Energy International Corp., Vancouver, BC, said it applied for oil and gas rights in eight undisclosed basins in seven unidentified European countries where it plans to exploit shale gas on more than 1.5 million acres.

Realm Energy, which is collaborating with Halliburton Consulting to apply North American shale gas technology in Europe, is evaluating other undeveloped shale plays and intends to make more applications in early 2010.

Gulfsands to develop Syria's Yousefieh oil field

Gulfsands Petroleum PLC expects to bring Syria's Yousefieh oil field on stream in early April. Gulfsands holds 50% interest and is the operator.

Recently, Syrian authorities granted Gulfsands a 25-year production license and a 10-year extension option. Yousefieh is 3 km east of Khurbet East field.

Production of 23° gravity oil is expected from two wells, Yousefieh 1 and Yousefieh 3, at an initial combined rate of up to 1,000 b/d.

Planning is under way to install permanent down-hole artificial lift equipment in both Yousefieh wells this year.

Yousefieh, on Block 26, was discovered in November 2008 (OGJ, Nov. 24, 2008, Newsletter).

At yearend 2008, Yousefieh was estimated to contain 11 million bbl of proved plus probable reserves. Gulfsands plans to issue a reserves update during the second quarter 2010. Another development well on Yousefieh is planned for 2010. Gulfsands anticipates Yousefieh production will reach about 6,000 b/d by 2012. ✦

Drilling & Production — *Quick Takes*

The 11,000-ton Valhall redevelopment integrated production and hotel facility deck, being built for BP Norge, leaves the fabrication hall at Heerema Zwijndrecht, one of the three production locations of Heerema Fabrication Group. Photo from HFG.

BP reports work progress on Valhall deck

BP Norge has reported its 11,000-ton BP Valhall redevelopment integrated production and hotel facility deck has left the fabrication hall.

The main deck will measure 100 m in length, 47 m in width, and 50 m in height. It is expected that the structures' main deck, weather deck module, flare boom, and first and second bridges will leave the Heerema Zwijndrecht location in May or June for its final destination off Norway. Once completed, the topsides will weigh more than 13,000 tons, excluding power-from-shore module and living quarters.

Heerema Zwijndrecht was awarded the fabrication and integration contract in March 2007 for the topsides with the 350-ton flare-boom structure of which fabrication started in November 2007. It also received the award for the fabrication of the 2,000-ton weather deck module on June 23, 2009.

Contracts let for Brazil's first TLWP

The Papa Terra Joint Venture has let contracts for construction and installation of the P-61 tension-leg wellhead platform (TLWP) in the deepwater oil field for which it recently revived development off Brazil (OGJ, Feb. 1, 2010, Newsletter).

The TLWP, to be installed in 3,900 ft of water 70 miles offshore in the southern Campos basin, will be the first facility of its kind off Brazil. It will produce 14-17° gravity crude into a floating production, storage, and offloading vessel with production capacity of 140,000 b/d.

Partners Petroleo Brasileiro SA (Petrobras), operator, and Chevron Corp. had suspended Papa Terra development in early 2009 because of business conditions.

J. Ray McDermott SA reported the contract award as part of a larger project covering design, engineering, construction, transportation, installation, and a 3-year limited operations contract let to FloaTEC Singapore Pte. Ltd., a venture of Keppel FELS Ltd., J.Ray, and FloaTEC LLC.

Construction of the TLWP will occur at the yard of a Keppel FELS subsidiary at Angra dos Reis, Brazil. The FloaTEC Singapore joint venture will supply risers, well systems, and tendon components. J.Ray will install the unit and provide topsides engineering and procurement services. Completion is due by mid-2013.

Guara pilot production FPSO chartered

Petroleo Brasileiro SA (Petrobras) along with partners BG Group and Repsol YPF SA signed a letter of intent with the Schahin Group and Modec Inc. for a 20-year charter and operation of a floating production, storage, and offloading vessel that will be used for the Guara pilot production.

Guara is a presalt oil discovery in the Santos basin on Block BM-S-9 off Brazil.

The FPSO will have 65% Brazilian content and be capable of handling 120,000 bo/d and 5 million cu m/day of gas. Conversion work on the hull will take place outside of Brazil while several modules will be integrated in Brazil.

Petrobras expects Guara to go on stream in late 2012.

Flow tests, limited by equipment capacity, on the Guara presalt discovery well 1-SPS-55 (1-BRSA-594), in 2,141 m of water, produced at about 7,000 bo/d and Petrobras estimates that the well initially could produce at about 50,000 bo/d (OGJ, Sept. 14, 2009, Newsletter). Petrobras believes that the area contains about 1.1-2 billion bbl of recoverable 30° gravity oil.

Operator Petrobras holds a 45% interest in the block. The remaining interest is held by BG 30% and Repsol YPF 25%.

Tullow plans Ugandan oil production this year

Tullow Oil PLC plans to begin oil production from its Uganda fields this year, starting at 500-1,000 b/d and rising to 10,000 b/d next year before reaching 150,000 b/d in 2015.

Initial production at midyear will not be "economically significant, but it is a great step forward for Ugandans to know that their oil is being used for industrial use," said Tullow Chief Operations Officer Paul McDade.

"We would like to produce oil on a test basis to see how the oil wells behave and how the crude can be transported by truck since it is waxy. We will have to heat the oil to keep it flowing," said McDade. The oil will be produced from Block 2, which is 100% owned by Tullow.

McDade said Tullow plans to invest $300-400 million in the initial phase, rising to $5 billion to reach the 150,000 b/d level. He said initial production will be used for local industry and power generation.

In addition to Block 2, Tullow has a 50% stake in Block 1 and in Block 3A. Tullow Uganda Ltd. recently entered into an agreement with Heritage Oil & Gas Ltd. and Heritage Oil PLC to purchase their entire interest in Blocks 1 and 3A (OGJ Online, Jan. 28, 2010)

Anticipating its takeover of the Heritage blocks, Tullow is considering farm outs. According to McDade, the two companies that Tullow prefers to work with are China National Offshore Oil Corp. and Total SA. "The Chinese are best in building refineries, and they move fast. CNOOC has just built a big refinery in China [that] can refine the same quality of oil as in Uganda. They built it in a period of 2 years."

Tullow recently announced plans to sell more than 80 million shares, equivalent to 10% of the outstanding equity in the company, to accelerate plans to develop huge oil discoveries in the Lake Albert Rift basin. Tullow Chief Financial Officer Ian Springett said the cash would also be used to help to buy out Heritage Oil's stake.

Production rising at Mangala field in India

Oil production from Mangala field in Rajasthan, India, has reached 20,000 b/d from five wells as work progresses to expand capacity of a processing terminal, reports Cairn Energy PLC.

The field, part of a complex that includes nearby Bhagyam and Aishwariya fields, started up last August and averaged 15,430 b/d in fourth quarter 2009 (OGJ, Sept. 7, 2009, Newsletter).

A 30,000-b/d train is on line at the Mangala Processing Terminal (MPT), which eventually will have four trains with total capacity of 205,000 b/d and room for expansion. Approved plateau production for the complex is 175,000 b/d.

Start-up of two more trains will expand MPT capacity to 125,000 b/d by the end of June.

Production now moves by truck to the Gujarat coast for shipment in heated tankers to refineries operated by Reliance Industries Ltd. and Mangalore Refining & Petrochemicals Ltd.

Cairn India is commissioning a 590-km, 32-in. insulated pipeline between the MPT and Salaya, near RIL's 660,000-b/d and 580,000-b/d refineries at Jamnagar, heated to keep the crude oil temperature above 65° C.

At Mangala, the company has drilled 45 producing wells, of which 33 have been completed in the Paleocene Fatehgarh formation and are producing or awaiting start-up. Three of the wells are horizontal. The company has been operating two rigs and a completion unit in the Mangala development area and soon will add a third rig.

Cairn also has drilled eight wells in Raageshwari Deep gas field, production from which combines with Mangala associated gas to fuel steam turbine generators at the MPT and heaters for the crude pipeline. The company said one Raageshwari well, Raag-14, tested gas at a field-high rate of 15.7 MMscfd after a hydraulic frac.

Construction is complete on the Raageshwari gas terminal, about 80 km south-southeast of the MPT, and facilities 20 km southeast of the MPT to produce water for secondary recovery.

Cairn has a pilot project testing enhanced recovery with polymer and alkaline-surfactant-polymer injection, which the company estimates might boost recovery from the Mangala complex by 300 million bbl. ✦

Processing — *Quick Takes*

Sunoco shuts refinery, sells PP business

Sunoco Inc. has made permanent its closure of the 150,000-b/d Eagle Point refinery at Westville, NJ, and is selling its polypropylene business to Braskem SA.

The company idled the refinery, which is interconnected with its refineries at Philadelphia and Marcus Hook, Pa., last No-

vember (OGJ Online, Oct. 6, 2009).

It said it has permanently shut down the refinery, citing "continuing weak demand for refined products and unfavorable market conditions."

Product storage and handling operations will continue at Eagle Point. Sunoco is considering options for the site, including biofuels production.

The company said it expects to report a loss for the first quarter of 2010 of $185-195 million.

Braskem, Sao Paulo, Brazil, will pay $350 million cash for Sunoco's PP plants in Marcus Hook; La Porte, Tex.; and Neal, W.Va. The plants can produce a combined 2.1 billion lb/year of the polymer.

Braskem also will acquire Sunoco's Research and Technology Center in Pittsburgh.

Foster Wheeler to study Ugandan refinery

The Ugandan government has let contract to Foster Wheeler AG's Global Engineering & Construction Group for a feasibility study of a 150,000-b/d refinery, which would be Uganda's first.

The Ministry of Energy and Minerals Development last year disclosed plans to study a 50,000-b/d refinery, saying production from recent Ugandan discoveries might reach 100,000 b/d (OGJ, Aug. 10, 2009, Newsletter). The country produces no crude oil at present.

The Foster Wheeler study will cover location and configuration of a refinery and options for oil-field development, crude transportation, and evaluation of alternatives to refinery construction such as pipeline export. Completion is due in midyear.

QP awards NGL control system contract

Qatar Petroleum has let a contract to Cegelec of Paris to replace, over the next 18 months the turbine and compressor control system for two NGL production trains in Mesaieed, Qatar.

Under the $15 million contract, an integrated GE-Mark VI system will replace the existing pneumatic control system for Trains 1 and 2, the Cegelec announcement said. In addition, the existing fire-protection system will be replaced with a water-mist system interfaced with the new control system.

This contract follows an earlier $40 million turnkey contract awarded to Cegelec to design and build a blast-proof control building at the QAPCO petrochemical complex, also in Mesaieed.

Cegelec has also provided technical assistance and commissioning for Phase 2 of the common water-cooling system in Ras Laffan, where the end customer was QP. ✦

Transportation — *Quick Takes*

Golar, PTTEP cancel FLNG project off Australia

Golar LNG Energy, Bermuda, and Thailand's PTTEP have cancelled their heads of agreement and joint study agreement signed last year to develop a floating LNG (FLNG) project off northwest Australia.

At the same time, the two companies also announced termination of a memorandum of understanding for the global cooperation to identify and develop other FLNG projects.

The Australian part of the agreement to enter into front-end engineering and design studies for the FLNG project on a 50-50 basis was signed in July 2009.

The plan was to develop stranded gas reserves in the Timor Sea originally found by BHP Petroleum Ltd. in the 1980s and then bought by Coogee Resources before PTTEP took over Coogee in late 2008. The main gas fields are Cash, Maple, Biliara, Tahbilk, Pathaway, and Montara.

The companies have not revealed a reason for the split, but Golar LNG says it will continue to pursue FLNG projects that fit its financial objectives and technical capabilities. The company added it still believes highly cost-efficient approaches to gas development based on FLNG are the key to substantial additional growth opportunities.

Alaska Pipeline Project files for open season

The Alaska Pipeline Project (APP) filed its plan with the US Federal Energy Regulatory Commission for approval to conduct its open season on a potential pipeline to move natural gas from the Alaskan North Slope to Alberta and on to the US. Members of the public can provide comment through the month of February. Pending approval, APP will finalize its open season and provide it to potential shippers at the end of April for assessment through July.

Two options will be submitted for shipper assessment in the open season. The first option is a 1,700-mile pipeline from ANS to Alberta, from where the gas could be delivered on existing pipeline systems to the US. The second option would transport gas 800 miles from ANS to Valdez, Alas., where it would be converted to LNG in a facility to be built by others and then delivered by ship to North American and other international markets.

Both options would allow off-take by Alaskan customers. Both also would include a gas treatment plant and a 58-mile pipeline from Point Thomson fields to the plant and main transmission line.

The results of the open season will determine the preferred development option. The open season process initiated with FERC applies to the US portion of the project. A separate but coordinated open season will occur for the Canadian portion of the project.

Updated cost estimates for the project are $32-41 billion for the ANS-to-Alberta option, and $20-26 billion for the Valdez option. Both options have an expected in-service date of 2020 and would provide capacity of either 4.5 bcfd (Alberta) or 3 bcfd (Valdez).

The project is a joint effort among TransCanada Corp. and ExxonMobil Corp. under the Alaska Gasline Inducement Act. ExxonMobil reaffirmed its commitment to this project, despite recent North American unconventional gas acquisitions, earlier this week (OGJ Online, Jan. 25, 2009).

Denali—a consortium of BP PLC and ConocoPhillips—will submit its open season package to FERC in April. ✦

Calendar

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

OIL&GAS JOURNAL online

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

2010

FEBRUARY

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

MARCH

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Calendar

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Georgian International Oil, Gas, Energy and Infrastructure Conference & Showcase (GIOGIE), Tbilisi, +44 (0) 207 596 5000, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 24-25.

NPRA International Petrochemical Conference, San Antonio, (202) 457-0480, (202) 457-0486 (fax), website: www.npra.org. 28-30.

APRIL

ATYRAU North Caspian Regional Oil, Gas and Infrastructure Exhibition, Atyrau, +44 (0) 207 596 5000, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 6-8.

Rocky Mountain Unconventional Resources Conference & Exhibition, Denver, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.RMURconference.com. 6-8.

Oil & Gas WestAsia Exhibition in conjunction with SPE EOR Conference, Muscat, +968 24660124, +968 24660125 (fax), e-mail: omanexpo@omantel.net.om, website: www.ogwaexpo.com 11-13.

SPE EOR Conference at Oil & Gas West Asia, Muscat, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 11-13.

AAPG Annual Convention and Exhibition, New Orleans, (918) 560-2679, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org 11-14.

✦ Annual Asian Petcoke Conference, Panaji, Goa, India, (832) 351-7828, e-mail: petcoke.conference@jacobs.com, website: www.petcokes.com. 12-14.

IPAA OGIS, New York City, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 12-14.

SPE International Conference on Health, Safety and Environment in Oil and Gas Exploration and Production, Rio de Janeiro, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 12-14.

IADC Well Control Europe Conference & Exhibition, Aberdeen, (713) 292 1945, (713) 292 1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 13-14.

GPA Mid-continent Annual Meeting, Oklahoma City, (918) 493-3872, (918) 493-3875 (fax), e-mail: gpa@gasprocessors.com, website: www.gasprocessors.com. 15.

International Liquefied Natural Gas Conference and Exhibition, Oran, +44 (0) 20 7596 5000, +44 (0) 20 7596 5111 (fax), website: www.lng16.org. 18-21.

Oil & Gas WestAsia Conference, Muscat, +968 24660124, +968 24660125 (fax), e-mail: omanexpo@omantel.net.om, website: www.ogwaexpo.com. 19-21.

Hannover Messe Pipeline Technology Trade Show, Hannover, +49 0 511 89 0, +49 0 511 89 32626 (fax), website: www.hannovermesse.de. 19-23.

Texas Alliance Annual Meeting and Expo, Wichita Falls, (940) 723-4131, (940) 723-4132 (fax), e-mail: texasalliance@texasalliance.org, website: www.texasalliance.org. 20-21.

API Pipeline Conference and Cybernetics Symposium, New Orleans, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 20-22.

SPE Improved Oil Recovery Symposium, Tulsa, (918) 366-7033, (918) 366-7064 (fax), e-mail: IOR@SPEIOR.ORG, Website: www.speior.org. 26-28.

Middle East Fertilizer Symposium & 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. 26-28.

API Spring Refining and Equipment Standards Meeting, New Orleans, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 26-28.

API/NPRA Spring Operating Practices Symposium, New Orleans, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 27.

MAY

Offshore Technology Conference (OTC), Houston, (972) 952-9494, (972) 952-9435 (fax), e-mail: service@otcnet.org, website: www.otcnet.org/2010. 3-6.

GPA Permian Basin Annual Meeting, Midland, Tex., (918) 493-3872, (918) 493-3875 (fax), website: www.gasprocessors.com. 4.

Asian Biofuels, New Feedstocks and Technology Roundtable, Singapore, +44 (0) 1242 529 090. +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 4-6.

OGU/Uzbekistan International Oil & Gas Exhibition & Conference, Tashkent, +44 (0) 207 596 5000, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 11-13.

International School of Hydrocarbon Measurement, Norman, Okla., (405) 325-1217, (405) 325-1388 (fax), e-mail: lcrowley@ou.edu. Website: www.ishm.info. 11-13.

APPEA Conference & Exhibition, Brisbane, 07 3229 6999, 07 3220 2811 (fax), e-mail: jhood@appea.com.au. website: www.appea.com.au. 16-19.

Mediterranean Offshore Conference & Exhibition, Alexandria, Egypt, +20 2 27065210, +20 2 25184980 (fax), e-mail: conference@omc.it, website: www.moc2006.com. 18-20.

NPRA National Safety Conference & Exhibition, San Antonio, (202) 457-0480, (202) 457-0486 (fax), website: www.npra.org. 19-20.

IADC Drilling Onshore Conference & Exhibition, Houston, (713) 292 1945, (713) 292 1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 20.

SPE International Conference on Oilfield Corrosion, Aberdeen, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 24-25.

ILTA Annual International Operating Conference & Trade Show, Houston, (202) 842-9200. (202) 326-8660, e-mail: info@ilta.org, website: www.ilta.org. 24-26.

Petrotech Middle East Refining and Petrochemicals Exhibition & Conference, Manama, +973 1755 0033, +973 1755 3288 (fax), e-mail: aeminfo@aeminfo.com.bh, website: www.aeminfo.com.bh. 24-26.

NPRA Reliability and Maintenance Conference and Exhibition, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. May 25-28.

SPE International Conference on Oilfield Scale, Aberdeen, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 26-27.

SPE Western North America Regional Meeting, Anaheim, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 26-30.

JUNE

Caspian International Oil & Gas/Refining & Petrochemicals Exhibition & Conference, Baku, +44 (0) 207 596 5000, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.oilgas-events.com. 1-4.

AchemAsia, Beijing, 0049 69 75 64 0, 0049 69 75 64 201 (fax), website: www.achemasia.de. 1-4.

ASME Annual Meeting, Pittsburgh, (800) 843-2763, (973) 882-1717 (fax), e-mail: infocentral@asme.org, website: www.asme.org. 4-9.

Society of Petroleum Evaluation Engineers (SPEE) Annual Meeting, Victoria, BC, (713) 651-1639, (713) 951-9659 (fax), website: www.spee.org. 5-8.

Asia Oil & Gas Conference, Kuala Lumpur, 65 6338 0064, 65 6338 4090 (fax), e-mail: info@cconnection.org, website: www.cconnection.org. 6-8.

IAEE International Conference, Rio de Janeiro, (216) 464-5365, (216) 464-2737 (fax), e-mail: iaee@iaee.org, website: www.usaee.org. 6-9.

PIRA Canadian Energy Conference, Calgary, Alta., (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 8.

SPE International Oil & Gas Conference and Exhibition, Beijing, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 8-10.

SUBSEA Asia, Kuala Lumpur, +44 0 20 7840 2102, +44 0 20 7840 2119 (fax), e-mail: sluff@oesallworld.com, website: www.allworldexhibitions.com.oil. 9-11.

IPAA OGIS London, London, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 10.

PIRA Scenario Planning Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 14.

PIRA London Energy Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 14-15.

EAGE Conference and Exhibition/SPE EUROPEC, Barcelona, Spain, +31 88 995 5055, +31 30 634 3524 (fax), e-mail: eage@eage.org, website: www.eage.org. 14-17.

ASME Turbo Expo, Glasgow, Scotland, (800) 843-2763, (973) 882-1717 (fax), e-mail: infocentral@asme.org, website: www.asme.org. 14-18.

GTI Global Unconventional Gas Conference, Amsterdam, (847) 768-0783, website: www.gastechnology.org/gug2010. 15-17.

IADC World Drilling Conference & Exhibition, Budapest, (713) 292 1945, (713) 292 1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 16-17.

PIRA Understanding Global Oil Markets Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 16-17.

All about Orinoco

Alan Petzet
Chief Editor-Exploration

Venezuela's Orinoco oil belt made headlines in January with word that the US Geological Survey had assigned the area technically recoverable volumes of 513 billion bbl of heavy oil and 135 tcf of associated-dissolved gas in Miocene sediments.

USGS noted that the Orinoco is the largest accumulation it has ever assessed and is one of the world's largest accumulations of recoverable oil (OGJ Online, Jan. 22, 2010).

Petroleos de Venezuela SA estimated 1.18 trillion bbl of oil in place in the Orinoco in 1987 and revised that in 2006 to a median of 1.3 trillion bbl, a maximum of 1.4 trillion bbl, and a minimum of 900 billion bbl.

The following is a perspective on this enormous resource by an editor who visited the former Hamaca area of the belt in 1983 on a PDVSA educational tour.

Exploration history

Early efforts to produce heavy crude from the belt led PDVSA predecessors to output by the early 1980s of 93,000 b/d.

Of that, 67,000 b/d came from traditional fields just south and east of El Tigre, and 26,000 b/d came from the area farther south between El Tigre and Ciudad Bolivar.

Venezuela's oil reserves at the end of 1982 were 24.6 billion bbl, of which 4.3 billion bbl were attributed to the Orinoco.

Venezuelan consultant Anibal Martinez wrote in 1987 that the Orinoco oil belt extends 285 miles westwards from Puerto Ordaz. The first well was drilled in 1936, and preliminary exploration ended in 1967.

Most of the 58 wells drilled in the next 3 decades weren't tested. Then PDVSA companies drilled 669 wells in 1979-83 totaling 2.1 million ft of hole and shot 9,320 line-miles of seismic.

La Canoa-1, the belt's 1936 discovery well, is 25 miles north-northwest of Ciudad Bolivar. It went to a total depth of 3,855 ft and found 7° gravity oil in tar sands. Giant Temblador field, 93 miles east-northeast, was discovered 9 months later. The first documented geophysical survey, in 1937, covered 130 line-km north of Zuata.

The belt, which underlies more than 4,600 sq miles at the southern end of the Eastern Venezuelan basin, has no significant surface indications of petroleum.

Martinez proposed to designate six main producing areas, which were later consolidated to four: from west to east, Machete, Zuata, Hamaca, and Cerro Negro, that eventually spanned the full 375 miles between Tucupita and Calabozo.

Venezuelan President Hugo Chavez's administration changed the names to Boyaca, Junin, Ayacucho, and Carabobo, respectively.

Cumulative estimates

The lion's share of Orinoco production has come from projects operated by four strategic associations that started up in 1998, 1999, 2000, and 2001.

The Petrozuata, Cerro Negro, Sincor, and Hamaca projects, if each ran at capacity since startup, could have produced no more than 2.1 billion bbl of raw crude by the end of 2009. Venezuela nationalized the projects in 2007.

PDVSA and its predecessor companies likely have not produced even 1 billion bbl from Orinoco, including the Bitumenes Orinoco SA plant that extracted bitumen for the Orimulsion boiler fuel product.

That leaves almost all of the USGS technically recoverable figure in the ground to be produced by the four legacy projects and numerous new ventures now being sanctioned (see map, OGJ, Nov. 21, 2005, p. 54).

PDVSA Pres. Rafael Ramirez said the Orinoco belt is producing more than 532,000 b/d of 16-32° gravity oil (OGJ Online, Jan. 6, 2010).

Last November, Ramirez—who also serves as Venezuela's minister of oil—told the third World Congress on Heavy Oil certified crude reserves in the Orinoco belt are expected to reach 235.6 billion bbl by this year's third quarter and its total reserves 316 billion bbl.

Trend in Colombia

Most maps show the Orinoco belt ending just west of Venezuela's sprawling Aguaro-Guariquito National Park southeast of Calabozo.

Calabozo, Venezuela, is 190 miles north of Venezuela's border with Colombia.

Along that border is Colombia's CPE-3 heavy oil development block in the remote eastern Llanos basin, a 6.4 million acre tract on which ExxonMobil Corp. signed a technical evaluation agreement in 2008. ExxonMobil was to run 2D seismic surveys in 2009 in CPE-3, on trend with the Orinoco belt (OGJ, Apr. 6, 2009, Newsletter).

BHP Billiton and SK Energy hold rights to CPE-5 on 7.9 million acres south of CPE-3, and other companies including Shell, Talisman, KNOC, Pacific Rubiales, and Ecopetrol hold smaller blocks west and southwest of CPE-3 and CPE-5. ✦

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Editorial

Obama's message

President Barack Obama to the US oil and gas industry: Get out of town. That's the message in the president's budget proposal for fiscal 2011.

Obama doesn't like fossil energy. He thinks anything that encourages production of fossil energy impedes development of what his budget narrative hails as the "clean energy economy." So he wants to tax away oil and gas.

Obama proposes the same errors on oil and gas that he offered in his fiscal 2010 offering but failed to push through Congress. The repetition is portentous. It means last year's menu of economic poison represented more than bumbling by beginners. Obama and his team have had a year to learn. Yet they reject any lesson that challenges their activist agenda. Obama proved his recalcitrance by promising, in his state-of-the-union speech Jan. 27, to keep promoting an unpopular, state-centered, and now politically disastrous program for health care reform.

Beyond arrogance

For the oil and gas industry, the problem goes beyond the arrogance with which Obama is undermining his presidency. It's antagonism. Reiteration of threats to industry capital formation follows a year of regulatory assault. The Department of the Interior has been systematically constricting exploratory access to hydrocarbon resources on federal land as its secretary chides representatives of the oil industry as "kings of the world." The Environmental Protection Agency has been tightening air-quality rules unnecessarily, maneuvering for control over much of the economy via regulation of greenhouse-gas emissions, and siding with the fearful in a controversy over hydraulic fracturing in New York.

Now, the administration says in its new budget proposal, "We are eliminating 12 tax breaks for oil, gas, and coal companies, closing loopholes to raise nearly $39 billion over the next decade." The statement will win populist points with Americans who think electricity comes from room walls and gasoline originates in service-station pumps. But the economic consequences of acting on that statement would be dire.

Those "loopholes" include percentage depletion, accelerated write-downs by independent producers of geological and geophysical costs, and expensing of intangible drilling costs. These aren't "breaks" on the order of a $1/gal tax credit for makers of biodiesel. Two of them are timing preferences that favor the taxpayer and the other, percentage depletion, is available only to small independent producers and limited even for them. Their elimination would hurt small producers, not "Big Oil," and slash drilling and production in the US.

The big companies take their spankings elsewhere. Obama's proposal would repeal the manufacturer's tax credit for oil and gas companies while leaving it intact for other industries. And the proposal assumes passage of cap-and-trade legislation to limit greenhouse-gas emissions, the version of which the House passed last year would hit refining especially hard.

Swirling elsewhere in Obama's fiscal soup are toxins that would gag oil and gas companies along with others: repeal of last-in first-out inventory accounting, reinstatement of Superfund taxation, and adverse changes in accounting for foreign taxes, for example. If everything passed, the Obama proposal would stifle oil and gas activity, upstream and downstream. That's the intent. "As we work to create a clean energy economy," the budget notes explain, "it is counterproductive to spend taxpayer dollars on incentives that run counter to this national priority."

Unproductive expenditure

This statement is not only redundant, it's bonkers. It flows from the delusion that the US can and should displace fossil energy with preferred alternatives and compensate the inescapable cost disparities with green jobs. In fact, any effort to displace commercial energy with the other kind requires unproductive expenditure certain to shrink net employment. And no such effort will knock oil, gas, and coal out of their dominant positions in the energy market anytime soon. Especially if implemented with punitive taxation, it will only push commercial energy work out of the country—along with supply, jobs, and taxable incomes.

The oil and gas industry must hope Congress shows more concern for national interests than the administration has with its budget proposal. It must hope a useful number of lawmakers, unlike the president, still can learn. ✦

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Chinese oil companies invest heavily abroad

Paula Dittrick
Senior Staff Writer

Chinese oil and gas companies have boosted their investments abroad since 2008 despite the global economic downturn, having committed billions of dollars into developing large fields in the Middle East and elsewhere.

"Looking ahead, the Chinese oil and gas companies will undoubtedly continue their aggressive investments in oversea oil and gas assets, either through corporate acquisitions or bidding rounds," said a January brief from FACTS Global Energy, based in Singapore.

Liutong Zhang and Kang Wu wrote the brief entitled "China's Overseas Oil and Gas Investment."

They said China's equity (net) oil production from its overseas operations in 2008 was 900,000 b/d. Although less that half of that actually reached China, the overseas production volume accounted for 25% of China's total crude oil imports, 23% of domestic oil production, and 12.5% of oil consumption.

Chinese companies' net oil production abroad is expected to reach 1.2 million b/d this year. The FACTS analysts forecast China's net overseas oil production at 1.7 million b/d by 2015 and 2 million b/d by 2020.

"With a flat domestic production, by 2020 the overseas equity oil could account [for] half of China's domestic oil production," they said.

CNPC abroad

China National Petroleum Corp. is the biggest investor among Chinese companies since late 2008. CNPC and its subsidiary, PetroChina Co. Ltd., currently are involved in more than 90 overseas projects, of which 65 involve oil or gas production and development.

Their 2008 net oil production from production outside China was 612,000 b/d of oil and 450 MMscfd of gas.

CNPC also has invested to build pipelines to import oil and gas from overseas, and it moved toward its goal of becoming an international company by buying Singapore Petroleum Co. (see Table 1).

The company and its subsidiaries hold stakes in oil and gas assets in 27 countries and provide field services, engineering, and construction in 49 countries worldwide.

CNPC-PetroChina concentrated their overseas investments in Africa, central Asia, Latin America, and the Middle East.

China National Offshore Oil Corp. (CNOOC) follows CNPC-PetroChina in its overseas investment while China Petroleum & Chemical Corp. (Sinopec) is third among Chinese companies in its international holdings.

In addition, state oil trading company Sinochem Group has begun investing abroad. Separately, the State Administration of Foreign Exchange and China Investment Corp. (CIC) also are acquiring interests in overseas ventures.

"There is no doubt that CNPC-Petrochina, CNOOC, Sinopec, and Sinochem have become important players in the global merger and acquisition market," FACTS said. "Nonetheless, the Chinese oil companies suffered a series of setbacks in 2009."

The Libyan government blocked CNPC International Ltd.'s proposed $499 million (Can.) takeover of Verenex Energy Inc. of Calgary. Instead, the Libyan Investment Authority, a sovereign wealth fund, acquired Verenex for $316 million (Can.).

Elsewhere, Angola's Sonangol reportedly moved to block Sinopec and CNOOC from obtaining deepwater acreage, FACTS analysts said.

ACQUISITIONS BY CHINESE OIL AND GAS COMPANIES

Table 1

Date	Company	Acquisitions, interest	Value, billion $
2009	CNPC, PetroChina	Buying 60% Athabasca Oil Sands Corp.'s Mackay River, Dover projects	1.9
2009	CNPC, KazMunaiGaz	Buying 50% MangistauMunaiGaz in Kazakhstan	3.3
2009	CNPC, PetroChina	Bought 96% of Singapore Petroleum Co.	2.0
2009	Sinopec	Bought 100% of Addax Petroleum Corp. of Calgary	7.2
2009	CNOOC, Sinopec	Bought 20% of Angola's Block 32 from Marathon Oil	1.3
2009	Sinochem	Bought 100% of Emerald Energy PLC to obtain assets in Syria, Colombia	0.878
2008	Sinopec	Bought 100% of Tanganyika Oil to obtain assets in Syria	1.8
2008	CNOOC	Bought 100% of Awilco Offshore ASA	2.5
2008	Sinopec	Bought 60% of AED Oil Ltd. for assets in Australia	0.561

Source: FACTS Global Energy

Recent agreements requiring major future investment

Table 2

Company	Country	Project	Investment notes
CNPC	Iran	MOU for a contract to develop South Azadegan oil field (CNPC 70%, Inpex 10%, NIOC 20%).	CNPC to invest $2.25 billion for first-phase development. MOU signed August 2009.
CNPC	Iran	Preliminary agreement to develop second phase of South Pars gas field (CNPC 40%, NIOC 50%, Petronas 10%).	CNPC plans to invest $4.7 billion. Preliminary agreement signed June 2009.
CNPC	Iraq	20-year service contract to develop Rumaila oil field (CNPC 37%, BP PLC 38%, and Iraqi South Oil Co. 25%).	Consortium to pay $500 million loan to Iraqi treasury and commits $300 million for short-term development. Long-term investment could be up to $20 billion. Service contract signed June 2009.
CNPC	Iran	25-year contract for exploration, development of North Azadegan oil field.	CNPC to invest $1.76 billion in first phase and $3.5-4 billion in second phase. Contract signed January 2009.
CNPC	Niger	Oil development of Niger's Agadem Block.	CNPC to spend $5 billion in 3 years. Development plan signed September 2008.
Sinopec	Iran	Development of Yadavaran oil field.	Sinopec to invest $2 billion. Work started in September 2008.

Source: FACTS Global Energy

Diverse investments

China's oil and gas companies, particularly CNPC-PetroChina, have signed several preliminary agreements and memorandums of understanding outlining billions of dollars in future investments (see Table 2).

CNPC is heavily involved in Iran and Iraq. FACTS attributed CNPC's ability to invest in Iran to the US sanctions keeping US-based oil companies away from investing there.

On Jan. 14, 2009, CNPC signed a buyback binding contract with National Iranian Oil Co. (NIOC) to develop onshore North Azadegan oil field. Duration of the agreement is 25 years. CNPC also has an MOU with NIOC to develop South Azadegan oil field.

Under the MOU, CNPC will take a 70% interest in South Azadegan while NIOC keeps a 20% share and Japan's Inpex owns 10%.

FACTS said the project reportedly will need up to $2.5 billion worth of investments, of which CNPC is expected to pay $2.25 billion and Inpex is to pay the rest.

"If the deal is successfully concluded, it will consolidate CNPC's interest in developing the Azadegan structure," FACTS said. "Azadegan is Iran's largest oil discovery in 30 years with estimated reserves of more than 30 million bbl."

Azadegan is close to the Iraqi border and has a complex geological formation, making the project both a strategic priority and an enormous technical challenge for Iran, FACTS said.

CNPC-PetroChina, already heavily involved in Kazakhstan and Turkmenistan, is looking to invest more in Russia, both in upstream and in pipelines.

In October 2008, CNPC and Transneft agreed to build a 300,000-b/d oil pipeline from East Siberia to China. On Apr. 27, 2009, Transneft launched construction of an offshore section from the East Siberia-Pacific Ocean to the Chinese border, just under 43½ miles. CNPC will build the remaining 609-mile stretch of pipeline.

Although not officially confirmed by the companies, FACTS said the estimated cost of the pipeline is $800 million.

Russia and China also plan cooperative gas pipeline projects. FACTS analysts said Russia reportedly reached an initial agreement in 2009 to supply China 6.76 bscfd, "which seems on the high end, given the capacity of the planned gas pipeline," adding, "It is expected that the gas fields in Siberia could be put into operation after 2015."

Chinese loans

The China Development Bank (CDB) last year signed a long-term agreement with CNPC in which CDB loaned CNPC $30 billion during 5 years to accelerate CNPC's globalization strategy of being an international operator in both upstream and downstream, FACTS said.

In addition to buying assets, China has offered $57 billion total in loans to several producing countries. China introduced the concept of loans for oil in 2004 by providing Angola with a $4 billion oil-backed loan for energy, infrastructure, and other projects.

Subsequently, China made a series of loans to Angola, which exports about 40% of its crude production to China.

China also has made loans to companies in Venezuela, Russia, Kazakhstan, Brazil, Turkmenistan, Bolivia, and Ecuador in exchange for long-term oil and gas supplies.

"Those countries could repay the loan through revenues from oil sales by selling upstream assets to Chinese oil and gas companies or through supplying crudes to China," FACTS said. "It is very likely that Chinese leaders will be able to negotiate a good return on their investment in future loans for oil and gas deals."

China also is building goodwill by providing capital to producing countries, analysts said.

The motivation for Chinese oil and gas companies to expand abroad is to take advantage of the Chinese government's concerns about security of energy supply, FACTS said. "Though the Chinese government actively encouraged overseas investment in the past, CNPC-PetroChina, Sinopec, CNOOC, and Sinochem are taking the lead today," FACTS said.

Other Chinese companies are interested in making overseas oil and gas investments, FACTS said, adding these smaller companies include ZhenHua Oil Co. and China Aviation Oil.

In late 2009, Shaanxi Yanchang Petroleum signed a production-sharing

contract with New Energy Chemical Investment Group of Thailand to explore and develop gas Block L31/50, covering 3,960 sq km.

Yanchang Petroleum also has a production-sharing contract with Cameroon's government to explore the Zina and Makari blocks, which cover 3,862 sq km and 4,644 sq km, respectively. Yanchang Petroleum plans to spend $60 million during a 7-year exploration period, FACTS said. ✦

Obama's speech contains good, bad news for industry

Nick Snow
Washington Editor

US President Barack Obama called for more domestic offshore oil and gas development in his 2010 State of the Union address on Jan. 27. He also said that it's time to end tax cuts for oil companies.

The observations came during a speech that emphasized job creation, economic recovery, and deficit reduction as his administration's top priorities for the coming year. Federal lawmakers should work together to solve serious problems the nation faces, Obama said. "The only reason we are here tonight is that generations of Americans were not afraid to do what is hard," he maintained.

China, Germany, India, and other countries are moving aggressively, and the US should do the same, the president told House and Senate members. "They're putting more emphasis on math and science. They're rebuilding their infrastructure. They're making serious investments in clean energy because they want those jobs," he said. "As hard as it may be, it's time to get serious about fixing the problems that are hampering our growth."

American innovation should be encouraged, he continued, "and no area is more ripe for such innovation than energy." He cited a North Carolina company that will create 1,200 jobs nationwide helping to make advanced batteries, and a California business that will employ 1,000 people to make solar panels as 2009 clean-energy successes.

"But to create more of these clean energy jobs, we need more production, more efficiency, more incentives," Obama said. "That means building a new generation of clean, safe nuclear power plants in this country. It means making tough decisions about opening new offshore areas for oil and gas development. It means continued investment in advanced biofuels and clean-coal technologies. And yes, it means passing a comprehensive energy and climate bill with incentives that will finally make clean energy the profitable kind of energy in America."

Oil tax plans

Obama also signaled that his administration would try again to remove federal tax incentives that independent oil and gas producers consider crucial to their operations as part of a wider effort to make the federal government more financially responsible. "We've already identified $20 billion in savings for next year," he said. "To help working families, we'll extend our middle-class tax cuts. But at a time of record deficits, we will not continue tax cuts for oil companies, for investment fund managers, and for those making over $250,000/year. We just can't afford it."

Oil and gas association leaders' responses varied. American Petroleum Institute Pres. Jack N. Gerard said on Jan. 28 that he was encouraged by Obama's statement that decisions should be made about opening new offshore areas to development. "These are important and necessary decisions for the American people and the American economy," he indicated.

Gerard said, "We support the president on jobs and are ready to do our part putting more Americans back to work. But to create these jobs, we will need policies that allow investment and development—policies that are pro-job, pro-consumer and pro-energy."

Noting that Obama called for passage of comprehensive climate and energy legislation, National Petrochemical & Refiners Association Pres. Charles T. Drevna added that the president did not aggressively promote carbon cap-and-trade legislation.

"He should be applauded for turning his attention to the economy, jobs, continued investment in innovation, and increased domestic energy production. A cap-and-trade climate bill would only run counterproductive to his objectives," Drevna said. "Aside from promoting new 'green jobs,' we hope President Obama will focus on preserving and creating red, white, and blue jobs, and that he will pledge to work with the American oil, gas, refining, and petrochemical community."

'Common-sense policies'

"With 1 in 10 Americans still out of work, President Obama was right to say last night that, 'Jobs must be our

number-one focus in 2010,'" Independent Petroleum Association of America Pres. Barry Russell said on Jan. 28. "We couldn't agree more and are eager to work with his administration and leaders in Congress to craft common-sense policies that will create good-paying oil and gas-related jobs through increasing access to more American energy and ensuring that higher taxes do not discourage US energy production."

Noting Obama's reference to the administration's next proposed budget, Russell said its last request called for more than $36 billion of new taxes on US oil and gas production which would have reduced investment in new production by 20-40%, and potentially would have cut domestic oil production by 20% and gas production by 12%, costing thousands of jobs.

US President Barack Obama called for more domestic offshore oil and gas development in his 2010 State of the Union address on Jan. 27. He also said that it's time to end tax cuts for oil companies. Photo from White House.

"If the president is sincere in his efforts to encourage responsible American energy production and ensuring that job creation is the No. 1 priority, these damaging tax hikes must be taken off the table," Russell said.

American Gas Association Pres. David N. Parker commended Obama for noting the critical need for increased offshore oil and gas production. "We should not, however, overlook the sustainable and immediately accessible resources of clean, abundant natural gas to be found throughout America trapped in shale. Our energy security, our environment, and millions of jobs hinge on the development of these resources," he added in a Jan. 28 statement.

He said AGA also was pleased that the president called for tax incentives for large businesses to invest in new plants and equipment. The association also would like Congress to pass an extension of the temporary 50% expensing, or "bonus depreciation," provision which expired at the end of 2009. "The extension of the bonus depreciation provision is an important incentive to encourage investments in our industry to serve new gas customers and upgrade existing facilities," he said.

Congressional responses

Congressional energy leaders also responded. "I'm pleased that President Obama continues to have energy and its connection to American jobs at the top of his agenda," US Senate Energy and Natural Resources Committee Chairman Jeff Bingaman (D-NM) said on Jan. 28. "'Green and clean' is the best way to create the American jobs of tomorrow, and I look forward to continuing to work with the president on this."

Committee member Mary L. Landrieu (D-La.) applauded Obama for promoting safe, clean nuclear power and for being open to offshore exploration. She said any energy bill should make the most of domestic resources "and our unmatched skill and innovation to reduce our dependence on foreign oil."

Republicans on the committee were critical. Sen. John Barrasso (Wyo.) said that in order for the US economy to improve, the administration should stop pursuing job-killing policies. "It should shelve the cap-and-trade scheme that would increase taxes on the American people and employers. It should ditch its bureaucratic, secretive plan to regulate carbon from small businesses. It should end the burdensome oil and gas regulations that will kill more red, white, and blue jobs," he said.

GOP energy leaders in the House also criticized Obama's remarks. "If the president really wants to spur job creation and economic growth, he will stop blocking American energy production and allow us to develop our own resources in an environmentally responsible way," said Doc Hastings (Wash.), the Natural Resources Committee's ranking minority member. "In addition to creating millions of jobs, it will create an influx of new revenue to the federal government that will help pay down the trillion dollar deficit."

"Countless energy-related jobs have been lost or prevented by the Obama administration," said Rep. Rob Bishop (R-Utah), a Natural Resources committee member and chairman of the Congressional Western Caucus. "Though 'green' jobs sound nice in speeches, the reality is that we need all jobs, not just those that fit with a special interest agenda." ✦

Obama renews call for oil taxes in 2011 budget

Nick Snow
Washington Editor

The Obama administration proposed $36.5 billion of new oil and gas taxes as it released its proposed fiscal 2011 budget. The proposed levies—which it framed as removing tax preferences to help balance the federal budget and promote clean energy—were essentially the same as the ones it presented a year earlier.

"Oil and gas subsidies are costly to the American taxpayer and do little to incentivize production or reduce energy prices," the budget request said. The White House Office of Management and Budget estimated that the $36.5 billion of new taxes over 10 years would represent about 1% of total projected domestic oil and gas revenue, it added.

Between Jan. 1, 2011, when they would take effect, and the end of 2020, OMB estimated that repealing the percentage depletion allowance would raise $10 billion, doing away with expensing of intangible drilling costs would generate $7.8 billion, and increasing independent producers' allowed geological and geophysical amortization would bring in $1.1 billion of new revenue.

The single biggest bite would be downstream, with the proposed repeal of the domestic manufacturing tax deduction for oil and gas companies. That would raise $17.3 billion over 10 years if enacted, OMB said. It also would make US refiners the only domestic business not covered by the manufacturing tax credit, which Congress enacted in response to foreign governments' subsidies of industries in their countries.

Other proposed oil and tax incentive repeals in the latest proposed budget include the exception to passive lost limitations for working interests in producing properties, which OMB said would generate $180 million over 10 years, and the deduction for tertiary injectants, which it said would bring in $67 million.

The White House also proposed repealing the enhanced oil recovery credit and the credit for production from marginal oil and gas wells, but did not project additional revenues from these moves.

Quick responses

The proposals drew immediate fire from oil and gas groups. "With America still recovering from recession and 1 in 10 Americans out of work, now is not the time to impose new taxes on the nation's oil and gas industry," American Petroleum Institute Pres. Jack N. Gerard said. "New taxes would mean fewer American jobs and less revenue at a time when we desperately need both."

"In repudiating the president's attempt last year to impose prohibitive tax policies on those who find and produce energy in America, Congress rightly recognized the important role that small, independent energy producers can play in fueling the short-term recovery and long-term revitalization of our struggling economy," said Independent Petroleum Association of America Pres. Barry Russell.

"Unfortunately, in his search for 'easy' revenue, the president appears once again to be endorsing a series of tax change that will result in fewer American jobs, less government revenue, and a tightening of our already dangerous dependence on foreign, unstable energy," Russell said.

National Petrochemical & Refiners Association Pres. Charles T. Drevna took particular issue with the administration's proposal to eliminate the tax credits refiners receive under Section 199 of the 2004 American Jobs Creation Act.

"We are disappointed that the administration has again chosen to single out the American oil, gas, and refining community for additional taxes under the guise of leveling the playing field with other corporations," Drevna said, adding, "In fact, it accomplishes the opposite and puts our members at a precarious disadvantage with foreign fuel producers."

Russell said contrary to what the White House's budget request implies, the US oil and gas industry pays more taxes and royalties than any other US business. "Very few industries have the potential to create as many high-wage jobs in our current economic climate as quickly and effectively as we do," he said, adding, "While efforts to impede that work may produce short-sighted budget relief in the near term, they will result in far less revenue, investment, and activity in American resource development in the long term."

'Knockout blow'

"For our members—the small businessmen and women of our nation's oil and gas industry—this is a knockout blow," Somerlyn Cothran, executive director of the National Stripper Well Association in Tulsa, said on Feb. 2. "Implementation of this budget proposal would mean a significant loss of jobs and a dramatic loss of tax revenues for each of the 35 states where our members are productive, contributing businesses. Plus, the resulting decrease in oil production will serve only to make America even more dependent upon foreign oil."

Cothran noted that while a marginal, or stripper, well produces 15 b/d or less of oil, US stripper wells collectively produce 20% of the country's oil or 1.2 million b/d—as much as the US imports from Saudi Arabia.

"There is a shocking difference between the 'big oil' companies and the little guys, who are Rotary Club and PTA members in their respective

hometowns," Cothran emphasized. "There should absolutely be a structural and financial difference in relation to tax subsidies between the large-scale, international oil companies and small, independent operators. This is the only way to ensure the survival of our industry's small businesses."

Marc W. Smith, executive director of the Independent Petroleum Association of Mountain States in Denver, said on Feb. 2, "I understand the temptation to go after 'Big Oil,' but the truth is that these punitive tax and fee increases will be most harmful to small businesses struggling to survive our current economic crisis. This administration continues to assure us that they are not 'anti oil and gas,' and yet every week brings some counterproductive new policy to make developing American energy even more burdensome."

Smith said the proposed tax hikes came in addition to proposed inspection fees, a nonproducing acreage fee, and a royalty rate increase in the US Department of the Interior's fiscal 2011 budget request. "Every day, I hear concerns from our members about whether they will be able to continue developing energy in the West," Smith said, adding, "I have to wonder if shutting down all energy production on public lands is the ultimate goal of this administration. They are forgetting that these are vital energy resources that belong to all Americans."

Other terminations

The proposed budget also calls for termination of US Department of Energy oil and gas research and development programs, which the 2005 Energy Policy Act had authorized. OMB said in addition to promoting fossil fuels instead of clean energy, the R&D typically funds development of technologies that can be commercialized quickly, such as improved drill motors.

Eliminating the EPACT-mandated programs would reduce DOE fossil fuel outlays by $200 million over 10 years to $240 million, according to the proposed budget. In addition, OMB

Rendell's plans in Pennsylvania

Pennsylvania Gov. Edward G. Rendell gets it. His state is on the verge of a natural gas development boom, so he has ordered the Department of Environmental Protection (DEP) to hire 68 new inspectors and other employees. He also plans to ask the Keystone State's general assembly to enact a severance tax.

"Interest in Pennsylvania's Marcellus shale formation is greater than ever before and as natural gas prices continue to rise, that interest will only increase," Rendell said. "In fact, the industry has told us that they expect to apply for 5,200 permits to drill in the Marcellus shale this year—nearly three times the number of permits we issued in all of 2009."

Rendell said, "Given these conditions, an extraction tax is gaining widespread support across our state and I will again ask the general assembly to enact such a levy. It is fair and affordable to drillers. They know it, and so do members of the House of Representatives who voted for it last year."

Stephen Rhoads, president of the Pennsylvania Oil & Gas Association, indicated that the group opposes the proposal, which state lawmakers rejected in 2009. The Marcellus shale gas industry's maturity is at least a decade away, he told the Harrisburg Patriot News.

Exempt from freeze

DEP's new employees will be exempt from a hiring freeze instituted last year, Rendell said. Their salaries would come from higher well permitting fees which the general assembly put in place in 2009 with industry and environmental groups' support. It was the first such increase since 1984, he said.

"We were able to hire 37 additional inspectors and permitting staff in 2009, but the industry's projected growth in 2010 means that we need additional inspectors to ensure oil and gas companies follow environmental laws and regulations," the governor added. DEP inspected 14,544 wells and took 678 enforcement actions in 2009, he said.

Rendell said the state also will amend its regulations to strengthen well construction standards and define an operator's responsibility to respond to gas migration issues.

Specific provisions

Specifically, the new standards will require well casings of Marcellus shale and other high-pressure wells to be tested and constructed of specific oilfield grade cement. They will clarify a producer's responsibility to restore or replace water supplies which are used.

They also will establish procedures for operators to identify and correct gas migration problems without waiting for DEP's direction, and require them to notify the agency immediately in such cases. Operators also will be required to inspect each well quarterly, report the results to DEP annually, and notify the agency promptly if problems such as overpressured wells and defective casings are found.

The new regulations were offered for public comment on Jan. 29. Rendell said that they would make Pennsylvania's standards comparable with other gas-producing states' or, for well casings, more rigorous. ✦

said, a recent Government Accountability Office report said DOE oil and gas programs are dwarfed by industry R&D ($20 billion for 1997-2006), and DOE has often conducted research in areas which already received private sector funding, especially for evolution advances and incremental improvements.

"The program is primarily operated by a private sector consortium; only 25% of the funding is spent through the National Energy Technology Laboratory," it indicated.

The White House also proposed ending the ultradeepwater research program at DOE, which it said would save $50 million from fiscal 2010 funding levels, and unconventional fossil technology R&D, which it estimated would save $20 million. It also recommended canceling the planned expansion of the Strategic Petroleum Reserve, which it said would save $71 million, and ending DOE's gas technology research support, which it said would save $18 million.

Responding to a reporter's question at the US Department of the Interior's budget briefing, Interior Sec. Ken Salazar noted that EPACT tax incentives he supported in 2005 as a US senator from Colorado have accomplished their purpose. "They were designed to provide incentives to explore the deepwater Gulf of Mexico. We know what's out there now, and that the oil and gas industry is interested," he said.

Salazar added that a proposal in the fiscal 2010 budget request to impose a severance tax on new gulf production is gone from the latest proposal. The money it would have raised has been made up elsewhere, he said. ✦

US Interior budget request contains cost increases

Nick Snow
Washington Editor

US Interior Secretary Ken Salazar said the nation's oil and gas industry will remain an important contributor to resource management as he presented the Department of the Interior's proposed fiscal 2011 budget on Feb. 1. He also said industry would have to pay more to produce those resources.

Noting that he has ordered the US Bureau of Land Management to review its royalty rates, which he said are 20-30% less than what Texas collects, Salazar said, "We believe taxpayers should get a fair return on their resources."

He also noted that markets—and not federal policies—will determine how extensively oil and gas resources on public lands are developed. "Some people will argue that a smaller number of rigs drilling reflects less interest. The fact is they aren't out there right now because natural gas prices are depressed," Salazar said.

The budget request anticipates fiscal 2011 revenue of $10 million from a new onshore inspection fee, which Interior said would cover 25% of expected oil and gas inspection costs, $10 million from a proposed doubling of an offshore inspection fee established under the 2010 budget, and $2.5 million from a $4/acre fee for nonproducing leases.

DOI also will ask Congress to repeal Section 365 of the 2005 Energy Policy Act, which diverts mineral leasing receipts from the US Department of the Treasury to a BLM permit-processing fund and prohibits BLM from charging producers for processing onshore drilling permit applications. BLM would promulgate regulations to begin charging to process the applications once the provision was repealed.

Asked if the additional costs might prove excessive for producers, Salazar replied: "I think the oil and gas industry will do just fine."

Negative impacts

In a Feb. 2 position paper, the Independent Petroleum Association of Mountain States warned that the higher costs would remove capital from domestic energy development and production, and cost more jobs.

"Operating on federal lands is already much more time-consuming and costly compared to operating on private lands," it said. "The sum total of all the negative proposals from DOI and the increase in fees and taxes will be a decrease in production on federal lands, a reduction of jobs that result from the productive use of public lands, and a decrease in the production of energy owned by Americans."

DOI's budget request proposed saving money by having producers pay a bigger share of programs' administrative costs. The IPAMS position paper noted that the industry "already more than pays for the administration of the federal onshore gas and oil program by return $46 for every dollar spent. When income and other taxes are factored in, companies return $123 for every dollar spent administering the program."

The proposed inspection fees, nonproducing acreage fee, and royalty rate increases would be in addition to $36.5 billion of tax increases in the proposed federal budget which would reduce capital investment in domestic oil and gas by 30-50%, said Marc W. Smith, IPAMS executive director.

"Every day, I hear concerns from our members about whether they will be able to continue developing energy in the West," Smith said, adding, "I have to wonder if shutting down all energy production on public lands is the ultimate goal of this administration. They are forgetting that these are vital energy resources that belong to all Americans."

Drilling permit pilot

In an interview following DOI's bud-

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get presentation, BLM Director Robert V. Abbey said a pilot program designed to facilitate drilling permit application processing will be retained. "We've learned a lot from it, particularly the benefit of involving other government agencies and stakeholders before the final decisions are made," he told OGJ.

He also said new onshore leasing guidelines that he and Salazar announced on Jan. 6 were a response to an increasing number of protests and their resulting delays. Protests were filed against half of BLM's proposed oil and gas leases during 2009, he pointed out. "We're not naive. We realize our reforms won't satisfy everybody," Abbey added. "But by proceeding more carefully, we'll be better able to defend our decisions if they're challenged in court."

DOI's fiscal 2011 budget request anticipated a nearly 45% increase in receipts to an estimated $13.98 billion from fiscal 2010's projected $9.65 billion from coal and hard-rock mineral as well as oil and gas activity. US Outer Continental Shelf receipts were expected to jump $3.69 billion year-to-year, or 102%, to $7.23 billion. Onshore receipts were budgeted to climb by $651 million, or 16%, to $4.04 billion.

Salazar said he expected to make announcements soon that he hopes will clarify uncertainties surrounding the department's offshore oil and gas leasing program. But he added that DOI and MMS have had to address two 5-year OCS programs simultaneously, which has caused delays.

The proposed budget said that the OCS program for 2007-12 includes six lease sales in fiscal 2011, including two in the Gulf of Mexico and one in the Beaufort Sea off Alaska. It said that a "special interest" sale in Alaska's Cook Inlet also could be held. "However, the resolution of ongoing litigation and the level of industry interest in certain frontier areas may affect the number of sales actually held," it continued.

Royalty management

MMS would receive $364.8 million under the proposed budget, $16.5 million more than the enacted level for fiscal 2010. The money includes $10 million to terminate the royalty-in-kind (RIK) program and move back to the more traditional cash-based royalty-in-value program, MMS officials said.

A reduction in outlays from royalty receipts previously used to fund RIK activities will offset a requested appropriations increase to enhance compliance activities and increase audit capacity, they indicated.

"This budget request will enable us to effectively terminate the RIK program without any net increase in the cost of our royalty management work," MMS Director S. Elizabeth Birnbaum said in a statement. "It reflects our commitment to ensuring that our federal and American Indian energy and minerals revenues are accurately reported and paid in compliance with laws, regulations, and lease terms."

The request also contains $4.4 million to fund technology to assess oil and gas potential and fair market value of OCS tracts offered for lease, according to MMS. It said that the money would be used to fund inspections, which have increased because of the number of new deepwater facilities on the OCS. Additional resources totaling $3.7 million will be used to improve royalty compliance and ensure companies are paying proper royalties on processed and transported gas, it added.

MMS and BLM also would receive more money for renewable energy projects under the proposed budget, reflecting a major Obama administration priority. "We're very aware of climate change and the need to consider potential impacts," Abbey said. "We also recognize that there's still a lot of oil and gas left to develop—responsibly—on our public lands." ✦

UK offers tax boost package as 26th bidding round opens

Eric Watkins
Oil Diplomacy Editor

The British government announced a package of tax incentives worth up to £12 billion aimed at unlocking oil and gas reserves in the Atlantic frontier west of Shetland—an area estimated to contain 20% of the country's remaining unexploited oil and gas reserves.

"The government recognizes the importance of the UK oil and gas industry to our economy and the dependable foundation it provides for the UK's energy security," said Chancellor of the Exchequer Alistair Darling.

"While we are trying to reduce our dependence on fossil fuels, we must and do recognize that this will be a long transition and our oil and gas reserves will continue to play a vital role in supplying our energy needs for many years to come," Darling told members of Parliament.

"Today's announcement will continue to support investment in the North Sea, the fuel this delivers, the contribution this makes to our economy, and the jobs and skills the industry supports and develops," he said.

"The legislation, if approved by the House, will extend the field allowance, announced in Budget 2009, to remote deepwater gas fields, which are found in the west of Shetland area," Darling said.

"Approval of the legislation will be sought no later than the end of March," a Treasury spokesman said.

"One project that could stand to benefit from the allowance is the project to develop the Laggan and Tormore

fields," the Treasury spokesman said. "The project partners will consider the sanction of the project in Spring 2010."

"If the project is sanctioned and proceeds on schedule, the first production of gas from Laggan and Tormore is expected by 2014," the spokesman said.

Malcolm Webb, chief executive of Oil & Gas UK, welcomed the announcement as a response to his organization's calls for support from the government.

"While we still have to study the details, we are delighted that the government has responded to our calls for the allowance to be extended to the West of Shetland area," Webb said.

"This could result in early investment of over £2 billion and another £12 billion over the next 8 years, ultimately bringing almost 2 billion [boe] of oil and gas into production," Webb told the Scotsman newspaper.

"The establishment of this gas-delivery infrastructure will stimulate exploration as it will enhance the viability of future discoveries in this frontier area," said Webb.

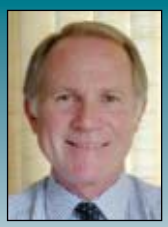
Offshore leasing round

The tax incentive coincided with an announcement by Britain's Department of Energy and Climate Change of a new round of offshore licensing aimed at giving a further boost to the UK's offshore oil and gas industries.

"This record-breaking 26th Round includes areas of the Continental Shelf not as yet explored, and will provide a new boost to activity in the basin," said Britain's Energy and Climate Change Minister Lord Hunt. "The round will help to secure the future of the UK's oil and gas industry which still provides three quarters of our energy needs and some 350,000 jobs," Hunt said.

"Estimates suggest there are still around 20 billion boe, or possibly more, to be produced, and this latest licensing round will help ensure we realize this potential," he said.

"As we make the transition to a



Swordfish? Not likely!

The oil and gas industry does not usually have to worry too much about swordfish, but might that situation have to change after reports from Angola last week?

Traders there said a school of swordfish created force majeure after puncturing a flexible loading pipeline feeding oil to tankers from the 200,000-b/d Girassol field.

"Total confirms that a force majeure was declared," said a company spokeswoman, adding, "There have been delays in the loading of tankers, but the loading was not halted."

Traders said it was not the first time swordfish had interrupted Angola's oil and gas industry, citing a similar situation in January 2009 when BP PLC shut oil production from its Greater Plutonio fields off Angola "for operational issues."

Force majeure

BP declared "force majeure" on Plutonio oil exports as a result of the shutdown, where oil and gas production had restarted in mid-October following a previous production halt in mid-August after an incident at a gas plant at the facility.

No one at BP has ever detailed publicly what the incident may have been, but neither does anyone at the British firm ever mention swordfish in connection with the shutdown at Plutonio.

Still, even in the absence of any mention of swordfish at Plutonio, there is a possible—and fascinating—connection with the current problems faced by Total at Girassol.

Around the time of the shutdown at Plutonio in August 2008, Subsea 7 Inc. confirmed that it had agreed to a $150 million pipeline engineering, construction, and installation contract for a gas export pipeline project for BP.

Enter Subsea 7

Subsea 7 said its workscope was to engineer, construct, and install a 74-km, 12-in. gas line from Block 18 to a gas delivery line on Block 3.

In addition, Subsea 7 was to perform the tie-in of the lines, including installing three client-supplied subsea manifold systems and a 1,000-m umbilical before carrying out the final commissioning of the completed gas export system.

Back to the present: The so-called "swordfish" incident came a week or two after Subsea 7 reported the successful completion of the Girassol line repair project for Total E&P Angola.

The project was an entirely diverless pipeline repair in 1,350 m of water and was based on a technical design competition issued by Total that resulted in Subsea 7 being awarded the contract for the design, manufacture, testing, and operation of a new deepwater pipeline repair system (PRS).

The PRS would then be used on the repair of a damaged 12-in. water-injection line in Girassol field. According to Subsea 7, final confirmation of the repair was achieved by a line leak test from the Girassol floating production, storage, and offloading vessel that was completed in December 2009.

Swordfish? Using Occam's Razor, where entities must not be multiplied beyond necessity, the simpler explanation would be: pipeline leak. ✦

low-carbon future, we must ensure we have secure energy supplies by making the best use of our indigenous energy resources in a safe and environmentally sound way," he said.

The blocks offered include a number relinquished under the government and industry's "Fallow Initiative," which stimulates activity on blocks where there had been no significant activity for 3 years.

The 14 blocks that were deemed as fallow in 2009 have either been fully, or partly, relinquished in time to be on offer in this round.

In addition, the ministry said that "the majority of areas licensed in the first licensing round in 1964 that have not been allowed extensions have been relinquished and are included for offer in the 26th Round."

The ministry also said the government has introduced "a new frontier license with an extended 9-year exploration term for the West of Scotland area, which aims to encourage oil and gas exploration in an area in which geological data is as yet scant." ✦

Three companies submit oil sands EIAs to Alberta

Korea National Oil Corp., Osum Oil Sands Corp., and Shell Canada Ltd. recently submitted to Alberta environment impact assessment reports concerning planned oil sands projects.

KNOC's EIA concerns the Blackgold expansion project. The report says KNOC continues to evaluate the potential of 15 sections of oil sands leases, about 10 km southeast of Conklin. Its proposed expansion project is adjacent to and integrated with its initial 10,000 b/d Blackgold project. KNOC holds 100% working interest in the leases and has identified sufficient reserves to support an additional 20,000 b/d of bitumen production over 25 years (2015-40).

KNOC initially plans to drill 28 steam-assisted gravity drainage (SAGD) well pairs from three pads, together with some modification of the central processing facility (CPF) and associated infrastructure to facilitate bitumen recovery on the site and its export off the site either by pipeline or truck. It plans additional production wells and well pads as required to maintain production during the project's life.

Osum's EIA is on its proposed Taiga project about 20 km north of Cold Lake. The project calls for using SAGD for extracting bitumen for much of the development with cyclic steam stimulation (CSS) starting later in the project's life.

Osum plans to install a 35,000 b/d bitumen processing facility and have a 30-year project production life. Pending regulatory approval, Osum expects construction to start in third-quarter 2011 with production starting in second-quarter 2013.

Shell's EIA concerns the Peace River in situ expansion of the Carmon Creek project. Shell continues to evaluate development of its in situ oil sands leases 40 km northeast of Peace River. Shell's Peace River complex is licensed to produce 12,500 b/d of crude bitumen using thermal techniques.

The company initiated development of its Peace River leases in the 1970s and expanded the in situ project in 1985 to its current operating capacity.

Based on its resource delineation and recovery evaluation programs, Shell proposes to increase thermal bitumen production from its Peace River leases to about 80,000 b/d.

It plans to use vertical steam drive thermal enhanced recovery methods to produce the bitumen. The project also may include new central processing facilities, cogeneration of power and steam, multiple well pads, and a steam distribution and bitumen gathering system as wells as additional infrastructure such as roads, natural gas and condensate supply pipelines, a diluted bitumen sales pipeline, and electrical power lines. ✦

Iran condemns US Senate for gasoline sanctions

Eric Watkins
Oil Diplomacy Editor

Iran has condemned the US Senate for approving gasoline import sanctions against the Middle Eastern country, saying it follows Washington's traditional line of ineffective policy-making.

"We have repeatedly announced that the sanctions the US has imposed against our people over the past 31 years…have had no result but solidifying the resolve and intention of our nation to seek independence and self-sufficiency and attain highest levels of sophisticated technology," said Iranian Foreign Ministry spokesman Ramin Mehmanparast.

"We have always announced that the war-mongering and military build-up policies of the unilateralist countries under the pretext of solving regional crisis are wrong as their failure has repeatedly been emphasized," Ramin said.

Iran's criticism came after the US Senate voted to strengthen existing sanctions against Iran and impose new ones which target its gasoline supplies as part of Washington's effort to dis-

suade Tehran from pursuing nuclear weapons and cracking down on internal dissent.

"We have all watched the Iranian regime oppress its own people on the streets of Iran and continue to defy the international community on nuclear issues," said Democratic Senate Majority Leader Harry Reid (Nev.). "That is why it is so important that we move this legislation forward quickly."

Gasoline prices rising

This week's Senate measure coincided with reports that Middle East gasoline prices rose this week due to slightly higher demand in the region—especially from Iran, one of the region's main consumer markets.

"What we are seeing is that demand has been picking up as Iran starts its stockbuild exercise in anticipation of stricter sanctions from the US," said one Asian-based trader.

Earlier this month, traders said Iran's January gasoline imports were expected to rise by 23% over December, as the Islamic republic continued to build stocks as the threat of stricter sanctions loomed.

They said Tehran was likely to import as much as 128,000 b/d of gasoline from the international spot market or about 15 cargoes. The increase amounted to 25,000 b/d over the 103,609 b/d of gasoline Iran imported in December.

"There was a flurry of activities towards the end of the month. It looks like they are now building inventories," said one Middle East-based trader at the time.

That buildup came after the US House of Representatives passed legislation in December authorizing President Barack Obama to levy sanctions on companies that directly provide gasoline to Iran, along with firms that provide insurance and tankers to facilitate fuel shipments (OGJ Online, Dec. 16, 2009).

At that time, reports said Iran was already storing about 1.45 million bbl of gasoline on tankers as it slowly built inventories in anticipation of the tougher sanctions regime.

Traders said the fuel was being stored on at least six oil tankers anchored in Iranian waters, a buildup that had been steadily taking place since September, traders said.

"They are definitely in a bit of a bind, they want to build inventories but at the same time they are struggling to find the money to buy surplus product," a trader said. ✦

Indonesia rejects development plan for LNG project

Eric Watkins
Oil Diplomacy Editor

Indonesia's upstream oil and gas regulator BPMigas rejected a plan of development for an LNG project proposed by Energy Equity Epic Sengkang (EEES), a wholly owned subsidiary of Energy World Corp. (EWC).

"The plan of development is not backed up with valid data," said BPMigas Chairman R. Priyono, adding, "How can we approve the plan of development if we don't even know the reserve data?"

Priyono said BPMigas rejected EEES's work program and budget for development of new gas reserves because they don't follow the standard operating procedures. "It's strange they want to drill without an initial seismic survey," Priyono said.

EWC's general counsel Thompson Situmorang said a 3D seismic survey would be expensive for a marginal field like Sengkang. "We propose a mini-seismic method, which will be more economical and cause no harm for the environment, but BPMigas has not agreed yet," he said.

Thompson claimed the development plan is "still under discussion" with government officials.

EEES holds the production-sharing contract for the Sengkang Block, which is estimated to hold reserves of 2-4 tcf of recoverable gas. Currently, the gas is being used to fuel the 195-Mw gas-fired combined-cycle Sengkang Power Plant operated by EWC subsidiary PT Energi Sengkang.

EWC is considering construction of an LNG plant near the Sengkang block, built with an initial production capacity of 2 million tonnes/year and later rising to 5 million tpy, according to EWC Chief Executive Stewart Elliot.

Elliot said the company had additional reserves that could be processed by the proposed LNG plant, a point reiterated by EWC Executive Director Brian Allen.

During a hearing with the House of Representatives Commission VII overseeing energy and mineral resources, Allen said the new reserves would be able to provide 300-500 bcf of gas for the proposed LNG plant

Allen said the proposed LNG development would cost EWC $500 million and "a small percentage" of the LNG would be exported to finance the construction and operation of the facility.

According to analyst BMI, rejection of the EEES proposal will set back plans for the liquefaction plant and is likely to delay the launch of LNG supplies to state-owned gas distributor PT Perusahaan Gas Negara (PGN).

BMI said PGN, following an agreement signed last September, had hoped to purchase 1.5-5 million tpy of LNG from Sengkang to feed its planned regasification terminals in North Sumatra and Java.

EWC owns 100% of the Sengkang

production-sharing contract. The project has a take-or-pay power sales contract until 2022 to supply power to state-owned power utility PT Perusahaan Listrik Negara. EWC also owns 95% of the Sengkang power plant, while Medco Sengkang holds a 5% interest. ✦

Indonesia seeks to purchase LNG carriers

Eric Watkins
Oil Diplomacy Editor

Indonesia's state-owned PT Pertamina said it will open a bidding round to procure ocean-going vessels to be converted into floating LNG-receiving terminals in East and West Java.

"We expect to hold the bidding by the end of February," said Pertamina Pres. Director Karen Agustiawan. "There are about two or three vessels that meet our criteria, but I cannot disclose that now," she said.

Regasification facilities would be constructed aboard the vessels once they are ready, Karen said. "The work will take about 9 months," she said, adding that the floating LNG terminals would require other facilities, including deepwater pipelines.

"The LNG terminals are expected to be in full operation by September," said Karen, referring to plans of Pertamina to construct two LNG terminals in West and East Java, each able to store 500 MMcf of gas. She said the facilities would cost $200 million each.

Indonesia has no LNG receiving terminal but is seeking supplies of gas and coal to meet rising domestic demand for power and to reduce consumption of oil as its reserves dwindle and production falls.

Karen said Pertamina would invite selected vessel owners to participate in the joint venture operating the terminals. She said Pertamina "must" hold majority interest in the JV because "we don't want the vessels to be leased; we want to own them."

Pertamina and state gas distributor PT Perusahaan Gas Negara have been ordered by the government to construct the LNG-receiving terminals to help state-owned power utility PT Perusahaan Listrik Negara secure gas supply for its power plants.

The proposed bidding for LNG carriers follows an announcement last month that Pertamina plans to buy 12 small-capacity gas tankers at a cost of $333 million this year, with the order expected to be finalized in 2012-13.

Four of the vessels are to carry LPG, two with a capacity of 3,500 cu m and the two with a capacity of 23,000 cu m. Suhartoko, Pertamina's senior vice-president of shipping, said a tender for the four vessels was already under way, and "will require a total investment of $128 million."

Suhartoko said Pertamina was waiting for shareholder approval to procure the remaining eight small-capacity tankers, which he estimated would cost a total of $205 million. He said the ships, all to be used in Indonesian waters, would range from 3,500 to 17,500 dwt. ✦

IADC/SPE: BP changes training, development focus

Guntis Moritis
Production Editor

To meet the increasing complexity of drilling and completing wells in higher pressure and temperature environments that are deeper and have longer deviations, Scott Sigurdson, vice-president of drilling and completions for BP PLC said the company's focus now is on training and development of engineers as specialists rather than its previous emphasis on generalists.

Sigurdson gave his remarks Feb. 2 at the International Association of Drilling Contractors and Society of Petroleum Engineers Drilling Conference & Exhibition in New Orleans during a plenary session to discuss the topic: Is technology outpacing competency?

He said wells now are being planned or drilled with bottomhole temperatures of 500° F. and wellhead pressures of 25,000 psi. Well deviations are also greater such as in the case of BP's planned development of the Liberty field off Alaska's North Slope.

The wells drilled from an existing island will have step-outs of up to 40,000 ft and 10,000-ft true vertical depths. Parker Drilling designed and constructed the rig, which arrived on ANS in July 2009 (OGJ Online, Nov. 23, 2009).

A BP predecessor discovered and appraised the field, an eastern satellite of Prudhoe Bay oil field, in 1997. Liberty is in federal waters 5 miles off the coast and 11 miles southeast of giant Endicott oil field (OGJ, Nov. 7, 2005, Newsletter).

Sigurdson said that BP will no longer assume competency but will require testing which is already being done for entry level engineers and is also being developed for engineers with 3-10 years of experience.

BP has developed specific roadmaps for personnel advancement, he said. For example drilling engineers have 15 elements while completion engineers have 18 elements.

The roadmap includes job experience, formal training, and assessment elements that still need to be finalized, Sigurdson said. ✦

OGJ FOCUS

Fall may be imminent for Kansas Cherokee basin coalbed gas output

K. David Newell
Kansas Geological Survey
Lawrence, Kan.

Natural gas production in the Kansas portion of the Cherokee basin (southeastern Kansas) for 2008 was 49.1 bcf (Fig. 1).

This constitutes about 13% of the annual gas production in the state, and for the last few years it has offset gas production declines elsewhere in Kansas.

The great majority of Cherokee basin gas production is now coalbed methane (CBM). The major producers are Quest Energy LLC (23.2 bcf in 2008); Dart Cherokee Basin Operating Co. LLC (10.5 bcf); and Layne Energy Operating LLC (6.1 bcf).

Production declines in CBM wells depend on the age of the well, with relatively steep initial declines that stabilize to low rates of decline in older wells. The average yearly production decline for all CBM wells in southeastern Kansas can be used to infer the number of wells that have to be drilled each year to maintain production.

If the last quarter of 2008 is an indication, present drilling for CBM in Kansas is about one third of the activity before the crash in gas prices in late 2008. Only about 200 to 300 new producing gas wells may have been drilled in the Cherokee basin in 2009. With the number of new wells being so low, CBM production in Kansas is probably at or near its historic peak.

Historical perspective

Gas production in Kansas is reported to the state by oil and gas operators for every lease, but the type of production (CBM, shale gas, or conventional) need not be specified.

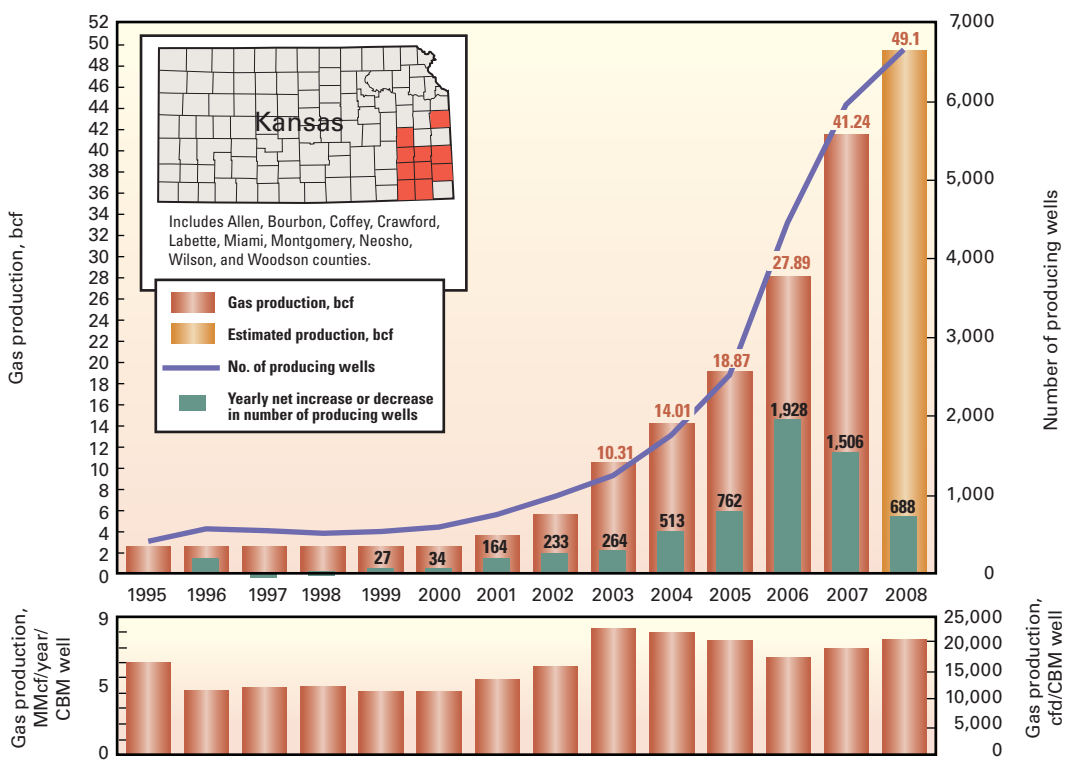
Specification of the producing zone for some leases, however, is positive identification of CBM production, but even in most of these cases the identification of the producing zone is generalized ("Cherokee Group coals"), and individual coal beds producing gas are usually not reported.

As a consequence, a precise figure for CBM production in the state is not possible, but historically, relatively little CBM was produced before 2000.

If southeastern Kansas annual gas production prior to 2000 (2.3 bcf/year) is considered as a baseline for conventional gas production (Fig. 1), approximately 165 bcf of CBM have been pro-

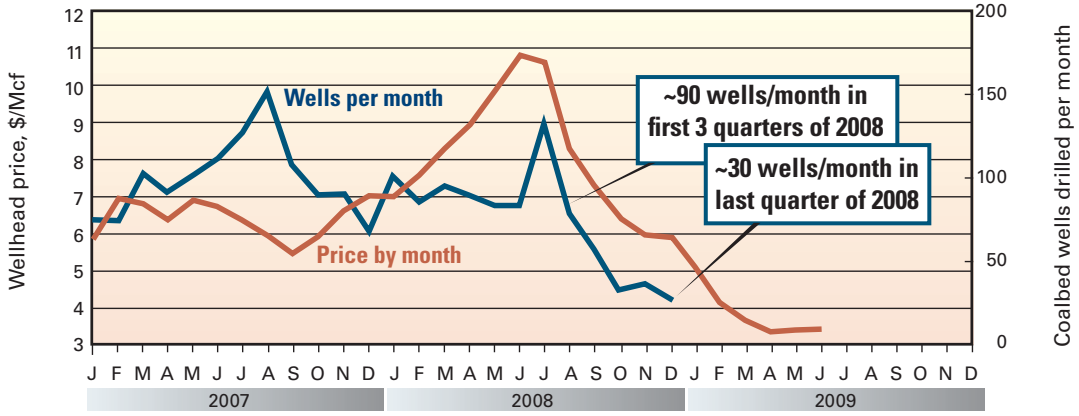
YEARLY GAS PRODUCTION IN SOUTHEAST KANSAS*

Fig. 1



SOUTHEAST KANSAS COALBED WELLS DRILLED AND GAS PRICES

Fig. 2



Wells from Kansas Geological Survey web site records (2009 statistics not yet compiled); gas prices from US Energy Information Administration (http://tonto.eia.doe.gov/dnav/ng/ng_sum_lsum_dcu_nus_m.htm).

duced cumulatively since 2001, which is the year southeastern Kansas gas production started rising dramatically.

CBM production data for Kansas, and associated links, are given on the Kansas Geological Survey (KGS) web site.[1]

2008 production snapshot

Production data for 2008 are almost complete with only a few records remaining to be submitted, but the most prolific CBM producers in Kansas in 2008 were (1,000,000 Mcf minimum cutoff [1 Mcf = 1,000 cu ft]):

- Quest Energy (23,245,227 Mcf, 2,247 producing wells).
- Dart Cherokee Basin Operating (10,471,873 Mcf, 1,084 producing wells).
- Layne Energy Operating (6,116,041 Mcf, 864 producing wells).

Most CBM in southeastern Kansas is from Middle and Upper Pennsylvanian high-volatile B and A rank bituminous coals at 800 to 1,200 ft depth.

To this writing in November 2009, approximately 6,800 wells have been drilled for CBM in eastern Kansas. The peak for drilling was in 2006. Successive declines in wells drilled were recorded in 2007 and 2008 (Fig. 1).

The compilation of drilling data for 2008 is nearing completion, and it is clear that the following companies are the most active according to wells spudded in 2008:

- Quest Energy (304 wells).
- Dart Cherokee Basin Operating (166 wells).
- Layne Energy Operating (134 wells).
- Cherokee Wells LLC (130 wells).
- All others (171, with no single company spudding more than 30).

Some of these 905 wells were dry holes, for to date 688 producing wells have been reported for 2008 in the 10 counties in Fig. 1. The number of wells spudded monthly for CBM commensurately dropped with the steep decline in gas prices starting August 2008 (Fig. 2).

Only about 30 wells/month were drilled in the last 3 months of 2008, whereas in 2007 and the first half of 2008, some 90 wells/month were being drilled. This low rate of drilling will likely continue in 2009, for gas prices in 2009 are even lower than they were in the last quarter of 2008—hovering between $3.25 and $5/Mcf, but periodically even dipping below $3/Mcf and sometimes rising above $5/Mcf.

All this raises the question: How will the decrease in price and drilling affect CBM production volumes in coming months? The answer may be inferred from analysis and projection of drilling and production statistics—specifically, with a calculation of the number of wells necessary to maintain production if present production declines at a predictable rate. This decline rate thus needs to be determined.

Analysis of past production

Production data for oil and gas leases are collected by the Kansas Corporation Commission and made available to the public on the web site of the KGS.[1]

Monthly production is recorded for leases, not individual wells, and in the situation of CBM production, it is not usually tied any specific coal seam. Virtually all wells are vertical and are completed in several coal seams.

A large majority of leases are reported as single-well leases, thus decline statistics for the individual wells constituting these leases can be calculated. Nevertheless, the lease production database is imperfect.

Operators may have varying attention to detail, and human errors in reporting and entry of the data after submission can create anomalies. For example, upon direct consultation with operators, it was determined that some "single-well leases" with suspiciously high rates of production turned out to be multiwell leases, or they were actually conventional gas wells with initial flush production.

An additional problem in ascertaining annual decline rates for CBM wells in Kansas is that most wells so far have short production histories. For example, wells drilled and completed in 2007 probably hit their peak production in 2008, and their annual rates of decline have yet to be ascertained because their 2009 production is still pending.

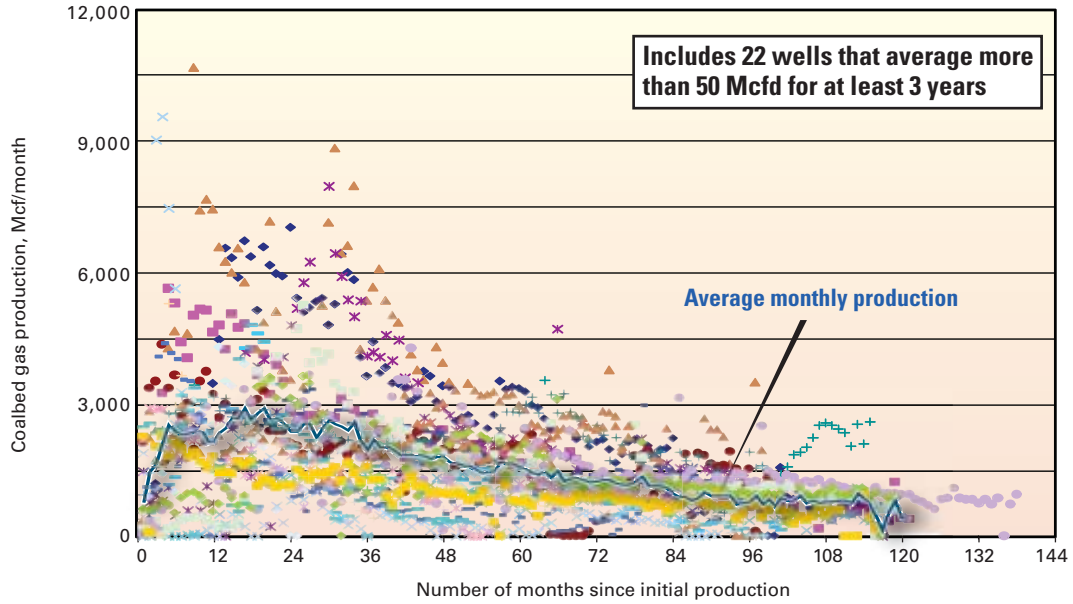
The production obtained from CBM

wells differs from conventional gas wells. Conventional gas wells typically have their best production 1-2 months after being brought on production, whereas production from CBM wells increases gradually with peak production occurring several months after initial reported production.

This production characteristic is actually useful for identifying CBM wells in the Kansas production database. Almost 12 years of production data for 22 CBM wells in eastern Kansas[2,3] (Fig. 3) show drastic month-to-month variations, probably due to geological, engineering, and mechanical influences. When averaged though, these wells show a relatively well-behaved production curve typifying CBM production, with building, peak, and declining phases (Fig. 3).

SOUTHEAST KANSAS COALBED GAS PRODUCTION BY WELL

Fig. 3



Source: Compiled by T.R. Carr (from Newell and others, 2002, 2004)

A distribution of CBM maximum monthly production rates (Fig. 4A), based on 2,973 single-well leases in southeastern Kansas, indicates that the average CBM well produces 66.7 Mcfd (2,000 Mcf/month) at its peak rate. Median maximum-rate per well per day is 48.9 Mcfd (1,466 Mcf/month).

The median may better typify CBM production because the average is influenced by a statistical "wing" of relatively prolific gas wells (Fig. 4A), some of which may be conventional or unreported multiple-well leases.

By monthly production, the most productive confirmed CBM well is the Dart Cherokee Basin Operating 2-26 'D' Orr, in southern Wilson County, which recorded 18,461 Mcf in July, 2004. This well is completed in the Bluejacket coal but may have a component of conventional production due to a sandstone in stratigraphic proximity to the coal.[4]

The time necessary for a well to reach its maximum monthly production rate (Fig. 4B) shows a similar type of distribution to the production-rate diagram (Fig. 4A). CBM wells reach their maximum rate 14 to 15 months on average after reporting their initial production. The median value is 10 months.

These results roughly agree with data collected by Ebers[5] on 96 wells in the Cherokee basin, where two thirds of them experienced peak production 7 months after the start of dewatering and the remaining wells took 8 months or longer.

Inferring future production

Future CBM production can be inferred by comparing the average production decline for producing gas wells drilled in previous years with the expected increase in production from wells drilled in the latest year.

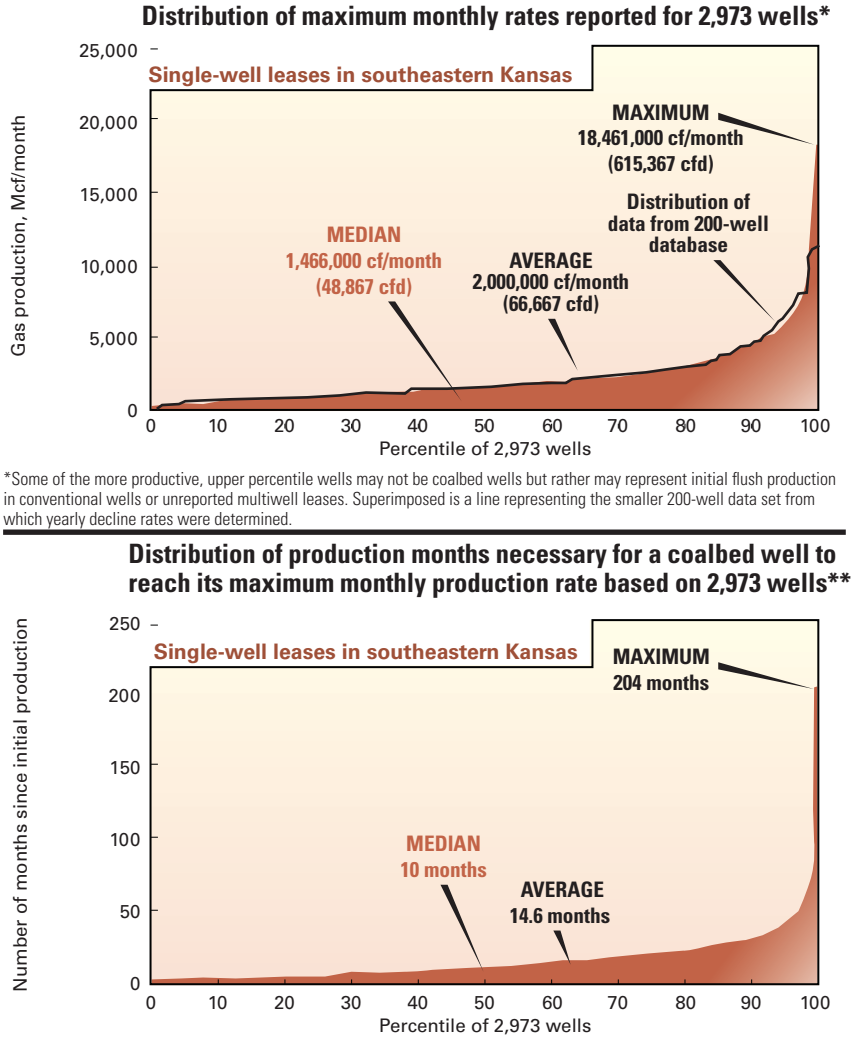
Considering that month-to-month production data vary greatly for almost every well (Fig. 3), a yearly time-scale was chosen to attempt to "damp out" the noise inherent in monthly production rates. A database of 200 wells selected in the 10 counties in southeastern Kansas with considerable CBM production (Fig. 1) was compiled so that a reasonably accurate (but nevertheless generalized) decline estimate could be determined and then applied to the larger population of CBM wells in this region.

Superimposing the monthly peak production distribution for this 200-well database on the distribution for 2,973 wells for southeastern Kansas (Fig. 4A) shows that the cumulative distributions of maximum monthly production in both databases are virtually identical.

In addition, present production of wells in the 200-well database (184 of which are still active) is 20,528 cfd, which is virtually identical to the average daily production for all wells in 2008 (20,249 cfd; Fig. 1). The 200-well database can therefore serve as a reasonable proxy in determining production characteristics for the larger database.

SOUTHEAST KANSAS COALBED GAS PRODUCTION DISTRIBUTIONS

Fig. 4



*Some of the more productive, upper percentile wells may not be coalbed wells but rather may represent initial flush production in conventional wells or unreported multiwell leases. Superimposed is a line representing the smaller 200-well data set from which yearly decline rates were determined.

**The inordinately long periods of time for the upper percentiles may actually represent wells that have had new producing zones added or other workover operations performed.

Prediction of future CBM production is approached in two ways.

The first method is simpler than the second, but generalizations have to be made for both methods. The first way (Method 1) is to apply a likely decline rate to the latest annual production (49.1 bcf in 2008) so that the hypothetical drop in production in 2009 can be determined if no new wells were drilled in 2009. The volume of this production decline can be compared with the expected production from new wells drilled in 2009.

The second way (Method 2) is more complicated than the back-of-the-envelope calculation utilized in Method 1. Method 2 models the production history of southeastern Kansas using the number of wells drilled annually, their estimated annual production, and likely annual decline rates based on their age.

Method 1

The month of peak production is selected as the anchor-point for all subsequent production declines.

For purpose of simplification, a typical CBM well is assumed to reach its maximum production 1 year after its initial reported production. This 1-year assumption is close to reality, for data depicted in Fig. 4A indicate the median time to reach maximum production is 10 months, and the average is 14-15 months.

The first year of production is typified by increasing monthly production. It is identified as "year 1," and it presumably culminates with the month of maximum production. The 12 months of production after the peak month constitutes production of "year 2," the following 12 months constitute "year 3," etc.

A production decline percentage can be calculated for year 3 by the conventional method of comparing its production to that of year 2 by the formula:

$$(V_{Year2}–V_{Year3})/V_{Year2} \times 100 \quad (1)$$

where V is yearly production volume.

This production decline percentage can be calculated for individual wells or for the summed production of various groups of wells, such as all wells drilled in a given year. For the 200 wells in the database, summed production in year 2 and year 3 was 3,341,152 and 2,457,273 Mcf, respectively, which calculates to a 26.5% decline.

Decline percentages for years 3 and beyond are relatively straightforward, as per equation (1). The calculation of production decline in year 2 is slightly different, for in this method, year 2 records the 12 months of production following the peak-production month.

The production decline for year 2 is calculated by:

$$((V_{max\ month} \times 12) - V_{Year2})/(V_{max\ month} \times 12) \times 100 \quad (2)$$

where $V_{max\ month}$ is the maximum monthly production. Although this value is determined for 2,973 wells in southeastern Kansas (median $V_{max\ month}$ = 1,466 Mcf/month; Fig. 4), V_{Year2} is not. However, it can be estimated with the 200-well test database.

The $V_{max\ month}$ production sum for the 200 wells in the database is 425,070 Mcf/month. Inserting this into equa-

tion (2), with 3,341,152 Mcf being V_{Year2} (production for year 2), a 34.5% decline is calculated. This indicates that CBM wells generally fall off in production by about one-third 1 year after their peak monthly production is recorded.

The histogram of yearly production declines for individual wells in the 200-well database, shown in Fig. 5, peaks around 32% for the first year, with declines ranging from 6% to 90%.

Rates of decline for the CBM wells generally decrease the longer a well produces (Fig. 5). The decline characteristics of CBM wells are different from those of most conventional wells. Most conventional gas wells have annual decline percentages that change little from year-to-year. This is termed "exponential decline."

Some CBM wells display this also, but the more usual ever-lessening percentages of decline for given time intervals is described as "hyperbolic" or "harmonic."[6] This is important, for these characteristics indicate that determination of a collective rate of decline for all CBM wells has to take into account the age of the wells and the numbers of these wells that have been drilled each year.

A decline percentage for "year 1" is somewhat conjectural, for this is the year when production typically increases for a CBM well. Nevertheless, "year 1" needs to be accounted for in an estimation of a collective decline percentage for CBM production.

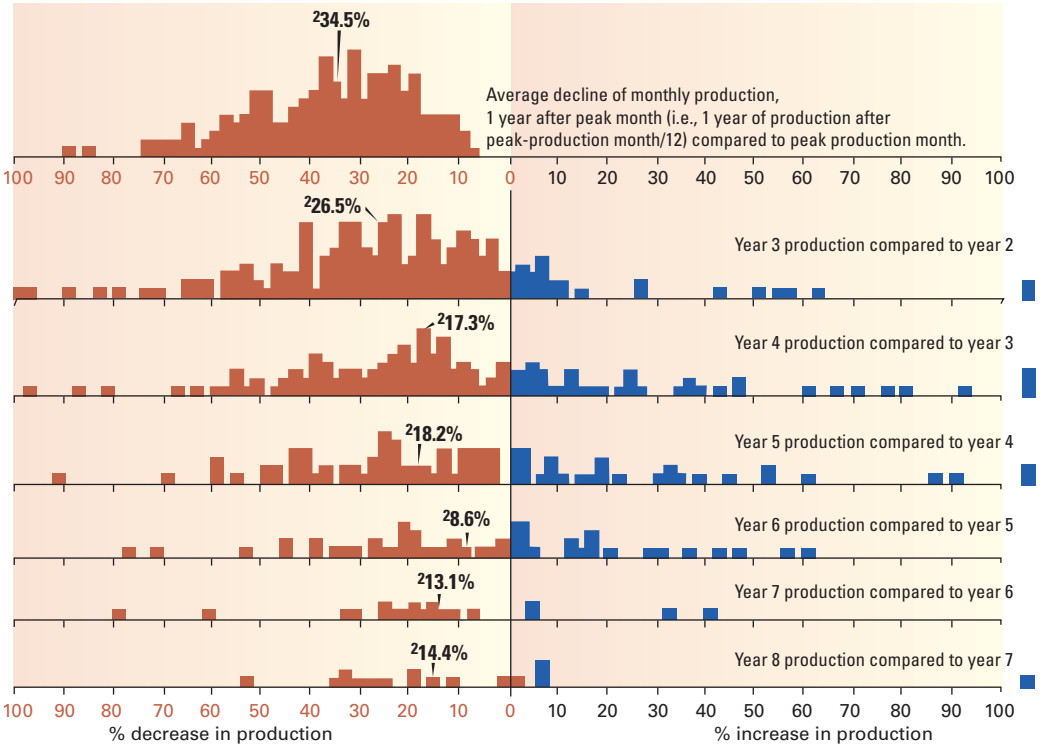
An estimate is possible by comparing "year 2" (declining) production with "year 1" (increasing) production. Year 1 total production (2,454,477 Mcf) in the 200-well database is 73.5% of the production in year 2 (3,341,152 Mcf); so the decline percentage in year 1 is estimated to be –36.1% (Equation 1). A negative decline percentage actually indicates an increase in production.

With this information, a collective decline rate for all the gas wells in 2009 in the 10-county area (Fig. 1) can be determined by averaging the decline percentages presented in Fig. 5, weighted by the number of wells drilled each year. The weighted average decline rate for all southeastern Kansas wells is thus determined to be 17.8% (Table 1).

A gentler collective decline of 13.8% is calculated by averaging the number of new producing wells in a given year with that of the previous year. This essentially estimates the number of wells at the midpoint of each year.

SOUTHEAST KANSAS COALBED YEARLY PRODUCTION DECLINES[1]

Fig. 5



[1]Data are for a 200-well representative database. [2]Average decline by total volume of all wells.

WELL DECLINE RATES FOR SE KANSAS CBM WELLS

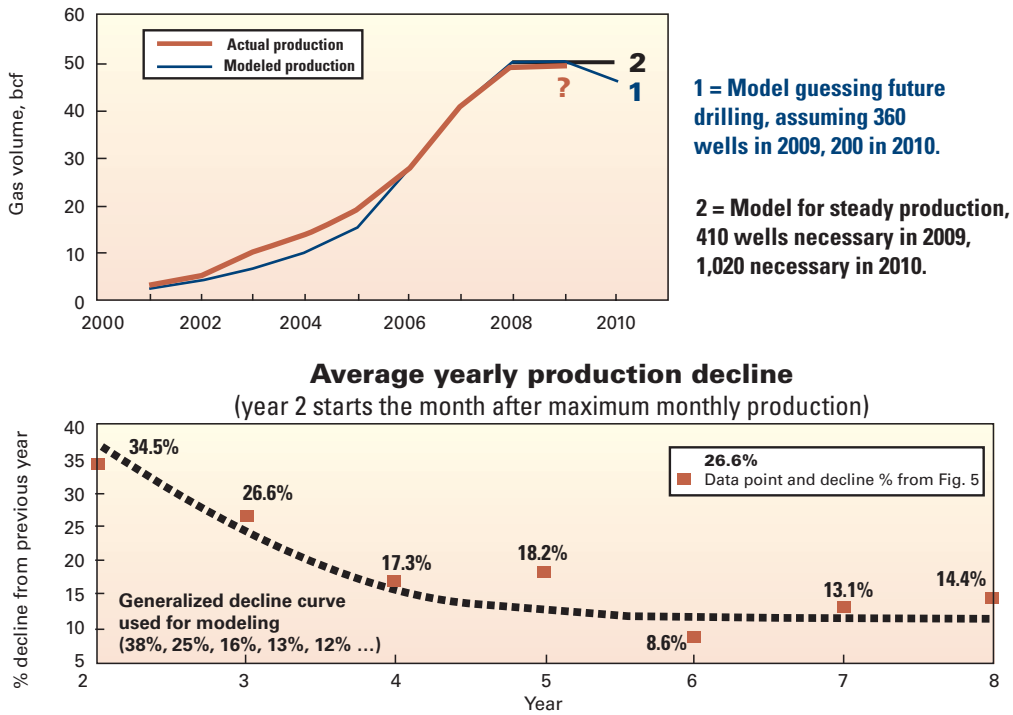
Table 1

Year well drilled	New producing wells (1)	New producing wells (2)	Decline rate in 2008, % (1)
before 2001	170	170	12.0*
2001	164	167	14.4
2002	233	199	13.1
2003	264	249	8.6
2004	513	389	18.2
2005	762	638	17.3
2006	1,928	1,345	26.5
2007	1,506	1,717	34.5
2008	688	1,097	–36.1

*Average of 14.4%, 13.1%, and 8.6%, respectively, reported for 2001, 2002, and 2003.
Weighted average decline (1) = 17.8 (calculation uses the wells reported for each year).
Weighted average decline (2) = 13.8 (calculation assumes the number of wells in a given year is the average of the given year with that of the previous year—a value that approximates the midpoint for that year).

ACTUAL VS. MODELED SOUTHEAST KANSAS GAS PRODUCTION*

Fig. 6



*Data are based on decline percentages (Fig. 5), median production characteristics (see Figs. 2 and 3), the number of wells put on production yearly, and an empirical relationship of the maximum monthly production rate to the expected production history of coalbed gas wells. By this model, 420 new wells have to be introduced in 2009 to maintain Cherokee basin annual gas production at 49.1 bcf.

If a yearly decline of 17.8% is applied to the 49.1 bcf of production recorded in 2008, then production would hypothetically decline by 8.7 bcf in 2009 to a total of 40.4 bcf if no new wells were drilled in 2009.

Generalizing that each CBM well averages 7,381 Mcf/year (Fig. 1), then 1,178 wells (i.e., 8.7 bcf/0.007381 bcf per well = 1,178 wells) would have to be drilled in 2009 to maintain the 49.1 bcf annual production of 2008 into 2009. If the 17.8% overall decline is too harsh, the lesser overall decline rate of 13.8% (using midyear well numbers; Table 1) results in a production drop of 6.8 bcf, which corresponds to 918 compensatory wells.

By the calculations using the gentler overall 13.8% decline rate, if more than 918 successful CBM wells are drilled in 2009, then gas production will increase from 2008 to 2009. Fewer than 918 successful wells drilled will mean a decrease.

Data are still being compiled for 2008, but as of November 2009 only 688 additional producing wells were reported for 2008. Experience with reporting patterns indicates that this number will not significantly change in coming months.

The net number of producing wells for 2009 is yet to be determined. If only 360 successful new wells in 2009 are ultimately reported (based on the highly speculative rate of 30 wells/month for the last quarter of 2008, shown in Fig. 2), then the midyear well number for 2009 will be 524 (i.e., (688 + 360)/2).

In effect, 2009 will be 394 wells (i.e., 918 – 524) short of maintaining the record 49.1 bcf production achieved in 2008. The approximate 2009 production decline will thus be 7,381 Mcf/well × 394 wells, or 2,908,114 Mcf (~2.9 bcf). Thus 46.2 bcf of production for 2009 is predicted by this method.

Method 2

A second check (Method 2) is to calculate production using the number of wells drilled each year, the expected production of each well, and the inferred annual production decline percentages.

Method 2 relies on the assumption that the median maximum monthly production (1,466 Mcf/month, Fig. 4) typifies all CBM wells. The decline percentages (Fig. 5) that were used in Method 1 for calculating the weighted average production decline (Table 1) can also be used in Method 2, but with the respective decline percentages applied throughout the history of a well.

Each CBM well is thus generalized to produce 11,523 Mcf in its second year of production (i.e., 1,466 Mcf/month × 12 months × (1 – 0.345)). The first year of production is 8,469 Mcf (i.e., 0.735 × 11,523 Mcf). Production for the third year, coincidently, is 8,469 Mcf (i.e., 11,523 Mcf × (1 – 0.265)). Production for the fourth year is 7,008 Mcf (i.e., 8,469 Mcf × (1 – 0.1725)), etc.

Smoothed decline percentages (Fig. 6) based on the raw data, however, were used in the modeling. The production history for the region can thus be constructed based on the number of CBM wells drilled every year and their expected production declines.

The number of new CBM wells drilled per year can either be taken as the actual number compiled for a given year, or as an average with the previous year so as to approximate the number of wells at the midpoint of each year (Table 1).

In circumstances where there is drastic variation in well numbers from year to year, the midyear number probably better characterizes the number of wells that are behaving in a similar manner with increasing or decreasing production.

An additional consideration is conventional gas production, which is not differentiated from CBM production in the production database. Not many CBM wells were drilled prior to 2001, so production from 1995 to 2000, which averages 2,332,175 Mcf/year, is considered for modeling purposes as a constant baseline for conventional production in southeastern Kansas.

By this method, modeled and actual production reasonably compare with each other (Fig. 6), with 2008 modeled production of 50.2 bcf being close to the 49.1 bcf actually recorded (Fig. 6).

By the model, approximately 420 new producing wells have to be added in 2009 maintain steady production. This causes the 2009 midyear well number to be 554 wells [(688 + 420)/2)]. Due to the composite production declines of all previous producing wells, approximately 1,020 new wells would be needed in 2010 to maintain steady production. Present drilling is far short of attaining these requisite numbers.

Individual well performance

The attempts above to describe the central tendency of CBM wells in southeastern Kansas and their collective behavior can also be utilized to typify what production history can be expected for individual wells.

Production behavior based on peak production of individual wells (Fig. 4) is thus used to infer the likely production history of a well (Fig. 7).

Just as each CBM well is different, production economics are also different, but for purpose of simplification, 5 Mcfd (1,825 Mcf/year) is considered the level at which a well will be shut down. By this scenario the median CBM well will produce 71.6 MMcf over a 15-year life. Not surprisingly, more prolific CBM wells will produce more and longer; less prolific wells will produce less and will be plugged earlier.

Gas prices will affect the payout time and the longevity of a well. Approximately $125,000 is necessary to drill and complete a CBM well in this region.[7]

Under these conditions, the median CBM well will recoup $125,000 in drilling and completion costs in slightly over 5 years with gas priced at $3/Mcf, whereas a less productive 25th-percentile well will not able to pay back its costs (Fig. 7). However, this 25th-percentile well will recover its costs in about 5 years if gas is priced at $6/Mcf; the median well will achieve this level of production in just over 2 years.

Some wells (certainly the lowest 10th-percentile) cannot pay for themselves even if gas prices are sustained at the relatively high level of $9/Mcf.

Feedback and caveats

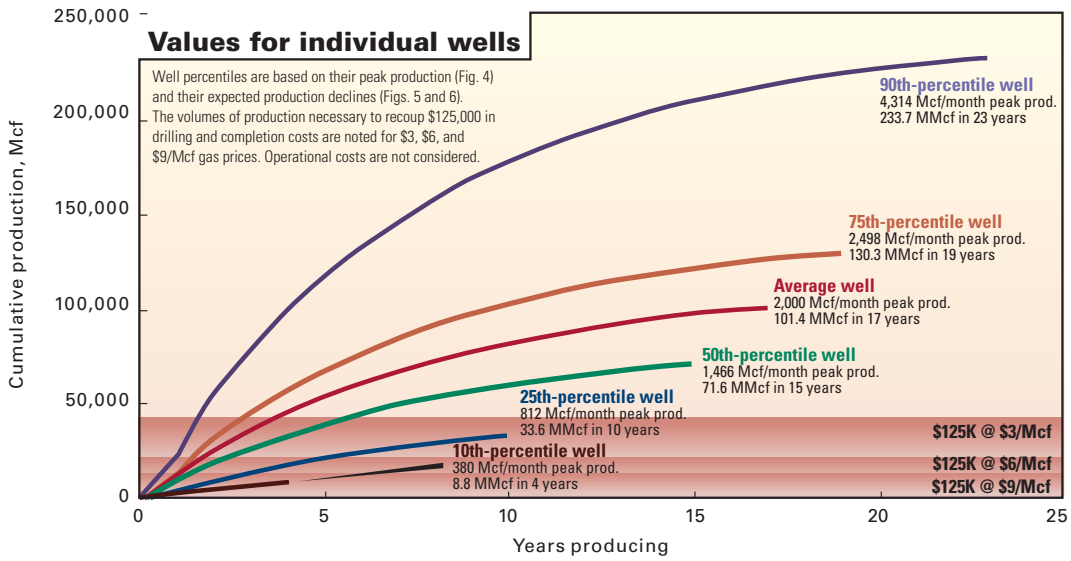
The statistical hinge on which much of the analysis depends is the average annual decline rate of CBM wells and its empirical relationship a central (median or average) maximum monthly production rate reported for CBM wells in the Cherokee basin.

Basic production data inherently have considerable scatter, and the numbers on which the modeling is based can also carry uncertainty. No two CBM wells are alike. Perhaps production data summed on a quarterly basis would reduce some of the scatter in the data, but a test of this speculation is best the subject of another academic exercise.

Any predicting of future production and drilling is at best an educated guess because commodity prices, well costs,

SOUTHEAST KANSAS CBM CALCULATED CUMULATIVE PRODUCTION*

Fig. 7



*Assumes typical declines, production shutdown at 5 Mcfd.

and technology will certainly change with time. The slow economic situation today may drastically change for worse or better, and all this will affect the number of wells drilled.

The number of producing CBM wells added for 2008 (688) is largely compiled by now, but the number of new CBM wells for 2009 was difficult to predict even at this writing in the last quarter of the year, for there is several months lag time before these data are finalized.

The crash in gas prices from the high recorded in mid-2008 also likely changes the way companies marshal their capital. Company resources do not necessarily dry up for new drilling during hard times, but they can be redirected in other ways. For example, instead of contracting rigs for drilling new wells, companies may decide it is more politic to employ workover rigs to maximize production in their existing wells.

Similarly, aggressive economizing may result in shutting-in or abandonment of marginal wells, thus the average and median well productivity could actually increase in coming years. This may be occurring for many leases in 2008 that were producing less than 8 Mcfd, with declining production, and have not had any production reported in 2009.

Are 360 and 200 new producing wells respectively projected for 2009 and 2010 realistic? Anemic rates of drilling in late 2009 indicate that fewer gas wells will be completed, but the final number depends on economic, technologic, and even political events.

Upon query by the author, geologists from the three primary CBM companies producing in southeastern Kansas (Quest, Dart, and Layne) stated that their companies were drastically scaling back developmental drilling in 2009, so the educated guess that 360 new producing wells will have been drilled in 2009 may be even wildly optimistic.

Some feedback on what can be expected for 2009 is available though, for 20.6 bcf of gas production is reported through May 2009 for the counties shown in Fig. 1. This is proportional to 49.4 bcf for the entire year. This hints that the two methods presented for predicting future production are pessimistic, but the point still stands that the impressive production increases of previous years due to development of CBM in this region cannot be expected even in the near future.

The predicted drop in production does not mean the CBM resource in this region is being depleted. More accurately, the resource simply cannot be offered to the market given low gas prices in late 2009.

Many drilling locations in southeastern Kansas are still available. For example, Quest Energy reports on its website that it had in 2008 an inventory of more than 2,100 drilling locations on its leased acreage, and that its CBM wells have a life of about 15 years.[8]

If a sufficient number of remaining locations are drilled and put on production in coming years by Quest and other Cherokee basin CBM operators, then annual gas production can conceivably rise by several billion cubic feet from the 49.1 bcf recorded in 2008.

The prediction of declining production is not to say that "the bloom is off the rose" (i.e., what was once attractive is no longer), but rather, even if production economics and technology do not radically change, CBM production will still be a vital part of the regional economy for many years.

The production-by-year graph will not be a symmetric bell-shaped curve with a decline as steep as its rise; it will likely resemble the positive-skewed curve characteristic of a CBM well (Fig. 3). Fortunes can still be made, and the economic impact of CBM in Kansas and the Midcontinent is and will be substantial.

Acknowledgments

The author thanks colleagues Larry Brady, Rex Buchanan, John Doveton, and Dan Merriam; and Shane Huffman (Dart Energy), Ken Recoy (Quest Resource), Jim Stegeman (Colt Energy), and Rolland Yoakum (Layne Energy) for critically reading the manuscript and giving helpful suggestions for its improvement. ✦

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Practical equations calculate gas flow rates through venturi valves

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Oil field operators can use several practical equations for calculating flow rates of natural gas through venturi gas-lift valves.

For critical flow, this analysis derived such equations from a rigorous theoretical model for gas isentropic evolution that uses real-gas calculations not restricted to density but encompassing also other relevant thermodynamic properties.

This rigorous model is complex and requires a computational algorithm and relatively much computer time.

For expeditious hand calculations or using simple spreadsheets, the equations presented in this article are within the accuracy needed and require much less computational effort.

For subcritical flow, this article suggests an approximate approach because venturi gas-lift valves should always be operated in critical flow.

Operators are installing more venturi nozzle, or simply venturi, gas-lift valves in continuous gas-lift wells worldwide. Various articles[1-4] describe field applications and the resulting benefits.

In Brazil, about 200 wells, mostly offshore, now have these valves.

Dynamic performance

The dynamic performance of a venturi valve is well-known.[1,2] One may define dynamic performance of a gas-lift valve as the behavior of gas flow through the valve as a function of the parameters involved, namely, pressure upstream and downstream, temperature upstream, gas composition, and characteristics of the valve, such as internal geometry, material, and surface finishing.

In experimental terms, a reference is used to obtain flow rate curves for each valve as a function of the downstream pressure while maintaining the upstream pressure (and temperature) constant.

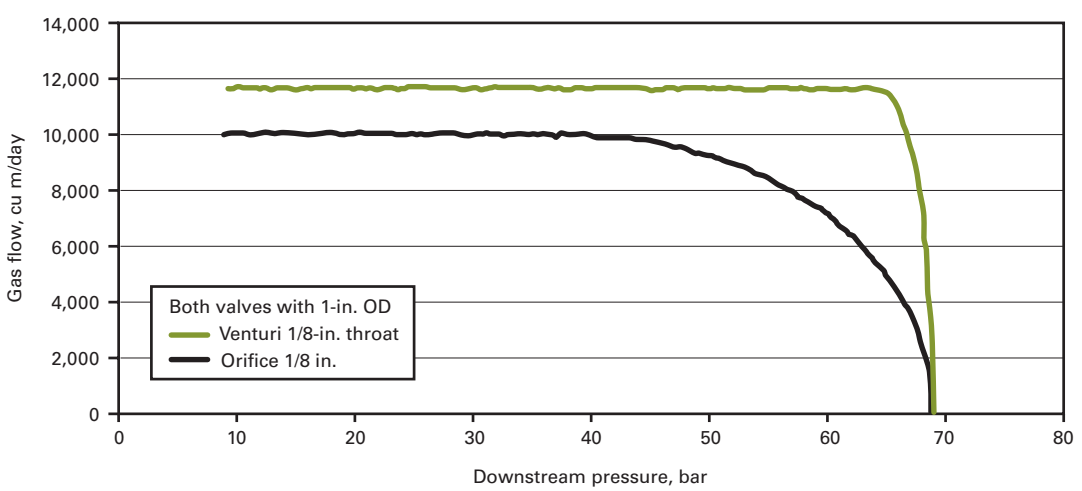
The figure compares experimental dynamic performance of a venturi valve with that of a conventional square-edged orifice valve. The most important difference relates to critical flow, the region of the curve where the gas flow rate through the valve is constant, irrespective of downstream pressure.

This happens when downstream pressure is less than a certain fraction of the upstream pressure. This fraction is about 0.5 for an orifice valve and 0.9 for a venturi valve.

Thus, in view of the usual pressure differentials between casing (injection pressure) and tubing (production pressure), orifice valves operate in subcritical flow and venturi valves in critical flow.

VENTURI, ORIFICE VALVE COMPARISON

Fig. 1



EQUATIONS

$$Q_{vgp} = C_s C_d A_2 P_1 \sqrt{\frac{2\frac{\xi}{\xi-1}\left(\Psi_{p2}^{\frac{2}{\xi}} - \Psi_{p2}^{\frac{\xi+1}{\xi}}\right)}{d_g z_{g1} \theta_1}} \quad (1)$$

$$Q_{vgc} = 8,640\, C_d A_2 C_R \frac{P_1}{\rho_{std}\sqrt{R_g \theta_1}} \quad (2)$$

$$\frac{1}{C_R} = \sum_{i=1}^{3} a_i P^{(i-1)} - \left(\frac{\sum_{i=4}^{8} a_i P^{(i-4)}}{\theta}\right)^{\alpha} \quad (3a)$$

$$\alpha = \sum_{i=9}^{14} a_i P^{(i-9)} \quad (3b)$$

$$C_{R,d_g} = C_{R,d_g=0.5538} + 3.967819\left[C_{R,d_g=0.75} - C_{R,d_g=0.5538}\right]\left[(d_g)^3 - 0.1698474\right] \quad (4)$$

$$\rho_{std} = \beta d_g \quad (5)$$

$$Q_{vgp} = Q_{vgpc}\left[1 + (\Psi_{p3} - \Psi_{p3c})^3\right]\left[1 - \left(\frac{\Psi_{p3} - \Psi_{p3c}}{1 - \Psi_{p3c}}\right)^{2.5}\right] \quad (6)$$

$$Q_{vgc} = 8,640 \times 1.0 \times \frac{\pi}{4}(6.4)^2 \times 0.7778 \times \frac{250}{0.7971\sqrt{441.54 \times 353.15}} \quad (7)$$

$$Q_{vgp} = 0.1549 \times 1.0 \times \frac{\pi}{4}(0.252)^2 \times 3,626 \times \sqrt{\frac{2 \times \frac{1.3}{1.3-1} \times 32.17 \times (0.546^{\frac{2}{1.3}} - 0.546^{\frac{2.3}{1.3}})}{0.65 \times 0.8981 \times 635.67}} \quad (8)$$

Nomenclature

A = Area, mm²
C_d = Discharge coefficient
c_p = Heat capacity at constant pressure, J/(kg K)
C_R = ASME critical flow factor
C_s = Coefficient of Equation 1, unit dependent on the system of units adopted
c_V = Heat capacity at constant volume, J/(kg K)
d = Specific gravity for a gas
$d_g = \rho_{g,std}/\rho_{air,std} = (M_g/M_{air}) \times (z_{air,std}/z_{g,std}) \approx (M_g/M_{air})$
M = Relative molecular mass (for air ≈ 28.97 kg/kmol; for natural gas, ≈ $M_{air} \times d_g$), kg/kmol
P = Pressure, bar
Q_{vgp} = Flow rate of gas in standard conditions, cu m/day
Q_{vgc} = Critical flow rate of gas in standard conditions, cu m/day
R_g = Gas constant (= R_u/M_g), J/(kg K)
R_u = Universal gas constant (= 8,314.34 J/(kmol K))
z = Compressibility factor

Greek symbols

ξ = Ratio c_p/c_v
θ = Absolute temperature, K
ρ = Density, kg/cu m
ψ_{pn} = Ratio between absolute pressures at position n (n = 2,3) and upstream of the venturi

Subscripts

1 = At position 1 (upstream the venturi with conditions P_1 and θ_1)
2 = At position 2 (at the venturi throat with conditions P_2 and θ_2)
3 = At position 3 (downstream the venturi with conditions P_3 and θ_3)
air = Air
c = Critical flow
g = Gas
std = In standard conditions (1.01325 bar and 20° C. or 60° F.)

References 2 and 5 contain an explanation of such performance difference and other aspects related to venturi valve behavior.

Thornhill-Craver equation

The traditional approach in gas-lift literature for modeling valve dynamic performance uses the Thornhill-Craver equation.[6] The equation is for compressible, one-dimensional, and isentropic flow of a perfect gas through a restriction, with the addition of a correction factor (discharge coefficient) to account for deviations encountered in real cases.

To partially correct the equation due to real-gas behavior, the compressibility factor is generally shown in the classical form of that equation, which then becomes Equation 1 in the equation box.

C_s is a factor that depends on the units used and on the reference conditions for volumes, for example, standard conditions.

Using English units (pressures in psia, flow rates in MMscfd, areas in sq in., temperatures in °R, and standard conditions of 60° F. and 14.70 psia), it has a value of 0.1549.

In this case, it is necessary to include the factor 32.17 (lb_m-ft)/(lb_f-sec^2) for multiplying the numerator of Equation 1.

For the standard conditions usually adopted in Brazil (20° C. and 1.01325 bar), pressures (absolute) in bar, areas in mm2, temperatures in K, and flow rates in cu m/day, the constant C_s has a value of 423.5.

If one reduces the ratio between absolute pressures at position 2 and upstream of the venturi ($\Psi_{p2} = P_2/P_1$) continuously, for example if the pressure at the restriction P_2 is continuously decreased with a constant upstream pressure P_1, the flow rate increases until Ψ_{p2} reaches the critical ratio, $\Psi_{p2c} = P_{2c}/P_1$, at which the velocity at the restriction is sonic and any further reduction in Ψ_{p2} does not change the flow rate. Thus, if $\Psi_{p2} < \Psi_{p2c}$, Ψ_{p2c} replaces Ψ_p in Equation 1.

One can obtain the critical ratio Ψ_p by differentiating Equation 1 with respect to Ψ_{p2} and equating it to zero (since Ψ_p is the Ψ_{p2} ratio for which the flow rate is maximum). For example,

with $\zeta = 1.3$ (a typical value for natural gas), $\Psi_{p2c} = 0.546$.

The derivation of Equation 1 comes from basic thermodynamics and is not discussed in this article. Reference 5 presents the assumptions associated with this equation and the reasons why the Thornhill-Craver equation is not the most adequate model to calculate flow rates through venturi gas-lift valves.

Petrobras's gas lift installations include high-pressure applications with venturi or similar valves. Improvement in modeling key equipment such as gas-lift valves is vital for a correct design and operation of that artificial lift method under these circumstances.

This motivated the development of a rigorous model, which Reference 5 presents for nitrogen and natural gas.

Critical flow

In terms of critical flow of gas in nozzles, an important reference is the ASME/ANSI MFC-7M-1987 standard[7] for measuring gas flow rate with sonic nozzles (venturi nozzles). From that standard, Equation 2 calculates the critical flow rate in cu m/day, where C_R is the critical flow coefficient. The coefficient takes into account the deviation from the perfect gas behavior. For a perfect gas, C_R is only a function of the heat capacities ratio ζ.

The conditions of temperature (K) and absolute pressure (bar) in Situation 1 are of stagnation (gas at rest). The equation requires area A_2 in mm^2, R_g in J/(kg K), and ρ_{std} in kg/cu m.

A computer application, written in Delphi, performed calculations for nitrogen and natural gas using the rigorous model discussed in Reference 5. Comprehensive comparison with literature data, both theoretical and experimental, validate the model. Table 1 gives values of C_R for three natural gas specific gravities, covering practical ranges of pressure and temperature.

The model is rigorous and limited only by the precision of the DAK (Dranchuk and Abou-Kassem)[8] equation of state used, and the assumptions made (particularly isentropic flow and stagnation conditions upstream of the venturi).

The equation of state is relatively simple, but, even so, the model requires a computational effort considerably greater than that of explicit models such as the classic Thornhill-Craver (Equation 1).

This somewhat restricts the model application, particularly in gas-lift simulators, which may calculate flow rate through gas-lift valves several times until reaching the convergence of the solution well flow rate.[9] Thus, it is highly desirable to have an explicit approach even with (acceptable) loss in accuracy.

CRITICAL FACTORS (C_R)*

Table 1

Stagnation temperature, °C.	Stagnation pressure, bar 0	25	50	100	150	200	250	300
20	0.6697	0.6859	0.7044	0.7486	0.7971	0.837	0.8613	0.8719
	0.664	0.6846	0.7094	0.775	0.8498	0.9016	0.9246	0.9286
	0.659	0.6852	0.7193	0.8257	0.9429	0.9978	1.0083	0.9984
40	0.6685	0.6815	0.6959	0.7286	0.7633	0.7936	0.8148	0.8265
	0.6624	0.6788	0.6976	0.7436	0.7949	0.8362	0.8602	0.8698
	0.6572	0.6777	0.7029	0.771	0.8494	0.9016	0.923	0.9254
60	0.6671	0.6777	0.6891	0.7142	0.7401	0.7633	0.7807	0.7918
	0.6607	0.6739	0.6887	0.7228	0.7596	0.7914	0.8129	0.8242
	0.6553	0.6718	0.691	0.7389	0.793	0.8356	0.8592	0.8676
80	0.6655	0.6743	0.6835	0.7032	0.7232	0.7411	0.7552	0.7648
	0.659	0.6698	0.6816	0.7078	0.7353	0.7597	0.7778	0.7887
	0.6535	0.6669	0.682	0.7175	0.7565	0.7898	0.8115	0.8222
100	0.6639	0.6712	0.6788	0.6945	0.7102	0.7242	0.7356	0.7437
	0.6572	0.6662	0.6758	0.6964	0.7175	0.7365	0.7513	0.7611
	0.6517	0.6628	0.6749	0.7022	0.7313	0.7572	0.7758	0.7865
120	0.6623	0.6683	0.6746	0.6874	0.6998	0.711	0.7202	0.7268
	0.6555	0.663	0.6709	0.6874	0.7039	0.7189	0.7309	0.7393
	0.65	0.6592	0.6691	0.6906	0.713	0.7333	0.7487	0.7585
140	0.6606	0.6657	0.6709	0.6814	0.6915	0.7004	0.7078	0.7132
	0.6539	0.6601	0.6666	0.6801	0.6933	0.7052	0.7149	0.7219
	0.6484	0.6561	0.6642	0.6816	0.6992	0.7152	0.7278	0.7363
160	0.659	0.6633	0.6677	0.6763	0.6845	0.6917	0.6976	0.702
	0.6523	0.6576	0.663	0.674	0.6847	0.6943	0.7021	0.7079
	0.6469	0.6534	0.6602	0.6743	0.6884	0.7012	0.7115	0.7187
180	0.6574	0.6611	0.6647	0.6719	0.6786	0.6845	0.6892	0.6928
	0.6508	0.6553	0.6598	0.669	0.6777	0.6855	0.6918	0.6965
	0.6455	0.651	0.6567	0.6683	0.6798	0.6901	0.6984	0.7045
200	0.6559	0.659	0.6621	0.6681	0.6736	0.6784	0.6822	0.685
	0.6494	0.6532	0.657	0.6647	0.6718	0.6781	0.6833	0.687
	0.6442	0.6489	0.6537	0.6634	0.6728	0.6811	0.688	0.6929

*In each table cell, the first line refers to pure methane ($d_g = 0.5538$), the second to a natural gas with $d_g = 0.6500$ and the third to a natural gas with $d_g = 0.7500$. The first column shows perfect gas values.

COEFFICIENTS FOR C_R CORRELATION

Table 2

a_i	Natural gas $d_g = 0.5538$	$d_g = 0.7500$
1	1.634214E+00	1.643304E+00
2	–1.041542E-03	–1.690827E-03
3	3.517203E-06	7.678912E-06
4	–1.168549E+01	3.179417E+00
5	2.613943E+00	4.310207E+00
6	–1.015222E-02	–2.798734E-02
7	1.273096E-05	7.897964E-05
8	9.910994E-10	–8.010277E-08
9	6.460394E-01	9.578202E-01
10	8.188871E-03	1.545911E-02
11	3.238264E-04	7.379477E-04
12	–3.019772E-06	–8.477320E-06
13	9.392400E-09	3.076955E-08
14	–1.014394E-11	–3.732852E-11

This article presents explicit correlations that fulfill that requirement and cover the region of interest (stagnation upstream conditions, 20-300 bar and 20-200° C, natural gas with specific gravity from 0.5538 to 0.75 with small quantities of N_2, CO_2, or H_2S).

Equations 3a and 3b show the correlations developed for natural gas with specific gravity of 0.5538 or 0.7500.

For intermediate gravities d_g, calculate C_R for 0.5538 and 0.7500 gravities with Equations 3a and 3b and apply the interpolating equation (Equation 4).

In Equations 3a and 3b, P (absolute pressure) in bar, and θ in K, are the upstream stagnation conditions and Table 2 gives the coefficients of a_i.

The comparison of C_R rigorous calculation with the correlation presented, in the range of interest for P, θ, and d_g, shows an absolute average deviation of 0.27% and a maximum deviation of 1.1%. One may use the correlation for specific gravities greater than 0.75 although the error increases accordingly.

As an example, for $d_g = 0.80$, the absolute average deviation is 0.43% and the maximum is 2.6%.

In any case, the rigorous model loses accuracy as specific gravity increases beyond 0.75 due probably to limitations of the DAK equation of state to accurately describe the behavior of such gases, particularly at high pressures. In this case, the preference is to employ a compositional equation of state.

Once one obtains the C_R, the next step is to calculate the critical flow rate with Equation 2. Equation 5 can obtain ρ_{std} for natural gas as a function of specific gravity d_g, based on standard conditions of atmospheric pressure and 20° C. In the equation the coefficient β in kg/cu m is 1.20761 (for a perfect gas, β is 1.20434).

For a standard temperature of 60° F., the ρ_{std} new coefficient β for Equation 5 is 1.22637 (perfect gas β is 1.22288).

Subcritical region

The intent is to always operate a venturi valve in critical flow. Thus, the main concern is for modeling critical flow instead of subcritical flow.

Reference 5 presents a simplified model to estimate throat pressures in subcritical flow from downstream pressures. Since such an approach is more complex, the suggestion is to use the empirical Equation 6 for the subcritical region $P_{3c}/P_1 = \Psi_{p3c} < \Psi_{p3} \leq 1.0$.

Accurate modeling for the subcritical region is not required for steady-state simulations (well in normal operation) involving venturi gas-lift valves. Its relevance for transient simulations (well discharge, for example), however, is not established. Moreover, it is highly relevant for other types of valves as in the case of orifice gas-lift valves, which nearly always operate in subcritical flow.

Example calculation

To illustrate the calculations, consider a 1.5-in. OD venturi gas-lift valve with a nominal 0.25-in. throat diameter. Casing pressure and temperature are 3,626 psia and 176° F. (635.67° R.), respectively. Natural gas specific gravity is 0.65.

The requirement is to calculate the theoretical critical flow rate in MMscfd (standard temperature of 60° F.).

It is advisable to check with the manufacturers the real throat diameter that corresponds to the nominal one because some differences may occur due to fabrication. In general, such differences are very small but for venturi valves, it may represent a significant difference in flow rates.

Check dimensional tolerances as well. For a 1.5-in. OD venturi valve model manufactured in Brazil, the throat diameter is 6.40 mm (Table 3).

Annular casing-tubing areas normally are much larger than throat areas and one may assume casing conditions as the stagnation ones with negligible error.

To convert from given field units to units adopted in this article, one needs to multiply pressure in psia by 0.0689476, obtaining 250 bar as the stagnation absolute pressure. Subtracting 32 from the given temperature in °F. and dividing by 1.8, results in 80° C.

To obtain the corresponding stagnation absolute temperature, add 273.15 to yield 353.15 K.

The gas constant is $R_g = 8,314.34/(0.65 \times 28.97) = 441.54$ J/(kg K) and, from Equation 4, ρ_{std} is 0.7971 kg/cu m (standard temperature 60° F.).

For the rigorous model, from Table 1, $C_R = 0.7778$. Applying Equation 2, as shown in Equation 7, one gets 171,709 cu m/day. To convert to MMscfd, multiply by 3.5315×10^{-5} to obtain 6.064 MMscfd.

As additional information, the model from Reference 5 yields critical (absolute) pressure at the throat of 126.75 bar (representing a throat critical pressure ratio of 126.75/250 = 0.507), with corresponding temperature and (sonic) velocity of 305.99 K and 403.9 m/sec, respectively.

For the correlation of C_R, use Equations 3a and 3b to obtain $C_R = 0.754646$ for $d_g = 0.5538$ and $C_R = 0.815716$ for $d_g = 0.75$. Interpolate for $d_g = 0.65$ with Equation 4 and get $C_R = 0.7800$. Then, applying the previous Equation 7 and substituting 0.7778 with 0.7800 for C_R, the calculation obtains a $Q_{vgc} = 172,195$ cu m/day or 6.081 MMscfd, a 0.28% difference from the rigorous model.

For a perfect gas, from Table 1, first

EXPERIMENTAL RESULTS*

Table 3

Throat diameter — Nominal, in.	Throat diameter — Real, mm	Valve performance parameters — Ψ_{p2c}	Valve performance parameters — C_d
3/16	5.20	0.97	0.98
1/4	6.40	0.95	1.02
9/32	7.14	0.93	0.99
5/16	8.00	0.92	0.98
3/8	9.50	0.92	1.02

*Preliminary results for 1.5 = in. OD valves. Reynolds number at the throat ranging from 8.0 million to 1,300 million.

column, C_R = 0.6590. From Equation 4, perfect gas ρ_{std} is 0.7949 kg/cu m (standard temperature 60° F.). Then, replace these values in Equation 7, to obtain a Q_{vgc} = 145,885 cu m/day or 5.152 MMscfd, a 15% difference.

For the Thornhill-Craver equation and from gas lift literature which says ζ = 1.3 is a typical value, the calculation give a Ψ_{pc} = 0.546. DAK equation gives z_{gl} = 0.8981.

The application of Equation 1 with English units, as shown in Equation 8, results in a gas flow rate of 5.504 MMscfd, a 9% difference.

Discharge coefficient

The model calculates theoretic flow rates. For real valves, the assumptions made, although accurate, are not strictly valid. Thus, there is a need to introduce a correction, in general in the form of a discharge coefficient, C_d, as shown in Equations 1 or 2.

In some cases, it is possible to derive theoretical or semitheoretical expressions for that coefficient. For gas-lift valves, however, that determination is experimental.

Petrobras is undertaking this work at its gas-lift test facility in Sergipe, Brazil and the results will be presented in the future.

Preliminary experimental curves for 1.5-in. OD venturi valves manufactured in Brazil under Petrobras license have shown discharge coefficients close to 1.0 (Table 3).

The same was found for a 1-in. OD model with a ⅛-in. throat. This comparison is limited but promising. ✦

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300-400° F., 22.8% OF REFORMER FEED

Table 1

Option		% of 300-400° F.	(R+M)/2	Cetane number
1	Paraffins	67.5	-3	55
	Naphthenes	5.4	54	33
	Aromatics	27.1	104	8
	Total	**100**	**29**	**41**
2	Paraffins + naphthenes	72.9	1	53
3	Aromatics + naphthenes	32.5	96	12

Calculating high cetane 300-400° F. cut for diesel

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This article provides a basis for deciding whether to evaluate a new process scheme or alter an existing one with a view toward moving a 300-400° F. cut from gasoline to diesel fuel.

Options

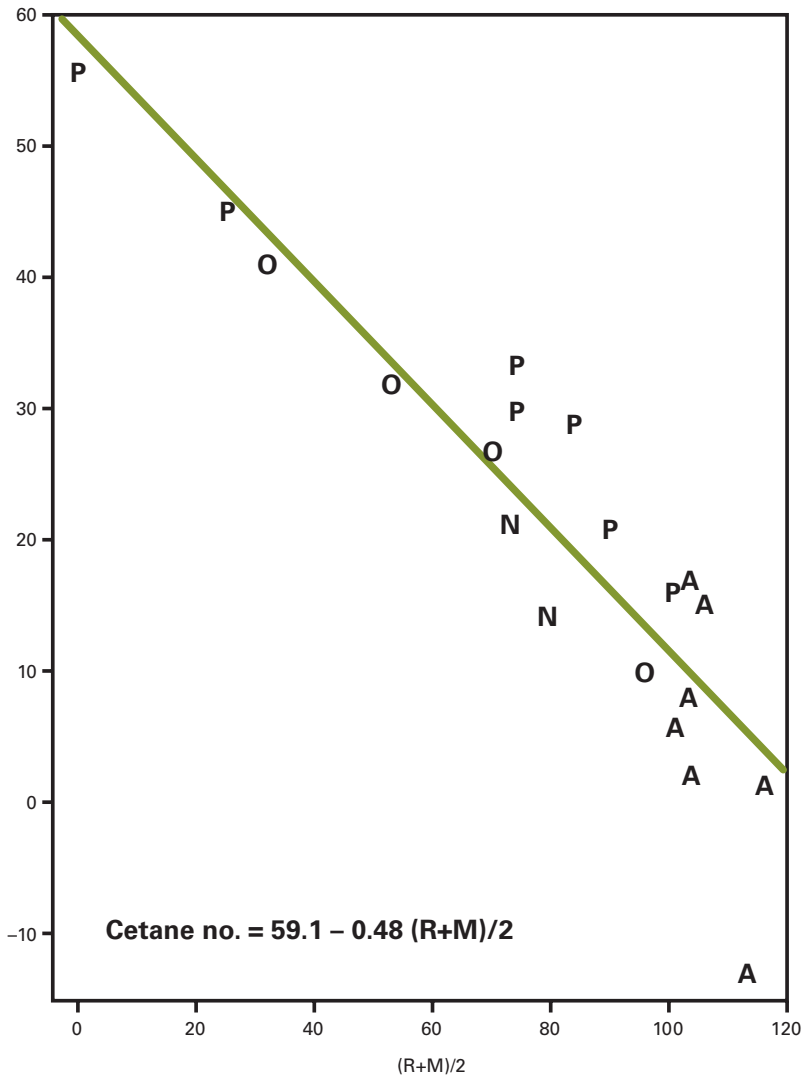
Average qualities for three options were calculated from a detailed gas chromatograph analysis of a reformer feed sample, along with octane and cetane numbers for individual hydrocarbons:

1. If a 300-400° F. cut were taken from the crude unit and hydrodesulfurized to less than the 15-ppm spec for low-sulfur diesel fuel, the average cetane number would be 41.

2. Extracting aromatics from the 300-400° F. leaves a premium diesel fuel blending component of 53 cetane number. The extracted aromatics could be a petrochemical feed or a 104 (R+M)/2 gasoline blending component. In either case, the economic advantage might be appreciable, depending upon the refinery's situation.

3. If paraffins were extracted separately, they would be only two cetane numbers better than the paraf-

FOUR HYDROCARBON TYPES



300-400° F. HYDROCARBONS IN A REFORMER FEED

Table 2

		B.P., °F.	Vol % of sample	(R+M)/2	Cetane number
Paraffins					
1	2,2,5-Trimethylheptane	303	0.31	84	19
2	n-Nonane	303	4.70	–38	72*
3	2,5,5-Trimethylheptane	307	0.50	86	18
4	2,3,3,5-Tetramethylhexane	308	0.10	103	10
5	2,2,4,4-Tetramethylhexane	309	0.13	102	10
6	3,3,5-Trimethylheptane	312	0.50	88*	17
7	2-Methyl-4-Ethylheptane	313	0.03	102	10
8	2,4,5-Trimethylheptane	314	0.17	86	18
9	4,4-Dimethyloctane	316	0.07	36	42
10	3-Methyl-5-Ethylheptane	317	0.25	87	17
11	2,2,3,4,4-Pentamethylpentane	319	0.23	106	8
12	2,2,3,3-Tetramethylhexane	321	1.14	103*	10
13	3,3,4-Trimethylheptane	323	0.29	94	14
14	4-Ethyloctane	327	0.27	15	52
15	4-Methylnonane	330	0.21	–4	61
16	3-Ethyloctane	332	0.02	9	55
17	3-Methylnonane	334	0.36	–8	63
18	"C10Alkylate"	334	0.54	87	17
19	n-Decane	345	3.16	–57	77*
20	"C11 Alkylate 1"	363	0.10	87	17
21	"C11 Alkylate 2"	373	0.20	87	17
22	"C11 Alkylate 3"	379	0.05	87	17
23	n-Undecane	385	1.12	–76	83*
Naphthenes					
1	1-Methyl-3-Ethylcyclohexane	304	0.06	54	33
2	1,1-Diethylcyclopentane	304	0.33	57	32
3	1,2,3-Trimethylcyclohane	304	0.24	82	20
4	1,2-Diethylcyclopentane	308	0.36	50	35
5	1-Methyl-2-Ethylcyclohexane	314	0.72	66	27
6	Propylcyclohexane	314	0.96	16*	51
7	1-Methyl-4-Isopropylcyclohenane	339	0.20	61*	30
8	Tertiarybutylcyclohexane	341	0.41	94*	14
Aromatics					
1	Isopropylbenzene	306	0.18	106*	15*
2	n-Propylbenzene	318	0.28	105*	9
3	1-Methyl-3-Ethylbenzene	322	0.87	106*	8
4	1-Methyl-4-Ethylbenzene	324	0.11	103*	10
5	1,3,5-Trimethylbenzene	329	0.11	123	0
6	1-Methyl-2-EthylBenzene	329	0.21	97*	12
7	Tertiary-Butylbenzene	336	0.52	113	–1*
8	1,2,4-Trimethylbenzene	337	0.77	108*	7
9	Secondary-Butylbenzene	344	0.48	101*	6*
10	1-Methyl-3-Isopropylbenzene	347	0.33	106*	8
11	1,2,3-Trimethylbenzene	349	0.26	103*	10
12	1-Methyl-2-Isopropylbenzene	353	0.09	101	11
13	1,3-Diethylbenzene	358	0.21	100	11
14	1-Methyl-3-n-Propylbenzene	360	0.24	106*	8
15	n-Butylbenzene	362	0.37	99*	12
16	1-Methyl-4-n-Propylbenzene	362	0.17	103	10
17	1,4-Diethylbenzene	363	0.15	101*	11
18	1,3-Dimethyl-5-Ethylbenzene	363	0.17	109*	7
19	1-Methyl-2-N-Propylbenzene	365	0.17	98*	12
20	1,4-Dimethyl-2-Ethylbenzene	368	0.07	101*	11
21	1,3-Dimethyl-4-Ethylbenzene	371	0.19	101*	11
22	1,2-Dimethyl-4-Ethylbenzene	375	0.27	101	11
23	2-Methylindan	377	0.10	97	12
24	1,2-Dimethyl-3-Ethylbenzene	381	0.03	98*	12
25	1,2,4,5-Tetramethylbenzene	386	0.02	105	9
26	1,2,3,5-Tetramethylbenzene	388	0.05	113	5
27	Isopentylbenzene	390	0.02	103	10

*Octane or cetane measurements. Other octanes estimated from structure. Other cetanes based on correlation with (R+M)/2.

HYDROCARBONS WITH MEASURED OCTANE, CETANE NUMBERS[1]

Table 3

	(R+M)/2	Cetane number
Paraffins		
n-Hexane	25	45
n-Heptane	–	56
2-Methylpentane	73	33
3-Methylpentane	74	30
2,3-Dimethylpentane	90	21
2,4-Dimethylpentane	83	29
2,2,4-Trimethylpentane	100	16
Olefins		
1-Hexene	70	27
1-Heptene	53	32
1-Octene	32	41
2,4,4-Trimethyl-1-pentene	96	10
Naphthenes		
Cyclohexane	80	14
Methylcyclohexane	73	21
Aromatics[2]		
Ethylbenzene	103	8
1,3-Dimethylbenzene	116	1
1,4-Dimethylbenzene	113	–13
Isopropylbenzene	106	15
Sec-Butylbenzene	101	6
1,2,3,4-Tetramethylbenzene	103	17
1-Methyl-4-Isopropylbenzene	104	2

[1](R+M)/2 from API Project 45. Cetane numbers from "Compendium of Experimental Cetane Number Data." [2]Aromatic cetane numbers are blending values at 10% or 20% with diesel fuel.

fin + naphthene mixture in Option 2. The remaining mixture of naphthenes and aromatics would have an average (R+M)/2 of 96.

New options for making these and other separations are described in US Patent applications 10/425,650 Apr. 30, 2003, and CIP 11/701,931 Feb. 2, 2007.

Table 1 shows percentages of the three hydrocarbon types and their average (R+M)/2 and cetane numbers used in the analysis

Percentages of the hydrocarbon types are the averages of those in C_{10+} fraction of 55 reformer naphtha samples from various refineries.[1] The (R+M)/2 and cetane values for each type are weighted averages of values for individual hydrocarbons, using detailed GC data that were available for a particular reformer naphtha.

The 300-400° F. portion comprised 24.9% of the particular reformer naphtha, similar to the 22.8% average of 55 samples.

The 1,3,5 trimethyl benzene (mesitylene) concentration for this sample was reported as 1.10%, compared with 0.77% of 1,2,4 trimethylbenzene, which is usually dominant. Straight-run, cat-cracked, and reformate samples consistently show the 1,2,4 trimethyl benzene concentration to be much higher than the mesitylene concentration. It is assumed, therefore, that the 1.10% is in error and was changed to 0.11% for this analysis.

Individual hydrocarbon data in Table 2 include boiling point, percentage in the particular reformer feed sample, along with (R+M)/2 octane and cetane number. The octanes are from API Project data, which are available for a large number of lower boiling paraffins.[2] Those data were used in estimating octanes, based on hydrocarbon structure.

As for cetane numbers, data were

available for only three aromatics and three paraffins.[3] The well-known negative relationship between cetane and octane was used to estimate cetane numbers (OGJ, Dec. 3, 2007, p. 58). Because published correlations did not seem satisfactory, a correlation was developed from data on lower boiling hydrocarbons shown in Table 3 and the accompanying figure.

Here is the result of the regression analysis: Cetane number = 59.1 – 0.48 ((R+M)/2).

Comments

The author is very knowledgeable about gasoline blending but less so about process technology or economics.[4] This article should be considered as a basis for deciding whether to evaluate a new process scheme or an alteration to the present process scheme.

Obviously, the exact cut points in gas chromatography do not apply to refinery operations. This is pertinent for the 4.7% normal nonane (303° F. boiling point) in the reformer feed. Elimination of the normal nonane would result in a 1.4 cetane decrease in the calculated cetane number for Option 2.

The linear calculations in this analysis do not take into account octane interactions between the hydrocarbons.[5] Their effects are economically significant but small in comparison with the differences between paraffins and aromatics in this analysis.

The (R+M/2) interactions range from barely negative for some hydrocarbon combinations to significantly positive for aromatics with low-octane paraffins. Data are not available for cetane interactions, but they are likely to be opposite in sign to octane interactions, in view of the negative correlation between octane numbers and cetane numbers.

In view of the large differences in octane and cetane numbers between paraffins and aromatics, limitations in the accuracy of these estimates are probably not serious. ✦

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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
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Despite the promulgation of multiple standards regarding materials and methods used in pipeline construction and the adoption of these by contractors and operating companies, pipelines can and do fail. The current rapid expansion of pipeline networks globally (OGJ, Feb. 9, 2009, p. 52) combined with a constrained pool of qualified labor in the oil and gas industry as a whole (OGJ, July 20, 2009, p. 34) only heightens the importance of preservice inspection and testing.

This article details a recent case in China in which pipeline flaws were only discovered during internal pressure testing.

Background

A leak occurred at 4.3 MPa during internal air pressure tests of a natural gas pipeline. A hole of about 500-mm diameter was found above the leak position, which lay 3 m underground.

Crews used down-direction welding technology to weld the 610-mm OD, 10-mm WT, grade X60 line pipe. FOX CEL 3.2-mm diameter welding rods acted as render first, then 71T8-Ni1 wire solders were adopted to fill weld and cover surface weld. Specification requires testing of new gas pipelines to 8.0 MPa.

Line pipe girth weld inspection conformed with SY4065-9,[1] SY0401-98,[2] GB/T9711.2-1999,[3] SY/T4103-1995,[4] JB4744-2000,[5] and SY4056-93.[6] Field inspection results of the girth weld offset measured 2.0 mm, beyond the 1.6 mm tolerance specified. The leaking girth weld was at the boundary between the area rolled and not rolled by a road roller (Fig. 1).

Two 30-40 mm samples of line pipe were taken from either side of the sample where the leak occurred. Test results showed a weld toughness of 96.7J at –20° C., according to the welding technique evaluation test result.

All the girth welds underwent X-ray inspection before the internal pressure test, and reinspection was done at the cracked girth weld. Failure analysis sought to determine the cause of the leak.

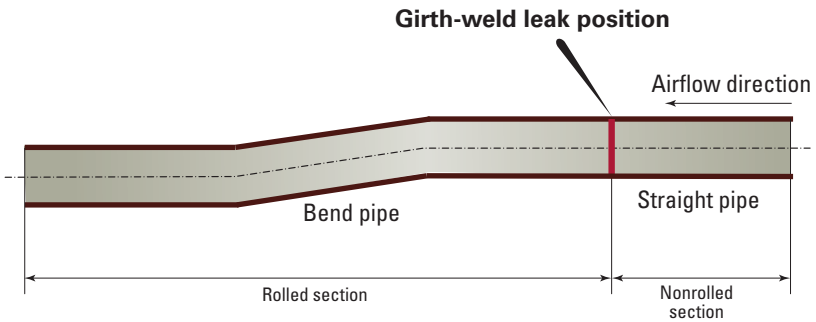
Macrofractography

The crack originated from the weld toe and ran from 10 o'clock to 1 o'clock positions on the girth weld (Fig. 2): 280 mm long and 4.1 mm wide. There were obvious offsets at the position opposite the crack. Asphaltum protected the line pipe's outside and the inside surface was rusty.

Opening the crack revealed a rough fracture, with an irradiation stripe along the inside surface and original flaws on the fracture in-

PIPELINE AT LEAK POSITION

Fig. 1



The left end of this cracked pipe section (left photo) was the bent side, with the right end the straight side (Fig. 2). The dark red belt lying close to the inner wall (right photo) shows the weld surface and the original flaw (Fig. 3).

ner wall (Fig. 3). The macrofracture morphology showed the crack originated from the original weld flaw on the inside surface, and the rupture took place suddenly during internal pressure test.

Measurements

Maximum offsets measured 4.5 mm at the crack position and 3.5 mm at the position opposite the crack (Fig. 4), beyond the tolerance of 1.6 mm specified in SY0401-98. The undercut was 1.4 mm deep and 50 mm long, not in accordance with a specified 0.5 = mm undercut tolerance.

These three specimens show the undercut and offset morphology affecting weld strength where the crack occurred. The upper specimen is from the crack origination. The left specimen, with an undercut of 1.4 mm and 1.4 mm deep crack on its bottom, came from the crack tip. The right specimen, with offsets of 3.5 and 3.0 mm on the inner and outer surfaces, respectively, came from the offset area opposite the crack (Fig. 4).

Composition analysis

Chemical composition analysis showed the pipe body material to meet API SPEC 5L and the weld material in accordance with specifications for the wire solder and welding rod.

Tension, impact

Testing showed the pipe body's tension and impact properties in accordance with API SPEC 5L. Pipe body toughness at –20° C. measured 189.6 J. Disqualification weld porosities of 4 mm in diameter appeared on the tension specimen's fracture. SY/T 4013-1995 disallows single or decentralized porosities ≤ 3.2 mm diameter. Impact energy measured only 13 J in the weld at –20° C., far lower than the welding technique evaluation test result.

Metallography

Metallography samples came from the crack origination, crack tip, and position opposite the crack. Severe offsets and undercuts existed on the weld, and many cracks on the toes and undercuts at the crack origination and tip (Figs. 5-6). The original weld cracks extended during the internal pressure test, with the rupture originating from the original toe crack and causing the leakage. The deformed microstructure feature at the crack tip showed shear stress bore vertically on the weld.

Microfractography

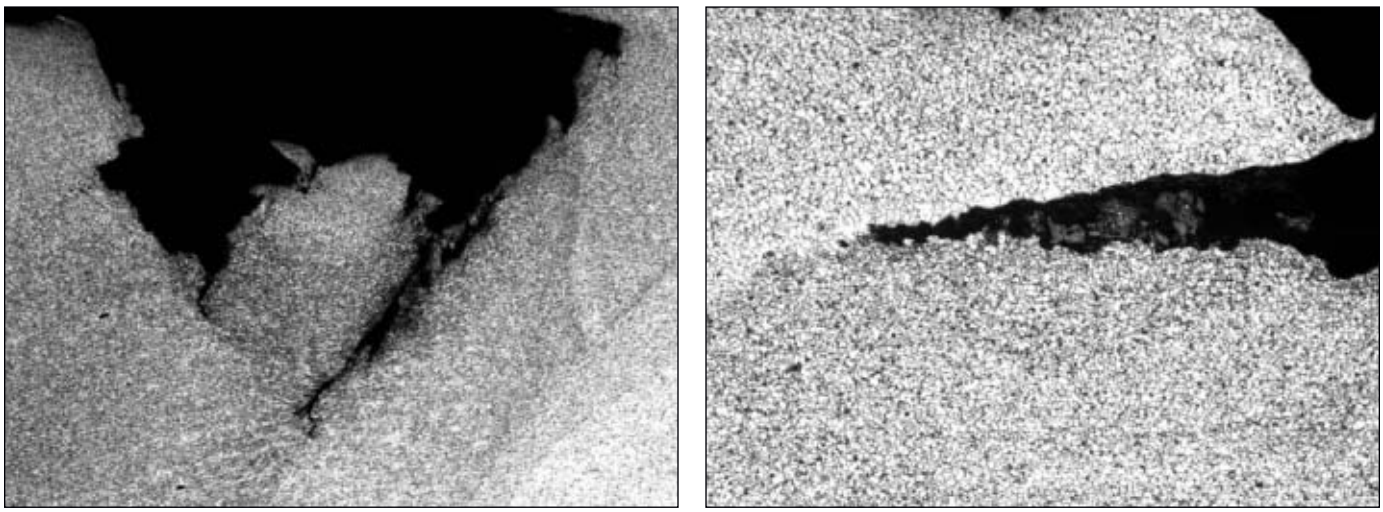
Microfractography specimens came from the crack origination and crack tip. The crack originated at the inner weld. There were weld dregs, weld flaws, and weld porosities at the fracture origination area (Figs. 7 and 8). The extended area of the fracture consisted of brittle cleavage and porosities.

Cause analysis

The pipe material conformed to standard. The girth-weld cracks related to weld quality and load borne by the pipeline. The causes of girth weld cracks are analyzed as the following.

The pipeline cracked at the girth weld. The stress resulting in girth weld cracking came mainly from internal pressure and structure stress borne by the pipeline.

The internal pressure of 4.3 MPa at the crack is only 53.8% of the 8 MPa specified. Axial load stemming from the internal pressures, however, was evidently sufficient to cause the girth-



This image (left photo) shows the crack morphology at the undercut bottom of the fracture tip at 25× magnification (Fig. 5). A 100× magnification (right photo) of the fracture tip shows the toe crack (Fig. 6).

EQUATIONS

$F_1 = 0.7854d^2P$ (1)

Where:
F_1 = axial load
d = inside diameter, d = 0.590 m
P = internal pressure, P = 4.3 MPa
Substitute formula (1):
F_1 = 1,176 kN

$F_2 = 0.7854(D^2–d^2)\sigma_b$ (2)

Where:
F_2 = joint strength of girth weld
D = outside diameter, D = 0.610 m
d = inside diameter, d = 0.590 m
σ_b = weld tension strength, σ_b = 579 MPa
Substitute formula (2):
F_2 = 1,0914 kN

Kt = 1+3(E+b)/t (3)

Where:
Kt = stress concentration coefficient
E = angle between two pipes after girth welding; for big diameter, E = 0
b = total of offset and undercut, b = 4.9 mm
t = WT, t = 10.0 mm
Substitute formula (3):
Kt = 2.47

weld crack. Supposing all axial loads from internal pressure acted on the girth weld, Equation 1 calculates the axial load.

The actual axial load from internal pressure, however, measured far less than the 1,176 kilonewton (118 tons) calculated in Equation 1 because the pipeline was buried 3 m under ground compacted by a road roller and stratum restricted the pipeline.

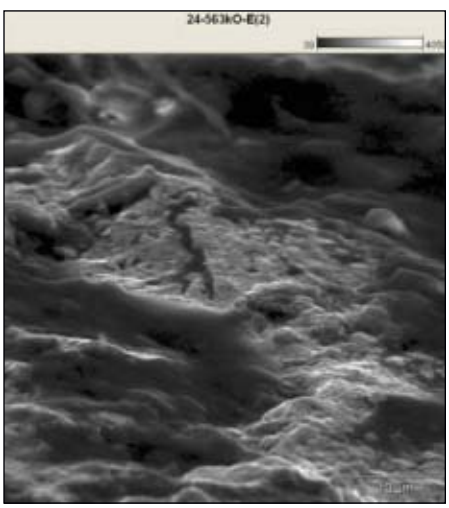
Equation 2 calculates joint capability of the girth weld according to weld tension strength and pipe cross area.

Calculations show axial load of only 10.8% of weld connection capability even if all axial load from internal pressure acted on the weld, suggesting the girth weld could not have cracked at 4.3 MPa internal pressure without severe weld flaws.

Structure stress

Vertical displacement of 30-40 mm existed between the two cutting sections of the pipe sample with the cracked weld. Deformed microstructures were at the crack position, demonstrating large vertical structural stress at the cracked weld. Accumulated structural stress on a pipeline can increase any cracking tendency. The girth weld's position at 10 o'clock-1 o'clock is consistent with the direction of structural stress, suggesting the structural stress accelerated the crack extension.

The road roller compacted the ground after the pipeline was buried, and the crack position lay just at the edge of roll area. Sinking of the ground as it was being rolled would cause the compressive load on the underground pipe, but the compressive load would not be borne on the section of line where the ground was not rolled, creating vertical shear stress at the boundary of rolling and not rolling (Fig. 9).



This image shows the crack and porosity morphology at the fracture origination area (Fig. 7).

The large vertical displacement of the two cutting sections taken as samples and the deformed microstructure in the vertical direction at the crack position show a large amount of structural stress.

Main cause

Measurement shows severe offset and undercut on the inner wall of the weld. The maximum offset is up to 2.2

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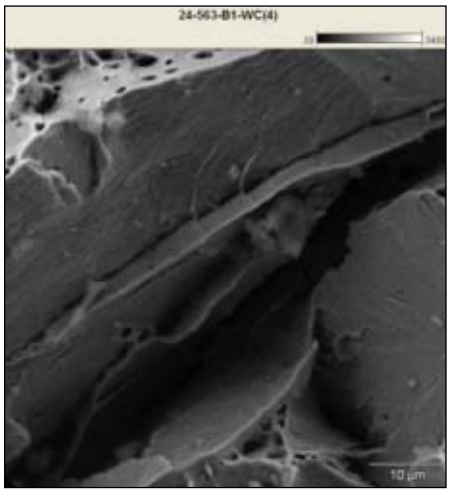


The crack and cleavage morphology at the fracture tip appear in this image (Fig. 8).

times specification, and the maximum depth of undercut is up to 2.8 times specification. Severe offset and undercut will reduce the efficient section, concentrate stress, and reduce pipeline capability. Equation 3 calculates stress concentration from offset and undercut.[7]

Equation 3 shows the stress at the weld measures 2.47 times the average stress because of offset and undercut. Cracks at the bottom of the undercut may cause the real stress concentration coefficient to be more than 2.47.

The crack began at the inner weld surface, where both toe cracks and weld flaws were present. The toe crack depth is 13% of the pipe WT. Not only do the toe cracks reduce the section, but they also produce severe stress concentration and result in cracks easily extending during service.

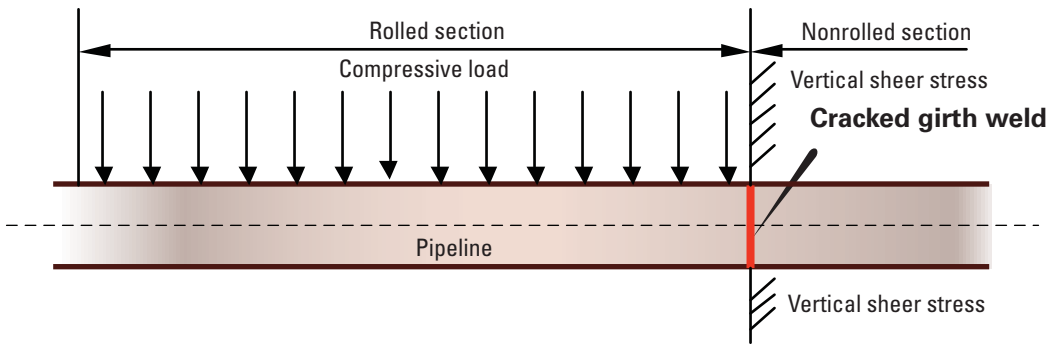
A fitness-for-service assessment using TGRC-AFSP software considered both simultaneously and separately the effect of cracks, undercuts, and offsets according to the weld flaws and test pressure. Fig. 10 shows the result, indicating the girth weld is unsafe in the presence of cracks, undercuts, and offsets.

Toughness plays a key role in evaluating weld quality. The higher the toughness, the more resistant to crack initiating and extending the weld seam is. The lower the toughness, the less resistant.[8] Weld-seam toughness is only 6.9% of pipe body according to test results.

X-ray examination took place on all the pipeline's girth weld seams before the internal pressure test, potentially exposing disqualification flaws at the crack origination position. A combination of inadequate equipment and inexperienced inspectors shielded these flaws from detection. An offset of 2.0 mm also exceeded specification (≤1.6 mm). ✦

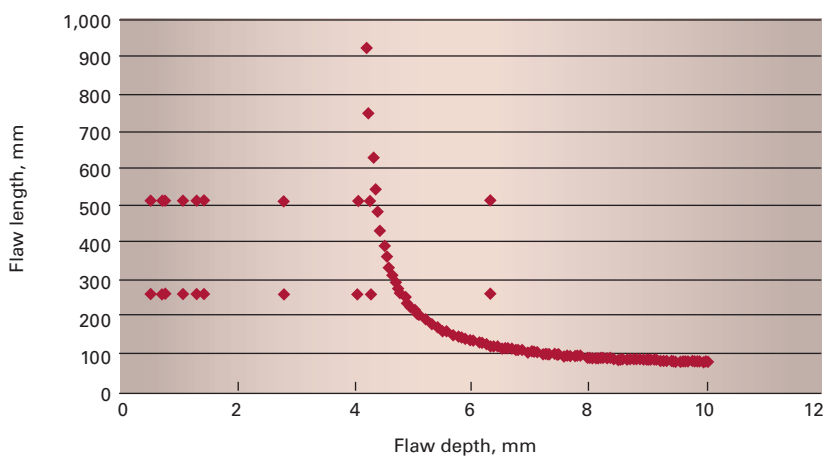
STRESS DIAGRAM

Fig. 9



FITNESS-FOR-SERVICE ASSESSMENT

Fig. 10



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Equipment/Software/Literature

New compact gauge valve

This new compact gauge valve is designed with a smaller footprint, promising quick, convenient access for the isolation and venting of pressure gauges.

The valve can be used with the firm's pressure gauges. The pressure gauges are positionable with tube adapter ends, eliminating threaded connections and leak points.

The design incorporates a purge valve for easy bleeding of trapped fluid pressure between the valve seat and gauge upon shutoff. The purge valve is machined directly onto the body, eliminating potential leak points while allowing the user to safely release the fluid before removing the gauge. A permanently assembled purge cap is crimped to the valve body for operator safety and to prevent accidental disassembly.

Available with either ½ in. or 12 mm tube fitting end connections, the compact gauge valve is constructed from 316 stainless steel. The valve is rated for temperatures as much as 450° F. depending on stem and packing. A soft-seat stem with PCTFE stem tip is available, and users can choose from UHMWPE, PFA, or PEEK packing. The valve is rated for pressures as high as 4,000 psig.

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Source: **Geoforce Inc.,** 222 Las Colinas Blvd. W, Suite 1650, Irving, TX 75039.

Services/Suppliers

Riverstone Holdings LLC,

New York, has completed its acquisition of Seajacks International for a total cash consideration of $207 million.

Seajacks owns and operates two self-propelled jack up vessels out of Great Yarmouth, UK: the Seajacks Kraken and Seajacks Leviathan. Both vessels are purpose-built for installing offshore wind turbines, as well as being able to perform a number of niche operations for the North Sea oil and gas industry. Riverstone plans to devote a lot of new capital to expand the Seajacks fleet into a leading European offshore wind service business, with an operational base in the UK, as well as continue to provide focused support services to the North Sea oil and gas industry.

Riverstone is an energy- and power-focused private equity firm founded in 2000. It conducts buyout and growth capital investments in the midstream, exploration and production, oil field services, power, and renewable energy sectors.

Seismic Micro Technology (SMT),

Houston, has appointed TengBeng Koid president, international, to oversee its sales and operations in Asia, Europe, Middle East, Australia, and Africa. The appointment follows the recent opening of SMT's fifth regional office, in Abu Dhabi. Previously, Koid was executive vice-president and COO for global business development at ION Geophysical from 2004. Prior to ION, he worked for Halliburton's Landmark division, where he oversaw expansion into the Asia-Pacific market from 1996 to 2000 as vice-president and general manager, in addition to other roles at both Halliburton and Landmark during 2000-04. Before Landmark, Koid was employed at IBM as a senior manager specializing in the oil and gas business.

SMT provides geoscience software to the oil and gas industry.

Aker Solutions,

Oslo, has entered into a contract with the construction company HENT to build a new combined office and hotel building at the K2 site at Fornebu, Norway. The building is planned with a total area of about 46,000 sq m, including underground and parking areas, of which 12,000 sq m is for the hotel. The building is planned to be completed in the first quarter of 2012, and Aker Solutions will be the tenant for the office building. The office building is an expansion to the existing headquarters to cover capacity needs from 2012.

The contracting party is Fornebu Gate 2 AS, which will be owned 93% by Aker Solutions and 7% by Arthur Buchardt Invest AS.

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Imports of crude and products

	Districts 1–4 1–22 2010	Districts 1–4 1–15 2010	District 5 1–22 2010	District 5 1–15 2010	Total US 1–22 2010	Total US 1–15 2010	Total US *1–23 2009
	1,000 b/d						
Total motor gasoline	764	712	59	18	823	730	1,154
Mo. gas. blending comp.	580	490	59	18	639	508	843
Distillate	653	236	5	36	658	272	264
Residual	194	413	0	0	194	413	524
Jet fuel–kerosine	95	89	45	19	140	108	101
Propane–propylene	151	228	15	20	166	248	212
Other	202	240	50	96	252	336	488
Total products	**2,639**	**2,408**	**233**	**207**	**2,872**	**2,615**	**3,586**
Total crude	**6,893**	**7,488**	**974**	**1,052**	**7,867**	**8,540**	**9,708**
Total imports	**9,532**	**9,896**	**1,207**	**1,259**	**10,739**	**11,155**	**13,294**

*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.

OGJ crack spread

	*1–29–10	*1–30–09	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	81.40	54.58	26.83	49.2
Brent crude	72.30	44.01	28.29	64.3
Crack spread	9.11	10.57	–1.46	–13.8
FUTURES MARKET PRICES				
One month				
Product value	81.47	53.84	27.64	51.3
Light sweet crude	74.03	42.52	31.51	74.1
Crack spread	7.44	11.32	–3.87	–34.2
Six month				
Product value	85.28	58.89	26.39	44.8
Light sweet crude	76.71	52.02	24.69	47.5
Crack spread	8.56	6.87	1.69	24.7

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

Purvin & Gertz LNG netbacks—Jan. 29, 2010

Receiving terminal	Liquefaction plant: Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	7.46	5.36	6.60	5.25	5.90	6.52
Everett	5.88	3.59	5.46	3.67	4.16	6.19
Isle of Grain	4.79	2.50	4.06	2.39	3.06	4.10
Lake Charles	3.08	1.11	2.82	1.29	1.53	3.76
Sodegaura	5.78	7.83	6.04	7.51	6.82	5.08
Zeebrugge	6.77	4.25	5.94	4.14	4.88	6.02

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

Crude and product stocks

District	Crude oil	Motor gasoline: Total	Motor gasoline: Blending comp.[1]	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual	Propane–propylene
	1,000 bbl						
PADD 1	12,932	61,666	43,281	10,096	62,943	13,809	3,141
PADD 2	86,115	54,751	26,886	8,781	33,180	1,089	14,889
PADD 3	165,913	73,685	44,069	13,726	44,933	18,771	17,545
PADD 4	15,578	5,977	1,906	535	3,181	195	[1]1,158
PADD 5	46,139	33,348	28,832	10,552	13,259	3,925	—
Jan. 22, 2010	**326,677**	**229,427**	**144,974**	**43,690**	**157,496**	**37,789**	**36,733**
Jan. 15, 2010	**330,565**	**227,442**	**143,273**	**43,733**	**157,138**	**38,781**	**41,138**
Jan. 23, 2009[2]	**338,881**	**219,859**	**121,376**	**38,401**	**143,952**	**36,045**	**47,487**

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

Refinery report—Jan. 22, 2010

District	Refinery operations: Gross inputs	Refinery operations: Crude oil inputs	Refinery output: Total motor gasoline	Refinery output: Jet fuel, kerosine	Refinery output: Fuel oils: Distillate	Refinery output: Fuel oils: Residual	Refinery output: Propane–propylene
	1,000 b/d						
PADD 1	1,111	1,098	2,242	79	311	77	38
PADD 2	3,219	3,208	2,166	257	892	38	243
PADD 3	6,783	6,703	2,536	616	1,753	419	658
PADD 4	506	502	268	25	154	4	[1]51
PADD 5	2,252	2,113	1,424	366	406	124	—
Jan. 22, 2010	**13,871**	**13,624**	**8,636**	**1,343**	**3,516**	**662**	**990**
Jan. 15, 2010	**13,859**	**13,824**	**8,565**	**1,374**	**3,483**	**586**	**956**
Jan. 23, 2009[2]	**14,531**	**14,136**	**8,660**	**1,385**	**4,170**	**529**	**1,103**
	17,681 Operable capacity		**78.5% utilization rate**				

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

OGJ GASOLINE PRICES

	Price ex tax 1-27-10	Pump price* 1-27-10	Pump price 1-28-09
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	235.2	266.6	177.2
Baltimore	229.4	271.3	174.5
Boston	225.7	267.6	177.8
Buffalo	218.1	281.3	180.5
Miami	231.7	284.6	180.9
Newark	231.2	264.1	169.5
New York	217.4	280.6	187.8
Norfolk	223.6	261.3	169.5
Philadelphia	224.9	275.6	186.8
Pittsburgh	223.6	274.3	193.5
Wash., DC	234.7	276.6	196.8
PAD I avg	226.9	273.1	181.3
Chicago	243.4	298.5	209.4
Cleveland	241.6	288.0	196.3
Des Moines	222.9	263.3	186.5
Detroit	238.7	290.3	194.4
Indianapolis	230.8	280.9	193.4
Kansas City	222.2	257.9	180.5
Louisville	229.7	270.6	186.5
Memphis	149.5	189.3	179.4
Milwaukee	228.0	279.3	191.4
Minn.-St. Paul	217.8	263.4	184.5
Oklahoma City	202.6	238.0	166.9
Omaha	216.3	262.0	178.9
St. Louis	214.3	250.0	179.5
Tulsa	200.6	236.0	171.6
Wichita	204.9	248.3	177.5
PAD II avg	217.6	261.1	185.1
Albuquerque	223.2	260.4	176.5
Birmingham	222.1	261.4	174.5
Dallas-Fort Worth	217.7	256.1	172.5
Houston	219.7	258.1	167.1
Little Rock	213.5	253.7	178.4
New Orleans	225.3	263.7	174.5
San Antonio	225.0	263.4	172.5
PAD III avg	220.9	259.5	173.7
Cheyenne	220.4	252.8	150.5
Denver	235.6	276.0	167.2
Salt Lake City	215.2	258.1	165.4
PAD IV avg	223.7	262.3	161.1
Los Angeles	232.3	298.1	199.4
Phoenix	241.6	279.0	179.3
Portland	248.4	291.8	204.4
San Diego	234.5	300.3	210.4
San Francisco	236.6	302.4	215.0
Seattle	239.4	295.3	202.4
PAD V avg	238.8	294.5	201.8
Week's avg.	**224.0**	**268.8**	**182.9**
Jan. avg.	**224.9**	**269.7**	**177.1**
Dec. avg.	**214.4**	**259.2**	**171.1**
2010 to date	**224.9**	**269.7**	—
2009 to date	**131.5**	**177.1**	—

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

REFINED PRODUCT PRICES

	1-22-10 ¢/gal		1-22-10 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	195.98	New York Harbor	191.74
Gulf Coast	192.73	Gulf Coast	188.74
Los Angeles	188.98	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	187.25	ARA	185.61
Singapore	203.57	Singapore	196.79
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	195.26	New York Harbor	159.24
Gulf Coast	193.73	Gulf Coast	164.81
Los Angeles	194.98	Los Angeles	190.34
		ARA	169.29
		Singapore	178.56

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

BAKER HUGHES RIG COUNT

	1-29-10	1-30-09
Alabama	3	2
Alaska	9	10
Arkansas	40	50
California	24	25
Land	23	24
Offshore	1	1
Colorado	47	78
Florida	0	1
Illinois	1	0
Indiana	3	3
Kansas	22	16
Kentucky	8	11
Louisiana	197	170
N. Land	133	87
S. Inland waters	14	8
S. Land	13	22
Offshore	37	53
Maryland	0	0
Michigan	0	0
Mississippi	10	12
Montana	4	4
Nebraska	1	0
New Mexico	53	57
New York	3	1
North Dakota	75	68
Ohio	7	8
Oklahoma	112	144
Pennsylvania	70	23
South Dakota	0	0
Texas	538	662
Offshore	4	5
Inland waters	0	0
Dist. 1	22	8
Dist. 2	16	35
Dist. 3	37	53
Dist. 4	47	57
Dist. 5	76	139
Dist. 6	67	110
Dist. 7B	10	19
Dist. 7C	49	47
Dist. 8	115	80
Dist. 8A	21	22
Dist. 9	30	38
Dist. 10	44	49
Utah	22	23
West Virginia	25	27
Wyoming	37	61
Others—HI-1; NV-4; TN-1	6	16
Total US	**1,317**	**1,472**
Total Canada	**531**	**432**
Grand total	**1,848**	**1,904**
US Oil rigs	444	309
US Gas rigs	861	1,150
Total US offshore	42	60
Total US cum. avg. YTD	**1,251**	**1,553**

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

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

SMITH RIG COUNT

Proposed depth, ft	Rig count	1-29-10 Percent footage*	Rig count	1-30-09 Percent footage*
0-2,500	94	2.1	67	—
2,501-5,000	48	79.1	67	50.7
5,001-7,500	132	29.5	195	23.5
7,501-10,000	256	7.4	329	3.3
10,001-12,500	249	10.8	292	2.7
12,501-15,000	197	3.0	290	0.3
15,001-17,500	187	—	145	—
17,501-20,000	78	—	63	—
20,001-over	37	—	43	—
Total	**1,278**	**10.2**	**1,491**	**6.7**
INLAND	15		18	
LAND	1,222		1,421	
OFFSHORE	41		52	

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

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

OGJ PRODUCTION REPORT

	[1]1-29-10	[2]1-30-09
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	20	21
Alaska	700	679
California	644	653
Colorado	68	66
Florida	5	2
Illinois	22	22
Kansas	110	109
Louisiana	1,420	1,351
Michigan	17	17
Mississippi	62	62
Montana	84	81
New Mexico	164	161
North Dakota	225	190
Oklahoma	180	177
Texas	1,407	1,375
Utah	65	62
Wyoming	149	142
All others	68	76
Total	**5,410**	**5,246**

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

US CRUDE PRICES

	1-29-10 $/bbl*
Alaska-North Slope 27°	70.46
South Louisiana Sweet	76.00
California-Midway Sunset 13°	65.00
Lost Hills 30°	73.05
Wyoming Sweet	63.39
East Texas Sweet	68.75
West Texas Sour 34°	64.25
West Texas Intermediate	69.25
Oklahoma Sweet	69.25
Texas Upper Gulf Coast	62.25
Michigan Sour	61.25
Kansas Common	68.25
North Dakota Sweet	60.50

*Current major refiner's posted prices except North Slope lags 2 months. 40° gravity crude unless differing gravity is shown.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

WORLD CRUDE PRICES

$/bbl[1]	1-22-10
United Kingdom-Brent 38°	75.61
Russia-Urals 32°	75.06
Saudi Light 34°	74.35
Dubai Fateh 32°	76.51
Algeria Saharan 44°	76.41
Nigeria-Bonny Light 37°	77.75
Indonesia-Minas 34°	79.10
Venezuela-Tia Juana Light 31°	75.43
Mexico-Isthmus 33°	75.32
OPEC basket	76.09
Total OPEC[2]	75.39
Total non-OPEC[2]	75.10
Total world[2]	75.26
US imports[3]	74.29

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

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

US NATURAL GAS STORAGE[1]

	1-22-10	1-15-10	1-22-09	Change, %
	bcf			
Producing region	807	810	815	-1.0
Consuming region east	1,334	1,401	1,231	8.4
Consuming region west	380	396	355	7.0
Total US	**2,521**	**2,607**	**2,401**	**5.0**
	Nov. 09	**Nov. 08**	**Change, %**	
Total US[2]	**3,833**	**3,346**	**14.6**	

[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

	Nov. 2009	Octt. 2009	11 month average production 2009	11 month average production 2008	Change vs. previous year Volume	Change vs. previous year %	Nov. 2009	Oct. 2009	Cum. 2009
	Crude, 1,000 b/d						Gas, bcf		
Argentina	600	616	606	609	–3	–0.5	100.0	110.5	1,283.97
Bolivia	40	40	40	40	—	–0.5	40.0	40.0	445.00
Brazil	1,986	1,991	1,946	1,809	137	7.5	31.0	33.0	327.00
Canada	2,740	2,670	2,582	2,601	–19	–0.7	416.6	403.8	4,654.70
Colombia	680	680	658	579	79	13.7	30.0	35.0	340.00
Ecuador	460	460	472	498	–26	–5.3	2.0	2.0	22.00
Mexico	2,553	2,602	2,602	2,806	–204	–7.3	210.0	222.0	2,353.38
Peru	114	111	106	79	27	34.3	10.5	11.0	111.50
Trinidad	103	103	107	113	–6	–5.2	123.2	118.6	1,264.14
United States	5,462	5,422	5,295	4,940	355	7.2	1,817.0	1,871.0	20,159.00
Venezuela[1]	2,200	2,220	2,161	2,357	–196	–8.3	68.0	72.0	760.00
Other Latin America	83	83	83	83	—	–0.1	5.4	5.5	60.14
Western Hemisphere	**17,021**	**16,997**	**16,658**	**16,515**	**143**	**0.9**	**2,853.7**	**2,924.5**	**31,780.82**
Austria	18	18	19	17	1	7.3	4.9	4.8	51.10
Denmark	241	237	262	287	–25	–8.6	17.8	19.3	237.86
France	18	18	18	20	–1	–7.1	2.4	2.5	28.88
Germany	52	51	56	60	–5	–7.7	41.8	41.4	465.85
Italy	91	87	82	101	–18	–18.2	22.0	22.0	242.50
Netherlands	23	27	26	34	–8	–23.6	200.0	190.0	2,210.00
Norway	2,123	2,077	2,068	2,170	–102	–4.7	319.0	289.0	3,309.84
Turkey	49	48	45	41	4	10.6	—	—	—
United Kingdom	1,381	1,321	1,346	1,411	–65	–4.6	178.0	178.6	2,004.81
Other Western Europe	5	4	4	4	—	–5.7	1.8	1.7	12.52
Western Europe	**4,000**	**3,888**	**3,925**	**4,144**	**–219**	**–5.3**	**787.8**	**749.3**	**8,563.36**
Azerbaijan	1,100	1,050	1,041	900	141	15.7	60.0	55.0	445.00
Croatia	13	13	14	15	–1	–7.5	5.4	4.2	55.16
Hungary	14	13	14	15	–1	–4.5	7.1	7.1	77.84
Kazakhstan	1,600	1,500	1,335	1,205	130	10.8	100.0	100.0	1,100.00
Romania	90	90	90	93	–3	–2.9	18.0	19.0	203.00
Russia	10,100	10,100	9,897	9,755	142	1.5	1,700.0	1,550.0	16,400.00
Other FSU	400	400	436	405	32	7.9	450.0	350.0	3,700.00
Other Eastern Europe	42	42	43	48	–5	–10.1	17.8	18.0	205.46
Eastern Europe and FSU	**13,359**	**13,209**	**12,870**	**12,434**	**436**	**3.5**	**2,358.2**	**2,103.3**	**22,186.46**
Algeria[1]	1,240	1,240	1,239	1,377	–138	–10.0	235.0	245.0	2,695.00
Angola[1]	1,880	1,900	1,784	1,900	–116	–6.1	6.0	6.0	58.00
Cameroon	70	70	73	84	–11	–13.2	—	—	—
Congo (former Zaire)	25	25	25	25	—	—	—	—	—
Congo (Brazzaville)	240	240	240	240	—	—	—	—	—
Egypt	640	650	645	677	–33	–4.8	115.0	120.0	1,325.00
Equatorial Guinea	320	320	320	320	—	—	0.1	0.1	0.66
Gabon	240	240	228	235	–6	–2.7	0.3	0.3	3.34
Libya[1]	1,520	1,520	1,548	1,725	–176	–10.2	37.0	38.0	409.00
Nigeria[1]	1,980	1,900	1,808	1,947	–139	–7.1	95.0	95.0	971.00
Sudan	500	500	500	489	11	2.2	ou	—	—
Tunisia	78	78	82	85	–3	–3.6	8.0	8.3	89.55
Other Africa	221	221	221	221	—	—	8.6	9.4	97.00
Africa	**8,954**	**8,904**	**8,713**	**9,326**	**–612**	**–6.6**	**505.0**	**522.0**	**5,648.55**
Bahrain	30	30	30	29	—	1.0	30.0	30.0	294.82
Iran[1]	3,700	3,660	3,735	3,909	–174	–4.4	275.0	285.0	3,130.00
Iraq[1]	2,360	2,500	2,398	2,430	–32	–1.3	20.0	22.0	223.00
Kuwait[1,2]	2,280	2,270	2,274	2,610	–336	–12.9	35.0	36.0	397.00
Oman	800	820	807	719	88	12.3	45.0	50.0	596.00
Qatar[1]	770	770	765	853	–87	–10.2	215.0	220.0	2,422.00
Saudi Arabia[1,2]	8,220	8,280	8,189	9,258	–1,069	–11.5	210.0	220.0	2,363.00
Syria	350	360	369	388	–19	–4.9	17.0	18.0	192.00
United Arab Emirates[1]	2,270	2,280	2,270	2,598	–328	–12.6	130.0	135.0	1,440.00
Yemen	280	280	276	307	–31	–10.2	—	—	—
Other Middle East	—	—	—	—	—	–11.2	7.4	9.7	100.38
Middle East	**21,060**	**21,250**	**21,114**	**23,102**	**–1,988**	**–8.6**	**984.4**	**1,025.7**	**11,158.21**
Australia	456	470	466	460	6	1.2	125.0	130.2	1,365.28
Brunei	170	160	151	161	–9	–5.6	35.0	35.0	381.36
China	3,823	3,838	3,766	3,811	–45	–1.2	277.6	253.7	2,738.39
India	670	685	662	676	–14	–2.1	126.2	126.9	1,159.33
Indonesia[1]	860	860	856	859	–3	–0.3	195.0	200.0	2,190.00
Japan	13	15	15	17	–1	–8.2	9.0	9.5	108.48
Malaysia	700	730	731	758	–27	–3.6	130.0	140.0	1,505.00
New Zealand	52	52	50	56	–6	–10.8	10.0	11.0	130.90
Pakistan	66	63	64	66	–3	–4.0	117.9	120.7	1,338.75
Papua New Guinea	35	35	37	41	–5	–11.0	0.9	1.0	10.50
Thailand	240	221	238	228	10	4.4	33.7	35.9	375.94
Vietnam	325	325	300	278	22	7.7	20.0	20.0	220.00
Other Asia–Pacific	49	48	48	41	7	16.9	91.5	94.5	1,022.50
Asia–Pacific	**7,459**	**7,501**	**7,383**	**7,452**	**–69**	**–0.9**	**1,171.8**	**1,178.3**	**12,546.43**
TOTAL WORLD	**71,854**	**71,749**	**70,664**	**72,972**	**–2,309**	**–3.2**	**8,660.9**	**8,503.2**	**91,883.83**
OPEC	28,880	29,000	28,644	32,321	–3,677	–11.4	1,328.0	1,376.0	16,990.00
North Sea	3,768	3,654	3,696	3,886	–190	–4.9	574.7	543.8	6,213.49

[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.

Marketplace

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Senior Engineering Consultant to work in cross-functional consulting teams involved in project management, delivery of medium and large scale projects, creative problem solving, business development and supporting clients primarily in the upstream/downstream oil and gas industry. Requires a MS in Mechanical Engineering or Chemical Engineering and relevant experience. Reference position: Job Code 28087.

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Obama's speech raises tax alarm for oil industry

For the oil and gas industry, President Barack Obama's State of the Union speech on Jan. 27 contained one carrot and two heavy sticks.

The carrot: "Making tough decisions about opening new offshore areas for oil and gas development."

The first heavy stick: "Passing a comprehensive energy and climate bill with incentives that will finally make clean energy the profitable kind of energy in America."

The second heavy stick: "At a time of record deficits, we will not continue tax cuts for oil companies, for investment fund managers, and for those making over $250,000 a year."

Although any hint of new offshore leasing from the Obama camp might seem like a healthy turn, no one should be fooled. This administration has consistently trimmed lease sales and tightened restrictions on what leasing it has allowed.

And if it did try to open more than isolated pieces of now-closed areas of the federal offshore to resource development, Congress under current leadership wouldn't fund the lease sales.

The sticks are what matter.

The cap-and-trade system proposed for climate-change mitigation would be disastrous for the industry, especially refiners. Even after Obama's prodding, however, the Senate probably won't ratify the House's misjudgment by passing it.

Most senators won't misread the national mood as badly as Obama has. Most can draw sound conclusions from a recent survey, conducted for the Pew Center for the People and the Press, of public opinions about "top priorities for 2010." Among 21 national concerns, global warming ranked last.

The greater worry must be Obama's allusion to "tax cuts for oil companies," embedded in a list of populist villains.

This can mean only new wheels on the wagon of horrors Obama rolled out in his budget proposal last year, with its repeal of percentage depletion for independent producers, new taxation of Gulf of Mexico production, and exclusion of oil companies from a tax credit available to competitors in other businesses, among other things.

Obama has made clear he's not retreating from the predilections evident in his first year in office. For the industry, this is reason to worry.

(Online Jan. 29, 2010; author's e-mail: bobt@ogjonline.com)

The Editor's Perspective

by Bob Tippee, Editor

Market Journal

by Sam Fletcher, Senior Writer

Floating inventories fall

The volume of crude in storage on supertankers at sea has fallen well below 40 million bbl from a peak of 100 million bbl last May.

Some say it may have fallen as low as 20 million bbl. "If that is right, and land stocks also reduce, the market could easily see prompt oil regain its premium to futures as demand recovers," said analysts at KBC Market Services, a division of KBC Process Technology Ltd. in Surrey, UK, on Feb. 1. "The contango in the market has already become much narrower, down to just 50-60¢/bbl on [North Sea] Brent compared [with] around $2/bbl towards the end of last year."

Some of the middle distillate held in floating storage off Europe also was drawn down in the recent cold wave in the Northern Hemisphere. KBC analysts said 70-90 million bbl of distillate are estimated to be still in floating storage, however.

US net exports of distillates were "on the high side" at 425,000 b/d during November, "which means that on a distillate yield of 27.3%, the US refineries are running about 1.6 million b/d of crude oil to export distillates," said Olivier Jakob at Petromatrix in Zug, Switzerland. "Those are contra-economics, since these exports [were] sold into the floating stocks, which then pressure other European refineries to reduce runs as well. The bottom line is that the Atlantic Basin refineries were still burning about 1.6 million b/d too much crude oil in November."

Ethanol production

US refineries are taking a "double-whammy" from low post-crisis demand and continued growth in ethanol blending that is taking market share from refined petroleum products.

Adam Sieminski, chief energy economist, Deutsche Bank, Washington, DC, said it's possible even a strong recovery in global gross domestic product might be accompanied by a "fuel-less" or tepid resurgence in oil demand. "Oil demand growth in Asia is likely to be one of the most important drivers for the crude oil markets over the next few years. India and China are growing strongly as new car registrations have performed strongly," he said.

"The US is now producing about as much ethanol as it is importing crude oil from Saudi Arabia, and on the current trend we would expect the US ethanol production to be over the US import of Saudi crude oil in 2010," Jacob said. "This is good news from a perspective of US internal politics, but the growing use of ethanol in a peak oil demand environment (in the US) should continue to be a strong pressure point on the US refining system."

He noted, "Saudi Arabia is not fighting the trend, and it is abandoning its storage installations in the Caribbean to focus instead on storage installations in Japan to better service 'Chindia.' With the 1 million b/d addition of Canadian pipeline capacity in the second quarter and the continued increase in ethanol production and blending, the US is cutting its dependency on oil that costs $5/bbl to produce (Middle East) and increasing its dependency on oil that cost $70/bbl to produce (Canada and ethanol)."

Enbridge Inc.'s Alberta Clipper pipeline from Canada to the Midwest will start operating in April rather than the third quarter as previously projected. "Combined with the start-up of the Keystone pipeline this means that we suddenly have 900,000 b/d of additional pipeline capacity from Canada to the US Midwest starting in the second quarter," Jakob said (OGJ Online, Jan. 25, 2010).

The China factor

Jakob said, "China is increasing its dependency on the cheap Middle-Eastern crude and would be shooting itself in the foot by allowing sanctions on Iran that would be too harsh and that would push Iran in a geopolitical escalation."

France assumed the rotating presidency of the United Nations Security Council at the end of January, prompting speculation of UN sanctions against Iran. However, the US proposed a $6.4 billion sale of military equipment to Taiwan, and China reacted by suspending military exchanges. Chinese officials said they also will impose sanctions on companies selling arms and will review cooperation with the US on "major issues." So it's doubtful "that the Chinese will provide a helpful hand over Iran," Jakob said. They also may not help the US confront North Korea over its nuclear program or with currency and trade issues.

In other news, at the end of January in the first test of the US military's ability to respond to a simulated Iranian missile attack, the US missile defense failed to intercept the test missile launched from the Marshall Islands.

(Online Feb. 1, 2010; author's e-mail: samf@ogjonline.com)

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