Week of July 6, 2009/US$10.00

PennWell

OIL&GAS JOURNAL

International Petroleum News and Technology / www.ogjonline.com

Drilling and the Environment

Gas find sets Norwegian Sea water depth mark
VOC, HAP emissions concern Rocky Mtn. regulators
US petchems experience rebound with new year
Process control upgrade boosts system flexibility

THE STATE OF ISRAEL

MINISTRY OF NATIONAL INFRASTRUCTURES

MINISTRY OF FINANCE

THROUGH

THE INTER-MINISTERIAL TENDER COMMITTEE for the Construction of an LNG Facility

1. The Inter-Ministerial Tender Committee **for the Construction of an LNG Facility** (The Tender Committee) hereby announces the publication of a Pre-Qualification Document with regard to an LNG Project that shall include: (**1**) the design, financing and construction of an offshore LNG Receiving Terminal with a daily processing capacity of no less than 16 million cubic meters of Standard Natural Gas (SNG) [annual processing capacity of approximately 4 billion cubic meters (4 BCM) of SNG] (the "**LNG Receiving Terminal**"); and (**2**) the operation and maintenance of the LNG Receiving Terminal including, inter alia, storage and regasification of the LNG (the "Project").

2. The LNG Receiving Terminal shall be executed through a build-operate-transfer (BOT) concession agreement according to which a license shall be granted to the entity which will execute the Project (the "**Successful Bidder**"), for a period of not less than 20 years and not more than 30 years. At the termination of the concession and license period, the LNG Receiving Terminal shall be transferred to the State at no cost.

3. It is the intention of the Tender Committee to conduct a two-phased competitive selection process in order to select the Successful Bidder as follows: (1) Pre-qualification of participants; (2) A Request for Proposals process, in which those participants which have complied with the requirements of the pre-qualification phase, will be invited to participate.

4. The pre-qualification stage includes several pre-qualification requirements, in the following areas, as detailed in the Pre-Qualification Documents:

   a) **Professional Experience** - Experience in the design, construction and operation of an offshore LNG Receiving Terminal; or Ownership and experience in the operation of one or more LNG carrier vessels that have transported LNG in international waters.

   b) **Financial Robustness** [Cash Flow, Turnover and Equity].

5. The Tender Committee reserves the right to conduct negotiations during the Tender Process and additional prerogatives, all as set forth in the Pre-Qualification Documents.

   The Pre-Qualification Documents shall be available for online review starting Monday, June 22nd, 2009 on the Ministry of Finance website at:http://mof.gov.il/Tools/tenders/Pages/TenderViewer.aspx?ListID=1e46ddc5-2830-43ae-ada4-dc82ef3b1e50&WebId=3d3b8a95-9ac3-4b2a-88c7-1d5dffd1e288&ItemID=129, and in the Ministry of National Infrastructure website at: http://www.mni.gov.il/mni/en-US/Energy/Tenders/EnergyTendersLNG.htm

   In addition, the Pre-Qualification Documents are available for review, free of charge, at the address detailed in Section 9 hereinafter, starting Monday, June 22nd, 2009, Sunday through Thursday, at 10:30-15:00, subject to prior coordination with the coordinator of the Tender Committee, Mr. Efraim Bibi, E mail address: efraimb@inbal.co.il and efrats@inbal.co.il.

6. The Pre-Qualification Documents may be purchased for twenty thousand NIS (NIS 20,000), at the address specified in Section 9 hereinafter, during the times as specified in Section 5 above. Payments shall be made to account no. 25636 at Bank Hadoar (Bank no. 09), Jerusalem branch (branch no. 001), in the name of the Accountant General.

7. Upon purchase of the Pre-Qualification Documents, each purchaser, or its appointed representative, shall be required to present a confirmation from the bank through which the payment was made, identify itself using an Israeli Identification Card or a foreign passport, and shall be requested to provide the identity of the purchasing entity, and provide details about its appointed representative, including its postal address, telephone and facsimile numbers and e-mail address. All notices and additional information pertaining to the tender process will be sent to appointed representative of each purchaser of the tender documents in accordance with such details.

8. Only Participants who purchased the Pre-Qualification Documents, will be entitled to participate in the Pre-Qualification Stage.

9. **Interested participants are required to submit their Pre-Qualification Submissions by no later than 14:00 on Tuesday, September 15th, 2009, to the Tender Committee's tender box, at the following address:**

   Private Public Partnerships Division, Inbal Insurance Company Ltd., Inbal House,
   Arava St., 5th Floor, P.O.B. 282, Airport City, Ben-Gurion Airport 70100

10. This notice contains general and preliminary information only. Further conditions and requirements with respect to the tender process are as detailed in the Pre-Qualification Documents. The Tender Committee reserves the right to annul and/or revise the conditions of the Pre-Qualification stage and its schedule, all in accordance with the provisions of the Pre-Qualification Documents.

Avi Dor
Deputy Accountant General
Chairman of the Tender Committee

OIL&GAS JOURNAL

July 6, 2009
Volume 107.25

Drilling and the Environment

Regular Features

Cover

A rig operated by Chesapeake Energy Corp. drills near downtown Fort Worth. Some of the Barnett shale lies beneath urban Tarrant County, home to more than 60 municipalities and 1.7 million people. Hydraulic fracturing, traditionally a state-regulated practice, is under intensifying scrutiny by several federal legislators. The Drilling and the Environment special report, starting on p. 18, opens with an article about the need for communication of accurate information on drilling-related topics. A second article discusses ongoing research to treat and recycle frac water. And a third article covers testimony of industry officials stating that individual states are already sufficiently regulating hydraulic fracturing. Photo froms Chesapeake.

OIL&GAS JOURNAL online

The full text of Oil & Gas Journal is available through OGJ Online, Oil & Gas Journal's internet-based energy information service, at http://www.ogjonline.com. For information, send an e-mail message to webmaster@ogjonline.com.

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General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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

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

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

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

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

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

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

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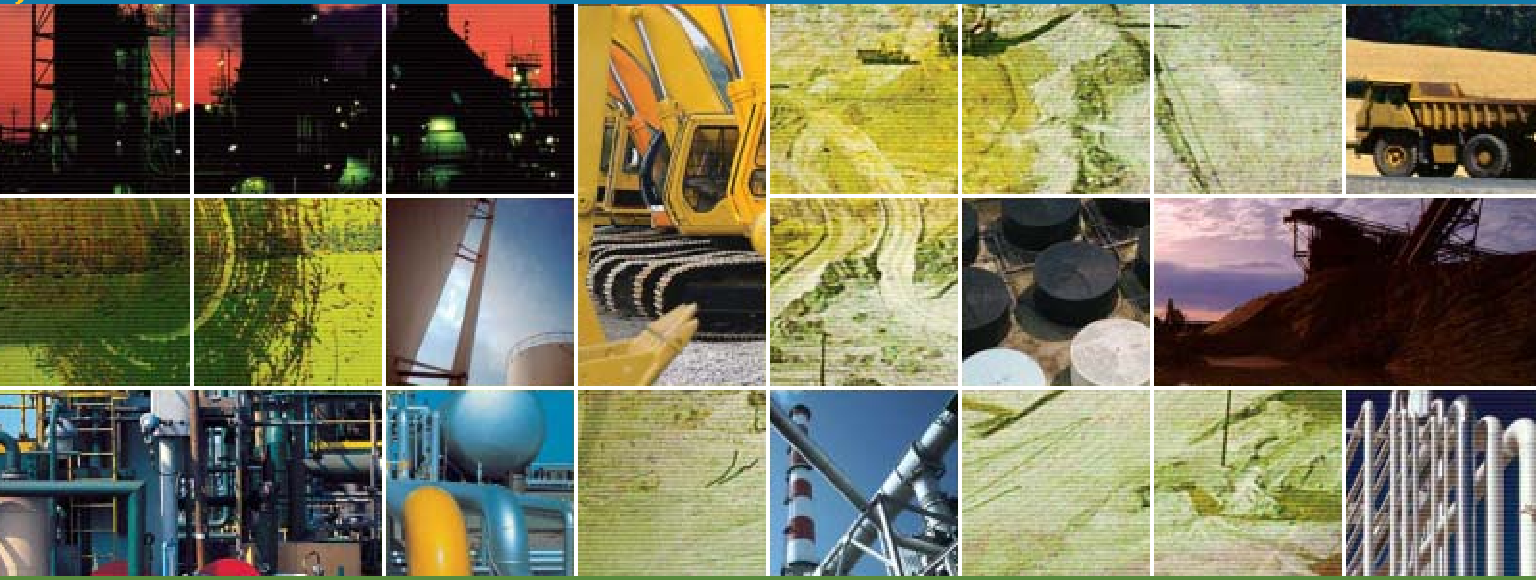


OGJ Newsletter

July 6, 2009

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

General Interest — *Quick Takes*

BP reports fastest oil demand fall since 1982

Worldwide oil demand has fallen at its fastest rate since 1982, according to BP PLC's statistical review of world energy.

Tony Hayward, chief executive officer of the company, said global oil production will fall because of dwindling demand and improvements in energy efficiency. Last year, oil consumption in the developed world fell by 1.6%—the largest decline since 1982. This trend is expected to continue.

For the first time, the developing world led by China consumed more energy than OECD countries: China represented nearly three quarters of global growth and its energy usage was 17.7%. This was the slowest rate for 5 years.

"This is not a temporary phenomenon but one that I believe will only increase still more over time," Hayward said. "It will continue to affect prices and bring with it new challenges over economic growth, energy security, and climate change."

Oil demand dropped by 1.5 million b/d in the developed world, spurred first by record oil prices and the global economy collapsing. Non-OECD countries also registered slower growth in demand at just 1.1 million b/d.

Hayward said he believes oil prices will hit $60-90/bbl in the future, arguing that oil producers need at least $60/bbl to underpin investment and consumers appeared comfortable with prices beneath $90.

"In the OPEC world, most OPEC countries need prices north of $60-70/bbl to be able to invest in today's capacity, to invest in their social government programs and to invest in tomorrow's capacity. If that price isn't realized, then the first thing that gets cut is tomorrow's capacity."

According to the energy review, worldwide oil production climbed by 0.4% last year.

In 2008, gas consumption crept along, below the decade average at 2.5%. China experienced the fastest rise in gas consumption, reaching a level of 15.8% while US gas consumption rose 0.6% and the UK 3%.

BP said: "Globally, gas production rose 3.8%, above the 10-year trend of 3%. This was driven strongly by the US, which recorded its highest ever annual increase in gas production as strong activity in the development of unconventional gas resources raised output by 7.5%."

Coal continued for the sixth year as the fastest-growing fuel.

"Our data confirms that the world has enough proved reserves of oil, natural gas, and coal to meet the world's needs for decades to come," Hayward said. "The challenges the world faces in growing supplies to meet future demand are not below ground; they are above ground. They are human, not geological."

Enterprise, TEPPCO reach merger agreement

Enterprise Products Partners LP and TEPPCO Partners LP have agreed to a major merger of US pipeline, storage, and gas processing systems.

The combined entity will retain the Enterprise Products Partners name. It will own more than 22,000 miles of NGL, oil product, and petrochemical pipelines; 20,000 miles of natural gas pipelines; and 5,000 miles of crude oil pipelines.

Combined storage capacities will be 200 million bbl of NGL, products, and crude oil and 27 bcf of natural gas. The partnership will own one of the largest NGL terminals in the US, on the Houston Ship Channel; 60 NGL, product, and petrochemical terminals throughout the US; and crude oil terminals on the Texas Gulf Coast.

The postmerger partnership will own interests in 17 fractionation plants with more than 600,000 b/d of net capacity, 25 gas processing plants with net capacity of about 9 bcfd, and 3 butane isomerization facilities with capacity of 116,000 b/d.

Enterprise and TEPPCO have entered into definitive agreements to enact the merger. The new partnership will have an enterprise value exceeding $26 billion.

TEPPCO and its general partner, Texas Eastern Products Pipeline Co. LLC, are to become subsidiaries of Enterprise.

Parties to the agreement agreed to settle lawsuits filed after Enterprise made its initial offer in March.

EU group prepares for possible Ukraine gas shortage

At a meeting scheduled for July 2, the European Union's Gas Coordination Group is to prepare for the possibility of another gas shortage in case Russia again shuts down the flow of its gas through Ukraine to the EU.

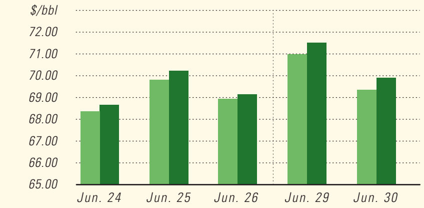
Ukraine is still looking for a $4.2 billion loan to pay for Russian gas deliveries. About 80% of Russia's gas supplies to Europe pass through Ukraine and accounts for one third of the EU's gas imports.

The directive that established the Gas Coordination Group in 2006 includes a three-step approach in dealing with a supply crisis. The first calls for the industry to take measures to resolve the emergency. If that fails, national programs are activated. If those fail and 20% of gas imports are curtailed, the coordination group provides assistance to countries in difficulty.

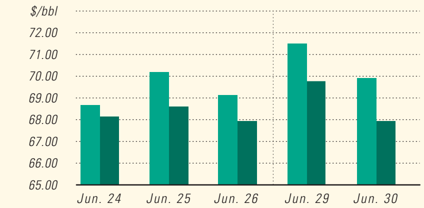
The January crisis showed a more coordinated approach is needed at EU level, and the commission suggested emergency plans be activated automatically in the event of supply disruption. It suggested the commission should have the authority to force member states to provide gas from their strategic stocks. These new measures should be proposed to the council and parliament before the end of summer. ✦

Industry Scoreboard

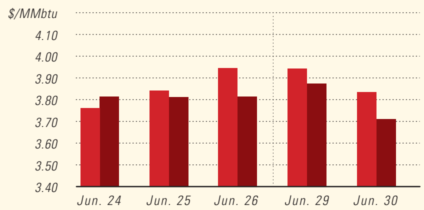
IPE BRENT / NYMEX LIGHT SWEET CRUDE



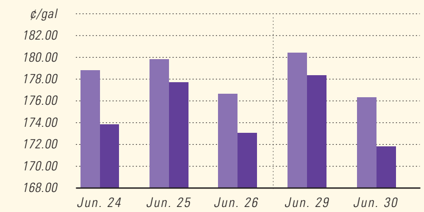
WTI CUSHING / BRENT SPOT



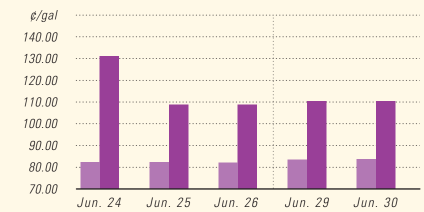
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



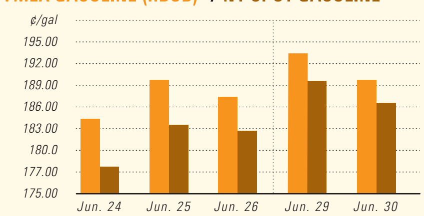
IPE GAS OIL / NYMEX HEATING OIL



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.

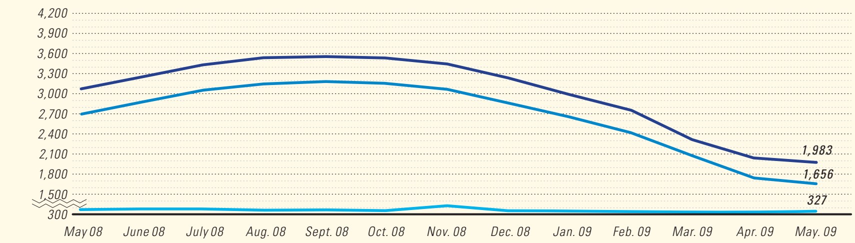
US INDUSTRY SCOREBOARD — 7/6

Latest week 6/19	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	9,161	9,123	0.4	8,950	9,019	–0.8
Distillate	3,449	3,802	–9.3	3,736	4,085	–8.5
Jet fuel	1,361	1,580	–13.9	1,387	1,558	–11.0
Residual	636	678	–6.2	567	635	–10.7
Other products	3,713	4,433	–16.2	3,953	4,500	–12.2
TOTAL DEMAND	18,320	19,616	–6.6	18,593	19,797	–6.1
Supply, 1,000 b/d						
Crude production	5,312	5,129	3.6	5,286	5,132	3.0
NGL production[2]	1,912	2,350	–18.6	1,858	2,240	–17.1
Crude imports	9,234	9,862	–6.4	9,367	9,771	–4.1
Product imports	2,675	3,313	–19.3	2,940	3,212	–8.5
Other supply[3]	1,698	1,354	25.4	1,663	1,402	18.6
TOTAL SUPPLY	20,831	22,008	–5.3	21,114	21,757	–3.0
Refining, 1,000 b/d						
Crude runs to stills	14,368	15,368	–6.5	14,368	14,879	–3.4
Input to crude stills	14,718	15,723	–6.4	14,718	15,204	–3.2
% utilization	83.4	89.3	—	83.4	86.4	—

Latest week 6/19	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	353,853	357,721	–3,868	301,758	52,095	17.3
Motor gasoline	208,905	205,034	3,871	208,757	148	0.1
Distillate	152,103	150,026	2,077	119,421	32,682	27.4
Jet fuel-kerosine	41,728	41,800	–72	40,500	1,228	3.0
Residual	37,736	37,824	–88	39,253	–1,517	–3.9
Stock cover (days)[4]			**Change, %**		**Change, %**	
Crude	23.9	24.3	–1.6	19.6	21.9	
Motor gasoline	22.8	22.1	3.2	22.5	1.3	
Distillate	44.1	42.7	3.3	29.4	50.0	
Propane	67.2	57.3	17.3	38.9	72.8	
Futures prices[5] **6/26**			**Change**		**Change**	**%**
Light sweet crude ($/bbl)	68.85	70.61	–1.76	134.37	–65.52	–48.8
Natural gas, $/MMbtu	3.87	4.14	–0.27	12.99	–9.12	–70.2

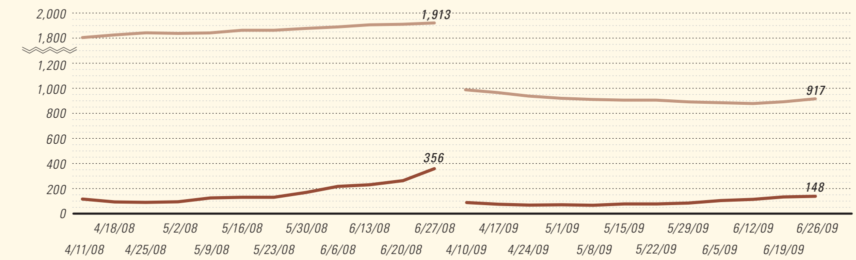
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

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



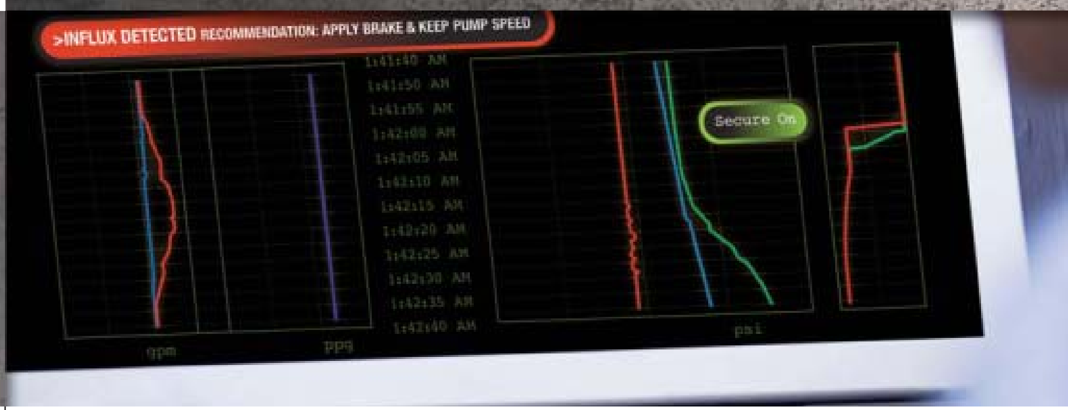
Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

Build more accurate control.



The Secure Drilling system makes previously undrillable wells drillable:

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- Enabled drilling to depths never reached previously when drilling conventionally (offshore Libya).

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Norwegian parliament approves Goliat field plan

The Norwegian parliament has given the go ahead for Eni Norge AS to develop Goliat field in the Barents Sea with a circular floating production platform.

Sevan Marine ASA has designed the Sevan 1000 floating production, storage, and offloading vessel and has signed an engineering contract and a technology license with Eni (OGJ Online, Apr. 24, 2009). Production from the field, which lies in 400 m of water, is scheduled to start in fourth quarter 2013.

"Use of the circular FPSO makes it possible to utilize electricity supplied from shore combined with a gas turbine for power and heat on the offshore facility. This will result in significantly lower levels of [carbon dioxide] emissions," said Eni.

Meanwhile, a consortium led by Aker Solutions AS pulled out of competition for the engineering, procurement, and construction contract for the Goliat FPSO.

Aker Solutions said Eni Norge would not prequalify the group for the field development.

Aker and its partners, Aibel and Samsung Heavy Industries, had suggested a floating production platform with production capacities of 100,000 b/d and 3.9 million cu m/day gas and storage capacity of 950,000 bbl.

The Sevan Marine Services circular floating production platform design calls for those production capacities and 1 million bbl of oil storage.

The field, which holds reserves of 180 million boe, is the first oil development in its area. Environmentalists are worried about its impact.

Total Goliat investments are estimated at 28 billion kroner ($4.4 billion) in 2008 money.

Goliat field, on Blocks 7122/7,8,9,10 and 7123/7, was discovered in 2000.

Eni is operator of Goliat with a 65% stake. StatoilHydro holds 35%.

StatoilHydro discovers oil in Titan prospect

StatoilHydro is considering tying in its discovery of 5.6-12.5 million boe of recoverable oil in the Tampen area of the Norwegian North Sea to its Visund project.

Exploration wells 34/8-13 A and 34/8-13 S, drilled to test Brent group targets, made the discovery on the Titan prospect directly east of northern Visund.

"Although it's only a small find, the volumes proven could be very significant for realizing a Visund North development," said Visund operations head Tom Karsten Gustavsen.

Visund field produces oil and gas from subsea wells tied to a floating production, storage, and quarters platform. North Visund is a separate subsea development about 10 km north of the platform.

While 13 A on the Titan prospect found a small oil column in Upper Jurassic sands, the underlying Brent group proved to be an aquifer. Well 13 S, drilled 2.7 km to the southeast, found oil in the Brent group.

The oil zones in the two wells are likely to be in communication, and both have been subject to extensive data gathering and coring, the company said.

Well 13 A reached a TVD of 3,108 m subsea and terminated in the Statfjord formation. Well 13 S reached a TVD of 3,258 m subsea and ended in the Hegre group.

StatoilHydro used the Scarabeo 5 semisubmersible rig to drill the wells in 381 m of water. The rig has moved to PL 199 for a workover of production well 6406/2-S-4 H.

Both wells have been plugged and abandoned.

Operator StatoilHydro has 59.06% of PL 120, where its partners are Petoro with 16.94%, ConocoPhillips 13%, and Total E&P Norge 11%.

Seychelles prepares for offshore licensing round

Seychelles Petroleum Co. (Seypec) completed an oil-slick mapping and interpretation project off Seychelles in partnership with Infoterra Ltd. to prepare for a licensing round later this year.

The companies have gathered more than 150 radar satellite scenes across 500,000 sq km—making it the largest slick-mapping project ever done off Seychelles.

The data will be used to identify mature source rocks and a petroleum system. "We will use this data to support the planning of seismic projects and subsequent geochemical programs," said Patrick Joseph, Seypec exploration manager.

Infoterra ranked all oil slicks as probable natural seepage or manmade pollution and mapped the location and movement of all shipping visible in the area to give a more complete picture.

According to reports, the Seychelles will offer 70,000 sq km of offshore acreage in the licensing round.

One operating company in the nation is East African Exploration Ltd., which signed a production-sharing agreement last year with the government covering 15,000 sq km.

The two larger tranches, Area A (7,510 sq km) and Area B (6,808 sq km) lie in shallow water in the northern half of the Seychelles plateau. Area C (680 km) is in the south.

EAX is required to shoot 2,000 line-km of seismic and drill one well by October 2012, according to its work program.

Algeria launches new licensing round

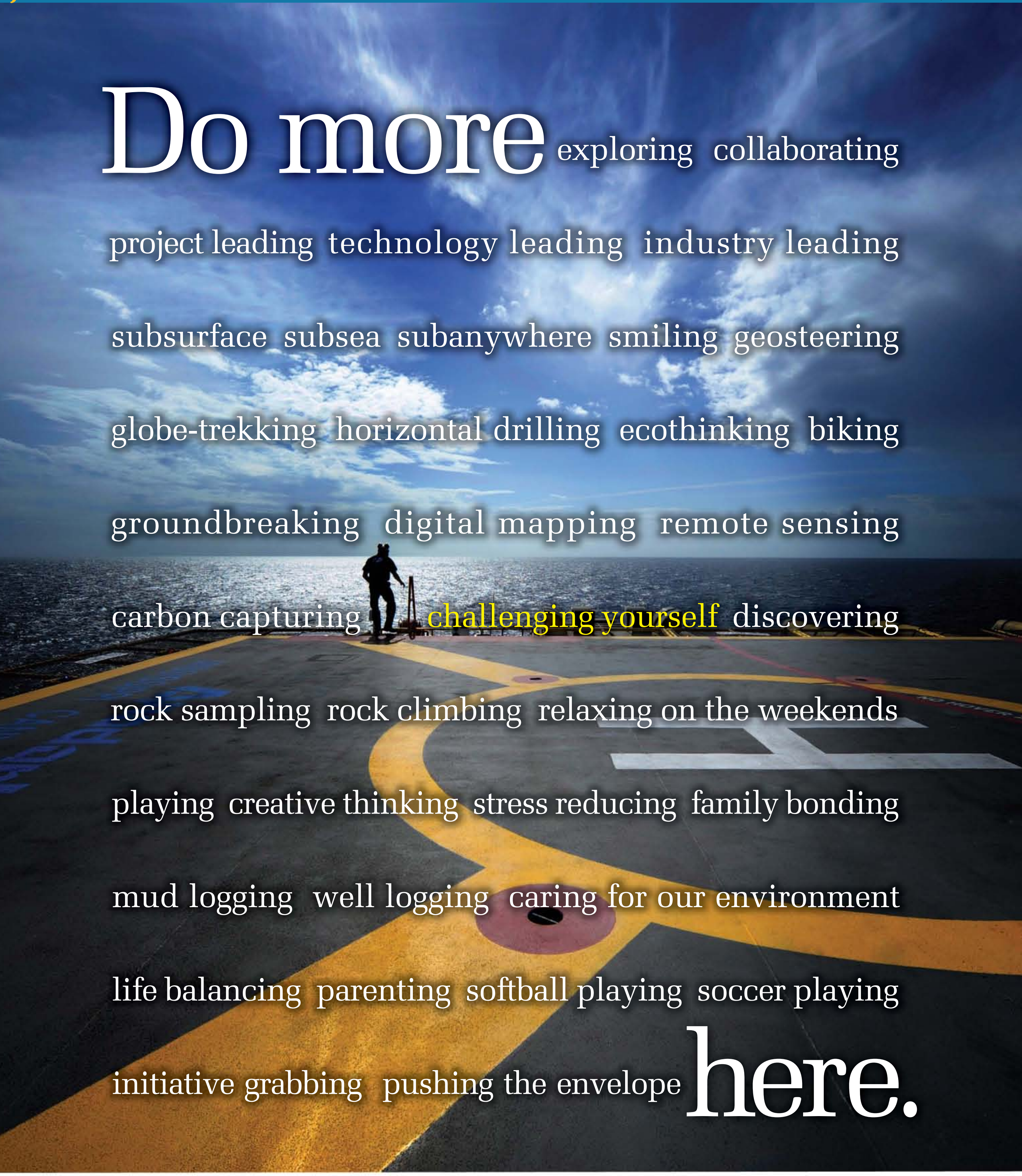
After failing to generate interest in its December offering, Algeria launched a licensing round for 25 blocks it said have "high-potential petroleum resources."

Energy and Mines Minister Chakib Khelil said Algeria would work with companies that have technology to handle unconventional gas, rather than those who want to swap reserves in other countries.

Khelil said, "It will be for companies with tight sands technology, so there will be some prequalification done in that area."

Potential operators have selected blocks being offered, said Khelil. They are to submit bids by Dec. 20 and contracts would be signed Jan. 16. The blocks are in basins where previous discoveries were made by Repsol-YPF SA and StatoilHydro.

Algeria will make a technical presentation July 27 and will open data rooms for each project from Aug. 15 to Oct. 22.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groundbreaking digital mapping remote sensing
carbon capturing challenging yourself discovering
rock sampling rock climbing relaxing on the weekends
playing creative thinking stress reducing family bonding
mud logging well logging caring for our environment
life balancing parenting softball playing soccer playing
initiative grabbing pushing the envelope here.

Foreign oil companies didn't show much interest under Algeria's last bidding round for 11 licenses, complaining poor acreage was offered and of the impact of the financial crisis.

E.On Ruhrgas AG, BG Group PLC, Eni SPA, and OAO Gazprom filed successful applications for the December licensing round. ✦

Drilling & Production — *Quick Takes*

BLM signs decision record on Rocktober gas project

The US Bureau of Land Management's Cody, Wyo., field manager signed a decision record on June 29 for seven proposed natural gas wells in the McCullough Peaks area east of Cody.

The action by Michael P. Stewart followed a 30-day review of a BLM environmental assessment (EA) of a proposal by Denver independent producer Bill Barrett Corp. for the wells and associated facilities in the Rocktober Natural Gas Unit.

The analysis determined that no significant long-term impacts would occur as a result of the project, BLM said. It also addressed issues raised during the EA's public comment and review periods including impacts on wild horses, sage grouse, and other wildlife; visual intrusions, and air and water quality, BLM said. It received 55 comments on the proposed project.

One of the comments came from the Greater Yellowstone Coalition, an environmental organization based in Bozeman, Mont. It said that Bill Barrett already has drilled two wells on state land in the McCullough Peaks area. It asked BLM to delay its final decision on the company's application until the federal agency's new resource management plan for the area is completed.

It also urged BLM to require Bill Barrett to use closed-loop drilling on the project, which the group said "eliminates massive pits filled with contaminates that pose a threat to wildlife and groundwater."

In an errata to the EA, BLM said that there is no reason to use a closed-loop system in drilling the Rocktober wells because reserve pits would be lined if required by BLM. "Standard drilling techniques (including isolating all water-bearing formations in the well bore with pipe and cement) will adequately protect water aquifers," it maintained.

All groundwater resources in the area are 600-700 ft deep and there are no water wells near the project area, it continued. The nearest water wells are more than 2 miles away and in a hydraulically up-gradiant direction "and therefore have little to no risk from project operations," the EA's errata said.

It also said that the EA follows the existing resource management plan for the area, and that BLM is required to follow that RMP until a new one is signed.

Chevron begins injecting steam in PNZ pilot

Saudi Arabian Chevron initiated steam injection in its large-scale pilot steamflood project at Wafra field, an Eocene heavy-oil carbonate reservoir in the Partitioned Neutral Zone (PNZ) between Kuwait and Saudi Arabia.

Chevron said the $340 million pilot is the final test phase for steamflooding the reservoir, and it expects the pilot to lead to full-field steamflooding, which would make the project the world's first commercial conventional steamflood in a carbonate reservoir.

"Full-field deployment of steamflood technology in the PNZ would significantly increase recovery of crude oil reserves, confirm the technology's potential applicability in other carbonate oil fields and build on Chevron's steamflood capabilities that date back 5 decades," said George Kirkland, executive vice-president, Chevron Global Upstream & Gas.

The large-scale pilot is the third in a series of staged tests for validating the feasibility of steamflooding at Wafra. Previous tests included the small-scale test completed in 2008 and simple steam stimulation in the late 1990s.

Steamflooding involves injecting steam into heavy-oil reservoirs to heat the crude oil underground, reducing its viscosity and allowing its extraction through wells. Chevron has employed steamflooding to produce heavy oil from sandstone reservoirs at Kern River, Calif. for more than 40 years and at Duri in Sumatra, Indonesia, for 25 years.

Saudi Arabian Chevron operates on behalf of Saudi Arabia that has a 50% interest in the onshore PNZ petroleum resources. Saudi recently amended and extended Chevron's operating agreement until February 2039.

The company's operations in the PNZ include four fields: Wafra, South Umm Gudair, South Fuwaris, and Humma. The fields produce mainly heavy crude from 10 reservoirs. In 2004, onshore PNZ produced its 3 billionth bbl of oil, according to Chevron. ✦

Processing — *Quick Takes*

Bidding resumes on Yanbu export refinery

Bidding will resume on the second of two major refineries in Saudi Arabia for which work was delayed late last year.

Saudi Aramco and ConocoPhillips have reinstated preconstruction work on the 400,000-b/d refinery they plan at Yanbu, Saudi Arabia.

The full-conversion export refinery will process Arabian heavy crude. Willie C. Chiang, ConocoPhillips senior vice-president, refining, marketing, and transportation, said bidding had resumed "now that markets are more favorable."

Work had been suspended during a review last year by Aramco of a several major upstream and downstream projects (OGJ, Nov. 17, 2008, p. 29).

Prequalified local and international contractors have received invitations to bid for early work and major Yanbu packages including a coker unit, crude facility, gasoline unit, hydrocracker, tank farm, offsite pipelines, high-voltage electrical facilities, and other infrastructure.

Earlier, the Saudi Aramco Total Refining Petrochemical Co. joint venture announced completion of an award plan for bids on the 400,000-b/d refinery it plans in Jubail, Saudi Arabia (OGJ, June 22, 2009, Newsletter).

Borouge to expand Abu Dhabi olefins complex

Borouge, a joint venture of Borealis AS of Vienna and Abu Dhabi National Oil Co., plans to make its already expanding ethane-cracking complex in Ruwais, Abu Dhabi, the world's largest.

It has let a $1.075 billion contract to Linde Group, Munich, for a third ethane cracker at Ruwais with capacity of 1.5 million tonnes/year (tpy).

The project will increase total polyolefins capacity of the complex to 4.5 million tpy by the end of 2013. In addition to the ethane cracker, it includes construction of second-generation polypropylene and polyethylene units based on Borealis's Borstar technology, a low-density polyethylene unit, and a butene unit, plus offsite utilities and marine facilities.

The new ethane cracker will add to an existing 600,000 tpy ethane cracker and a 1.5 million tpy unit under construction.

The world's largest olefins complex in terms of ethylene capacity now is Nova Chemicals Corp.'s 2.8 million tpy facility at Joffre, Alta.

The cracker under construction at Ruwais is part of a project to increase Borouge polyolefins capacity to 2 million tpy by mid-2010. Net ethylene output from that plant will be 600,000 tpy, according to Chemical Market Associates Inc., Houston, because some of the product will be dimerized to butene, and butene and more ethylene will be metathesized to propylene (OGJ, Aug. 25, 2008, p. 48).

In that project, Borouge is adding a 752,000-tpy olefins conversion unit, a 540,000-tpy polyethylene plant, and two 400,000-tpy polypropylene plants.

Total resolves Lindsey refinery dispute

Total SA has settled a dispute with hundreds of contract workers that were fired from constructing a hydrodesulfurization unit (HDS) at its 200,000 b/d Lindsey refinery in the UK.

The employees will vote on the measures to be reinstated to work on June 29, unions said. They were fired after embarking on unofficial strikes about 51 planned redundancies by the sub contractor while another employer on the site was hiring people.

Their actions triggered sympathy strikes at other construction and energy sites around the country.

The HDS unit is already 6 months behind schedule and €100 million over budget. It is meant to be ready before the end of the year, but this is the second strike this year that has derailed its progress. Total said it was pleased that "a positive conclusion" had been reached. "We expect this means that the contractors will be able to get back to work as soon as possible and get the project completed on time and with no further disruption or additional costs." ✦

Transportation — *Quick Takes*

Gorgon-Jansz gas gets interim marketing nod

The three joint venturers in the Gorgon-Jansz gas and LNG project in Western Australia have been given conditional interim authorization from the Australian Competition and Consumer Commission (ACCC) to market gas in the state.

The approval enables Chevron Corp., ExxonMobil Corp., and Royal Dutch Shell PLC to talk to potential customers and obtain information relevant to the project's final investment decision expected later this year.

ACCC Chairman Graeme Samuel said authorization was unlikely to result in irreversible changes to the market because any gas sales agreements reached during this period would be conditional on final authorization.

The move has disappointed the so-called DomGas Alliance, which represents Western Australia's largest customers and which told the ACCC in early June that it opposed the request for joint marketing.

Alliance Chairman Stuart Hohnen pointed out that vigorous gas competition was important for businesses and households. He said a lack of competition had resulted in gas prices recently four or five times those in eastern Australia on a delivered basis.

The ACC has addressed this issue by only allowing the interim authorization to take place after the Gorgon partners had their ring-fencing arrangements independently audited, and any changes required to make them effective had been implemented.

The commission will make a draft determination by September following a public comment period.

The Gorgon-Jansz project includes a three-train LNG plant with total capacity of 15 million tonnes/year alongside a domestic gas plant capable of supplying 300 terajoules/day of gas to the Western Australian grid. Gas is scheduled to come on stream in 2014.

Chevron is operator with 50%. ExxonMobil and Shell have 25% each.

Qatar, Poland sign 20-year LNG contract

Qatar Liquefied Gas Co. III (Qatargas) has signed a 20-year agreement to sell Poland 1 million tonnes/year of LNG.

Poland's Treasury Ministry said value of the contract is about $550 million/year.

Poland will receive the LNG at a terminal under construction at Swinoujscie, scheduled for completion in 2015.

Qatargas expects its LNG production to rise to 42 million tonnes/year by the end of the decade from 10 million tonnes/year in 2008. ✦

Correction

A recent story about a ramp-up in production from BP PLC's Thunder Horse project incorrectly attributed Thunder Horse as solely accounting for 1 of every 6 bbl of oil produced in the US (OGJ Online, Apr. 17, 2009). The statement should have read: "Offshore deepwater developments like Thunder Horse now account for 1 of every 6 bbl of oil produced in the US."

Letters

Part of the story

Whilst I agree with the thrust of your editorial entitled "'Pollutant's' new meaning threatens hydrogen vehicles"—that is, governments really have no clue what they are talking about when it comes to greenhouse gases, climate change, and so forth, to say that hydrogen vehicles produce water vapor, which is a more powerful greenhouse gas than CO_2, is only part of the story (OGJ Online, May 1, 2009).

The more damaging problem with hydrogen fuel usage is where does one get hydrogen from? The inconvenient truth, which BP, the politicians, and other agents of disinformation will not tell you, is that you have to burn coal, oil, or gas to produce the energy to create hydrogen. The energy needed to drive a hydrogen-based car is obtained in a two-stage process and is therefore inherently even more inefficient that simply burning natural gas or oil to provide the necessary energy.

Chris Matchette-Downes
Black Marlin Energy Ltd.
London

Calendar

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

OIL&GAS JOURNAL online

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2009

JULY

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

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

Oil Sands and Heavy Oil Technologies Conference & Exhibition, Calgary, Alta., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilsandstechnologies.com. 14-16.

AUGUST

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

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

EnerCom's The Oil & Gas Conference, Denver, (303) 296-8834, email: kgrover@enercominc.com, website: www.theoilandgasconference.com. 9-13.

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

Petroleum Association of Wyoming (PAW) Annual Meeting, Casper, (307) 234-5333, (307) 266-2189 (fax), e-mail: suz@pawyo.org, website: www.pawyo.org. 18-19.

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

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

SEPTEMBER

Oil & Gas Maintenance Technology North America Conference, New Orleans, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.ogmtna.com. 1-3.

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

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

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

GPA Rocky Mountain Annual Meeting, Denver, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gpaglobal.org, website: www.gpaglobal.org. 9.

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

Turbomachinery Symposium, Houston, (979) 845-7417, (979) 847-9500 (fax), e-mail: inquiry@turbo-lab.tamu.edu, website: http://turbolab.tamu.edu. 14-17.

Annual IPLOCA Convention, San Francisco, +41 22 306 02 30, +41 22 306 02 39 (fax), e-mail: info@iploca.com, website: www.iploca.com. 14-18.

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

Annual Energy Policy Conference, Oklahoma City, (202) 580-6532, (202) 580-6559 (fax), e-mail: info@energyadvocates.org, website: www.energyadvocates.org. 20-22.

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

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

Groningen field turns 50

Uchenna Izundu
International Editor

Last month, Nederlandse Aardolie Maatschappij BV (NAM), a joint venture of ExxonMobil Corp. and Royal Dutch Shell PLC, celebrated the 50th anniversary of its discovery of the massive Groningen natural gas field in the northern part of the Netherlands. It is one of the largest gas fields in Europe and—in 1959—was the third largest in the world based on its known reserves.

National transformation

Groningen, which lies 3,000 m underground, changed the Dutch economy. Gas from the field was exported to western Europe, which positioned the Netherlands as an important supplier. However, several events including the oil crisis in the 1970s, the liberalization of the European gas market, and the rise of other gas producers like Norway and Algeria forced the Dutch government to devise a 'small fields' policy, which exploited smaller fields in the hopes of slowing Groningen field's depletion rate.

To date, the field has produced more than 60% of its original producible gas reserves estimated at 2.7-2.8 trillion cu m.

Groningen is set to contribute to Europe's gas supply security for at least another 50 years. About 300 wells have been drilled over 29 production clusters. The reservoir is 900 sq km. In September NAM will complete its compressor installation program and update equipment so that it can be operated remotely.

When the field was first discovered, it was a disappointment because gas was not a highly valued commodity at the time. At discovery, the field also was only thought to hold 50-150 billion cu m in reserves.

Also underappreciated was Groningen's future impact on economic terminology. The term 'Dutch disease' emerged: "Because the natural gas exports kept the balance of payments in surplus, the Dutch gilder remained a hard currency," wrote Joep Schenk, author of 'Groningen's Gas Field—The First 50 Years.' Schenk wrote, "This made it increasingly difficult for companies to sell their products abroad. Consequently, employment in the Dutch economy suffered a severe decline: the economists' diagnosis was that the Dutch economy was suffering from the 'Dutch disease.'"

Celebration program

NAM has launched different initiatives to mark the anniversary of Groningen. Queen Beatrix inaugurated artwork created by Marc Ruygrok: a gas molecule, which commemorates the first gas well and symbolizes the past, present, and future importance of Groningen gas, along the A7 Motorway.

There is also an interactive exhibition depicting the history of the field at the stunning Fraeylemaborg estate, which is frozen in the 19th century. The exhibition has technological, geological, social, and economic details and will end in October.

The sculpture trail—'Gas in glass'—has different glass sculptures symbolizing various themes, such as the dimensions and shape of the gas field and the significance of natural gas. Glass was chosen to represent the invisible nature of natural gas. A free arts program also will run until Sept. 12 and will showcase pop and classical music, theatre, multimedia, and crossover theatre.

Public-private partnership

Speakers at the conference reflecting on the history of the field stressed the importance of the public-private partnership between NAM and the Dutch government that ensured the field would be quickly commercialized. Maria van der Hoeven, minister of economic affairs, said, "There is no need to be humble here. Our performance as a gas-producing country has over the years been absolutely world-class."

Jeroen van der Veer, Royal Dutch Shell PLC chief executive officer, said this type of gas-building hasn't been seen in other countries. In his opinion, the Netherlands had probably been successful because of its stable fiscal system and coalition government structure; in other places successive governments could block previous policies and delay projects.

Groningen has become a landmark in Dutch history and predictions failed to capture the magnitude of its development. Although it will no longer be a net exporter of gas in 15 years, the Dutch government is keen to position the nation as the gas hub of northwest Europe with gas storage capacity, transport capacity, and trading facilities. This will ensure that the Dutch gas industry will be a prominent force for many decades to come. ✦

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Climate bill misinformation

The American rush toward economic peril continues.

"Don't believe the misinformation out there that suggests there is somehow a contradiction between investing in clean energy and economic growth," commanded President Barack Obama while praising a monstrous climate bill passed by the House of Representatives. "It's just not true."

As always, Obama sounded totally sure of himself. But being sure and being right aren't the same thing.

Without the context of the American Clean Energy and Security Act, the president's statement would be true enough. Clean energy and economic growth don't have to be contradictory. Nobody's saying they are.

The bill in question, however, goes beyond simply investing in clean energy. It establishes an already corrupt cap-and-trade system for emissions of greenhouse gases. It also fosters governmental fuel choice by setting a renewable-energy standard for electric utilities and committing the federal government to spending of $190 billion on the energy technologies politicians like.

Massive intrusion

The bill represents a massive intrusion by government into energy markets. It can't achieve its goal of lowering emissions of carbon dioxide except by painfully raising the costs of hydrocarbon fuels. To insist, as Obama does, that this won't create hardship is to overlook much.

But glib claims and propaganda tricks—such as assertions about climactic "tipping points" and "scientific consensus"—are what pushed the US to this economic precipice. Days before the vote on the climate bill, supporters of the legislation trumpeted a Congressional Budget Office report estimating that costs to the average household would be just $175 in 2020. That seems like a small price to pay for saving the planet, even to those who believe the planet's need for rescue isn't all that dire.

Again, however, things aren't so simple. CBO's analysis came under immediate criticism from economists who said that the agency didn't fully account for economic responses to elevated energy costs and that it spotlighted a year in which emissions allowances still will be relatively cheap.

The conservative Heritage Foundation, moreover, said CBO's numbers simply don't add up. CBO estimates the gross cost of emission allowances at $91.4 billion in 2020. But projected emissions times the assumed price of $28/ton of CO_2 imply a cost of $141 billion, which is more in line with CBO's projections of allowance revenues in 2015-19.

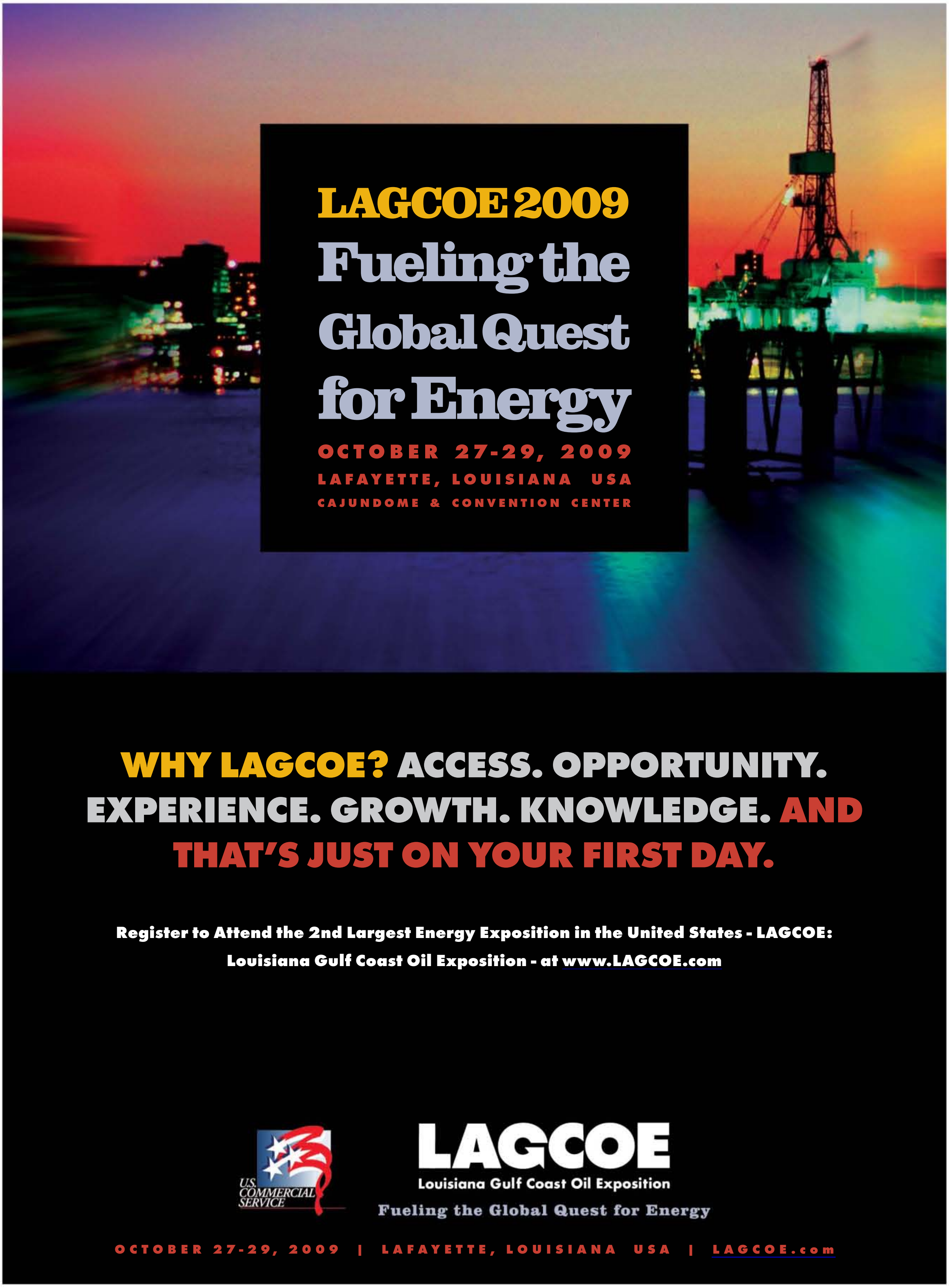
The Heritage Foundation critique, by David W. Kreutzer, Karen Campbell, and Nicolas D. Loris, further criticizes the CBO for treating government spending and distribution of allowance revenue as a direct cash rebate to energy consumers—"that is, that the carbon tax is not a tax if the government spends the money, which is simply preposterous." And the analysts call "most problematic" CBO's acknowledged omission of general economic damage resulting from restricted energy use.

The high probability of serious economic damage doesn't faze Obama, who while disparaging observers who worry about cost resorted to his standard invocation of green jobs. "Make no mistake," he said, "this is a jobs bill." Amazingly, one of his cheery examples was California, where "3,000 people will be employed to build a new solar plant that will create 1,000 permanent jobs."

Little help

A thousand jobs won't much help a state already leading the nation in economic self-destruction through governmental mischief in energy markets. In May alone, reports the California Employment Development Department, nonfarm payroll jobs declined by 68,900 from the same month a year earlier. The number of people unemployed in California in May was 2.138 million—885,000 more than a year earlier. Putting them all to work would require construction of 716 solar plants of the size Obama mentioned. And, oh yes, the state's broke.

The rest of the country should in fact treat California as an example but draw conclusions quite different from those intended by the president. The state is reeling from, among other things, egregious energy governance. It shows where the whole country will be headed if the Senate, encouraged by a self-assured president on a spending binge, upholds the House's mistake. ✦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Hydraulic fracturing, water use issues under congressional, public scrutiny

Paul Hagemeier
Chesapeake Energy Corp.
Oklahoma City

Jason Hutt
Bracewell & Giuliani LLP
Washington, DC

The need for communication of accurate information to the public, lawmakers, and regulators is imperative on various drilling-related topics, including hydraulic fracturing, water use and supply, and surface use. This is especially the case given active development of massive US natural gas shale plays in regions of the country less accustomed to oil and gas development.

Hydraulic fracturing, traditionally a state-regulated practice, has been targeted for intensifying scrutiny by several federal legislators and possibly by the US Environmental Protection Agency (EPA). In June, representatives in Congress introduced legislation that would give the EPA authority to regulate hydraulic fracturing under the Safe Drinking Water Act. This would reverse the explicit exemption for fracturing contained in the Energy Policy Act of 2005 and introduce a new requirement that the ingredients used in proprietary fracing fluids be disclosed and made available to the public (OGJ, June 15, 2009, p. 30).

Furthermore, EPA Administrator Lisa Jackson has testified that the increased use of hydraulic fracturing is "well worth looking into," suggesting that EPA may reexamine its established position that federal regulation of fracing is not warranted.

If past is prologue, however, the historic innovation and entrepreneurial spirit of America's gas industry bodes well for what lies ahead. This special report outlines examples of Chesapeake Energy Corp.'s attention to environmental issues in its Barnett shale operations.

Fracing gets attention

Hydraulic fracturing increasingly is being used in the development of shale gas plays. A quick internet search reveals the attention that fracturing is receiving as well as a number of misguided allegations about the associated environmental impacts of fracturing.

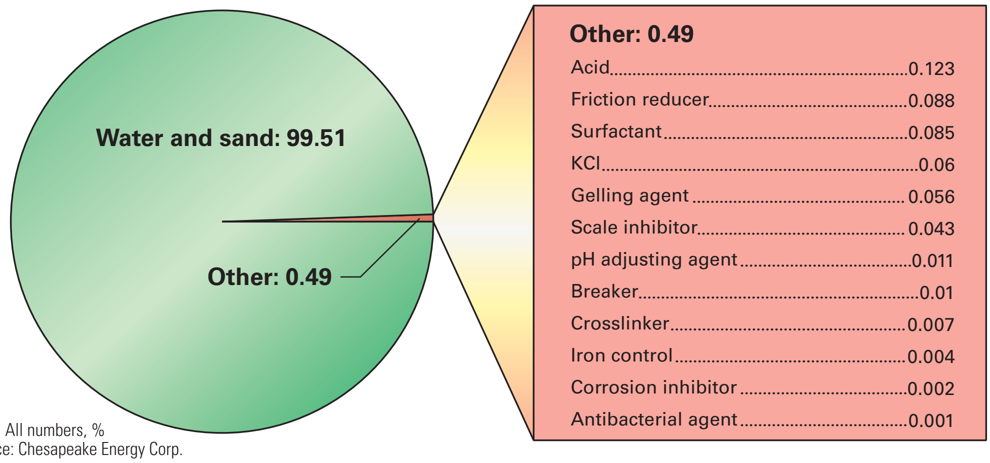
Before the introduction of any chemicals used in the drilling process, engineers, geologists, and geophysicists (and other specialists) collaborate to develop a fracturing program tailored to the specific characteristics of the formation and the well. A well-designed and installed casing program, combined with proper cementing, provides the first layer of protection and groundwater isolation from an oil- or gas-bearing formation.

States traditionally rely on casing and cement regulations as a primary means of protecting subsurface water. The typical state-mandated program requires steel casing that meets a specific standard (usually American Petroleum Institute Spec. 5CT), as well as the use of specific cement and cementing techniques.

By requiring compliance with API recommendations, each casing string effectively is ensured to meet or surpass a multitude of strength, pressure, and corrosion tests. Engineers design meticulous protective casing programs to prevent pressure collapse, burst pressure, corrosion, and joint failure—all while maintaining isolation from groundwater formations.

The fracing programs put in place by knowledgeable operators are overwhelmingly effective and frequently exceed minimum requirements of state-casing regulations. Doing so ensures isolation of the wellbore from nearby subsurface waters as well as protection of the producing zone.

Deep shale fracturing mixture



Note: All numbers, %
Source: Chesapeake Energy Corp.

Subsurface protections are not the only challenges presented and met by today's fracing process. Hydraulic fracturing also requires the temporary installation and use of water storage equipment, chemical storage, mixers, pressurizing, and other equipment at the well site. By giving care attention to the transportation, storage, and use of the various components associated with fracing, operators, contractors, and service providers protect the surface and surface water in addition to groundwater resources.

Many of the misunderstandings about hydraulic fracturing fluid focus on the "chemicals" used during the process. In deep shale plays, fracing fluid typically is made up of 99% water and sand; the rest consists of additives required to facilitate the process. The quantity of additives used is diluted and typically remains far below any level that may pose a danger to health.

Numerous protections are inherent with deep well fracturing. Deep formations (such as shale plays) are isolated from groundwater by geologic barriers and by precautionary engineering systems. With study and input from geologists, engineers, and others, fracturing activities are contained safely within the formation.

While much of this is "old hat" in many parts of the country, the development of newer plays like the Marcellus shale will cause review of the legal and regulatory frameworks governing fracturing. Alarmingly, several states have examined these rules, or are beginning to do so, with little or no input from experts within the industry.

Industry's future ability to use hydraulic fracturing technology could hinge upon interaction with legislators and regulators to educate them on the differences between shallow and deep natural gas operations. This includes discussion about adopting additional protective measures where fracturing activity occurs in close proximity to drinking water sources.

Constructive dialogue will require input from legislators, regulators, industry, environmental organizations, and community stakeholders to evaluate the existing, extensive state regulatory frameworks and to ensure that any new federal laws and regulations provide needed additional environmental protection, not just an added layer of permitting, paperwork, and unproductive use of public agency resources.

Protecting water

Water resources are protected from surface operations by a host of federal, state, and local regulatory programs. Notably, some operators exceed these regulatory requirements. An example is the installation of secondary containment (steel, plastic, earthen material, or some combination) at drilling and production sites around virtually all equipment containing liquids, not just oil. Many operators store produced fluids in steel tanks rather than earthen pits as a means of staging for recycling or for proper waste disposal. This practice eliminates spillage and overflow of pits in case of excessive rainfall and unforeseen soil saturation if protective liners fail.

Separately, the industry created the Reasonable and Prudent Practices for Stabilization (RAPPS) document to provide guidance and information on suggested methods to protect fresh water resources. EPA considers RAPPS as acceptable best practices for water resource protection. Among the practices suggested in RAPPS is to design drilling locations to prevent storm water runoff. A drilling location commonly uses a combination of mitigation measures to prevent runoff and reduce sediment erosion. Proper site construction and RAPPS implementation alone are only partial solutions. Maintenance and upkeep are required throughout the operation to reduce sediment erosion.

While RAPPS provides sound guidance, industry currently is working to update and refine the document to provide greater clarity and stronger

Chesapeake, the largest leasehold owner in the Marcellus shale, is drilling in West Virginia. Chesapeake currently produces 30 MMcfd equivalent net (45 MMcfd gross operated) from the play and anticipates reaching 100 MMcfd equivalent net (220 MMcfd gross operated) by yearend. Photo from Chesapeake.

environmentally protective practices.

In addition to protecting water resources, many operators work proactively with state regulators on collecting predrilling water samples from public and private wells. These samples are analyzed by the state and independent laboratories to provide a better understanding of local water quality before drilling. This effort insulates companies from frivolous litigation by establishing baseline conditions and, perhaps more importantly, educates the public about groundwater quality. It is incumbent upon the industry to champion the development and implementation of sampling and analytical standards.

Industry efforts such as additional secondary containment and proper sediment runoff control demonstrate a proactive approach to environmental protection. By further educating the general public on industry's efforts, false allegations can be defused, and the industry can continue to serve as a leader in developing sound, environmentally responsible practices.

Water use issues

Water use is another issue receiving increasing attention. Oil and gas wells cannot be drilled or completed without using water. A typical deep shale gas well requires a total of 3 million gal of water for the drilling and hydraulic fracturing processes.

To put that in context, 3 million gal of water is the amount used by:

- A city with a population of more than 8 million people in 4 min.
- A 1,000-Mw coal-fired electric power plant in 7½ hr.
- A typical golf course in 1 week.
- Irrigating a 5-acre corn field for one season.

Unlike drilling and hydraulic fracturing, these examples are ongoing, constant uses.

The amount of water used to produce 1 million MMbtu of natural gas is about 10% of the amount required to produce 1 MMbtu of coal and one-tenth of 1% of the water it takes to produce that amount of energy from ethanol.

Water use for oil and gas drilling and completion is temporary. Drilling and hydraulic fracturing generally are completed within weeks. A gas well provides clean-burning energy for years without requiring additional water.

Availability of water resource is inseparable from the issue of water use. Currently, water resources are protected through a set of stringent federal, state, and local permitting processes that assure water quality and availability. Permits and contracts must be obtained before an operator takes water.

For now, industry obtains water from a variety of sources, typically rivers, creeks, lakes, wastewater treatment discharge facilities and groundwater. In addition to these protected sources, many companies heavily invest in research and development to develop best management practices and new technologies for water recycling, water reconditioning, and high-flow diversion ponds.

In areas such as Pennsylvania and Arkansas, high-flow diversion ponds are being constructed (often by the state) for water collection during high-flow events. The ponds are constructed in accordance with regulations to maintain environmental sensitivity. The diversionary mechanism operates only when the river or creek is in "high-flow," thereby minimizing impact on aquatic resources. By diverting water flow to these ponds, the potential for flood damage is reduced. Diversion ponds also provide an alternate water source for drilling and completion.

As is the case with virtually every

Researchers develop ways to treat, recycle frac water

Paula Dittrick
Sention Staff Writer

The use of membrane filtration to recycle water from fracturing flowback is among the research projects being funded by the Research Partnership to Secure Energy for America (RPSEA), a nonprofit organization that works with government, universities, research organizations, and industry.

RPSEA, a program financed by revenues from oil and gas leases to the federal government, is cofunding the Environmentally Friendly Drilling Systems Program (EFD) for 3 years. Previously, EFD was cofunded by the US Department of Energy and industry.

Current EFD funding is part of RPSEA's efforts that leverage industry spending to develop technology for unconventional gas, specifically to help industry produce shale gas while protecting the environment. The EFD program includes hydraulic fracturing research and other projects.

Richard Haut, senior research scientist at the Houston Advanced Research Center (HARC), currently manages EFD. During 2005-08, EFD was managed by David Burnett, director of Technology for the Global Petroleum Research Institute (GPRI) at Texas A&M.

Both HARC and GPRI are active participants in EFD. Haut said, "Our program takes a systematic approach to develop and integrate new, low-impact technologies that reduce the footprint of drilling and production activities."

Treating frac water

Burnett's goal is to treat and recycle frac water to reduce the expense of transporting waste water and also to provide water for more fracturing. He has worked for 10 years on using membrane filters to treat frac water.

Frac water is a mixture of chemical additives and sand to prop open fractures. About 75% of injected frac water is recovered. The flowback water contains traces of barium, calcium bicarbonate, iron, magnesium sulfate, sodium chloride, and strontium that it picked up while passing through the rock formation.

A petroleum engineer, Burnett has discovered that more than 12,000 different types of membranes exist but only 15-50 types are available in commercial quantities. He works to find membranes that are suitable for oil and gas operations.

Researchers at the Global Petroleum Research Institute at Texas A&M University built a mobile pretreatment and desalination unit to extract fresh water in the treatment and recycling of water used in hydraulic fracturing. Photo from David Burnett of Texas A&M.

"Instead of trying to invent a new membrane, I am trying to find a membrane that already has been invented and seeing if it is useful," Burnett said. "I am a bridge between the scientist in the laboratory and the guy that wants to do something in the field."

He built mobile treatment units for demonstration purposes using membranes that were designed originally for seawater desalination. About half the flowback water can be recycled, and the rest must be reinjected into saltwater disposal wells, he said.

"We know the technology works. We need to show that the technology works for long periods of time, like 1-2 years, and make sure it's cost effective."

Treatment costs

The operating cost of actually doing the treatment is less than $1/bbl, Burnett said. Other costs involve transporting the water and disposing of the waste removed from the flowback water.

"Based on what I know, I would estimate that less than 10% of the potential Barnett shale water is being treated right now," Burnett said.

He believes the Fayetteville shale play could benefit from the membrane filters based upon the Fayetteville shale's salinity. Membranes are apt to prove very beneficial in the Haynesville shale, he said.

"The Marcellus shale is the biggest problem because the water is hypersaline, and so it needs a pretty robust pretreatment before you can deploy a membrane," he said.

The fracturing flowback salt content of Barnett shale averages 100,000 ppm while that of Marcellus is more than 200,000 ppm. The salinity of seawater is 33,000 ppm.

Membrane filters also could prove helpful in the Bakken oil shale because the technology to complete those wells is the same as gas shale, Burnett said.

Recently, Texas A&M licensed its membrane filtration technology to M-I SWACO, which plans to put a pilot filtration unit in either the Barnett or the Marcellus shale this year.

facet of exploration and production, continued research, development, and education will serve the industry well going forward.

Reduced surface disturbances

Oil and gas reserves are not confined to neat geographic boundaries mapped on the earth's surface. Reserves often are found in environmentally-sensitive areas, underlying major metropolitan cities, in undeveloped or rural areas, and beneath the ocean floor. Drilling rigs are compelled to go where the science and geology direct, although industry seeks to avoid wetlands and riparian areas, sensitive species and habitat, and densely populated areas. Considerable efforts are made to avoid sensitive areas.

In practice, this means increasing efficiency while also reducing the geographic footprint. For example, improvements in seismic technology and its increased use have enabled Chesapeake Energy to drill with a success rate of over 95% (and even the industry average as a whole is over 90%). Successful drilling rates help companies avoid drilling dry holes and the accompanying surface disturbance.

In addition, the increased use of horizontal drilling allows for more source rock exposure while requiring fewer surface locations. Industry also has reduced its surface footprint by drilling and completing multiple wells from a single pad. While the pad is larger than a traditional pad, it drastically reduces the amount of disturbed surface acreage necessary to produce the same volume of gas. By drilling multiple big stepout wells, field development is maximized, which allows more gas to flow from fewer wells.

The surface area used by these larger pads can be reduced when the right geology, surface area, equipment, and a host of other factors come together. Reducing pad size requires specially designed top-drive rigs with high-capacity pumps, a high derrick load rating, complete solids control equipment, and skid packages—all features of a smaller yet more powerful rig. These built-for-purpose rigs can be combined with a closed loop system and dewatering unit, eliminating the need for reserve pits and reducing water use requirements.

Prudent and responsible operations require that surface locations be selected based on environmental and social stewardship considerations, not just upon economic return on investment. This is particularly important in metropolitan settings and environmentally sensitive areas.

In both instances, industry can tap into valuable natural resources while preserving the character of the surrounding area. This is done using specialty rigs, equipment, and platforms that reduce noise, power use, and emissions. For example, drilling rigs can be fitted (when appropriate) with sound-deadening barriers to reduce the amount of noise, a tactic that has allowed industry to successfully operate in urban settings.

Personnel, public relations

While policies and regulations are designed to minimize the environmental impact of gas drilling, history demonstrates that it is industry's people who make the greatest difference.

As with all industries, it is incumbent upon the "old guard," including management, to demand environmental prudence in operations. This requires unflinching dedication to hiring good people, and more importantly, educating and training them on how to "do things the right way."

The gas industry is made up of thousands of companies and individuals with specialized functions spanning the exploration and production value chain. As a result, it often is not well understood to those outside its ranks. Clear and accurate communication with regulators, legislators, and the public is essential to addressing misconceptions about environmental impacts and formulating sensible policies that balance environmental protection and America's goal of greater energy independence.

Energy companies and energy-related service and supply vendors are being called upon to know the business and its practices, comply with governing rules and regulations, participate meaningfully in trade groups, and engage policymakers and the public. As an illustration of success, industry's outreach efforts led to the development of the Department of Energy's recently published Shale Gas Primer. These outreach efforts must continue.

Industry faces constant pressure to innovate, comply, and educate—while, of course, demonstrating value to shareholders. Additional pressures stem from coordinated efforts by well-funded and organized non-governmental organizations that have set their sights and public relations machines on the industry. Their efforts are producing results. The challenge is to navigate the laws and regulations while developing better practices and technologies that provide solutions for oil and gas production in an environmentally sound manner. ✦

The authors

Paul Hagemeier (paul.hagemeier@chk.com) is vice-president of regulatory compliance for Chesapeake Energy Corp. He is responsible for oversight of Chesapeake's compliance with state and federal regulations. This includes the development and enforcement of corporate policies and issues related to the dispensation of hazardous and nonhazardous waste. He also oversees the company's environmental and safety programs. Having more than 25 years' experience in the energy industry, Hagemeier has worked as a petroleum geologist and later as an environmental consultant on thousands of projects in the petrochemical, aircraft, agricultural, and municipal management sectors. He graduated from the University of Arkansas in 1981 with a Bachelor of Science in geology and continued his education with graduate work in environmental management.

Jason Hutt (jason.hutt@bgllp.com) is a partner in Bracewell & Giuliani LLP's Environmental Strategies Group, where he regularly advises energy companies, project developers, investor groups and financial institutions about environmental risks and liabilities associated with policy initiatives, regulatory compliance, and enforcement proceedings. In the oil and gas industry, his representative experience includes strategic advice on policy initiatives (hydraulic fracturing and storm-water permitting), counseling on corporate governance systems and environmental disclosures, and leading environmental due diligence teams in the context of acquisitions, divestitures, and arranging financing. Hutt is a graduate of Colgate University and the Vermont Law School.

States regulate hydraulic fracturing well, officials testify

Nick Snow
Washington Editor

US states already regulate hydraulic fracturing aggressively and effectively, and a federal law would be redundant, two officials told a US House subcommittee in early June.

"As the head regulator of oil and natural gas development in North Dakota and an office of the Interstate Oil & Gas Compact Commission, I can assure you that we have no higher priority than the protection of our states' water resources," said Lynn D. Helms, director of North Dakota's Department of Mineral Resources.

"Within our respective states, we are responsible for implementing the state regulations governing the exploration and development of oil and gas resources. First and foremost, we are resource protection professionals committed to stewardship of water resources in the exercise of our authority," said Scott Kell, president of the Ground Water Protection Council and deputy chief of the Minerals Resources Division in Ohio's Department of Natural Resources.

But a former director of New York City's Water and Sewer System told the House Natural Resources Committee's Energy and Minerals Resources Subcommittee that current state regulations are inadequate.

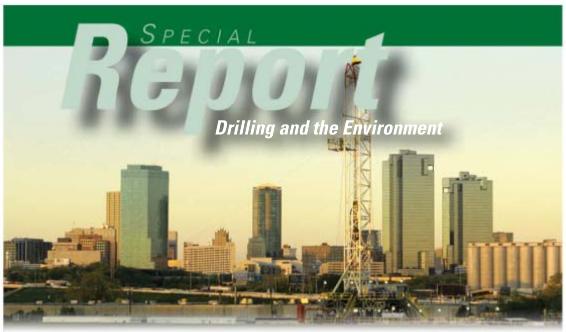
"All the improvements they've talked about are welcome. What we're dealing with is good housekeeping. All that has to happen is to have 2% of the wells that are planned go south and we'll have thousands of incidents," said Albert F. Appleton, who is now an infrastructure and environmental consultant.

'Take the initiative'

"The industry could help by developing biodegradable fracing fluids. I don't understand, for the life of me, why it hasn't taken the initiative," Appleton said.

They testified, with Douglas Duncan, associate coordinator of the US Geological Survey's Energy Resources Program, and Mike John, eastern division vice-president of corporate development and corporate resources at Chesapeake Energy Corp., at a hearing called by the subcommittee's chairman, Jim Costa (D-Calif.), to examine issues associated with shale gas production.

"Shale gas actually is not new. It's been developed for almost 50 years and could play a sizable part in the US energy portfolio. A single play, the Barnett shale, produces 6% of all gas consumed in the US today," Appleton said in his opening statement.



Doug Lamborn (R-Colo.), the committee's ranking minority member, said, "While this is a great opportunity for the country to have access to a significant reserve of clean-burning fuel well into the future, for some unfamiliar with the oil and gas industry, it has raised concern over the potential impact to water quality and use from the practice of hydraulic fracturing."

Lamborn said, "Hydraulic fracturing has been used by the oil and gas industry since the late 1940s. More than 1 million frac jobs have been completed in the US since the technique was first developed. And there have been no demonstrated adverse impacts to drinking water wells from the fracing process or the fluids used in the process."

Another subcommittee member, Maurice D. Hinchey (D-NY), disagreed, saying, "This is not an issue that's newly important. It's been around for a long time." Congress dealt with it when it passed the Safe Drinking Water Act in 1974, but a later group of federal lawmakers exempted oil and gas drilling under the 2005 Energy Policy Act, an action which needs to be reversed, he said.

Will reintroduce bill

Hinchey and Diana DeGette (D-Colo.) said following the hearing that they plan soon to reintroduce a bill that they initially offered in 2008, which would bring oil and gas drilling back under the SDWA. "This bill would make drillers subject to the same reporting requirements as any other industry under the SDWA. They would have to file reports about what chemicals are in the fracing fluid," DeGette told reporters during an afternoon teleconference.

Hinchey, who also participated, said, "We are being contacted by people from around the country who report bad experiences from drilling near their property. We're not trying to do anything revolutionary. We're trying to restore a safe, solid piece of legislation that was passed back in 1974."

But Kell noted that reports of problems have been exaggerated. "In recent months, the states have become aware of press reports and websites alleging that six states have documented over 1,000 incidents of groundwater contamination from the practice of hydraulic fracturing. Such reports are not accurate," he said.

Officials from Ohio, Pennsylvania, New Mexico, Alabama, and Texas wrote letters to GWPC Executive Director Mike Paque disproving the reports, Kell continued. A sixth official, from Colorado, did not respond because he had not been on the job long enough, he added.

In his May 29 letter to Paque, Texas Railroad Commission Chairman Victor G. Carillo said a majority of 354 active groundwater cases associated with the oil and gas which were reported in the state in 2007 involved "previous practices that are no longer allowed or result from activity now prohibited by our existing regulations." He said, "A few cases were due to blowouts that primarily occur during drilling activity. Not one of these cases was caused by hydraulic fracturing activity."

Safely used since '40s

Mike John of Chesapeake Energy acknowledged that hydraulic fracturing has become somewhat controversial, but added that it has been safely used since the 1940s. "It is very important to reiterate that these deep shale formations exist thousands of feet below the land surface and are separated from freshwater supplies by layers of steel casing, protected by concrete barriers as well as millions of tons of hard, dense solid rock geologic formations," he said in his written statement.

John also submitted a fact sheet that listed fracturing fluid additives, main compounds, and purposes, including hydrochloric or muriatic acid, borate salts (which maintain fluid viscosity as temperatures rise), petroleum distillate (to "slick" the water to minimize friction), and ethylene glycol (to prevent scale deposits in the pipe). "Additives used in hydraulic fracturing fluids include a number of compounds found in common consumer products," the fact sheet said.

But Appleton characterized fracturing fluid ingredients as "a witch's brew of toxic chemicals, nearly all of which are intrinsically hazardous to the environment." They are dangerous, he maintained, because they don't biodegrade: "Once in the environment, they stay there. Most of them bioaccumulate. The remainder volatize, removing them from water and land, but adding them to the atmosphere where they become contributors to global warming."

WATCHING GOVERNMENT

Nick Snow, Washington Editor

Blog at www.ogjonline.com

Protesting BLM lease sales

The US Department of the Interior has made progress in the last 6 months in responsibly developing oil and gas on public land, Interior Secretary Ken Salazar said on June 24. It has offered 2.5 million acres, and companies have paid $60 billion in bonus bids and leasing fees for 782,280 acres, he reported.

"We have held 17 oil and gas lease sales since January and plan to hold another 20 sales in the next 6 months," Salazar said. So far this year, BLM has offered 1,749 parcels totaling 2,261,854 acres and has sold leases on 866 parcels totaling 782,280 acres, collecting $60,108,904 in revenue.

Salazar's statements came a day after Utah's BLM office held its second lease sale for 2009. It was quieter than one that took place Dec. 18, 2008, when conservation groups sued because they felt the tracts were too close to national parks and monuments. Salazar agreed soon after becoming secretary and ordered BLM to reject the 77 successful bids.

But the June 23 sale still generated comment. Utah's BLM office delayed issuing the 31 sold leases until protests arriving after the deadline are resolved.

Deviation from procedures

"The deviation from the set procedures by accepting the late protests does not promote confidence that the Obama administration is committed to an orderly and predictable lease sale process that allows development of energy resources that belong to the American people," American Petroleum Institute Pres. Jack N. Gerard said on June 24.

Bethany Crandall, a Utah BLM spokeswoman, said the move was not a change. "We told bidders we were evaluating additional protests which had been received late, and to be aware that they may successfully bid for a parcel which has been protested," she said on June 26.

The Center for Native Ecosystems and the Theodore Roosevelt Conservation Partnership (TRCP) each notified Utah's BLM office that they intended to protest leases at the sale but would miss the filing deadline by a few hours, according to Crandall. "The only unusual part of the situation was that we accepted the protests late," she said.

Protests are routine

BLM officials in other states told me that protests are routine. Sometimes, they can lead to delays for a few leases. Other times, all awarded tracts are put on hold.

Joel Webster, TRCP's associate director of campaigns, welcomed the Utah decision. The group protested 2.5 million acres in five western states in 2007 and 2008 after concluding that fish and wildlife resources or hunting and fishing could be significantly affected if the areas were developed as proposed, he said.

"Sportsmen unreservedly support oil and gas production on America's public lands. But responsible administration of these resources demands a consistent approach to leasing and development activities in order to sustain fish and wildlife, and to provide companies wishing to extract energy from our lands and waters an increased level of certainty in their investments and planning," Webster said. ✦

Hydraulic fracturing introduces these chemicals into the environment by leaving a significant portion of the fluid underground, where it is free to migrate into groundwater, he continued. More oversight is needed to assure that wells are properly drilled so their integrity is not breached, that the fracing fluids are properly handled and not spilled, and the liquids are properly disposed, he said in his written statement.

Appleton said shale-gas drilling is inappropriate in any area that is a major drinking water source, that zoning is essential particularly in rural areas to minimize impacts of incompatible land uses, and that a system of impact payments to local rural governments will be needed to deal with community infrastructure issues.

'Inaccurate information'

That drew a strong reaction from one subcommittee member. "Mr. Appleton essentially said the oil and gas industry is making so much money it can afford to be over-regulated," said Dan Boren (D-Okla.). "Well, natural gas producers in my district are stacking rigs and companies like Frac Tech are laying off employees. I'm proud that I'm supported by the oil and gas industry because it employs a lot of people in my state, and I'm tired of people trying to shut it down with inaccurate information."

Hinchey pressed Kell for information about oil and gas industry support of the GWPC. Kell said that the group gets its main support from government agencies including the US Department of Energy, the Environmental Protection Agency, and numerous industries besides oil and gas. "Our opinions are not for sale. Our emphasis is on protection of water resources," he declared.

Quite a few states already require disclosure of ingredients in hydraulic fracturing fluids, he added. "As a member of the GWPC and an Ohio official, I don't believe any federal regulation of hydraulic fracturing is necessary," he said.

When Cynthia M. Lummis (R-Wyo.) asked what impacts federal hydraulic fracturing regulations would have on state programs, Helms responded that Alabama spent 2 years rewriting its regulations in the 1990s after losing a lawsuit brought by an environmental organization. "We're also concerned that requiring additional regulations will divert states' resources from other higher priority programs," Kell said.

When she was asked about this during her teleconference, DeGette replied: "The reason we passed the [SDWA] to begin with is that we decided safe drinking water is a national priority. Also, water like any resources crosses state lines. I'm very proud of Colorado for passing new stringent regulations, but other states haven't followed it. Further, the SDWA is being administered by state agencies in 34 states already for other industries so this wouldn't be an additional burden." ✦

Industry groups condemn climate bill passed by House

Nick Snow
OGJ Washington Editor

Oil and gas associations generally condemned the climate-change bill narrowly passed by the US House of Representatives on June 26.

"In approving the Waxman-Markey climate bill, the House has chosen to ignore the legislation's harmful effects on American consumers, businesses, and the economy," said American Petroleum Institute Pres. Jack N. Gerard. "At a time when America is trying to recover from a serious recession, the House has approved legislation that would cost energy users billions of dollars and add new stress to the economy."

House Energy and Commerce Committee Chairman Henry Waxman (D-Calif.) and Ed Markey (D-Mass), chairman of the Select Committee on Energy Independence and Global Warming, sponsored HR 2454, which caps emissions of greenhouse gases and provides for trading of emissions credits.

The bill also requires electric utilities to meet 20% of their demand with renewable energy by 2020, calls for federal spending of $190 billion on clean-energy technology, and mandates energy-saving standards for buildings, appliances, and industry.

It targets cuts in greenhouse gas emissions against 2005 levels of 17% by 2020 and 80% by 2050.

Industry objections

Like API, other groups representing producers and refiners objected to the bill.

"Independent natural gas and oil and producers are targeted twice in the bill," said Independent Petroleum Association of America Pres. Barry Russell. "First, it skews energy policy away from clean-burning natural gas. Second, it imposes new limits on gas and oil trading that will cripple independent producers' access to commodity markets."

While removal of the bill's low-carbon fuel standard was a victory for consumers, said National Petrochemical and Refiners Association Pres. Charles T. Drevna, HR 2454 still is "a tremendous tax hike for American consumers that will threaten domestic energy supplies and could actually increase the nation's reliance on foreign refined products."

Drevna decried "the unfair burden placed on American refiners by the mandated responsibility for emissions resulting from the use of their products, including home heating oil, gasoline, diesel, jet fuel, and industrial fuels. He said the burden "creates a significant cost advantage for foreign refiners who are already preparing to target US retail markets for fuel and other refined products."

NPRA's Drevna said, "Despite the many modifications made to the bill since the Energy and Commerce Committee passed it, the American Clean Energy and Security Act still fails domestic refiners and consumers alike. It dismisses the real concerns Americans have over rising energy costs and the adverse effect those costs will have on our nation's economic recovery."

Rep. Gene Green (D-Tex.), who voted for the bill, conceded during floor debate that domestic refiners would be at a competitive disadvantage despite HR 2454's giving them 2% of available allowances of emissions credits from 2014 to 2016, plus another 0.25% for smaller refiners. "To level the playing field, importers of foreign refined oil [products] must also pay for the carbon content," he said.

"While I believe the refining industry could use additional assistance, and I hope any final agreement does so, this is a reasonable first step to protecting our energy infrastructure and keeping good-paying jobs here at home," said Green, whose Houston area district includes several refineries and petrochemical plants. "These proposals, however, cannot substitute the need for a strong international agreement with binding carbon reductions among the world's largest emitters, including developing countries."

American Gas Association Pres. David N. Parker cited the bill's benefits to residential and commercial gas customers, who would not be covered under a carbon cap until 2016. Gas utilities would receive 9% of emissions allowances until 2025, when they would begin to reduce their allowances to zero by 2030, he said.

Narrow margin

The close, 219-212 vote on the bill showed that several Democrats, as well as most Republicans, had problems with the measure's provisions.

Passage nevertheless met the deadline House Speaker Nancy Pelosi (D-Calif.) established months earlier and won praise from President Barack Obama, who called the legislation "balanced and sensible."

Obama said, "We cannot be afraid of the future, and we must not be prisoners of the past. Don't believe the misinformation out there that suggests there is somehow a contradiction between investing in clean energy and economic growth. It's just not true."

Heavy lobbying before the final vote suggested that even the bill's most ardent supporters recognized it would barely pass. House Republicans objected to the measure's proposed creation of a new federal bureaucracy, taxes, and omission of programs to encourage domestic production of oil, gas, and other traditional energy sources. Of the 51 Democrats in the politically moderate Blue Dog Coalition, 28 voted against it.

Their reasons varied, as several of their statements showed following the vote.

"God's beautiful earth must be protected and preserved, but this bill is not the answer," said Mike McIntyre (D-NC). "It will cost jobs, increase electricity rates, pass on financial burdens to the next generation, and hurt ourselves in this global economy. It would potentially allow more jobs to go overseas to countries who do not comply with the same standards."

Several of the dissenting Democrats expressed concern over the way HR 2454's distribution of emissions allowances and its renewable portfolio standard could affect their constituents. "We all agree that we need to take measures to make our nation more energy-independent, but this bill does that the wrong way and would end up raising rates and imposing unacceptable new taxes on the companies that power the Tennessee Valley," said Parker Griffith (D-Ala.). "During these economically challenging times, we simply cannot let this happen."

Jim Matheson (D-Utah) said the bill's 50-50 emissions allowance distribution formula would give extra, unneeded allowances to utilities with lower fossil fuel resources and less to utilities which rely more heavily on fossil fuels. Regions which received excessive allowance would sell them to other US regions which received less, he suggested.

HR 2454 also overreaches with respect to carbon markets and would effectively destroy derivatives trading, he continued. "This is a very complicated financial system, and while it is clear that we are not appropriately regulating this market today, we should also avoid gutting the market altogether," Matheson said. "I think there is a reasonable way to structure the new carbon market and to address deficiencies in the commodity markets. The provisions in the bill are not the right approach, and these provisions were never really debated in a House committee hearing."

Harry Mitchell (D-Ariz.) also voted no. "This bill literally recommits the United States to coal, a step backwards at a time when it is vitally important for us to move forward. Clean, renewable energy should be our chief priority, not fossil fuels. In Arizona, this bill asks us to pay more for our energy but fails to deliver what is necessary to help us grow our emerging solar industry," he said.

Dennis C. Kucinich (D-Ohio), who is not a Blue Dog Democrat, also voted against HR 2454 because he believed its offsets favor coal-fired power plants.

Republicans object

House Republicans continued to condemn the measure because it would impose new taxes and costs without taking direct steps to increase domestic production of energy from traditional sources.

"Instead of the Democrats' high-priced gourmet plan that cherry-picks what types of energy Americans are allowed to use, our nation needs a plan that includes all types of energy," said Doc Hastings (R-Wash.), the Natural Resources Committee's ranking minority member. "The American Energy Act, a Republican alternative, does this by encouraging the development of renewable energy sources like nuclear, wind, solar, hydropower, and biomass while increasing production of American-made oil and natural gas."

Tim Murphy (R-Pa.) said, "Democrats and Republicans alike want to make sure that we reduce pollution in our country and clean up our land and water. But we need to find a way of doing this without shutting down coal, increasing family electric bills, or losing manufacturing jobs." He said HR 2227, which he cosponsored with Neil Abercrombie (D-Ha.), not only would encourage more domestic oil and gas exploration and production but also would dedicate much of the revenue to environmental cleanups and alternative and renewable energy research and development. Abercrombie voted for HR 2454 on June 26, however.

As the vote on HR 2454 approached, the Congressional Budget Office and Joint Committee on Taxation released a new estimate of the amended bill's budgetary impacts. Enacting the legislation would increase federal revenues by $873 billion and raise direct spending by $864 billion during 2010-19, CBO Director Douglas W. Elmendorf said in a June 26 letter to Waxman. ✦

Industry stands at early dawn of new energy future

Jeroen van der Veer
Chief Executive Officer, Royal Dutch Shell PLC

COMMENT

We stand at the early dawn of a new energy future. It will be powered by alternative energy and cleaner fossil fuels. If governments adopt the right rules and incentives, by the middle of this century renewable sources will provide nearly 30% of the world's energy. Society will be on the road toward sustainable mobility. The world's highways will rumble and whir with vehicles powered by all manner of energy: gasoline, diesel (yes, still there), electricity, biofuels, natural gas, and hydrogen.

In the years ahead, conventional diesel and gasoline-run cars will go increasingly far on every liter of fuel. Biofuels will account for up to 10% of liquid transport fuel in the next few decades. By 2020 up to 15% of new cars worldwide could be hybrid electrics like Toyota's Prius—some of them capable of plugging in to recharge their batteries. After 2030, fuel-cell vehicles powered by hydrogen will be a small but growing part of the fleet. By 2050, more than a billion extra vehicles are expected on the world's roads, more than double today's total.

Greater variety of fuel choices will be a boon for consumers. Different fuels will be stronger in different regions. In South America, biofuels will likely predominate. In Brazil, ethanol from sugar cane already supplies more than 40% of demand for gasoline. China, meanwhile, plans to expand production and use of hybrid and electric vehicles, tapping its vast coal deposits to generate power.

As more vehicles go electric, the environmental footprint of the world's power generators will become even more important. Wind, solar, and hydropower will account for 30% of electricity generation by 2030, up from about 18% today. Many new coal-fired power plants are expected to capture carbon dioxide emissions and store it safely underground, rather than pump it into the atmosphere. Plants will increasingly turn coal into a gas, rather than burn it. They will burn the gas to generate power, or use it as raw material for a variety of chemical products, while CO_2 will be captured and stored. Such integrated plants will begin to resemble refineries.

Indeed, fossil fuels—coal, oil, and natural gas—will continue to provide more than half the world's energy in

2050, building a long bridge to an era when alternatives can take over. A growing population and higher standards of living for billions of people in the developing world will mean we need all available sources of energy to keep the world's economies humming. So while the world races to build up alternative fuels, it must also find new sources of fossil fuels, including unconventional ones like oil sands. And we must accelerate efforts to make fossil fuels cleaner, by reducing the CO_2 emitted in their production and use.

None of this will be easy or cheap. Industry and government regulations must change on a huge scale, at an unprecedented pace.

According to the International Energy Agency, by 2030 we will need to invest $5.5 trillion just in renewable energy. That's like buying more than 18,000 Boeing 747 jumbo jets at $300 million apiece (only about 14,000 have been built since its introduction in 1970). Billions more must go into upgrading electricity transmission networks to handle increased demand and the on-and-off power generated by wind and solar.

Much of this money will come from private companies, but governments will need to continue using tax credits and other incentives to encourage the growth of renewables. They are still small, relative to the world's overall energy needs. Including hydropower, renewables account for about 7% of global energy. Wind today supplies about 1%, with approximately 70,000 turbines. Biofuels, thanks partly to billions of dollars in government subsidies, now also supply about 1%.

Judging from society's experience with nuclear power and other technologies, new energy sources take at least 25 years to reach significant scale. To illustrate the challenge, in the case of wind the world will need another 1-1.5 million turbines covering an area nearly the size of France in order to reach 10% of the electricity generated by 2030. That means expanding today's worldwide turbine production of around 15,000 a year to just under 100,000 a year by 2030.

"Despite the massive hurdles, the push to create a new energy system for the future will benefit us all. The race is on; may the best companies and technologies win."

Jeroen van der Veer
Chief Executive Officer, Royal Dutch Shell PLC

Energy companies are already preparing for the future, increasing production of natural gas, the cleanest fossil fuel, investing in renewables such as sustainable biofuels, and researching ways to capture CO_2 and store it safely underground. But the enormity of the challenge means government should do its part to encourage society's shift to a new energy system. For instance, new technologies with great promise to reduce CO_2 emissions will require initial government support to quickly achieve the scale necessary to have real impact.

One critical step is to put a price on greenhouse gas emissions—doing so in all major countries, not just a few. I prefer a system that caps emissions and allows companies to trade emission allowances, as Europe's already does. Judiciously limiting the number of allowances should encourage a relatively steady CO_2 price, which will have the strongest influence on energy consumers' behavior and on the efficiency designed into factories, homes, and offices. It will also harness the ingenuity of industry and channel investment to the most efficient emission reductions.

While energy policy can drive technology, it may ultimately raise costs and be politically unpopular. As society and political leaders face difficult choices, they should remember that failure to act now could force us into more painful choices down the road. Influencing consumer behavior may prove toughest of all. While technology will give society greater energy choices, it remains unclear whether people are willing to become better users of energy.

Despite the massive hurdles, the push to create a new energy system for the future will benefit us all. It will reverse the rapid rise in the greenhouse gas emissions responsible for global warming. It will provide new business opportunities for companies and entrepreneurs. It will create well-paid jobs in a thriving new industry. Competition among energy sources will drive innovation, keep energy affordable and increase global energy security.

The race is on; may the best companies and technologies win. ✦

FACTS: 2008 Chinese LPG production, imports, demand drop

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

Chinese refinery production of LPG fell for the first time in history last year. At the same time, the country's imports of LPG continued in 2008 a decline begun in 2005 and Chinese LPG consumption fell for the first time since 2000.

These are the major conclusions of a report by Lijuan Wang and Kang Wu of FACTS Global Energy, Singapore, issued June 9.

For 2009, the authors forecast that China's LPG output will recover as a result of expected higher refinery crude runs when a couple of local refineries come online. Imports, however, will continue their slide, while exports will "increase moderately."

LPG consumption in 2009 will recover only slightly, as markets continue to suffer from the global economic slump and natural gas makes inroads into traditional LPG demand.

Production

Sources for China's LPG output in 2008 were Sinopec refineries (50%), PetroChina refineries (30%), and local refineries (20%). Supply from these sources made up 87.3% of China's total LPG; the remaining 12.7% came from the Middle East, Australia, Asia, and other countries.

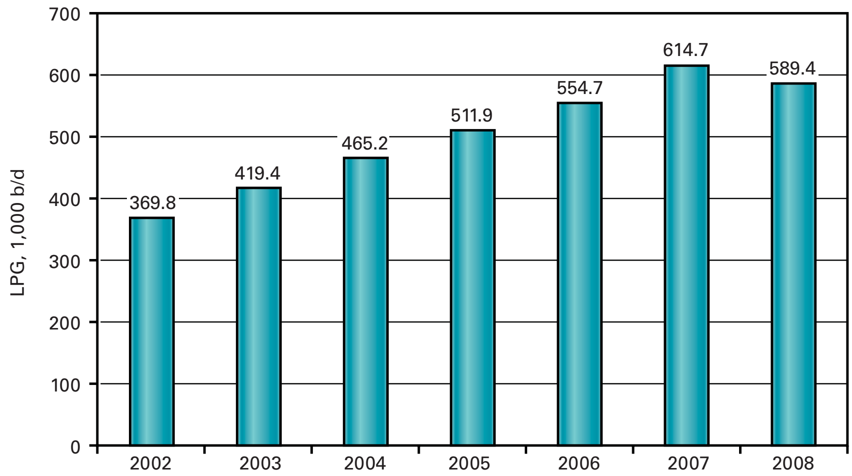
Domestic output last year reached 589,400 b/d, down 4.1% from 2007, said the report (Fig. 1), the "first time that China [had ever seen] a decrease in LPG output." Two factors lie behind the decline: Local refineries increased production of both gasoline and diesel through the first three quarters of 2008 to supply the Beijing 2008 Olympics; and weak domestic LPG demand pushed output lower in final quarter.

China's LPG production profile differs drastically from that of almost every other LPG producing country in the world. Globally, LPG production on average comes about 60% from gas processing with the great majority of the remainder from refinery operations.

According to OGJ data for 2008, China operated only two gas processing plants. Both were operated by Petrochina in the Ordos basin with total inlet capacity of 774 MMcfd. No throughput or production data were available for 2008 (OGJ, June 22, 2009).

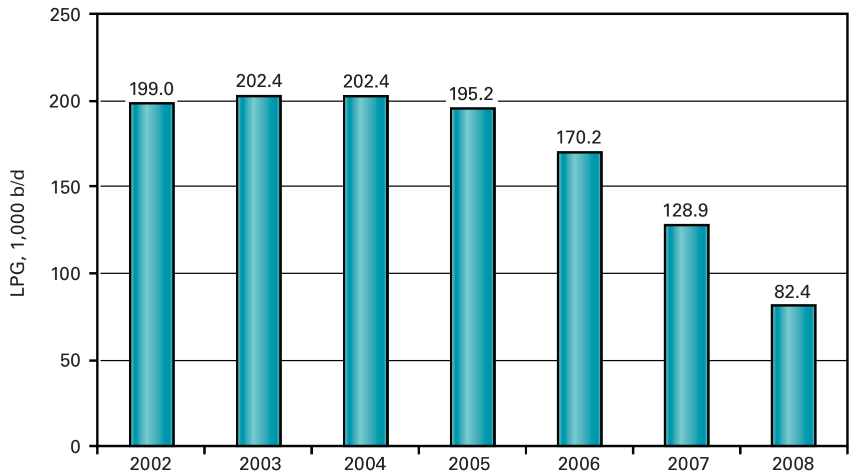
CHINA'S LPG OUTPUT

Fig. 1



CHINA'S LPG IMPORTS

Fig. 2



Imports, exports

The decline in China's LPG imports since 2005 accelerated last year, according to the FGE report, averaging 82,400 b/d, down 36.1% from 2007 (Fig. 2). The authors explained that a sharp increase in international prices during first-half 2008 combined with weaker demand during second half were behind the decline.

On the other hand, China's LPG exports since 2005 have been rapidly increasing, to 21,400 b/d in 2008 from

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

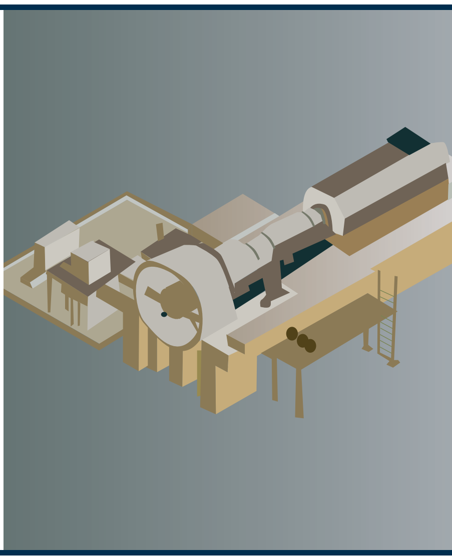
The Rolls-Royce Trent 60 is an advanced aeroderivative gas turbine that delivers up to 58 MW of electric power in simple cycle service. At 42% efficiency, the Trent 60 is highly fuel efficient. It offers operators fast delivery and installation times, and beneficial environmental performance. All or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

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

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

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

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



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

All parts professionally stored in Pensacola, Florida

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

Solar Centaur 40 T4701S Turbine Generator Package Now Available

Offered by Williams Field Services Company exclusively through PennEnergy

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

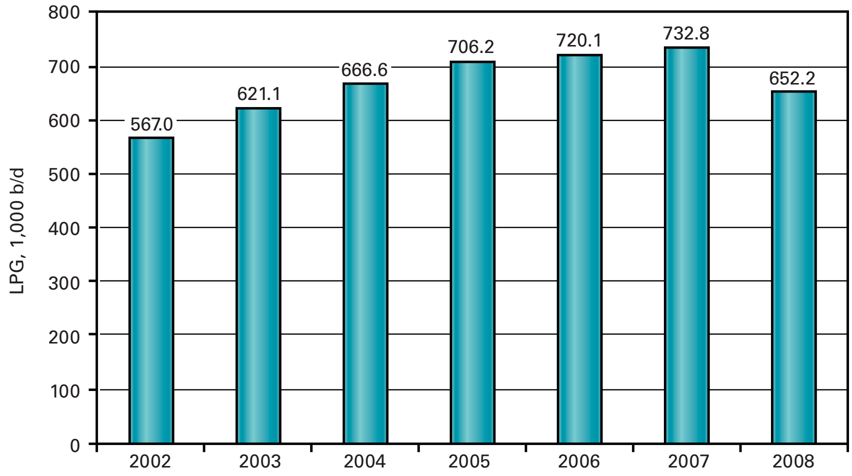
Williams.

For Info or Pricing Contact

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

CHINA'S APPARENT USE OF LPG

Fig. 3



800 b/d in 2005.

Again, a major explanation can be found in the higher international prices, while Chinese refineries faced negative margins overall in domestic markets last year. China's LPG prices are controlled by its government.

The report's authors also explained that the geographical differences "for this huge country is another reason why China exports LPG, while importing it."

Yet another explanation for imports and for Chinese producers' looking last year to international markets is the drop in domestic consumption. In a reversal of a steady increase 2002-07, Chinese consumption of LPG in 2008 dropped to an average 652,200 b/d, down 11% from 2007 (Fig. 3).

Most of the LPG in China is consumed as fuel by the residential sector accounting for 65% of the total, said the FGE report. Another 25% is consumed by the industrial sector, 2% for vehicle use, and 8% for other uses.

By region, South China and East China are main consumers of LPG.

Guangdong Province is the largest importer of LPG in China, according to the report, "even as imports declined in recent years." Guangdong's in 2008, however, dropped to 56,000 b/d from 92,600 b/d in 2007 and 121,300 b/d in 2006.

Sources

Of China's 82,400 b/d imports in 2008, 70,500 b/d (85.6%) came from Middle East countries: 17,000 b/d from the UAE, 16,100 b/d from Kuwait, 15,100 b/d from Saudi Arabia, 14,100 b/d from Iran, and 8,200 b/d from Qatar.

About 80% of LPG imports was imported by foreign-owned companies or joint-venture companies with a foreign base, said the report. ✦

Recent reports reveal shifting LNG trends in 2009

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

At mid-2009, prospects for global LNG demand "remain bleak," according to a research report issued at the end of June by Barclays Capital. The LNG market in 2009 is proving itself "truly global," as supply-demand fundamentals for the first 6 months forced regional prices to converge, said the report.

With demand deteriorating sharply in Asia, spot prices for most Pacific basin collapsed to below those in Europe and the US.

Canaport LNG LP officially opened Canada's first LNG terminal at St. John, NB, on June 18. The terminal, jointly owned by Repsol (75%) and Irving Oil (25%), has vaporized LNG storage equivalent of 9.9 bcf and sendout capacity of 1.2 bcfd. On June 27, the new terminal accepted delivery of its first shipment, discharged from the 138,000-cu m LNG tanker Bilbao Knutsen, which had lifted its cargo from Atlantic LNG in Trinidad and Tobago. (Photos from Canaport LNG and Rod Stears.)

Major Asian economies that import LNG—Japan and Korea, primarily—continue to struggle, and "emerging market participants"—mainly China—are only partially offsetting the slowing demand, says the report.

In the Atlantic Basin market, relative weakness in US gas prices compared with European benchmarks is "proving to be a limiting factor for US LNG imports." Europe, however, continues to unload record LNG cargoes, its natural gas prices maintaining relative strength.

Given these global supply-demand trends, LNG imports to the US will grow only modestly for the rest of the year, averaging 1.6 bcfd for all of 2009. Barclays said European storage levels and transatlantic price differentials are the leading indicators for US LNG import trends.

Asian patterns

Earlier in June, Houston-based Waterborne reported that continuing recession and decline in demand for natural gas had pulled down Asian LNG imports by more than 12% in May, compared with May 2008.

It was the fifth consecutive month in 2009 that levels had fallen below those of 2008, said Waterborne Pres. Steve Johnson. And it explains why US LNG imports at that point in 2009 were up 36%.

Johnson said, "There is very limited capacity for LNG storage in the global market today besides the US, and we have yet to feel the effect of incremental supply."

According to Waterborne, decreased demand and recession had depressed May LNG imports for Japan and South Korea, compared with 2008. Japan's LNG imports dropped 11%; South Korea's 17%.

Taiwan, on the other hand, imported 5% more LNG in May, said the Waterborne report. China, taking advantage of relatively low spot prices, imported a record 576,000 tonnes of LNG, pushing up its May imports by 59% over 2008. ✦

CLNG: Regulatory, market questions dog US LNG industry

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

The US LNG industry faces several questions, according to Center for Liquefied Natural Gas Pres. Bill Cooper. He spoke recently with OGJ about the state of the industry at mid-2009.

What will climate change legislation, currently being debated in the US Congress, eventually look like? How will its provisions affect the LNG industry? Will congressional reauthorization for the US Coast Guard continue to define LNG as a threat, which Cooper and industry believe lacks basis in history or even in the commodity's nature?

Bill Cooper, president, Center for Liquefied Natural Gas

For global trade, will the US market be the dumping ground for LNG regardless of price, as many observers have expressed?

Trade evolution

Answers to regulatory questions will have to wait, Cooper acknowledged. And CLNG has been involved in decisions about ways to educate lawmakers.

Recent industry history, however, may hold answers to market questions.

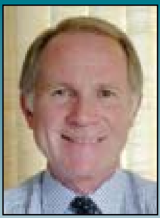
The current reality of LNG supply movements is that a combination of a robust spot LNG market, on the order of 15-20% of traded LNG, has combined with shorter contract terms and more-flexible destination clauses to make global trade more flexible than ever before.

Trade among the world's three major markets—North America, Europe, and Asia-Pacific—has grown. This has been partly due to the scale of some supply projects, chiefly in Qatar, Australia, and to some extent Trinidad and North Africa. But this growth has been accompanied by growth in population and capacity of the global LNG fleet.

Cooper doesn't believe that fleet has

Eric Watkins, Oil Diplomacy Editor

Blog at www.ogjonline.com



Will UK's Brown act swiftly?

British Prime Minister Gordon Brown, as we have said before, has very rarely been viewed as a friend of the oil and gas industry. But the time has come for that to change.

According to reports coming our way, Brown has not done enough to encourage investment in the country's offshore oil and gas sector, with the result that thousands of jobs could be at risk.

In fact, Parliament members issued a report last week warning that urgent government action is needed to prevent a decline in North Sea oil and gas revenue that could lead to the loss of 50,000 jobs.

"The difficulties currently faced by oil and gas companies in accessing affordable lending and the bleak prospects this heralds for investment in the oil and gas industry pose an issue of grave concern," said Parliament's Energy and Climate Change Committee.

Committee members called for more effective tax breaks, action over the credit crunch, and moves to ensure new developers can access existing platforms and pipeline to get oil ashore from fields too small to justify building their own facilities.

50,000 jobs

"We have learned a lack of affordable lending and bleak investment prospects could wipe out 50,000 jobs and lead to a significant fall in production," said committee chairman Paddy Tipping.

"If the government does not respond to this problem by giving better fiscal and regulatory signals then we may never recover anything like as much of our domestic reserve as would be desirable," Tipping said.

The report follows demands from the industry for urgent action by the British government to help maintain vital exploration and development, especially after the Department of Energy and Climate Change said exploration had decreased by 75% in this year's first quarter.

The British government last year introduced a supplementary tax of 10% over the standard rate of corporation tax to raise revenues, a tax hike that occurred when international prices for oil and gas were high and going higher.

Windfall tax

Since then—in the wake of falling oil and gas prices—the government has moved to reduce the windfall tax burden, in the unlikely hope that would spur production of an additional 2 billion bbl of North Sea oil.

But the committee clearly feels that has not worked and it wants more action taken.

It is not clear what will move Brown to act. Without doubt, being a tax and spend man, he would like to see increased production as a means of generating more tax revenues for his government to spend.

But with a general election due in Britain next year, we suspect it is the figure of 50,000 jobs on the line that will resonate most roundly at Number 10 Downing Street.

Be that as it may, whatever moves Brown to act will be welcomed by the oil and gas industry—and the sooner the better. ✦

yet reached a "tipping point," however, after which the trade more resembles the oil trade. But he thinks that point is near.

There has been a "deepening of markets," he said, that is good for the industry and good for the natural gas consumer.

This state of the global industry, currently moderate prices, and prospects for their continuing at that level ensure natural gas availability and affordability, said Cooper.

US picture

Two effects of industry's evolution, at least in the US, said Cooper, are that:

• The industry will not again see LNG terminals being mothballed as they were in the 1980s.

• The time has passed when LNG developers plan terminals along the US Gulf Coast to use the extensive gas pipeline network to reach major markets in the Midwest and Northeast.

Must surplus global supply come to the US because of its greater liquidity and storage capacity? Not necessarily, Cooper said. For one thing, US storage is closing in on full with levels well ahead of their 5-year average for June. And Cooper again cites the greater trade flexibility.

He also believes that, after the current crop of LNG terminals is completed and commissioned, the US market will likely enter a flat period when no new terminals will be built. Permitted projects that continue to fight through local resistance toward fruition can continue that effort so long as the sponsors are willing to pay the legal and other costs. He cited the Sparrows Point, Md., project as an example of one that seems to be making headway against stiff opposition.

This month, OGJ data show, two North American terminals are being commissioned: Canaport LNG's St. John, NB, site and Sempra's Cameron terminal near Hackberry, La., just downstream from Trunkline LNG's Lake Charles terminal.

ExxonMobil's Golden Pass terminal,

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in Texas on Sabine Pass across from Cheniere Energy's new terminal in Louisiana, was severely damaged by Hurricane Ike in September 2008 and is unlikely to open this year as planned.

And at Pascagoula, Miss., El Paso Corp. is building Gulf LNG. The terminal will have an initial sendout capacity of 1.3 bcfd from two full-containment storage tanks with combined capacity of 6.6 bcf. The company says the terminal capacity is fully contracted under 20-year contracts and targets start-up sometime in 2011.

Once all these are commissioned, it will likely be some time before ground is broken for another round of terminal construction. ✦

Gazprom seeks to rattle EU with Azerbaijan gas agreement

Eric Watkins
Oil Diplomacy Editor

Russia's OAO Gazprom, in an apparent effort to exert greater control over the European Union's energy supplies, signed an agreement to import natural gas from Azerbaijan and transport it to Europe.

Under its agreement with State Oil Co. of the Azerbaijan Republic, Gazprom has secured the supply of 500 million cu m/year of gas starting Jan. 1, 2010.

Gazprom Chief Executive Officer Alexei Miller, who this week accompanied Russia's President Dmitry Medvedev on a flying visit to Baku, acknowledged the amount of gas as small but, eyeing future growth potential, said, "Well begun is half done."

That view was apparently endorsed by Azerbaijan's President Ilham Aliyev who said, "We plan in the future to increase supplies as the volume of Azerbaijani natural gas production goes up."

Aliyev noted the "commercial character" of the contract and played down any political overtones that might be read into it. "It is very important because the theme of gas relations has been groundlessly politicized lately," said Aliyev.

"For us this is an opportunity to enter a new market. The agreement fully meets our interests and has a good future," Aliyev said.

The Russian president also played down the political dimensions of the agreement, saying it was necessitated by the need to develop bilateral cooperation between the countries and to ensure energy supplies.

Medvedev said it was "extremely important" that "the two countries that consider energy resources as one of the main riches have not only come to agreement but see big prospects not for political reasons but out of mutual benefit."

Medvedev said, "This is the energy security we have been talking about so much lately," adding, "Such exemplary agreements can serve as an example for others to follow."

European unease

Despite the assurances of both presidents, the agreement between them is likely to stir some unease in Europe—especially following Gazprom's agreement with Nigeria last week, also regarding gas supplies.

In fact, the formation of the 50-50 joint venture of Gazprom and Nigerian National Petroleum Corp. (Nigaz) has caused concerns in Europe's capitals which see Nigerian gas as a way of reducing their dependence on Russia, which already supplies up to half the gas consumed by the EU.

Nigaz intends to explore for gas and to develop infrastructure for its development and transport—even including a section of pipeline that could form part of a proposed trans-Sahara pipeline to export gas directly to Europe.

The EU even has pledged political and economic backing for the trans-Sahara pipeline, but in the absence of a Western consortium to emerge to fund and build the project, Gazprom looks to step into the gap.

Boris Ivanov, head of Gazprom International, played on Europe's concerns, saying, "We will take part in building the first segment of gas pipeline from southwestern Nigeria northwards."

Underlining Gazprom's determination to be Europe's supplier, regardless of European sentiments, he said, "If [the] trans-Sahara pipeline is realized, it [the Gazprom segment] will be its first segment."

Meanwhile, concerns in Europe over the agreement between Moscow and Baku will be focused on supplies for the Nabucco pipeline, which is designed to bolster the EU's energy security by circumventing Russia and carrying gas directly to Europe from Azerbaijan's Shah Deniz field in the Caspian Sea.

However, according to Miller, also in words calculated to cause concern in the capitals of Europe, Gazprom has been promised priority in buying gas from the second phase of the Shah Deniz field—the very source Europe is counting on as a main point of supply for the Nabucco line.

Azerbaijan expects to reach production of 9 billion cu m/year by 2010 within the first stage of Shah Deniz 1, while Shah Deniz 2—expected to come online in 2014—might produce 10-15 billion cu m/year according to state officials.

How much of that will go to Russia remains to be seen. While the Russians appear eager to play on European anxieties, independent analysts suggest that Baku is unlikely to jeopardize its independence from Moscow by supplying Russia with large amounts of gas, especially at the expense of its political allies in the EU. ✦

Shale plays push up US gas resource estimate

Reevaluation of shale plays has pushed the Potential Gas Committee's assessment of the US natural gas resource to its highest level ever.

The PGC, guided by the Potential Gas Agency of the Colorado School of Mines, raised its biennial assessment to 1,836 tcf at yearend 2008 from 1,321 tcf at yearend 2006.

The committee has been reporting resource estimates for 44 years.

The 2008 assessment ascribes 1,673 tcf of gas to traditional reservoirs, up 45% from the 2006 report, and 163 tcf to coalbed methane reservoirs, down 1.9%.

The technically recoverable resource in the new assessment combines with the US Department of Energy's gas reserves estimate of 238 tcf to project total future supply of 2,074 tcf. That's 542 tcf above the 2006 total.

"Our knowledge of the geological endowment of technically recoverable gas continues to improve with each assessment," said John B. Curtis, professor of geology and geological engineering and director of the Potential Gas Agency. "Furthermore, new and advanced exploration, well drilling, and completion technologies are allowing us increasingly better access to domestic gas resources—especially 'unconventional' gas—which not all that long ago were considered impractical or uneconomical to pursue."

Shale gas accounts for 616 tcf of the new estimate of technically recoverable gas.

The richest US resource area remains the Gulf Coast, including the continental shelf and slope and deep water. Next richest is the Rocky Mountain region, followed by the Atlantic and Midcontinent areas. Those areas account for 87% of the resource total.

The largest volumetric and percentage increases over the 2006 report resulted from reassessment of shale plays in the Appalachian, Arkoma, Forth Worth, and Uinta basins and in several basins of the Gulf Coast.

The 2008 assessment of traditional resources includes mean values (not arithmetically additive to subtotals) of 441.4 tcf of probable resources (current fields), 736.9 tcf of possible resources (new fields), and 500.7 tcf of speculative resources (frontiers).

The coalbed gas assessment includes 14.2 tcf of probable, 49.8 tcf of possible, and 98.9 tcf of speculative resources. ✦

Gas find sets water depth mark in Norwegian Sea

A/S Norske Shell has drilled a potentially large gas discovery in the Norwegian Sea in the deepest water of any find there, said the Norwegian Petroleum Directorate.

The 6603/12-1 well on the Gro prospect in 1,376 m of water cut a 16-m gas column in a reservoir of varying quality of Upper Cretaceous age.

In light of the variations in reservoir quality, the NPD estimated the range of recoverable gas at between 353 bcf and 3.5 tcf. The well was not formation tested, but the operator performed extensive sampling and data acquisition.

"Further delineation drilling is needed in order to clarify the resource potential, including the possibility of additional volumes," the NPD said, and may indicate a petroleum system that extends farther to the west where no drilling has taken place.

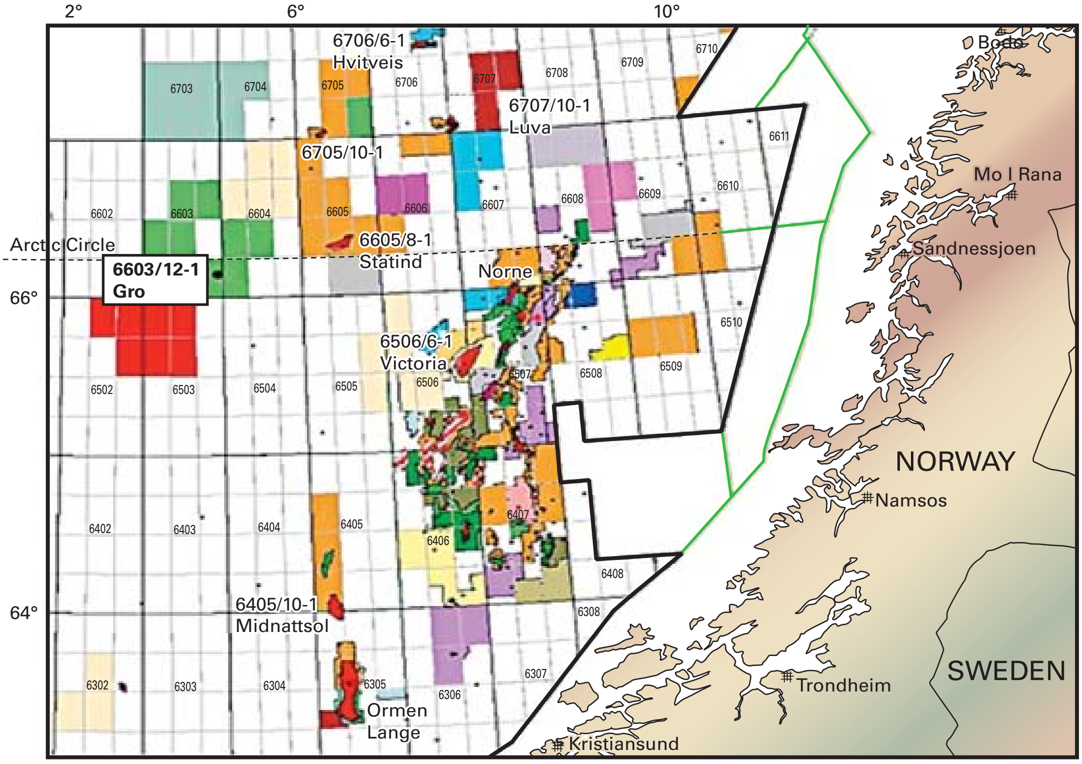
TD is 3,805 m true vertical depth in Upper Cretaceous, probably the Springar formation. The well is the first exploration test in Petroleum License 326.

Gro is 150 km northwest of the 6506/6-1 Victoria discovery well drilled by Mobil Exploration Norway in 2000 and thought to be the largest undeveloped gas discovery on the Norwegian shelf. Bottomhole temperature at Victoria is 200° C., NPD said.

Victoria, a high-pressure, high-temperature Jurassic gas find in 420 m of water 200 km offshore, is now operated by Total with 50% interest. StatoilHydro Petroleum AS has 30%, and Eni Norge has 20%. Victoria is in PL 211.

Participants in Gro in PL 326 are Norske Shell 50%, StatoilHydro 40%, and GDF Suez E&P Norge AS 10%. ✦

SOUTHERN NORWEGIAN SEA GAS FIELDS, DISCOVERIES



After Norwegian Petroleum Directorate

Quebec shales due tests after TBR yields gas

Talisman Energy Inc. plans to stimulate and test multiple shale intervals in the St. Edouard-1 exploration well in Quebec's St. Lawrence Lowlands after the well tested gas from Ordovician Trenton-Black River.

The TBR carbonate open hole interval flowed at the rate of 2.2 MMcfd of gas with 2,000 psi wellhead pressure on a 7⁄32-in. choke at the end of a 3-day test after acid stimulation, insufficient by itself to support tie-in cost, judged participant Questerre Energy Corp., Calgary.

Questerre Energy said, "The natural fracturing contributed to strong initial flow rates from the TBR. More importantly, the cuttings indicate altered limestone that confirms the potential for the TBR exploration model. While we do not expect to tie-in this well, we believe the TBR remains a valid exploration target and plan to test additional prospects with future wells."

The well is to be tested in the Utica and Lorraine shales. St. Edouard-1, which encountered natural fracturing and overpressured intervals while drilling, offsets the Leclercville-1 well that recently stabilized at 900 Mcfd from the Utica. ✦

St. Mary Land tests Eagle Ford in Webb County

St. Mary Land & Exploration Co., Denver, completed its first operated horizontal Cretaceous Eagle Ford shale well in South Texas, where it is running two rigs in the play.

The Briscoe G 1-H in Webb County averaged 4.4 MMcfd of gas and 192 b/d of condensate in 7 days during which it was facility constrained. The well, in which St. Mary Land's interest is 100%, took 10 frac stages in a 3,200-ft lateral at 7,500 ft TVD.

The company expects future completed well costs to be $3.5-4.5 million, compared with $5.2 million at the Briscoe well, which involved the extra cost of drilling a pilot hole, coring, logging, and microseismic monitoring during the fracs. Eagle Ford is shallower on the company's acreage than in some other areas of the Maverick basin.

St. Mary Land has 225,000 net acres earned with Eagle Ford potential in Dimmit, LaSalle, Maverick, and Webb counties. Of that, 159,000 acres are fully owned and 66,000 net acres are earned through its joint venture with Anadarko Petroleum Corp. and TXCO Resources Inc., in which 20,000 more net acres may be earned.

One rig is drilling in Webb on company acreage and the other in Dimmit on joint venture acreage. Shape Ranch 1-H in Dimmit is drilled, cased, and awaiting completion. The 2009 plan calls for two more wells each on owned and joint venture lands and for completing and interpreting 3D seismic. ✦

East Resources gets funds for Marcellus work

East Resources Inc., a privately-owned independent in Warrendale, Pa., said Kohlberg Kravis Roberts & Co. LP (KKR), New York, bought a minority equity position in the company with a "significant investment" from private equity funds.

East Resources' management and employees retain responsibility for day-to-day operations.

Proceeds will be used to strengthen the company's balance sheet through the repayment of all outstanding balances under the company's credit facility. It also will help finance long-term oil and gas exploration and development, particularly in the Marcellus shale.

"Given the increased competition in the Appalachian basin's Marcellus shale region from a number of well capitalized publicly traded oil and gas companies, we chose a capital provider that has both relationships and skills that could add value to East Resources," said Terrence M. Pegula, founder, president, and chief executive officer.

East Resources has one of the top acreage positions—more than 650,000 net acres—in the southwestern and northeastern regions of the Marcellus shale trend, particularly in northeastern Pennsylvania where it is focused on ramping up development.

Company officials said Marcellus shale represents the most promising gas opportunity in North America, extending from the southern tier of New York through western Pennsylvania into the eastern half of Ohio and south through West Virginia. These deposits are close to existing interstate pipelines supplying US population centers in the Northeast.

East Resources expanded its operations within Pennsylvania and into West Virginia through its acquisition of some former Pennzoil assets from Devon Energy Corp. in 2000. It owns and operates 2,400 producing oil and gas wells in New York, Pennsylvania, West Virginia, Colorado, and Wyoming. ✦

Apache reports work in three Argentine basins

Apache Corp., Houston, reported progress in its operations in Argentina, where it has positions in the Neuquen, Austral, and Cuyo basins.

Argentina, where 72 of the 83 wells Apache drilled in 2008 were productive, holds 5% of the company's net proved reserves and 9% of its production. Net production averaged 47,600 boe/d in the quarter ended Mar. 31, down 4% from the last quarter of 2008 even though liquids output didn't decline.

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

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

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

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In the Neuquen basin, Apache finalized the extension of eight federal development blocks that cover 590,000 acres and produce 7,000 b/d of oil and 100 MMcfd of gas. The government extended the lease 10 years to 2027. Apache has a capital commitment of $320 million on the lease.

Apache drilled nine wells in Ranquil and Guanaco deep gas fields that tested 3-7 MMcfd/well in the quarter ended Mar. 31.

In the Austral basin, Apache plans to drill two development wells near its Bajo Guadaloso X-2001 discovery, which tested 2.4 MMcfd of gas and 300 b/d of oil. The 2-km feature is a look-alike to several structures identified on a 2,500 sq km 3D seismic survey shot in 2008.

Apache is operator with 70% working interest in San Sebastian field, the newly discovered Seccion Veintinueve field, and an extension to Sara Norte field.

Meanwhile, Apache plans to shoot two large 3D surveys once permitting is completed in mid-2010 in the Cuyo basin, where it was awarded more than 1 million sparsely drilled, nonproducing net acres that surround 22 of Argentina's largest oil fields.

The CCyB Block 17B in Mendoza Province is next to and on trend with several fields and hasn't been explored with 3D seismic. It is the company's first acreage in the basin. ✦

Guatemala

The PetroLatina subsidiary of Quetzal Energy Ltd., Toronto, is redeveloping the A7-2005 license that contains Atzam and Tortugas fields in Guatemala's southern Peten (Chapayal) basin.

It plans to drill three development wells at Atzam and six in Tortugas.

PetroLatina has spud the Atzam-3 well in Guatemala's Atzam oil and gas field in License A7-2005 in the southern Peten (Chapayal) basin.

Projected depth is 4,200 ft at the well, 500 m east of the productive Atzam-2 well. Quetzal chose the location to gain a structural advantage to Atzam-2 at the productive Coban C-18 and C-19 intervals.

Basic Petroleum (Bahamas) Ltd. drilled Atzam-2 in 1993. The reworked Atzam-2 has produced 102,168 bbl of 34° gravity oil from March 2008 until May 31, 2009. Previous operators produced 90,000 bbl before the well watered out.

PetroLatina also completed Atzam-1A as a water disposal well for a savings of $18,000/month.

Mexico

Mexico's state-run Petroleos Mexicanos plans to start oil and gas production in 2010 from small Kambesah field in Campeche Sound, press reports said.

Reserves weren't specified, but output is expected to peak at 13,700 b/d of oil and 9.3 MMcfd of gas. Kambesah, near Ixtoc field, was discovered in late 2008.

Zambia

Zambia launched its debut oil licensing round for 23 blocks in the northwest, west, and eastern provinces of the country. Bids are to be opened Aug. 7.

Godwin Beene, permanent secretary for the ministry of mines and minerals development, said winning operators will need to show they have the cash, assets, technical expertise, and equipment to explore and produce. Winners will be required to pay a nonrefundable $10,000 bidding fee.

Traces of oil have been found in areas that border Angola, Zambian authorities said.

Canadian Beaufort

BP Exploration Co. Ltd. has proposed to shoot 1,800-2,300 sq km of 3D seismic surveys in the Canadian Beaufort Sea in mid-2009.

The Pokak air gun program is to be shot in 70-1,050 m of water on EL 449 and EL 451 about 180 km off the coast from late July to October. The vessel would return in 2010 if it could not complete the program in the 2009 open water season.

Geologic depths of interest are at 4-8 km, BP said in a filing with Canada's National Energy Board.

Kentucky

Kentucky USA Energy Inc., London, Ky., plans to negotiate and sign within 30 days a contract with Seminole Energy Services LLC, Tulsa, for purchase of Kentucky USA's gas production in western Kentucky.

Kentucky USA, which operates in the Devonian New Albany shale gas play, has an existing sales contract with Atmos Energy Marketing LLC. Kentucky USA said it has laid and tested more than 45,000 ft of pipe in the company's gathering system.

Seminole Energy supplies 900 MMcfd of gas to more than 30,000 customers.

Texas

South

Abraxas Petroleum Corp., San Antonio, improved production from a horizontal Cretaceous Edwards well in DeWitt County, Tex., with a six-stage frac.

The company has also identified three more locations on existing leasehold.

Nordheim-2H came on line in January 2009 at 6 MMcfd, natural, from the first section of the lateral and was choked back to 3 MMcfd.

After the six-stage frac, the well is capable of more than 10 MMcfd, exceeding expectations. It is restricted to 4.6 MMcfd due to low gas prices.

Abraxas is operator with 75% working interest.

Produced-water VOC, HAP emissions concern Rocky Mountain regulators

Gennaro Dicataldo
Stantec Consulting Inc.
Salt Lake City

Gary H. Richins
Dalbo Holdings Inc.
Roosevelt, Utah

Kerry J. Spiroff
Montgomery Watson Harza Consulting Inc.
Salt Lake City

Mark B. Nelson
ECONOVA Inc.
Salt Lake City

Increasing volatile organic compound and hazardous air pollutant emissions from a growing number of private and commercial produced-water surface disposal facilities, using evaporation ponds, are raising regulatory and public concerns in the Western US. Various studies have identified VOC emissions as contributors to ground-level ozone formation.

Currently the US Environmental Protection Agency regulates VOC under the Clean Air Act (CAA).

VOC and HAP emission odors and vapors may raise health concerns for operators and the public, especially near populated areas.

Increasing urbanization and more stringent state and federal regulations aimed at protecting human health and the environment from harmful HAP is making it more difficult for owners and operators of produced-water disposal facilities using evaporation ponds to meet VOC and HAP emission limitations.

Current VOC and HAP estimation methods required by regulators in Colorado, Utah, Wyoming, New Mexico, and Montana may overestimate VOC and HAP emission levels. This overestimation creates a controversy among regulators, concerned public, environmentalists, and owners of produced-water facilities over the continued viability of evaporation ponds as a produced-water disposal method.

Existing and emerging engineering controls may reduce or destroy VOC and HAP before their release into the ambient air. These control technologies could increase produced-water disposal facility profitability and potentially generate sufficient revenue to cover or at least help defray their capital cost.

Produced water

Produced water represents the largest waste stream volume generated by the oil and gas industry during exploration and production. Each year the US generates about 20 billion bbl of produced water.[1] The Western US, including Wyoming, New Mexico, Colorado, Utah, and Montana (Fig. 1), produced 2.6 billion bbl in 2002.[1] This volume is about four times the yearly culinary water consumption of the Salt Lake City metropolitan area.

Produced water is defined as water extracted from the earth's subsurface during exploration and production of oil and gas. This water may include geologic formation water, injection water, and chemicals added to the formation to stimulate production or improve oil-water separation.

Produced water generated from oil, natural gas, and coalbed methane production may contain compounds harmful to humans and wildlife, including potential toxic hydrocarbons and trace metals, which require proper disposal.[3]

Current practices of produced-water disposal include surface discharge such as evaporation ponds, reinjection into the subsurface with injection wells, reuse, and land application.[1 4]

Surface discharge

Regulators have a particular concern with surface discharge to evaporation ponds because of poten-

ROCKY MOUNTAIN REGION OIL, GAS BASINS

Fig. 1

Source: Adapted from Reference 2

VOC EMISSION RULES IN FIVE STATES

Table 1

State	Regulated VOC emissions	State rules	Water sampling requirements[1]	VOC computation	VOC permitting limits	Fees and fines
Colorado	Yes	CO-AQCC Regulation No. 3 and 7	TPH, BTEX, methanol, and others[2]	Assuming 100% TPH and methanol in water is volatile	>5 tons/year (Attainment) >2 tons/year (Nonattainment) APEN reporting >2 tons/year (Attainment) >1 tons/year (Nonattainment)	$22.90 VOC, $152.90 HAP/ton-year above reporting threshold $15,000/ day failure to report/ permit
Utah	Yes	UAC R307-401	TPH, BTEX, n-hexanes, and methanol	Assuming 100% TPH in water is volatile or canister	<5 tons/year reactive VOC <500 lb/year single HAP (benzene, toluene, ethylbenzene, xylene, n-hexane, methanol) <1 ton/year of combined BTEX, n-hexane & methanol	$10,000/day nonpermitted violator
Wyoming	Yes	WAQSR Chapter 6	TPH-GRO, TPH-DRO, Total HAP, and methanol	Assume 100% TPH in water is volatile or canister air sampling	<10 tons/year	$10,000/day nonpermitted violator
New Mexico	Yes	NMAC Title 20 Part 70, 72, & 74	TPH and BTEX	Assuming 100% TPH in water is volatile	>10 lb/hr or >25 tons/year	$10,000/day nonpermitted violator
Montana	Yes (under Title V)	NA	NA	NA	See EPA rules	Case-by-case

[1]Information obtained from Rocky Mountain Region States Air Quality regulatory agencies. [2]Other contaminants as deemed appropriate by operator knowledge of waste water stream.
NA = Not applicable.

tial emission of reactive VOC and HAP into the ambient air. Studies have found that these emissions are precursors to ground-level ozone formation when reacting with nitrogen oxides (NO_x) in the presence of sunlight.

The CAA in 40 CFR 51.100(s) defines reactive VOC very broadly as "any volatile compound of carbon…that participates in atmospheric photochemical reactions."

The agency has indentified several VOC, including methane and ethane, as having negligible photochemical reactivity and, if properly quantified, operators of emitting facilities are allowed to subtract these from total VOC emission estimates.

EPA has designated many urbanized areas in the Rocky Mountain region, such as metropolitan Denver and the Northern Front Ranges of Colorado, as nonattainment areas. These areas are noncompliant with the 8-hr federal ground-level ozone standard levels as listed in the National Ambient Air Quality Standards (NAAQS).[5]

The government established NAAQS (40 CFR 50) to cover ozone (with VOC and NO_x as precursors) and other harmful air pollutants to protect human life and health (primary standards), and vegetation, animals, and property (secondary standards).

The five Rocky Mountain states have seen a rapid increase in the number of disposal facilities using evaporation ponds. This presents environmental compliance challenges to both regulators and facility owners.

Reasons that have fostered the growth in private and commercial produced-water disposal facilities include the relatively dry climate, availability of low-cost land, and low costs to operate and maintain evaporation ponds. Operating costs range from $0.01 to 2.50/bbl of produced water.[1]

Disposal facility layout

Fig. 2 shows a typical layout of a private or commercial produced-water disposal facility using evaporation ponds in the Rocky Mountain region. The main components include:

- Condensate and oil recovery tanks.
- Separation basins, with or without baffles, used as oil-water separator systems.
- Skim pits.
- Evaporation ponds.

Oil and gas field operators truck or pipe produced water containing oil, natural gas condensate, and chemicals from the production and exploration sites to private or commercial produced-water disposal facilities.

At the facility, oil-water separators, by gravity, separate the condensate and oil, usually 1-2% by volume, from the bulk produced water. The separation basins, constructed of concrete, fiberglass, or steel, can be either open to the atmosphere or have a permanent or floating roof to help limit VOC emissions.

The disposal process then involves piping the produced water to one or more skim pits. These pits are relatively small open-air basins designed to separate additional oil or condensate not captured in the oil-water separators.

From the skim pit, produced water typically enters one or more lined evaporation ponds generally in series and 1-10 acres or more in surface area. Some ponds may have portable misting towers, sprinkler systems, or commercial snowmakers to enhance mechanically water evaporation.

Vacuum trucks collect oil and condensate from the oil-water separators and skim pits for temporary storage in oil or condensate tanks before shipping to market or further processing.

Table 1 summarizes VOC and HAP emission rules in Colorado, Utah, Wyoming, New Mexico, and Montana. The table excludes rules for the EPA-regulated disposal facilities on Native American tribal land in these states.

Rules in Colorado

The Colorado Department of Public

OIL&GAS JOURNAL Previous Page | Contents | Zoom In | Zoom Out | Front Cover | Search Issue | Next Page qMags

BTEX, N-HEXANES, METHANOL PROPERTIES

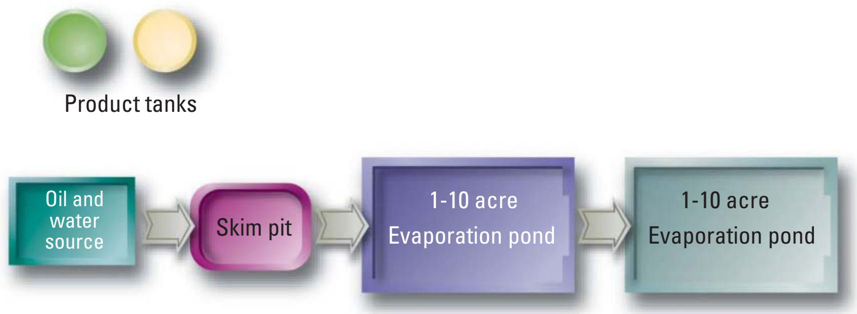
Table 2

Compound	Molecular formula	Molecular weight	Water solubility, mg/l.	Vapor pressure at 25° C., mm Hg	Henry's Law constant at 25° C., atm l./mol
Benzene	C_6H_6	78.10	1,760	95.2	5.5
Toluene	$C_6H_5CH_3$	92.4	540	30	6.7
Ethylbenzene	$C_6H_5C_2H_5$	106.2	165	10	6.4
o-Xylene	$C_6H_4(CH_3)_2$	106.17	221	7	5.2
m-Xylene	$C_6H_4(CH_3)_2$	106.17	174	8	5.2
n-Hexane	C_6H_{14}	86.2	immiscible	150	122
Methanol	CH_4O	32.0	miscible	114	0.0027

Sources: References 8 and 9

PRODUCED WATER DISPOSAL FACILITY

Fig. 2



Health and Environment regulates evaporation ponds as stationary sources of VOC subject to Air Quality Control Commission Regulations No. 3 and No. 7.

These regulations define evaporation ponds as any open-air surface impoundment for the purpose of solids settling, residual oil skimming, or water evaporation. CDPHE provides guidance to facility operators on how to quantify emissions of VOC and HAP to ambient air.[6]

The accompanying box shows an example calculation for VOC and HAP emissions, based on a mass-balance equation that uses water sampling analysis of:

- Total petroleum hydrocarbons (TPH) that include gasoline range organic (GRO) compounds, diesel range organic (DRO) compounds.
- Benzene, toluene, ethylbenzene, and xylene (BTEX).
- Methanol added by well operators to natural gas processes to prevent freezing during winter months.
- Other contaminants as determined appropriate by operator knowledge of the waste water stream.

The mass-balance equation assumes that 100% of the TPH concentration contained in the produced water volatilizes to the atmosphere as VOC and establishes the maximum potential to emit.

Section 112(b) of the CAA lists BTEX as HAP; and therefore HAP require a similar mass balance.

Facility operators need to sample the TPH, methanol, and BTEX compounds after the primary oil-water separator and upstream of the evaporation ponds.

AQCC Regulation No. 7 states that no source shall dispose of VOC by evaporation unless the facility uses a Reasonably Available Control Technology. The RACT analysis includes an evaluation of available economically feasible technologies that would provide maximum VOC emission control at regulatory agency acceptable levels.

CDPHE requires use of enhanced gravity separation or VOC-destruction technologies. It does not consider conventional gravity-separation technologies and natural biodegradation as viable RACT for facilities, but these technologies could potentially be employed by facilities whose business model is characterized as industrial waste water treatment, which is typical of most commercial facilities accepting produced water for treatment and disposal.

AQCC Regulation No. 3 requires facilities emitting VOC emissions of more than 2 tons/year in an attainment area (1 ton/year in a nonattainment area) to submit an Air Pollution Emission Notice every 5 years.

HAP emissions must be reported as discussed in Regulation No. 3, Part A, Appendix A based on different scenarios and depending on the BIN classification of the pollutant, such as 50 lb/year (Scenario 1 and Bin A) to 5,000 lb/year (Scenario 3 and Bin C).

Facilities must obtain a construction permit before construction if they will emit more than 5 tons/year of VOC in an attainment area or 2 tons/year in a nonattainment area. They also may need an air-quality model.

A facility requires a federal Title V operating permit under the CAA if its VOC emissions are greater than 100 tons/year, or emits 10 tons/year of single HAP, or 25 tons/year combined HAP.

CDPHE may subject a facility to a maximum $15,000/day/violation fine for failing to report emissions, or failing to obtain a valid construction or operating permit (Table 1).

Rules in Utah

Facilities in Utah require a permit if the emissions exceed 5 tons/year of reactive VOC, 500 lb/year of single HAP including benzene, toluene, ethylbenzene, xylenes, n-hexanes, and methanol, or 2,000 lb/year of combined HAP, as per the Utah Administrative Code R307-401-9 "de minimis" threshold (Table 1).

Similar to Colorado, Utah Division of Air Quality estimates the total VOC emission based on a simple mass balance assuming that 100% of TPH, BTEX, n-hexanes, or methanol escapes into the ambient air. Nonpermitted facilities that exceed the de minimis may be fined $10,000/day/violation. UDAQ identifies the required water sample point as the outflow of the oil-water separator.

Most Utah produced-water disposal facilities using evaporation ponds are in Grand and Uintah counties. Grand County passed Ordinance No. 476 in 2008 that limits the total VOC emission from all disposal facilities in the entire county to 50 tons/year. The county also charges a $0.10/bbl monitoring fee for produced water entering disposal facilities.

Rules in Wyoming

The Wyoming Air Quality Standards and Regulations Chapter 6 provides guidance for stationary sources of VOC and HAP emissions. It requires a permit for major sources (CAA Title V) of air pollutants that emit 10 tons/year or more of single HAP, 25 tons/year or more of combined HAP, or 100 tons/year or more of other regulated pollutants.

As shown in Table 1, Wyoming Department of Environmental Quality requires new facilities to collect and analyze water samples for TPH-GRO, TPH-DRO, BTEX, and methanol. Required sampling frequency could be up to a sample every 2,000 bbl of produced water accepted by the facility for disposal.

Potential emission estimates are based on the assumption that 100% of the TPH, BTEX, and methanol volatilize.

Rules in New Mexico

New Mexico MAC Title 20, Chapter 2, Parts 70, 72, and 74 (NMAC 2009), establishes limits for existing and new facilities. New stationary sources of VOC need a permit if the emission rates are greater than 10 lb/hr or 25 tons/year.

It bases VOC emission estimates on water concentrations of TPH and HAP and 100% volatilization of hydrocarbons from the water.

Rules in Montana

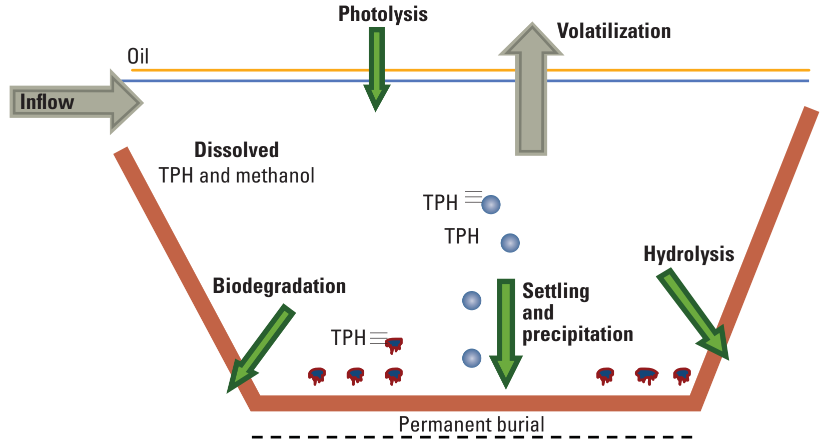
The Montana Department of Environmental Quality regulates and enforces major and minor sources of HAP under the federal Title V program.

Title V bases limits on major sources as those emitting 10 tons/year of any HAP or 25 tons/year of any combination of HAP. The minor-source permitting threshold for Montana is 25 tons/year of any HAP. Therefore, a facility may require a Title V permit without first obtaining a Montana Air Quality Permit if the calculated potential to emit is between 10 and 25 tons/year.

In general, most major sources require both an MAQP and a Title V permit.

Well-mixed evaporation pond

Fig. 3



Source: Adapted from Reference 7

Fate of VOC, HAP

It is important to understand the fate of TPH (including BTEX and n-hexane) and methanol in produced water to determine the potential effects of VOC-HAP emissions on the ambient air and the competing mechanisms that reduce TPH and methanol volatilization (Fig. 3).

The composition of TPH determines its propensity to separate from soil, sediments, water, or air.

In general TPH in produced water may exist as:

- Free floating or dispersed droplets.
- Dissolved compounds.
- Volatile gases.
- Sorbed to organic or inorganic suspended solids or sediments.

A large portion of TPH can be free floating or a dispersed oil fraction, usually with droplet size greater than 0.45 µm. A facility can separate this readily from the bulk water using specific gravity differences or other physical processes.

The remaining portions of TPH are susceptible to volatilization and may escape into the atmosphere. Sorbed TPH may form particle coatings and may follow the fate of suspended solids, which tend to settle out and be trapped in sediments.[7]

Depending on the water geochemistry, other mechanisms may reduce the amount of TPH and in turn VOC and HAP in produced water. These may include:[7 8]

- Biodegradation due to microbial activity.
- Oxidation and reduction reactions due to changes in pH and dissolved oxygen driven by photosynthesis and biological respiration.
- Photolysis, which is decomposition due to exposure to sunlight.
- Hydrolysis, which is chemical reactions with acid and bases in water.
- Precipitation or mineralization.

These competing mechanisms in concert with temperature changes, diffusion and convection mechanisms, water retention time, evaporation basin depth, oil film thickness, and differential water solubility of hydrocarbons may reduce formation of VOC and HAP.[9]

In fact, these complex biological, physical, and chemical processes can degrade and deplete TPH compounds within the evaporation pond and therefore may significantly reduce the propensity for volitization. In addition, many produced-water disposal facilities

Equations

$$k_g = (4.82 \times 10^{-3})(U_{10})^{0.78}(Sc_G)^{-0.67}(d_e)^{-0.11} \quad (1)$$

$$Sc_G = \frac{\mu_\alpha}{\rho_\alpha D_\alpha} \quad (2)$$

$$d_e = 2\left(\frac{A}{\pi}\right)^{0.5} \quad (3)$$

$$K_{oil} = k_g * Keq_{oil} \quad (4)$$

$$Keq_{oil} = P^* \rho_\alpha MW_{oil}/(\rho_{oil} MW_\alpha P_o) \quad (5)$$

$$N = \left(1 - \frac{Ct_{oil}}{Co_{oil}}\right)\frac{V_{oil}Co_{oil}}{t} \quad (6)$$

$$\frac{Ct_{oil}}{Co_{oil}} = \exp\left(\frac{(-K_{oil})t}{D_{oil}}\right) \quad (7)$$

$$Co_{oil} = \frac{K_{ow}Co}{[1 - FO + FO(K_{ow})]} \quad (8)$$

$$V_{oil} = (FO)(V) \quad (9)$$

$$D_{oil} = \frac{(FO)(V)}{A} \quad (10)$$

$$V_R = \frac{g}{18}\left(\frac{\rho_S - \rho_W}{\mu}\right)d^2 \quad (11)$$

Nomenclature

k_g	= Gas phase mass transfer, m/sec
U_{10}	= Wind speed at 10 m above the liquid surface, m/sec
Sc_G	= Schmidt number on gas side, dimensionless
μ_α	= Air viscosity, g/cm-sec
ρ_α	= Air density, g/cc
D_α	= Methanol diffusivity in air, sq cm/sec
d_e	= Effective number, m
K_{oil}	= Overall mass transfer coefficient for transfer of methanol from oil phase to gas phase, m/sec
Keq_{oil}	= Equilibrium constant or partition coefficient (concentration in gas phase over the concentration in oil phase), dimensionless
P^*	= Methanol vapor pressure, atm
MW_{oil}	= Oil molecular weight, g/gmol
ρ_{oil}	= Oil density, g/cc
MW_a	= Air molecular weight, g/gmol
P_o	= Total pressure, atm
N	= Emission rate, g/sec
Ct_{oil}/Co_{oil}	= Ratio, dimensionless
Ct_{oil}	= Methanol concentration in oil phase at time = t, g/cu m
Co_{oil}	= Initial constituent concentration in the oil phase considering mass transfer resistance between water and oil phases, g/cu m
Co	= Initial constituent concentration in the liquid phase, g/cu m
K_{ow}	= Octanol-water partition coefficient, dimensionless
V_{oil}	= Oil volume, cu m
t	= Residence time of disposal, sec
D_{oil}	= Oil film thickness, m
FO	= Oil volume fraction, dimensionless
V	= Pond volume, cu m
V_R	= Oil droplet rise rate, cm/sec
g	= Acceleration due to gravity, cm/sec^2
ρ_S and ρ_W	= Oil droplet density and water density, respectively, g/cc
μ	= Water dynamic viscosity, g/cm-sec
d	= Oil droplet diameter, cm

are in regions where air temperatures may fall below freezing for several months. As a result, ice or snow may cover ponds for several months especially during late fall, winter, and early spring thus inhibiting VOC and HAP emissions.

The inclusion of methanol in VOC mass balances assumes erroneously that it volatilizes completely into the ambient air. Table 2 shows that methanol is very soluble in water (infinite miscibility) and tends to remain dissolved in water as determined from the low Henry's constant (0.0027 atm l./mol).

Also, BTEX has a higher tendency to partition from air (Henry's constants between 5.2 and 6.7 atm l./mol) as compared to methanol, but much lower than n-hexane (Henry's constant of 122 atm l./mol).[8 9] Based on the chemical data presented in Table 2, one needs more rigorous estimates to accurately represent methanol and TPH contributions to VOC and HAP emissions.

Waste water collection

Colorado approves the EPA AP 42 (Chapter 4.3) "Waste Water" method as an alternative approach for estimating VOC emissions.[6 9] This method uses well established mass transfer correlations and emission equations to estimate VOC emission rates from oil and gas waste water treatment facilities containing hydrocarbons.

This method may require additional sampling of the produced water such as biomass, oil film thickness, wind speed, etc. (with concomitant sampling and laboratory analysis costs), but it could be more accurate for estimating VOC emissions than the simple mass balance described previously.

Methanol calculations

Total VOC and HAP estimates include methanol because of its wide use as antifreeze in oil and gas extraction operations. Methanol, however, is very soluble in water and has a tendency to remain dissolved rather than volatilize.

A comparison of the AP 42[9] and the CDPHE[6] methods shows the difference in the estimated results using the two methods.

For both methods, the calculation includes data from a produced-water disposal facility in Colorado.

The scenario used for the AP 42 method is typical of produced-water disposal facilities using evaporation ponds in the Rocky Mountain region and includes the following assumptions:

- A nonmechanically aerated evaporation pond.
- An oil film thickness on the pond greater than 1 cm.
- No outlet, flow through, in the pond.
- A well-mixed evaporation pond.
- No significant removal of VOC by biodegradation, adsorption, or other forms of degradation.
- 10-day residence time.
- No significant loss in water volume.

The assumptions determined the theoretical equations as reported in AP 42 for computing the methanol emission rate (N).[9]

To estimate N, the first step is to calculate the gas-phase mass transfer coefficient k_g (Equation 1 in equation box) and the overall mass transfer coefficient in the oil phase K_{oil} (Equation 4). Equations 1-3, 4, and 7-10 determine the emission rate N.

Table 3 shows the emission estimation parameters used for the AP 42 computations. The calculated emission rate was 0.291 g/sec of methanol,

EPA AP 42 METHANOL EMISSION ESTIMATION PARAMETERS

Table 3

Coefficient	Value	Unit	Notes
k_g	8.50×10^{-3}	m/sec	
U_{10}	4.47	m/sec	Annual historical average in Denver
Sc_G	1.006	dimensionless	
d_e	226.99	m	
μ_a	1.81×10^{-4}	g/cm-sec	
ρ_a	1.20×10^{-3}	g/cc	
D_a	0.15	sq cm/sec at 25° C.	
P*	0.15	atm at 25° C.	
Mw_{oil}	83	g/gmol	Average BTEX + methanol
ρ_{oil}	0.86	g/cc	Average BTEX + methanol
Mw_a	29	g/gmol	
P_o	0.848	atm at 25° C.	At 4,500 ft elevation above mean sea level
K_{oil}	6.01×10^{-6}	m/sec	
C_{toil}/Co_{oil}	1.4×10^{-60}	dimensionless	
Co_{oil}	165	g/cu m	
V_{oil}	1,523	cu m	
t	864,000	sec	
D_{oil}	0.0376	m	
K_{ow}	0.19953	dimensionless at 25° C.	
C_o	820	g/cu m	Methanol concentration
FO	0.01	dimensionless	
V	152,336	cu m	10-acre pond
A	40,469	sq m	10-acre pond
Depth	3.96	m	13 ft
N	0.291	g/sec	

Source: Reference 9

which corresponds to about 10 tons/year of methanol.

Example 2 in the accompanying box shows the CDPHE[6] estimation method assuming 100% loss of methanol.

Comparison of the AP 42 (10 tons/year) and the CDPHE[6] (137 tons/year) methods indicated that the 100% methanol volatilization assumption overestimates the VOC emission by about 93%.

Air canisters

Both Utah and Wyoming DEQ approve air canisters as VOC and HAP emission sampling methods. Air canisters collect VOC and HAP by automatically drawing ambient air into evacuated stainless steel canisters for a predetermined time.

This relatively simple method may provide a good comparison with the simple mass-balance estimate, as previously discussed.

The state agency must approve the selected air-sampling protocol before its use. The direct air measurement method may present some challenges including selecting representative sampling locations based on prevalent wind direction, wind speed, and local weather conditions.

CDPHE does not currently approve air canisters as an alternative VOC estimation method. However, they may approve flux chambers.

Flux chambers

Some facilities have used flux chambers for measuring fugitive VOC from open water bodies containing hydrocarbons.

The method usually involves the placement of the flux chamber directly on the water surface to establish the flow rate for drawing air from the chamber and measure the VOC emission rate.[10]

Remote sensing

Remote sensing is an emerging technology that oil and gas refineries have widely used for detecting fugitive emissions. Currently, it is being tested as an alternative emission estimation tool.

This technology combines laser-based instruments, such as light detection and ranging, with VOC absorption techniques for determining VOC flux estimations, such as Fourier transform infrared, etc.

Remote sensing technologies are expensive but some field applications have shown promising results.[11]

Engineering controls

Some facilities have employed successfully several commercially available engineering controls for recovering and reducing VOC and HAP.

Generally, engineering controls include a single treatment technology or a combination of technologies that fall into the following four categories based on the process employed:[12]

1. Physical, which relies on physical means such as gravity (driven by density differences, oil droplet size, etc.), and filtration to separate oil and water.
2. Biological, which uses microbes to biodegrade or biotransform hydrocarbons.
3. Chemical, which includes enhanced sorption, precipitation, etc.
4. Thermal, which uses high temperatures to destroy or remove VOC and HAP.

Physical separation technologies only can recover free floating and dispersed oil from the bulk water. These separation technologies can be divided into two main groups: conventional gravity separators and nonconventional or enhanced gravity separators.

Conventional oil-water separators involve gravity separation of immiscible fluids as modeled by Stoke's Law.[7]

Stoke's Law states that an oil droplet's rise rate depends on the difference in density between the oil droplet and its surrounding fluid, the surrounding fluid viscosity, and the droplet size.

Equation 11 shows that oil droplet size has the largest effect on the separation efficiency of these types of separators because it is proportional directly to the rise rate to the power of 2. Hence, larger droplets will rise much faster and will have a better chance to separate from the bulk water.

In addition, the larger the difference in specific gravity between the oil mixture and the bulk produced water, the better the separation process.

An important design consideration in these oil-water separators is the residence time of the produced water to accomplish the desired separation efficiency. Emulsifying agents can inhibit this efficiency, which depends on the chemical conditions such as pH, and surface tension and composition such as colloidal matter and salinity of the bulk produced water.

In addition, pumps, valves, pipe restrictions or other devices used for transporting produced water can cause shearing or breaking of oil droplets that can decrease separation efficiency.

Conventional oil-water separators may include tank-type separators such as gun barrels, and API-type gravity separators (rectangular, square or circular in shape) with or without design modifications such as coalescing plates.

Design modification in an API separator can increase separation efficiency by increasing coalescing rates of oil droplets, which can enhance the rise rate of oil droplets and require a shorter residence time and in turn a smaller system footprint.

Table 4 lists the oil-removal capabilities of different types of oil-water separators by droplet size.[13]

Conventional API separators with coalescing plates are more effective at separating oil droplets larger than 40 µm, whereas more energetic processes such as centrifugal separators can remove oil droplets greater than 2 µm in diameter.

Enhanced gravity separators include:

- Centrifugal separators, such as spinning bowl, hydrocyclones, etc.
- Forced-air devices (induced air flotation (IAF), induced gas flotation (IGF), and dissolved air flotation (DAF)).
- Mass transfer units such as air stripping, activated carbon, etc.
- Filtration devices.

Centrifugal separators use centrifugal force to enhance gravity separation by spinning the fluid in a rotating bowl. The lighter oil will collect toward the inside of the bowl, whereas the heavier fluids, including solids, will tend to move toward the outer edge of the bowl.[15]

Some centrifugal systems may include perforated disk stacks[16] or internal fin packs[17] inside the bowl to increase separation efficiency.

The ECONOVA system provides differential pressure control of the oil-water interface, to handle oil slugs effectively and optimize oil dehydration.[17]

Hydrocyclones use the same principle as centrifugal separators, but spinning of the fluid, not the vessel, accomplishes separation.

Example calculations

Example 1

VOC emissions

Produced water analysis data:

◦ TPH: 100 mg/l.

◦ Methanol: 5 mg/l.

Produced water volume: 1,000,000 bbl/year

Combining methanol and TPD in the estimation as shown in the CDPHE (2007b) document the annual VOC emission is estimated as follows:

$$\frac{1{,}000{,}000\text{ bbl}}{\text{year}} \times \frac{42\text{ gal}}{\text{bbl}} \times \frac{3.76\text{ liter}}{\text{gal}} \times \frac{105\text{ mg VOC}}{\text{liter}} \times \frac{\text{g}}{1{,}000\text{ mg}} \times \frac{\text{lb}}{454\text{ g}} \times \frac{\text{ton}}{2{,}000\text{ lb}} = \frac{18.3\text{ tons VOC}}{\text{year}}$$

Example 2

100% methanol volatization

$$VOC_{methanol} = \frac{152{,}336\text{ m}^3}{\text{year}} \times \frac{6.289\text{ bbl}}{\text{m}^3} \times \frac{42\text{ gal}}{\text{bbl}} \times \frac{3.76\text{ liter}}{\text{gal}} \times \frac{0.82\text{ g methanol}}{\text{liter}} \times \frac{\text{lb}}{454\text{ g}} \times \frac{\text{ton}}{2{,}000\text{ lb}}$$

$$VOC_{methanol} = 137\,\frac{\text{tons methanol}}{\text{year}}$$

Oil droplet removal size

Table 4

Separator type	Process	Oil droplet removal size, µm
API	Gravity	> 150
API with coalescing plates	Coalescing /gravity	> 40
IGF/IAF without chemical addition	Air or gas bubbles / buoyancy	> 25
IGF/IAF with chemical addition	Air or gas bubbles / buoyancy	> 3 - 5
Hydrocyclone	Centrifugal force	> 10 - 15
Mesh coalescer	Coalescing /gravity	> 5
Media filter	Filtration	> 5
Centrifuge	Centrifugal force	> 2
Membrane filter (ultrafiltration)	Filtration	> 0.01

Source: Reference 13

Spinning results from pressurizing the fluid and forcing it to rotate against the walls of a cone-shaped chamber. As the fluid moves toward the bottom of the hydrocyclone, it swirls faster. The lighter oils collect in the center of the vessel and exit through one end, whereas the heavier fluids and solids will move toward the walls and exit through a second opening in the hydrocyclone.[1]

Forced-air or gas devices use mechanically driven pressurized air or gas bubbles that attach to oil droplets and force them to rise by buoyancy force to the top of the water. At this point, various conventional methods can remove them.

Chemical separation technologies use chemical sorption processes, or air stripping techniques to transfer oil or VOC from one phase to another, for example liquid to solid or gas to liquid.

Also companies have used ultrafiltration to physically separate out small droplets of oil and solids from produced water (Table 4).

Biological processes using microbes of bacteria (such as bioreactors) are also employed to transform or biodegrade toxic organic compounds to less or nontoxcic organics.

Abatement technologies may employ heat, such as thermal-oxidizers, heater treaters, flares, or chemical agents to destroy VOC and HAP.

These methods although effective in reducing VOC may destroy valuable commodities that could be recovered and sold for profit.

Emerging technology

The separation technologies previously described can effectively separate free floating and dispersed oils. They

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are, however, unable to remove dissolved hydrocarbons that may represent a large portion of the VOC.

One emerging separation technology uses conventional oil-water separation technologies in combination with a vapor compression, turbulent flow, flash evaporation treatment system to handle a wide range of produced and flow back waters.

The system removes and recovers marketable hydrocarbons and alcohols. It produces clean, distilled water for use at drillsites for completions fluids makeup, surface drilling, or discharge directly into environmentally sensitive areas.

Operators in the Pinedale anticline of Wyoming have used this technology to exceed established water-quality standards. It soon will also be in operation in the Piceance basin of Colorado.[17]

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The authors

Gennaro Dicataldo (gennaro.dicataldo@gmail.com) is a consulting engineer at Stantec Consulting Inc. His work involves remediation technologies (including oil-water separators), water-quality modeling of toxic trace elements, and water and waste water treatment and facilities design. Dicatado holds a BS and MS from Brigham Young University and a PhD in civil and environmental engineering from the University of Utah. He is a registered professional engineer in Utah and Wyoming.

Gary H. Richins (grichins@dalboholdings.com) is the corporate environmental manager for Dalbo Holdings Inc. He holds a BS and MS in zoology and wildlife biology from Brigham Young University and is a Certified Wildlife Biologist.

Kerry J. Spiroff (kerry.j.spiroff@mwhglobal.com) is a project manager for Montgomery Watson Harza Consulting Inc. He has 30 years of experience in the energy, municipal, and industrial areas. Spiroff is currently leading several produced-water disposal facilities projects in the intermountain west. He holds a BS in civil engineering from Iowa State University and an MS in structural engineering from the University of Missouri, Columbia. He is a registered professional and structural engineer in Utah.

Mark B. Nelson (mnelson@212Resources.com) is director of mechanical engineering at ECONOVA Inc. with more than 25 years of experience in industrial and municipal waste water treatment including oil-water separation technologies. Nelson holds a BS in mechanical engineering from the University of Utah. He is a registered professional and structural engineer in Utah.

FIRST-HALF 2009

US petchems experience rebound with new year

Dan Lippe
Petral Worldwide Inc.
Houston

While economic activity in North America remained weak during first and second-quarters of 2009, petrochemical industry developments call into question the most bearish views of a protracted global economic recession for 2009-10.

Specifically, ethylene production began to rebound during first-quarter 2009, and the rebound was stronger than forecast in fourth-quarter 2008. Exports of all major ethylene derivatives rebounded in first-quarter 2009.

These trends indicate that worst-case scenarios need to be replaced with moderately optimistic and more realistic forecasts for third and fourth-quarters 2009.

Feed slate trends

Ethylene industry's demand for fresh feed averaged 1.31 million b/d in first-quarter 2009. In January the industry began to recover from the devastating impact of the financial crisis and global economic recession. Demand for fresh feed increased steadily and averaged 1.56 million b/d in April 2009 vs. 1.03 million b/d in December 2008.

Demand for LPG feedstocks (ethane, propane, and normal butane) averaged 0.85 million b/d in fourth-quarter 2008 and increased to 0.93 million b/d in first-quarter 2009 and 1.12 million b/d in March-April 2009.

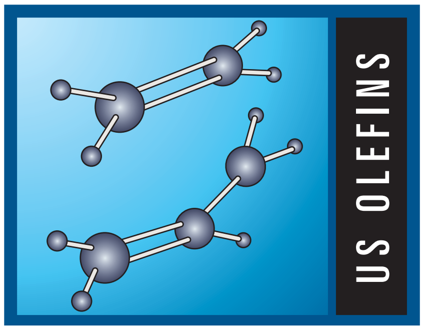
The industry feed slate was heavier during fourth-quarter 2008 than in any-quarter since fourth-quarter 2005; LPG feeds accounted for only 67% of total fresh feed in fourth-quarter 2008.

Ethylene producers began to swing back to lighter feeds in January 2009 and continued to increase LPG feeds through April. LPG feeds accounted for 71% of total fresh feed in first-quarter 2009 and 75% in April.

Economics for ethane were very favorable during first-quarter 2008 and ethane's share of fresh feed averaged 54% in first-quarter 2009 vs. 49% in fourth-quarter 2008. Total demand for ethane increased to 860,000-870,000 b/d in April 2009 and accounted for 55% of total fresh feed.

Based on projected ethylene industry operating rates of 78-82% for second and third-quarters 2009, total demand for fresh feedstocks will average 1.45-1.50 million b/d. Total demand for LPG feedstocks will average 1.05-1.10 million b/d during second and third-quarters 2009.

Fig. 1 illustrates historic trends in ethylene feed slates.



US ETHYLENE FEED SLATE — Table 1

2008-09	Ethane	Propane	n-Butane	Naphthas, gas oils
	Feed type, 1,000 b/d			
July	795.0	423.5	117.6	429.8
August	798.9	346.7	112.1	394.8
September	398.7	165.4	37.4	193.3
October	661.9	246.8	62.8	476.7
November	653.4	203.3	37.3	443.5
December	541.2	128.2	8.0	349.7
January	613.5	176.9	0.0	414.1
February	705.1	226.6	2.2	318.6
March	807.6	255.1	9.1	402.9
April	865.7	287.8	20.8	388.6

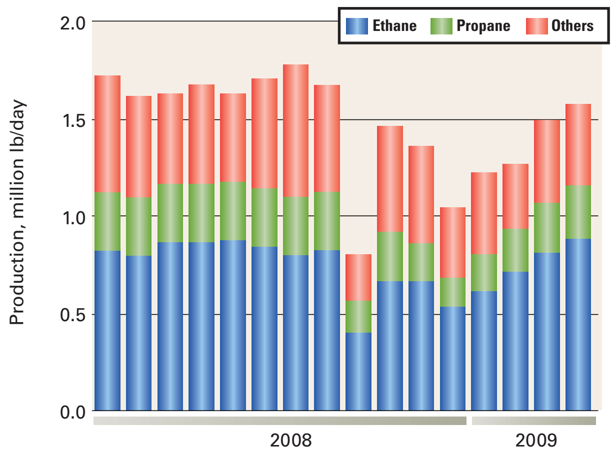
Source: Petral Monthly Olefin Feedslate Survey

Ethylene production

Ethylene production from fresh feed totaled only 10.3 billion lb in fourth-quarter 2008 but increased to 10.5 billion lb in first-quarter 2009. Ethylene production from steam crackers during fourth-quarter 2008 was 1.18 billion lb lower than in third-quarter 2008 (almost 10 days' output based on average daily production during third-quarter 2008).

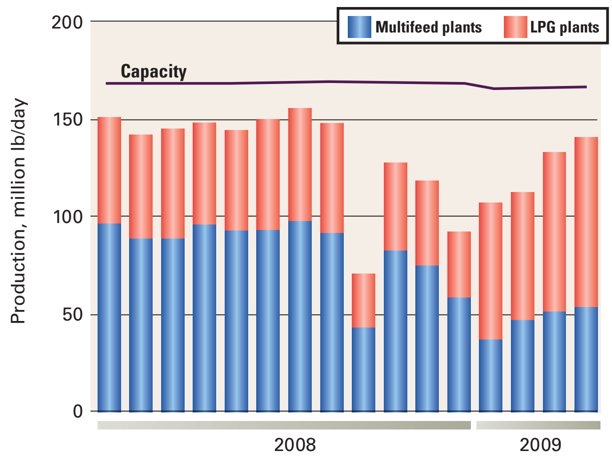
Production in first-quarter 2009 was 225 million lb higher than in fourth-quarter 2009 (about 2 days' production). Production remained at the depressed levels of November-Decem-

US ETHYLENE PLANT FEED SLATE PRODUCTION Fig. 1



Source: Petral Monthly Olefin Plant Feedslate Survey

US ETHYLENE PRODUCTION Fig. 2



Source: Petral Monthly Olefin Plant Feedslate Survey

ber 2008 during January and February 2009 but increased to 136 million lb/day during March and April 2009 (an equivalent of 49-50 billion lb/year). Production in March-April 2009 was only 6.7% below the prerecession daily average for first-half 2008.

Production from LPG plants totaled only 3.69 billion lb in fourth-quarter 2008, or 671 million lb (about 14 days of production) less than in third-quarter 2008. Production from LPG crackers increased to 4.11 billion lb in first-quarter 2008, or 418 million lb (about 10 days of production) more than in fourth-quarter 2008.

Production increased to an equivalent of 4.8-4.9 billion lb/quarter in March and April 2009. Production from LPG plants in March and April 2009 was 0.5 million lb/day higher than the average for first-half 2008.

Production from multifeed crackers totaled 6.63 billion lb in fourth-quarter 2008, or 511 million lb (about 7 days' production) less than in third-quarter 2008. Production from multifeed crackers declined again in first-quarter 2009 and totaled only 6.44 billion lb, or 193 million lb (about 3 days' production) less than in fourth-quarter 2008.

LPG plants operated at 68% of capacity in fourth-quarter 2008. During first-quarter 2009, however, ethylene producers responded to the significant cost advantages provided by light feeds and operated LPG crackers at 90% of capacity in March 2009 and 96% in April 2009. Multifeed crackers operated at 66% of nameplate capacity (based on capacity of 39.2 billion lb/year) during fourth-quarter 2008 and only 67% during first-quarter 2009.

Overall operating rates for the industry declined in fourth-quarter 2008 and averaged 67.0%. Operating rates increased to 72% during first-quarter 2009 and averaged 86% in April.

Fig. 2 illustrates trends in ethylene production.

US propylene production

Coproduct propylene supply from steam crackers totaled only 2.38 billion lb in fourth-quarter 2008, or 227 million lb less than in third-quarter 2008 (about 8 days' production). Furthermore, coproduct propylene production during fourth-quarter 2008 was 712 million lb less than year-earlier volumes (about 21 days of production). Coproduct propylene supply during fourth-quarter 2008 was significantly

ETHYLENE FROM US STEAM CRACKERS Table 2

2008-09	LPG crackers	Multifeed crackers	Total
	Production, billion lb		
July	1.80	3.01	4.81
August	1.71	2.86	4.57
September	0.85	1.28	2.12
October	1.41	2.54	3.95
November	1.25	2.29	3.54
December	1.03	1.80	2.83
January	1.16	2.14	3.31
February	1.34	1.81	3.15
March	1.60	2.49	4.09
April	1.65	2.56	4.21

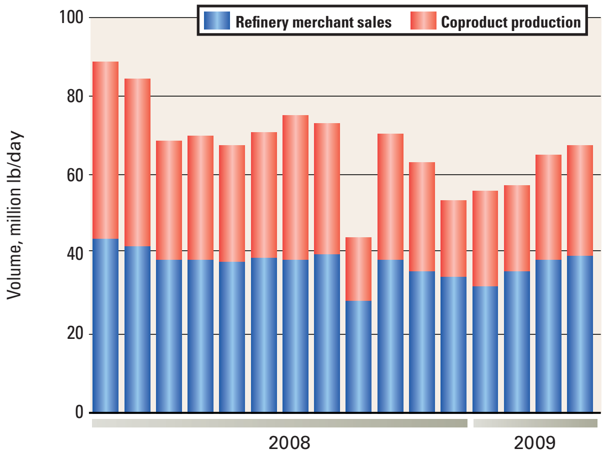
Source: Petral Monthly Ethylene Feedslate Survey

PROPYLENE FROM US STEAM CRACKERS Table 3

2008-09	LPG feeds	Naphthas, gas oil feeds	Production (est.)
	Production, million lb		
July	587.1	546.3	1,133.4
August	511.1	504.3	1,015.3
September	219.8	238.8	458.6
October	350.3	604.1	954.4
November	268.5	544.8	813.3
December	167.2	444.9	612.1
January	205.9	530.3	736.2
February	234.5	368.0	602.5
March	304.1	514.7	818.8
April	340.7	480.1	820.8

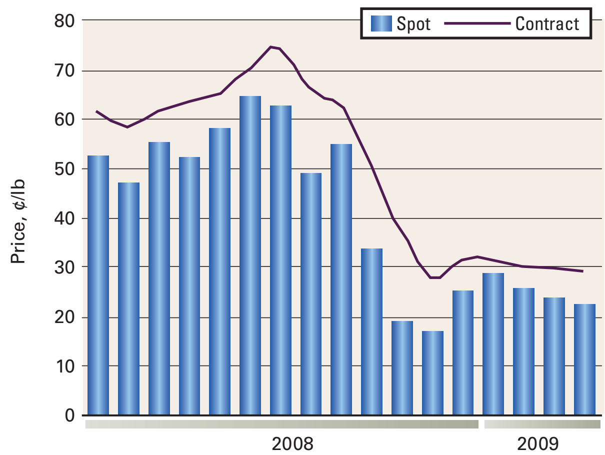
Source: Petral Monthly Propylene Supply Analysis

PROPYLENE PRODUCTION, SALES Fig. 3



Source: Petral Monthly Coproduct Supply Analysis

ETHYLENE PRICES Fig. 4



Source: Petral market research

lower than year-earlier volumes due to reduced operating rates for all olefin plants.

Although industry's average operating rate rebounded during first quarter, the rebound in rates for LPG plants was significantly stronger than for multifeed crackers. Furthermore, ethane's share of total fresh feed to multifeed crackers averaged 38% in first-quarter 2009 vs. 34% during fourth-quarter 2008.

As a result, coproduct propylene supply declined again in first-quarter 2009 and totaled only 2.16 billion lb, or 222 million lb less than during fourth-quarter 2008 (almost 9 days' production). The combined volume of coproduct propylene supply during fourth-quarter 2008 and first-quarter 2009 was 1.09 billion lb (19.3%) less than total production during first and second quarters 2008.

Propylene production from LPG feeds totaled 0.79 billion lb in fourth-quarter 2008 and was 532 million lb less than production in third-quarter 2008. Coproduct propylene supply from LPG feeds was also 733 million lb less than year-earlier volumes. Propylene production from LPG feeds declined slightly in first-quarter 2009 and totaled 0.74 billion lb, or 42 million lb less than in fourth-quarter 2008.

Propylene production from naphthas, condensates, and gas oils totaled 1.59 billion lb in fourth-quarter 2008 and was 305 million lb more than during third-quarter 2008. Coproduct propylene supply from heavy feeds declined by 181 million lb during first-quarter 2009 and totaled 1.41 billion lb.

US REFINERY MERCHANT PROPYLENE Table 4

2008-09	Texas	Louisiana	Other states	Total
	Sales, million lb			
July	435.3	460.3	294.5	1,190.2
August	500.1	429.8	298.6	1,228.5
September	229.5	333.8	286.0	849.3
October	437.0	468.9	302.2	1,208.1
November	429.1	396.6	239.4	1,065.1
December	443.0	363.4	231.5	1,037.9
January	369.2	392.4	225.0	986.6
February	377.1	340.2	236.8	954.1
March	578.1	451.2	154.9	1,184.2

Source: EIA Petroleum Supply Monthly

ETHYLENE COSTS, HOUSTON SHIP CHANNEL Table 5

2008-09	Purity ethane	Purity propane	Normal butane	Light naphthas	Industry composite
	Variable, direct fixed cash costs, ¢/lb				
July	57.9	51.1	44.2	68.0	56.6
August	45.3	47.4	37.8	57.0	47.3
September	35.8	45.4	33.3	45.1	39.9
October	22.6	24.4	18.0	24.3	23.0
November	20.4	23.3	19.4	24.1	21.7
December	18.7	23.1	18.6	23.8	20.7
January	19.8	28.0	28.5	28.8	27.7
February	19.2	23.3	25.6	29.6	26.0
March	18.1	24.1	23.2	32.1	23.4
April	18.9	22.4	21.7	31.0	23.0
May	20.3	21.0	18.6	29.4	22.7

Source: Petral Consulting Co. production cost analysis

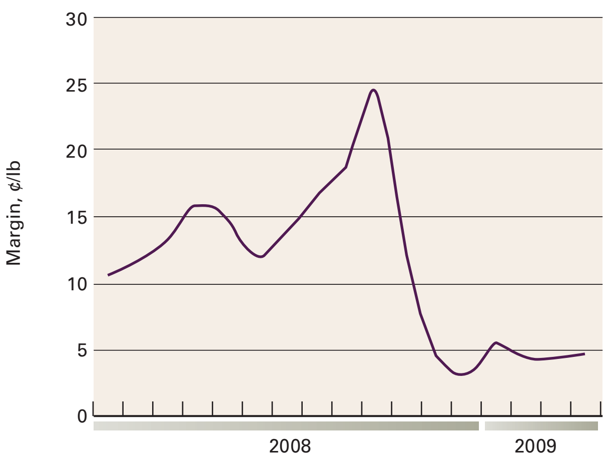
Refinery supply

Refinery propylene sales into the merchant market are a function of fluid catalytic cracker feed rates, FCC operating severity, and economic incentives to sell propylene rather than use it as alkylate feed or burn it. Normally, FCC unit feed rates and operating severity are at their seasonal peaks during second and third quarters and decline to minimum seasonal levels during fourth and first quarters.

According to the US Energy Information Administration statistics, however, FCCU feed in the Gulf Coast increased by 7.7% during fourth-quarter 2008 from third-quarter 2008. The increase in sales during fourth-quarter 2008 was consistent with the recovery to normal operations after substantial downtime in September and

ETHYLENE PROFIT MARGIN

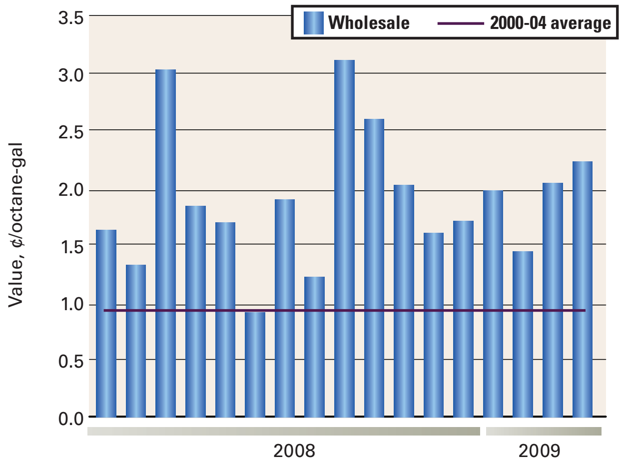
Fig. 5



Source: Petral analysis

US GULF COAST OCTANE VALUES

Fig. 6



Source: Petral analysis

October due to Hurricanes Gustav and Ike. FCCU feed rates, however, were 9.3% lower than year-earlier levels during fourth-quarter 2008.

EIA reported that refinery-grade propylene sales during fourth-quarter 2008 averaged 36.0 million lb/day and were 43 million lb more than in third-quarter 2008 (about 1.2 days' production). Refinery-grade propylene sales averaged 34.7 million lb/day during first-quarter 2009 and were 186 million lb less than in fourth-quarter 2008 (about 5.2 days' production).

Domestic propylene supply from both sources totaled 5.66 billion lb in fourth-quarter 2008 and was 182.5 million lb less than in third-quarter 2008. Domestic production declined again in first-quarter 2009 and totaled only 5.22 billion lb, or 0.44 billion lb less than in fourth-quarter 2008 and 1.38 billion lb less than year-earlier volumes.

Fig. 3 illustrates trends in coproduct and refinery merchant propylene sales.

Ethylene production costs

Consistent with the accelerating decline in crude oil prices during fourth-quarter 2008, production costs for ethylene in the Houston Ship Channel (based on full spot prices for all coproducts) declined by 55-65% during fourth-quarter 2008. Production costs for ethane averaged 15-16¢/lb during fourth-quarter 2008 vs. 41-42¢/lb in third-quarter 2008. Production costs for propane declined to 18-19¢/lb in fourth-quarter 2008 vs. 42-43¢/lb in third-quarter 2008. Production costs for natural gasoline posted the largest decline during fourth-quarter 2008 and averaged 17-18¢/lb vs. 49-51¢/lb in third-quarter 2008.

Feedstock prices continued to decline during first-quarter 2009 but the rate of decline was measurably slower than during fourth-quarter 2008. Production costs averaged 13.5-14.5¢/lb for ethane, 19-20¢/lb for propane and 22.5-23.5¢/lb for natural gasoline.

Feedstock prices, coproduct values, and ethylene plant yields determine ethylene production costs. Petral maintains direct contact with the olefin industry and tracks historic trends in spot prices for ethylene and propylene. We use a variety of sources to track trends in feedstock prices.

Some ethylene plants have the necessary process units to convert all coproducts to purity streams. Some ethylene plants, however, do not have the capability to upgrade mixed or crude streams of various coproducts and sell some or all their coproducts at discounted prices. We evaluate ethylene production costs in this article based on all coproducts valued at spot prices.

Average production costs for natural gasoline during fourth-quarter 2008 were only 1.5¢/lb higher than ethane and were 1¢/lb lower than for propane. However, prices for natural gasoline were depressed because prices for unleaded regular were unusually weak throughout the fourth-quarter. Prices for unleaded regular gasoline rebounded during first-quarter 2009 but coproduct prices remained relatively weak. Average production costs for natural gasoline during first-quarter 2009 were 9¢/lb higher than for ethane and 3¢/lb higher than for propane.

Crude oil production cuts by OPEC began to have their full impact during second-quarter 2009. Prices for crude oil and unleaded regular gasoline increased by 30-35% Prices for all ethylene feedstocks were also higher in second-quarter 2009. Ethylene production costs increased to 15-17¢/lb based on ethane and 16-18¢/lb based on propane. Variable production costs based on light naphthas and natural gasoline increased to 23-26¢/lb.

Ethane again benefited from strong economic support in both LPG plants and multifeed crackers during first and second-quarter 2009. Ethane's share of fresh feed to LPG plants increased to

84% in March and averaged 82% during first-quarter 2009 vs. the historic norm of 74-78%. Ethane's share of fresh feed to multifeed crackers increased to 38% in first-quarter 2009 vs. 34% during fourth-quarter 2008.

Ethylene pricing, margins

Contract prices for ethylene averaged 38.9¢/lb in fourth-quarter 2008, or 28.9¢/lb (42.6%) lower than in third-quarter 2008. During fourth-quarter 2008, contract prices fell to 28.25¢/lb in December from 50.75¢/lb in October.

After the extraordinary volatility of 2008, contract prices varied by fewer than 2¢/lb during first-quarter 2009 and averaged 31.3¢/lb. The industry most often negotiates contract prices for ethylene retroactively, usually 30 to 60 days after the end of the contract month. Contract prices for April and May settled at 30.25¢/lb for May.

Spot prices for ethylene averaged 23.3¢/lb for fourth-quarter 2008 and were 32.2¢/lb, or 58.2% lower than third-quarter average. During fourth-quarter 2008, spot prices averaged 33.5¢/lb in October but fell to 17.2¢/lb in December.

Spot prices began to rebound from the December low and averaged 25.0¢/lb in January 2009 and 28.4¢/lb in February 2009. Spot prices slipped in March and averaged 25.7¢/lb. For the full quarter, spot ethylene prices averaged 26.4¢/lb, or 9.2¢/lb higher than in December 2008.

The increase in ethylene production in April and May ended the rally in spot prices. These averaged 21-22¢/lb in May, but rising feedstock prices pushed them to 26-27¢/lb in June. We estimate that spot prices averaged 24.0-24.5¢/lb for second-quarter 2009.

Margins based on spot ethylene prices and LPG feedstocks began to erode in third-quarter 2008 and continued to weaken during fourth-quarter 2008. Margins based on purity ethane production costs averaged only 2.7¢/lb in fourth-quarter 2008 and were 6.4¢/lb lower than average for third-quarter 2008. Margins in the fourth quarter averaged 0.3¢/lb negative for propane and 0.8¢/lb negative for natural gasoline.

Margins in first-quarter 2009 improved to 7.3¢/lb for purity ethane and 1.3¢/lb for propane. Margins in first-quarter 2009, however, eroded to 3.8¢/lb negative for natural gasoline. Margins in second-quarter 2009 weakened to 2.8¢/lb for purity ethane, 0.7¢/lb for purity propane, and were 8.2¢/lb negative for natural gasoline.

Fig. 4 illustrates historic trends in ethylene prices (spot prices and net transaction prices). Fig. 5 illustrates profit margins based on contract ethylene prices and composite production costs.

Octane values; propylene prices

Octane values weakened during fourth-quarter 2008 and fell to 1.59¢/octane-gal in December from 2.59¢/octane-gal in October. Octane values for

NELSON-FARRAR COST INDEXES

Refinery construction (1946 Basis)
(Explained on p.145 of the Dec. 30, 1985, issue)

	1962	1980	2006	2007	2008	Mar. 2008	Feb. 2009	Mar. 2009
Pumps, compressors, etc.	222.5	777.3	1,758.2	1,844.4	1,949.8	1,918.3	2,010.9	2,006.2
Electrical machinery	189.5	394.7	520.2	517.3	515.6	515.0	516.4	514.6
Internal-comb. engines	183.4	512.6	959.7	974.6	990.9	986.5	1,019.3	1,017.4
Instruments	214.8	587.3	1,166.0	1,267.9	1,342.1	1,328.0	1,377.8	1,395.0
Heat exchangers	183.6	618.7	1,162.7	1,342.2	1,354.6	1,374.7	1,253.8	1,253.8
Misc. equip. average	198.8	578.1	1,113.3	1,189.3	1,230.6	1,224.5	1,235.6	1,237.4
Materials component	205.9	629.2	1,273.5	1,364.8	1,572.0	1,466.1	1,325.2	1,313.1
Labor component	258.8	951.9	2,497.8	2,601.4	2,704.3	2,664.1	2,785.5	2,785.5
Refinery (Inflation) Index	237.6	822.8	2,008.1	2,106.7	2,251.4	2,184.9	2,201.4	2,196.5

Refinery operating (1956 Basis)
(Explained on p.145 of the Dec. 30, 1985, issue)

	1962	1980	2006	2007	2008	Mar. 2008	Feb. 2009	Mar. 2009
Fuel cost	100.9	810.5	1,569.0	1,530.7	1,951.3	2,019.5	988.0	859.2
Labor cost	93.9	200.5	204.2	215.8	237.9	221.8	259.1	265.4
Wages	123.9	439.9	1,015.4	1,042.8	1,092.2	1,023.8	1,141.2	1,170.2
Productivity	131.8	226.3	497.5	483.4	460.8	461.6	440.5	440.9
Invest., maint., etc.	121.7	324.8	743.7	777.4	830.8	806.2	806.4	804.6
Chemical costs	96.7	229.2	365.4	385.9	472.5	431.2	401.0	397.6
Operating indexes								
Refinery	103.7	312.7	579.0	596.5	674.1	659.6	578.2	568.0
*Process units**	103.6	457.5	870.7	872.6	1,045.1	1,055.5	705.7	661.9

**Add separate index(es) for chemicals, if any are used. See current Quarterly Costimating, first issue, months of January, April, July, and October.*

These indexes are published in the first issue of each month. They are compiled by Gary Farrar, OGJ Contributing Editor.

Indexes of selected individual items of equipment and materials are also published on the Costimating page in the first issue of the months of January, April, July, and October.

> We determine the incremental value of octane by tracking the differential between unleaded premium unleaded regular gasoline prices divided by the difference in octane (87 octane for unleaded regular gasoline and 93 octane for unleaded premium gasoline). Octane values are a primary economic influence on spot prices for refinery-grade propylene and toluene. Trends in spot prices for these two coproducts tend to drive prices for other coproducts.

fourth-quarter 2008, however, averaged 2.06¢/octane-gal and were almost unchanged from average of 2.07¢/octane-gal for third-quarter 2008.

During first-quarter 2009, octane values varied from 2.0¢/octane-gal in February to 1.5¢/octane-gal in March and averaged 1.7¢/octane-gal for the quarter. Octane values rebounded to 2.03¢/octane-gal in April and 2.33¢/octane-gal in May.

Fig. 6 illustrates trends in octane values

Refinery, polymer-grade C_3=

Spot prices for refinery-grade propylene averaged 22.2¢/lb during fourth-quarter 2008 and were 42.1¢/lb (65.6%) lower than the average for third-quarter 2008. Spot prices fell to a low of 12.8¢/lb in December 2008 from 36.9¢/lb in October 2008. Refinery-grade propylene prices averaged only 0.75¢/lb higher than unleaded regular gasoline prices for fourth-quarter 2008 and averaged 2.6¢/lb less than unleaded regular gasoline prices in November/December 2008.

> Prices for all grades of propylene move in tandem with each other, and differentials between grades are generally constant within a narrow range. We highlight trends in refinery-grade prices and discuss differentials between polymer and refinery-grade propylene. The premium for polymer-grade propylene covers operating costs and profit margins for the various merchant propane-polypropylene splitters in Texas and Louisiana.

Spot prices for refinery-grade propylene increased to 19.3¢/lb in January and 24.6¢/lb in February. For full first-quarter 2009, spot RGP prices averaged 21.5¢/lb and were 1.7¢/lb higher than unleaded regular gasoline. Spot prices remained within the first-quarter range in April but jumped to 33-35¢/lb in May. Spot prices for the second quarter were an estimated 30¢/lb.

From the October settlement of 60¢/lb, contract prices for polymer-grade propylene collapsed during fourth-quarter 2008 and settled at 20¢/lb in December. For the fourth quarter, contract prices for polymer-grade propylene averaged 36.7¢/lb, or 14.5¢/lb higher than spot refinery-grade propylene prices.

Contract prices increased to 22¢/lb in January and 29¢/lb for March and April. Contract prices increased again in May and settled at 31.5¢/lb.

Summer-fall 2009 outlook

Spot prices for West Texas Intermediate crude oil fell to a monthly average of $39.15 in February 2009 but rallied to $49.82/bbl in April and $59.00/bbl in May. Following the historic collapse in prices during third and fourth-quarter 2008, the rebound in crude oil prices during March was not surprising. The shift to sharply higher prices during April/May, however, was unexpected.

We reviewed trends in pricing for other benchmarks such as dated Brent and Dubai/Oman and trends in differentials between WTI and other benchmarks. This review suggested that production cuts by the Organization of Petroleum Exporting Countries and slower but continued growth in demand in Asia and other economies of countries outside the Organization for Economic Cooperation and Development (non-OECD) were sufficient to reverse the collapse in prices during third and fourth quarters 2008. We also note, however, that demand in OECD countries remains weak. OPEC has achieved better compliance with its series of production quota agreements than expected early in fourth-quarter 2008.

We revised our price forecast to $50/bbl in late April. Escalation of tensions in Nigeria, however, increased the supply risk to Nigeria's crude oil production of 2 million b/d. Threats to Nigerian crude oil production will reinforce bullish influences of OPEC production curtailments and demand growth in non-OECD economies. Forecasts are now based on WTI prices of $55-65/bbl for third and fourth quarters 2009.

Ethylene production costs (full cash costs) are likely to be in the range of 18-24¢/lb for third and fourth quarters for ethane and propane and 30-33¢/lb for natural gasoline. Spot ethylene prices are to average 22-24¢/lb. Profit margins are to average 2-4¢/lb for purity ethane and break even for purity propane. Profit margins for natural gasoline are to average 7-10¢/lb below break-even. ✦

The author

Daniel L. Lippe (danlippe@petral.com) is president of Petral-Worldwide Inc., Houston. He founded Petral Consulting Co. in 1988 and cofounded Petral Worldwide in 1993. He has expertise in economic analysis of a broad spectrum of petroleum products including crude oil and refined products, natural gas, natural gas liquids, other ethylene feedstocks, and primary petrochemicals. Lippe began his professional career in 1974 with Diamond Shamrock Chemical Co., moved into professional consulting in 1979, and has served petroleum, midstream, and petrochemical industry clients since that time. He holds a BS (1974) in chemical engineering from Texas A&M University and an MBA (1981) from Houston Baptist University. He is an active member of the Gas Processors Association, serving on the NGL Market Information Committee and currently serving as vice-chairman of the committee.

Canadian gas plant handles NORM in replacing C_3 treater's mol sieve

JoAnn Tan
Denis Pelletier
Shell Canada Ltd.
Calgary

Gas Processing

The presence of naturally occurring radioactive materials complicated 2007 plans at Shell Canada Ltd.'s Jumping Pound gas plant, near Calgary, to replace the molecular sieve in two propane treaters.

At the plant, the Deepcut unit recovers sales gas, ethane, propane, butane, and pentane plus products. Jumping Pound uses the two propane treaters to reduce total sulfur levels to meet propane sales specification.

In a gas processing plant, where propane is processed is more susceptible to NORM contamination because radon has a boiling point similar to propane. NORM pose long-term health risks when inhaled or ingested; excessive exposure can lead to cancer.

This article presents the experiences at the Jumping Pound gas plant with removal of NORM-contaminated molecular sieve from the propane treaters.

Results of a NORM survey prompted development of a method to minimize personnel exposure to dust particles from the treaters during removal of the molecular sieve and ensure appropriate disposal because the treaters were suspected to contain NORM.

Based on a presentation to the Laurance Reid Gas Conditioning Conference, Norman, Okla., Feb. 23-25, 2009.

Treater background

The Deepcut unit at the plant is a cryogenic fractionation train that processes residue gas and recovers individual streams of sales gas, liquid ethane, and C_3, C_4, and C_{5+} (Fig. 1).

Of the streams recovered, sulfur compounds tend to accumulate in the propane and butane streams because they have similar boiling points. Hence the products from the depropanizer and debutanizer are fed through molecular-sieve treaters to reduce total sulfur levels to the customer's specifications.

Jumping Pound has two identical externally insulated propane treaters, each of which contains 10,206 kg (22,500 lb) of 5A RK-29 ¹⁄₁₆-in. molecular sieve. Each treater has a 1.7 m ID and a height of 9.8 m. At any time one treater is online removing sulfur, while the other is in regeneration or standby. Regeneration involves flowing hot sweet fuel gas (methane) through the bed to release the sulfur compounds that have been adsorbed during the treating cycle. Total regeneration time is 12 hr, including 6.5 hr of heating at 320° C. and 3 hr of cooling at 30° C.

In 2006, a business decision to replace the molecular sieve in the propane treaters was based on two justifications:

1. The molecular-sieve capacity had declined to ~30% of its original capacity.

2. Blended sulfur concentration in the propane sales product was estimated to reach 50% of sales specification by late 2007.

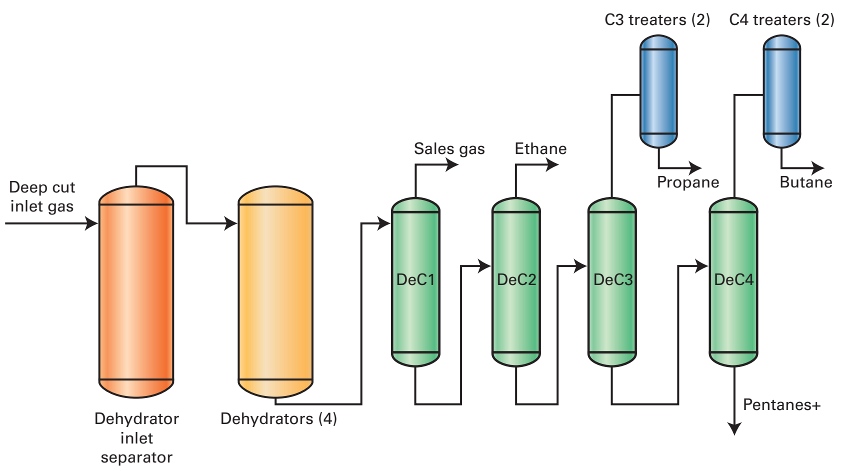
With NORM in the propane stream, specifically in the propane treaters, the

Deactivation methods: pros and cons

N_2 purge & N_2 and CO_2 purge – Pros	N_2 purge & N_2 and CO_2 purge – Cons	Steam purge – Pros	Steam purge – Cons	Waterflood – Pros	Waterflood – Cons
Reduce risk of flammable atmosphere	Will not effectively displace materials concentrated within the internal cavities. N_2 purge is done to remove residual process gas from void volume of bed.	May displace materials concentrated within the molecular sieve and vessel. However, effectiveness depends on steam flow rate and channeling through bed.	Once steam purge is completed, molecular sieve and vessel need to be cooled for workers to remove spent molecular sieve; hence extra time is required.	Will displace materials concentrated within the molecular sieve and vessel.	It was believed that molecular sieve would clump together and cause difficulty in removal.
No water carryover to flare header	Cost of bringing in N_2 truck, as the plant does not have a N_2 system.	Reduce dust during removal of spent molecular sieve.	It was believed that molecular sieve would clump together and cause difficulty in removal.	Effectively reduce dust during removal of spent molecular sieve.	It was believed that water would contain NORM contamination, which results in disposal concerns.
No freezing concern	Restricted piping size to flare, resulting in extra time required and a need to purge to atmosphere through manway.	Eliminate need for N_2 purge, resulting in cost savings.	It was believed that condensed steam would contain NORM contamination, which results in disposal concerns.	Eliminate need for N_2 purge, resulting in cost savings.	Vessel must be dried before loading fresh molecular sieve.
	N_2 does not suppress dust; therefore dust hazard needs to be managed.		Freezing concern due to steam condensation	Vendor preferred deactivation method.	Freezing concern
			Vessel must be dried before loading fresh molecular sieve.		

JUMPING POUND DEEPCUT PROCESS

Fig. 1



planned molecular-sieve change out would require additional health and safety and waste-management measures.

NORM

Radiation exposure to individuals can arise from such natural radiation sources as terrestrial radiation from radionuclides found in soils, cosmic radiation from space, naturally occurring radionuclides deposited in the body from foods and man-made sources such as medical diagnostics. This is known as background radiation.[1]

A major component of background radiation, NORM consist of long-lived radioactive elements such as uranium and thorium that are naturally present in the earth's crust. The presence of these materials in gas-producing formations varies geographically. These elements naturally decay to become more stable.

Although the concentration of NORM in most geological formations is low, higher concentrations may result as radioactive materials scattered across a large area are brought into one facility.

Uranium is typically insoluble and remains largely within the underground reservoir. Radium 226 and Radon 222, however, which are decay products of uranium, are slightly soluble and can thus be mobilized within extracted fluids and gasses, allowing these materials to be brought to surface.

The primary source of NORM in gas processing facilities is Radon 222 (or radon gas). It can be brought to surface with natural gas and concentrated in the propane stream through fractionation because radon and propane have similar boiling points. Radon gas has a short half-life of 3.8 days and quickly decays to Lead 210, which has a half-life of 22 years and forms a thin film that builds up on the inner walls of process equipment (Fig. 2).

In addition to radon gas, another potential source of NORM accumulation in gas plants is Radium 226, found in produced-water streams. Radium within geological reservoirs is soluble and transported to gas plants with produced water. Radium precipitates out of the produced water as a radium sulfate scale due to changes in temperature, flows, and pressure. Radium 226 has a half-life of 1,600 years (Fig. 3).

Health risk from exposure

Human exposure to NORM sources can occur externally and internally. External radiation exposure occurs when people are exposed to gamma radiation from outside the body. Within the oil and gas industry, NORM typically do not give rise to exposures above the annual exposure limits for an external source. Internal radiation exposure occurs when NORM enter the body, which poses a far greater concern than external radiation exposure because radioactive isotopes that enter the body may not be eliminated from the body for several decades and result in a cumulative dose build up.

There are three possible internal exposure pathways:

- Inhalation of NORM-contaminated dust or radon gas.
- Ingestion of NORM-contaminated particulates or liquids.
- Absorption of NORM-contaminated particulates or liquids through open cuts on the skin.

Long-term exposure to NORM can lead to increased risk of cancer, just as similar exposure to asbestos, coal dust, and cigarette smoke can cause lung cancer.[2]

Guidelines in Alberta

In Canada, working with man-made radioactive sources falls under federal jurisdiction and is regulated by the Canadian Nuclear Safety Commission. NORM are exempt from CNSC legislation except for the import, export, and transportation of the material. The jurisdiction over radiation exposure to NORM is thus the responsibility of each Canadian province and territory. To date, the province of Alberta has not yet implemented NORM-specific legislation or regulations.

In 2000, Health Canada published the Canadian Guidelines for the Management of NORM, prepared by the Federal Provincial Territorial Radiation Protection Committee. These guidelines establish safe practices for management of NORM in Canada to protect workers and the public from situations in which NORM have been concentrated as a result of industrial activities.

The guidelines establish four NORM thresholds; natural background radiation is excluded from the dose limitations.

- Investigation threshold: A site-specific assessment should be carried out where doses exceed an incremental dose of 0.3 millisievert/year.

- NORM management threshold: an assessed incremental dose of greater than 0.3 millisievert/year.
- Dose management threshold: an assessed incremental dose of 1 millisievert/year.
- Radiation protection management threshold: an assessed or measured incremental dose of 5 millisievert/year.

(Sievert is an SI unit measuring the extent of tissue damage resulting from radiation adsorption. In the US, it is measured in units of millirem; 1 mSv = 100 mrem.)

The guidelines also address management of NORM-contaminated waste. The unconditional derived release limit (UDRL) for fixed surface contamination is 1 Bq/sq cm averaged over a 100 sq cm area. NORM-contaminated scales, sludges, and waste above the UDRL of 0.3 Bq/g must be sent to a licensed NORM disposal site.

(A Becquerel, Bq, is an SI unit of radioactivity; 1 Bq = the activity of a quantity of radioactive material in which one nucleus decays/second.)

In Alberta, typical average background radiation is in the range of 60-120 millisievert/hr (60e-6 to 120e-6 millisievert/hr) according to Normcan, Calgary.

NORM survey

In September 2005 and July 2006, a certified radiation safety officer conducted a NORM gamma screening survey at Jumping Pound. The officer used a calibrated Ludlum 3-97 General Purpose Survey Meter that incorporates both an internal 1-in. by 1-in. sodium iodide (Na-I) scintillator and an external 44-9 Geiger-Mueller pancake probe (Fig. 4).

The survey entailed data logging gamma radiation levels on the exterior of piping, vessels, and equipment. Measurements were taken within 1 to 3 cm from external surfaces and at a distance of 0.5 m. Gamma scintillation surveys provide a rapid and efficient means of screening a facility for the presence of NORM, allowing for an evaluation of the presence of NORM from the exterior of operating equipment without taking the equipment out of service.

The bottle contains Lead 210 dust (Fig. 2; photo from Normcan).

This scale contains a buildup of NORM (Fig. 3; photo from Normcan).

The survey revealed that NORM were present within the Deepcut unit, LPG loading areas, propane storage bullets, sour-water slop tank, and inlet slug catcher. The highest readings were found on the downstream propane treater filter.

While the vessels and equipment are in operation and sealed, the exposure levels to incidental workers were determined to be less than the dose-management threshold of 1.0 millisievert/year. There is potential, however, for exposure to higher doses through inhalation and ingestion of NORM when vessels and equipment are open for maintenance.

Job planning

The site's awareness of NORM affected the job planning, especially in terms of worker safety and waste management. Removal of molecular sieve that is not NORM-contaminated would typically involve workers using supplied-air breathing apparatus (SABA) in addition to regular personal protective equipment (PPE) when blinding the treaters and entering the vessels. The regular PPE would include boots, gloves, hardhat, and safety glasses.

Dust control would not be a major issue to address throughout the removal procedure. Workers around the perimeter of the job site, for example, would not wear additional respiratory protection, and sealed storage bins would not be required to control any dust generated during removal of spent molecular sieve. Finally, spent molecular sieve that is not NORM-contaminated would be sent to a regular industrial landfill.

The presence of NORM in the propane treaters required additional health and safety and waste-management measures. With no plan for dust suppression, NORM-contaminated dust would be deposited around the job site during removal of spent molecular sieve. Moreover, without disposable PPE, NORM-contaminated dust may remain on workers' coveralls, boots, and gloves, creating a potential for inhalation or ingestion of the dust.

Extensive planning started about 1 year before execution of the project. Due to the collective lack of experience on site with NORM, many of the planning meetings were focused on NORM handling. The planners of the job were unsure how the presence of NORM would affect safe work practices at Jumping Pound. Thus, Normcan, a contractor with experience handling NORM, was brought on site.

Deactivation method

One of the challenges was to select how to deactivate the molecular sieve before unloading. It's necessary to deactivate the molecular sieve because there may be residual toxic or flammable compounds remaining on it even after a full regeneration cycle. Reasons for this include bed channeling, liquid carryover, or adsorbent agglomeration. Deactivation removes potential hazardous adsorbed materials and renders the molecular sieve incapable of picking up more.

The planning team considered four

options for deactivating the molecular sieve, with the help of external contractors that included UOP, Normcan, and Catalyst Services. The four options were N_2 purge, N_2 and CO_2 purge, steam purge, and waterflooding. The table displays the pros and cons of each option; note that N_2 and CO_2 purge has the same pros and cons as N_2 purge.

This approach led to waterflood being preferred because it addressed most of the hazards:

- Waterflood will displace all absorbed material within the cavities of the molecular sieve and within the vessels.
- NORM-contaminated dust can be effectively controlled and minimized by immersing it in water.

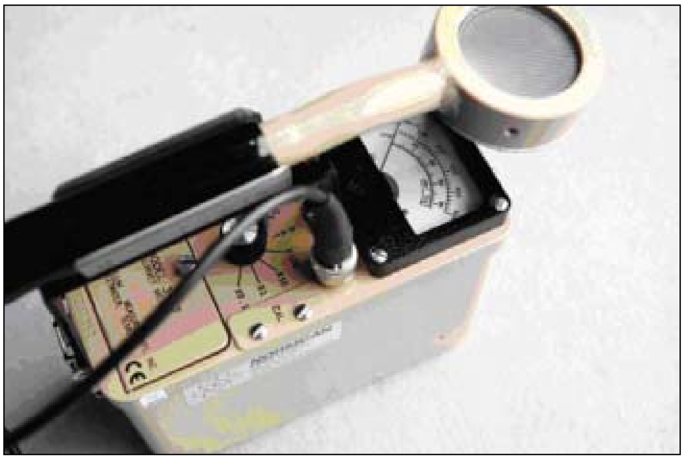
Once the method to deactivate the molecular sieve was chosen, several other challenges needed to be addressed.

Personnel protection

One challenge was to minimize personnel exposure to NORM-contaminated materials. Throughout the job, workers were required to wear disposable Tyvek coveralls, disposable gloves, and disposable Tyvek boot covers in addition to their regular protective equipment. Workers who blinded the vessels and entered the treaters to remove spent molecular sieve were required to use SABA.

Inspectors were required to use the high-efficiency particulate arrestor (HEPA) P-100 cartridge half-mask to enter the vessels for their respiratory protection once the atmosphere in the treaters was tested and proven fit for occupancy. All ground workers around the job site were required to don HEPA P-100 cartridge half-masks.

In addition to PPE, good personal hygiene practices were enforced among workers, such as washing their hands before eating and leaving for home.



The project employed this Ludlum 3097 Scintillator and an external 44-9 Geiger-Muelier pancake probe (Fig. 4; photo from Normcan).

Flooding rate; exothermic reaction

Another major item discussed during meetings was the water flow rate that would be required to fill the treaters. Much time was spent searching for past practices on waterflooding within the Shell Foothills gas facilities. But none was found because the Foothills facilities have no experience with waterflooding, which led the planning group to consult external contractors.

One contractor's experience with waterflooding at a different facility led him to recommend filling the treaters with 30.5 cm of water every 15 min. Using this recommendation, the operations engineer had calculated the required flow rate for flooding the treaters at 28 cu m/day.

In conjunction with determining the flooding rate was a concern about the volume of steam that would be generated due to the exothermic reaction created when molecular sieve adsorbs water. Initial calculations were that the existing 25.4-mm line to flare would potentially be insufficient to divert the expected steam to flare. Thus, the job plan included about 61 m of temporary 50.8 mm pipe and 61 m of properly rated hose to be connected to the flare header.

Waste management

The planning group, uncertain if the spent molecular sieve would be NORM-contaminated once deactivated, explored options for disposing of it. After much discussion, however, the group decided Normcan was able to dispose of the spent molecular sieve in either scenario: NORM-contaminated or non-NORM-contaminated.

Normcan was able to provide sealed bins to contain the spent molecular sieve, which would minimize worker exposure to NORM. Three sealed bins, named Vacuum Box, each with a volume of 19 cu m, were to be brought on site.

Filled bins were to be transported off site once the job was completed, and Normcan would complete its lab analysis to determine options for disposal. Potential permanent disposal options for NORM-contaminated waste included salt cavern disposal, abandoned-well disposal, and landfill disposal.

Job execution

The molecular sieve in the propane treaters was replaced between Apr. 23 and Apr. 30, 2007.

Personnel protection

A radiation safety officer from Normcan was present on site throughout the job, from blinding the treaters to transporting the spent molecular sieve off site. A control area was set up around the job site to establish the boundaries of the area within which the officer monitored all personal protection and other equipment for surface contamination. Inside the control area, a small area was set up to collect all disposable PPE and HEPA P-100 cartridges in a bin provided by Normcan.

Blinding was the first opportunity for workers to be exposed to NORM hazards. While blinding, workers wore disposable Tyvek coveralls, disposable gloves, boot covers, and SABA in addition to regular PPE. Once the task was completed, they went into a disposal area, where each worker was measured for NORM contamination with Ludlum 44-9 Geiger-Mueller pancake probe. Once proven clear of contamination, workers were then directed to remove and dispose of all disposable PPE.

Once the treaters were opened to the atmosphere, the manways, mesh screen, molecular sieve, and inner surface of the vessels were tested for NORM readings by the radiation safety officer, who obtained measurements from within 1-3 cm from the surface.

NORM contamination above the UDRL was found on the manways, grating, mesh screen, and interior surface of the treaters that were not in contact with the molecular sieve. The molecular sieve and interior surface of the treaters that came in contact with the molecular sieve, however, had readings below the UDRL limit.

During removal of the spent molecular sieve, workers wore the appropriate PPE and SABA. Once the molecular sieve was removed, inspectors who entered the vessels wore HEPA P-100 filters in addition to the appropriate PPE, as specified by the plan. Once the job was completed, all personnel were measured for surface contamination on their PPE and then disposed of all disposable PPE.

Throughout the job, readings taken on all workers' regular PPE, disposable PPE, HEPA P-100 filters, and SABA were below the UDRL.

Flooding rate; exothermic reaction

One treater was flooded at a time, starting with V-3020A. Firewater was introduced to V-3020A from the bottom and the vessel filled at a rate of 50 cu m/day. The treater was filled in batch (i.e., it was filled and held, then filled and held).

As the treater was being filled with water, displaced gas flowed to flare via piping connected to the flare header. A temporary level bridle on the treater indicated the water level. When the tower came close to being completely filled, a dedicated operator diverted excess water and gasses to the sealed bins provided by Normcan.

It took 9 hr to fill the treater, which included the holding duration. Once the tower was completely flooded, it was drained. Nitrogen was introduced at the top of the tower to force the water out and into the sealed bin. That process took 1.75 hr.

The second treater, V-3020B, was filled at a slower but continuous rate in 6 hr at 33 cu m/day. This treater was also allowed to overflow to the storage bins, before filling was stopped. The drain process was the same as for treater V-3020A.

During the job execution, two aspects did not proceed as planned:

• Although the operations engineer had calculated a flow rate for flooding, the rate could not be maintained because it was too low to control with a ball valve. The calculated flooding rate based on the contractor's recommendation may not have been the preferred flow rate for this job.

• Much time and energy was invested in installing temporary piping and hose connection to flare to accommodate the substantial exothermic reaction that had been anticipated. The temporary 50.8 mm piping and hose connection were not used to direct steam generated to flare. Instead, the existing 25.4 mm piping was used to route expelled gasses and steam to flare. After further discussion, it was believed that the waterflood rate was sufficient to dampen the exothermic reaction.

Waste management

Normcan dealt with all solid waste generated throughout the job, placing all used gaskets and mesh screen into the bin, together with disposable Tyvek coveralls, disposable gloves, boot covers, and HEPA P-100 cartridges. Normcan removed the bin for disposal.

Once wastewater was drained from the treaters into the sealed bins, Normcan tested the bin externally with the Ludlum 3-97 scintillator. Absence of readings above the background radiation allowed for the disposal of the water into Jumping Pound's sour-water disposal well.

Spent molecular sieve was vacuumed from the vessels to the sealed bins, which were transported away by Normcan. Although field readings measured on the spent molecular sieve were below the UDRL, it was suspected that the molecular-sieve pellets might not meet the limit. The radiation safety officer suspected field readings below the UDRL due to the geometric shape of the pellets, absorption of the particles into the molecular sieve itself, and potential shielding of beta particles from the field detector due to other contaminates surrounding the pellets.

Thus, a laboratory analysis verified the contamination levels, confirming that the spent molecular sieve exceeded the UDRL threshold requiring NORM-specific waste-management practices as outlined by Health Canada's NORM Guidelines. Two samples of spent molecular sieve that were analyzed showed 1.0 Bq/g and 2.1 Bq/g of Lead 210. Since the samples showed readings greater than the unrestricted release limit of 0.3 Bq/g, the spent molecular sieve was not sent to an industrial landfill but to a salt cavern in Unity, Sask.

Lessons

After the molecular-sieve replacement job ended successfully, a review focused on lessons from the job.

• Bringing in an external contractor with experience in dealing with NORM contamination was the right decision. Normcan not only provided expertise in controlling NORM hazards, it also provided excellent education and confidence to workers. Involving Normcan, UOP, and Catalyst Services during planning phase contributed to the success of the job; having Normcan on site before the job execution greatly helped the planning group determine logistics details.

The personal protection equipment

used throughout the job worked well in terms of:

—Eliminating workers' contact with NORM-contaminated dust and equipment.

—Workers feeling comfortable with their tasks.

—Providing confidence to workers to perform the job.

—The deactivation method of waterflooding had proven to minimize personnel exposure to NORM-contaminated dust. The continuous fill method of treater V-3020B proved to be more successful than the fill and hold method of treater V-3020A.

On V-3020A, spent molecular sieve in the upper layers of the bed was easily removed. The pellets, however, were progressively wetter down the vessel. Towards its bottom, the pellets were stuck together and had hardened to a consistency similar to wet clay. This prevented use of a vacuum and led workers to resort to jackhammers. As a result, the job fell behind schedule by a few hours.

On the other hand, the spent molecular sieve in V-3020B was not soggy and thus was easily removed. Because water was immediately drained as soon as the vessel was fully flooded, however, the bed did not have sufficient time to cool.

Its top was too hot for workers to stand on in order to insert the vacuum hose for removal. A Raytek temperature gun measured the top layer of the bed at 95° C. The temperature subsided progressively down the vessel. The high temperature also resulted in a delay of a few hours.

It was hence determined a combination of the two flooding methods would have achieved greater success: continuous fill and a short hold once the vessel was fully flooded before draining the vessel.

• Qualified radiation protection personnel should be used on field test equipment. This equipment only provides information to determine if a laboratory analysis is required to verify if waste meets the UDRL. Lab analysis should be performed to confirm disposal options.

Acknowledgment

Special appreciation is due Cody Cuthill of Normcan, Gerry Nell of UOP, and Mike Hatch of Catalyst Services for supporting the molecular-sieve replacement job and the writing this article. Special thanks and recognition are also due Joanna Williams, Harvey Malino, Greg Hanlon, and Stacey Ferrara for supporting the writing of this article. ✦

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2. Cuthill, Cody, NORM Safety Training. 2nd Ed. Canada: Enform Canada, February 2008.

The authors

JoAnn Tan (JoAnn.Tan@shell.com) has worked at Shell Canada's Jumping Pound gas plant as an operations engineer for 3 years and has gained operating experience in the sulfur recovery, amine, and cryogenic fractionation units. Tan holds a bachelors in chemical and biological engineering (2006) from the University of British Columbia.

Denis Pelletier (Denis.Pelletier@shell.com) is a turnaround planner at Shell Canada's Jumping Pound gas plant. He graduated from the SAIT Power Engineering program in 1988 and has been employed with operations at the Shell Canada's Jumping Pound gas plant.

How Nelson-Farrar indexes of chemical costs have changed

Gary Farrar
Contributing Editor

NELSON-FARRAR INDEXES OF CHEMICAL COSTS

Year, quarter	Inorganic	Hydrofluoric acid	Sulfuric acid	Platinum	Sodium carbonate	Sodium hydroxide
2006						
1st	648.9	414.9	397.4	1,140.8	427.5	586.2
2nd	692.8	414.9	397.4	1,336.0	456.4	625.3
3rd	691.2	414.9	397.4	1,434.3	455.3	624.1
4th	714.2	414.9	397.4	1,466.4	470.5	644.9
Year	**686.8**	**414.9**	**397.4**	**1,344.4**	**452.4**	**620.1**
2007						
1st	706.5	414.9	397.4	1,422.1	465.3	637.9
2nd	725.8	414.9	397.4	1,621.1	479.1	656.6
3rd	759.7	414.9	397.4	1,577.7	500.5	685.5
4th	782.2	414.9	397.4	1,610.3	515.4	706.6
Year	**743.6**	**414.9**	**397.4**	**1,557.8**	**490.1**	**671.7**
2008						
1st	834.6	414.9	397.4	1,593.1	549.9	753.7
2nd	1,041.2	414.9	397.4	1,768.7	686.1	940.1
3rd	1,135.9	414.9	397.4	1,621.5	748.5	1,025.5
4th	1,167.7	414.9	397.4	1,114.7	769.6	1,054.4
Year	**1,044.9**	**414.9**	**397.4**	**1,524.5**	**688.5**	**943.4**

The costs of two important chemicals used in crude-oil refining changed very little during 2006-08, while the costs of three others varied significantly.

The two stable chemicals were hydrofluoric acid with an index constant of 414.9 and sulfuric acid with an index average of 397.4.

Platinum rose significantly to 1,768.7 from 762.1 in the first quarter of 2006 before falling back to 1,114 in the last quarter of 2008. However, the average for 2006 was 1,344.4 vs. the 1,524.5 average for 2008.

Sodium hydroxide rose to 1,054.4 in fourth-quarter 2008 from 586.2 in first-quarter 2006.

Sodium carbonate ended at 769.6 in fourth-quarter 2006 after rising mildly from 427.5 in first-quarter 2004.

During 2006-08, sodium carbonate averaged 452.4, 490.1, and 688.5 for the 3 years, respectively.

The Nelson-Farrar overall inorganic chemical index showed an increase throughout the period, varying from 648.9 during first-quarter 2006 to 1,167.7 in fourth-quarter 2008. ✦

ITEMIZED REFINING COST INDEXES

The cost indexes may be used to convert prices at any date to prices at other dates by ratios to the cost indexes of the same date. Item indexes are published each quarter (first week issue of January, April, July, and October). In addition the Nelson Construction and Operating Cost Indexes are published in the first issue of each month of Oil & Gas Journal.

Operating cost (based on 1956 = 100.0):	1954	1972	2006	2007	2008	Feb. 2009	*References	Index for earlier year in Costimating and Questions on Technology issues
Power, industrial electrical	98.5	131.2	850.2	897.3	939.2	939.6	Code 0543	No. 13, May 19, 1958
Fuel, refinery price	85.5	152.0	1,523.6	1,497.0	1,821,7	940.3	OGJ	No. 4, Mar. 17, 1958
Gulf cargoes	85.0	130.4	2,023.9	1,968.0	2,755.5	1,281.6	OGJ	No. 4, Mar. 17, 1958
NY barges	82.6	169.6	1,837.5	2,066.9	2,829.7	1,599.3	OGJ	No. 4, Mar. 17, 1958
Chicago low sulfur	—	—	1,765.8	2,046.7	2,754.0	1,524.5	OGJ	July 7, 1975
Western US	84.3	168.1	2,358.1	2,704.2	3,642.4	1,736.4	OGJ	No. 4, Mar. 17, 1958
Central US	60.2	128.1	1,765.9	1,886.9	2,615.7	1,191.7	OGJ	No. 4, Mar. 17, 1958
Natural gas at wellhead	83.5	190.3	6,306.5	6,118.7	7,260.5	3,761.3	Code 531-10-1	No. 4, Mar. 17, 1958
Inorganic chemicals	96.0	123.1	686.8	743.6	1,044.9	1,264.8	Code 613	Oct. 5, 1964
Acid, hydrofluoric	95.5	144.4	414.9	414.9	414.9	414.9	Code 613-0222	Apr. 3, 1963
Acid, sulfuric	100.0	140.7	397.4	397.4	397.4	439.1	Code 613-0281	No. 94, May 15, 1961
Platinum	92.9	121.1	1,344.5	1,557.8	1,524.5	920.5	Code 1022-02-73	July 5, 1965, p. 117
Sodium carbonate	90.9	119.4	452.4	490.1	688.5	833.4	Code 613-01-03	No. 58, Oct. 12, 1959
Sodium hydroxide	95.5	136.2	620.1	671.6	943.4	1,142.3	Code 613-01-04	No. 94, May 15, 1961
Sodium phosphate	97.4	107.0	733.7	733.7	733.7	733.7	Code 613-0267	No. 58, Oct. 12, 1959
Organic chemicals	100.0	87.4	764.5	799.9	958.1	687.3	Code 614	Oct. 5, 1964
Furfural	94.5	137.5	1,103.1	1,174.1	1,382.7	991.9	Chemical Marketing Reporter	No. 58, Oct. 12, 1959
MEK, tank-car lots	82.6	87.5	625.0	625.0	625.0	625.0	Reporter	
Phenol	90.4	47.1	374.9	413.0	479.4	500.3	Code 614-0241	No. 58, Oct. 12, 1959

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Itemized refining cost indexes

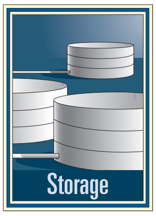
Operating cost (based on 1956 = 100.0):	1954	1972	2006	2007	2008	Feb. 2009	*References	Index for earlier year in Costimating and Questions on Technology issues
Operating labor cost (1956 = 100)								
Wages & benefits	88.7	210.0	1,015.4	1,042.8	1,092.2	1,141.2	Employ & Earn	No. 41, Feb. 16, 1969
Productivity	97.2	197.0	497.5	483.4	460.8	440.5	Employ & Earn	No. 41, Feb. 16, 1969
Construction labor cost (1946 = 100)								
Skilled const.	174.6	499.9	2,240.7	2,344.4	2,434.3	2,501.1	Eng. News Record	No. 55, Nov. 3, 1949
Common labor	192.1	630.6	2,971.7	3,083.0	3,200.4	3,313.6	Eng. News Record	No. 55, Nov. 3, 1949
Refinery cost	183.3	545.9	2,497.8	2,601.4	2,704.3	2,785.5	OGJ	May 15, 1967
Equipment or materials (1946 = 100):								
Bubble tray	161.4	324.4	1,484.0	1,561.4	1,737.8	1,570.5	Computed	July 8, 1962, p. 113
Building materials (nonmetallic)	143.6	212.4	969.6	1,003.2	1,065.3	1,104.0	Code 13	No. 61, Dec. 15, 1949
Brick—building	144.7	252.5	1,408.6	1,429.1	1,427.6	1,436.2	Code 1342	No. 20, Mar. 3, 1949
Brick—fireclay	193.1	322.8	1,540.5	1,616.2	1,742.9	1,939.7	Code 135	May 30, 1955
Castings, iron	188.1	274.9	1,351.3	1,414.3	1,576.6	1,577.8	Code 1015	Apr. 1, 1963
Clay products (structural, etc.)	159.1	342.0	951.6	963.2	972.9	979.2	Code 134	No. 20, Mar. 3, 1949
Concrete ingredients	141.1	218.4	1,092.0	1,172.2	1,231.3	1,259.3	Code 132	No. 22, Mar. 17, 1949
Concrete products	138.5	199.6	921.1	961.6	997.3	1,028.5	Code 133	Oct. 2, 1967, p. 112
Electrical machinery	159.9	216.3	520.2	517.3	515.6	516.4	Code 117	May 2, 1955
Motors and generators	157.7	211.0	880.3	917.1	964.2	989.8	Code 1173	May 2, 1955
Switchgear	171.2	271.0	1,147.3	1,212.2	1,254.4	1,275.8	Code 1175	May 2, 1955
Transformers	161.9	149.3	612.5	696.9	766.4	733.6	Code 1174	No. 31, May 19, 1949
Engines (combustion)	150.5	233.3	959.7	974.6	990.9	1,019.3	Code 1194	No. 36, June 23, 1949
Exchangers (composite)	171.7	274.3	1,162.7	1,342.2	1,354.6	1,253.8	Manufacturer	Mar. 16, 1964
Copper base	190.7	266.7	1,059.4	1,201.8	1,221.6	1,161.0	Manufacturer	Mar. 16, 1964
Carbon steel	156.8	281.9	1,162.1	1,344.7	1,369.2	1,287.3	Manufacturer	Mar. 16, 1964
Stainless steel (304)	—	—	1,174.8	1,322.1	1,319.5	1,183.0	Manufacturer	July 1, 1991
Fractionating towers	151.0	278.5	1,207.2	1,274.3	1,379.5	1,348.6	Computed	June 8, 1963, p. 133
Hand tools	173.8	346.5	1,792.5	1,830.6	1,918.2	1,988.2	Code 1042	June 27, 1955
Instruments								
(composite)	154.6	328.4	1,166.0	1,267.9	1,342.1	1,377.8	Computed	No. 34, June 9, 1949
Insulation (composite)	198.5	272.4	2,257.4	2,258.6	2,213.1	2,221.2	Manufacturer	July 4, 1988, p. 193
Lumber (composite):	197.8	353.4	1,309.8	1,204.1	1,134.5	1,031.2	Code 81	No. 7, Dec. 2, 1948
Southern pine	181.2	303.9	984.3	846.4	780.3	695.2	Code 81102	No. 7, Dec. 2, 1948
Redwood, all heart	238.0	310.6	1,948.1	1,744.3	1,607.9	1,434.0	Code 811-0332	July 5, 1965, p. 117
Machinery								
General purpose	159.9	278.5	1,213.7	1,271.8	1,338.9	1,381.1	Code 114	Feb. 17, 1949
Construction	165.9	324.4	1,559.7	1,594.4	1,645.6	1,699.8	Code 112	Apr. 1, 1968, p. 184
Oil field	161.9	269.1	1,599.1	1,715.8	1,858.8	1,896.9	Code 1191	Oct. 10, 1955
Paints—prepared	159.0	231.8	1,040.8	1,078.5	1,150.1	1,221.2	Code 621	May 16, 1955
Pipe								
Gray iron pressure	195.0	346.9	2,687.9	2,730.8	2,865.0	3,071.0	Code 1015-0239	Jan. 3, 1983
Standard carbon	182.7	319.9	2,306.9	2,299.2	2,904.9	2,727.3	Code 1017-0611	Jan. 3, 1983
Pumps, compressors, etc.	166.5	337.5	1,758.2	1,758.4	1,949.8	2,010.9	Code 1141	No. 29, May 5, 1949
Steel-mill products	187.1	330.6	1,527.5	1,620.0	1,973.5	1,490.1	Code 1017	Jan. 3, 1983
Alloy bars	198.7	349.4	1,311.8	1,239.7	1,469.8	1,128.9	Code 1017-0831	Apr. 1, 1963
Cold-rolled sheets	187.0	365.5	1,658.4	1,916.6	1,935.6	1,388.6	Code 1017-0711	Jan. 3, 1983
Alloy sheets	177.0	225.9	862.4	996.7	1,006.6	722.3	Code 1017-0733	Jan. 3, 1983
Stainless strip	169.0	221.2	920.7	1,064.2	1,074.7	771.0	Code 1017-0755	Jan. 3, 1983
Structural carbon, plates	193.4	386.7	1,766.6	1,945.3	2,383.6	1,910.4	Code 1017-0400	Jan. 3, 1983
Welded carbon tubing	180.0	265.5	2,337.3	2,329.6	2,943.2	2,763.6	Code 1017-0622	Jan. 3, 1983
Tanks and pressure vessels	147.3	246.4	1,014.3	1,076.4	1,160.7	1,174.1	Code 1072	No. 5, Nov. 18, 1949
Tube stills	123.0	125.3	579.9	612.0	714.1	591.2	Computed	Oct. 1, 1962
Valves and fittings	197.0	350.9	1,839.6	1,943.9	2,048.8	2,116.8	Code 1149	No. 46, Sept. 1, 1940
Nelson-Farrar Refinery (Inflation Index)								
(1946)	179.8	438.5	2,008.1	2,106.7	2,251.4	2,201.4	OGJ	May 15, 1969
Nelson-Farrar Refinery Operation								
(1956)	88.7	118.5	579.0	596.5	674.2	578.2	OGJ	No. 2, Mar. 3, 1958
Nelson-Farrar Refinery Process								
(1956)	88.4	147.0	870.7	872.6	1,045.1	705.7	OGJ	No. 2, Mar. 3, 1958

*Code refers to the index number of the Bureau of Statistics, US Department of Labor, "Wholesale Prices" Itemized Cost Indexes, Oil & Gas Journal.

Process control upgrade boosts system flexibility

Bertrand Viala
Siemens AG
Karlsruhe, Germany

Bernd Rastatter
Rosberg Engineering GMBH
Karlsruhe, Germany



Comprehensive modernization of process control systems at gas storage facilities can increase gas-transfer flexibility and shorten response times, even with existing field equipment. Wingas undertook such upgrades on the largest underground gas storage site in Europe: Rehden in Lower Saxony, Germany (Fig. 1).

Background

Until recently storage facilities acted purely as a compensating buffer between producer and consumer, making up for seasonal fluctuations in demand for natural gas. During cold months of the year, European demand can rise to 10-15 times its summer level. Extraction of natural gas, however, is a continuous process, transport via high-pressure pipelines is more efficient without interruption, and import quantities are often agreed for long terms.

German domestic production of natural gas barely covers one-fifth of its demand, which continues to rise, increasing dependence on imported gas. In this context, natural gas storage facilities help ensure a permanent supply of energy. The ongoing liberalization of Europe's natural gas market has heightened the role of storage facilities in terms of energy policy; non-discriminating access to the gas supply network requiring access to storage facilities.

Free access for third parties and increased natural gas spot and futures trading require the supply of large amounts of natural gas at short notice, creating a new situation for storage operators and requiring increasingly flexible approaches in running their facilities.

Rehden

More than 600 operational natural gas storage facilities operate worldwide, with a working capacity of about 340 bcm.[1] Roughly 25% of the storage facilities are in Europe, storing more than 60% of the world's total working gas.[1] Germany is the largest storage nation in Europe and the fourth largest in the world. The Rehden natural gas facility is about 60 km south of Bremen. Wintershall AG discovered and developed the original field in the 1950s.

Rehden field produced well into the 1990s. A large part of the main dolomite formation now stores natural gas (Fig. 2) transported to Rehden via pipeline. About 4.2 billion cu m (bcm) is available as usable working gas, enough

With only 16 wells for its 7 billion cu m capacity, Rehden uses horizontally drilled wells tied back to this central location for injection and offtake (Fig. 1).

to supply roughly 2 million single-family homes for an entire year.

Wingas GMBH & Co. KG operates the Rehden storage facility (Fig. 3, box). The company is a joint venture with Wintershall Holding AG owning 50.02% and OAO Gazprom 49.98%.

Process control

Maximum natural pressure of the Rehden gas reservoir is 280 bar. Injection therefore requires operating pressures between 110 bar and 280 bar, achieved with five gas-operated turbines and two electrically powered compressors. Start-up included installation of a Linux-based Aprol Scada with a cascading and redundant method of operation. The supervisory control and data acquisition system (SCADA) also monitors probes for injection and offtake processes and ensures adherence to safe pressure levels, temperatures, and other operating values. Proprietary programmable logic controllers monitor the compressors.

When changes in the gas market required more flexible operations management, Wingas hired automation specialists Rosberg Engineering GMBH to modernize instrumentation and control systems. Besides meeting its general future needs, Wingas sought a system with short commissioning times that could use existing field technology and retain its working environment. Participants selected Siemens Simatic PCS 7 process control system, which was easily adaptable ro Rehden facility by Rosberg.

Replacement of the S5 systems with S7-400 automation systems and continued use of the same I/O modules allowed use of existing wiring. This approach also ensured the deadlines set by Wingas could be met.

Wingas allowed Rosberg three times 2 weeks conversion time in situ and a 4-week total shutdown of the natural gas storage facility. At an early stage Rosberg said it could shorten the shutdown by at least 2 weeks, persuading Wingas that PCS 7 AS-417 controllers would result in greater economic efficiency and a more capable system. The 16 new automation systems replaced various subsystems, lowering both preventive and corrective maintenance costs and total cost of ownership (TCO).

Plant operators

Plant operators in Rehden wanted everything to remain as it was, having been satisfied with the Aprol system for years. The flexibility of the new process control system would have allowed adaptation to an extent requiring only minimal changes in the operating philosophy. But this would have negated many of the system's advantages and functional additions.

Introducing the new system as it stood, however, would have required a corresponding amount of training.

Rosberg rejected both approaches, relying instead on presentations to show the framework Simatic PCS 7 would offer and its advantages for operating personnel. The system's Faceplate technique increased comfort and enabled standardization of user interfaces, offering the same control facilities for operator control, visualization, alarm displaying, etc., in respect to components of the same type.

Establishing a model project on a server at Rosberg for the operating team to access remotely followed initial presentations. Moderator-supported sessions exposed operators to PCS 7 while at the same time clarifying their requirements. Knowledge gained flowed back into engineering planning for the new system.

This process and the use of extensive software-aided simulation shortened the time needed on site for adaptation to the dynamic processes. The entire operating team also became familiar with the new operator control system well in advance, allowing personnel to start working immediately on it without additional training.

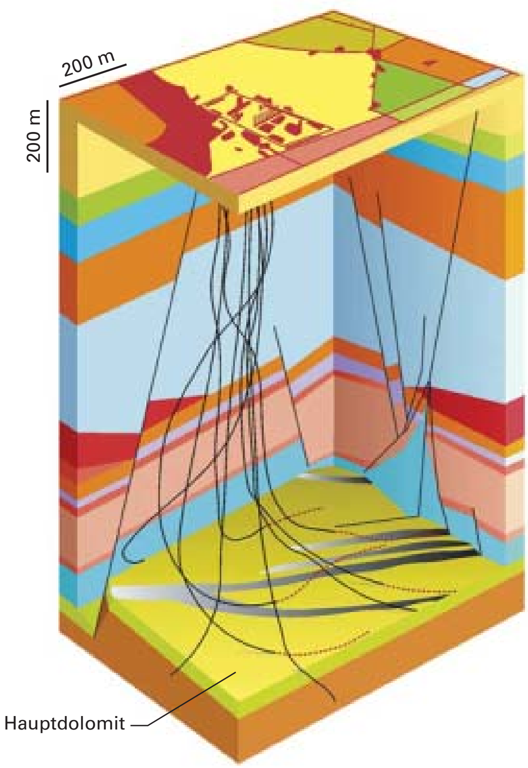
Implementation

Cooperation between operating personnel, project management, and project engineers allowed Rosberg to get even further ahead of schedule. IT specialists linked the new process control system to existing doubly redundant bus systems. Switches allowed building different logical networks by way of the same physical layer. Reuse of both the system bus and the terminal bus occurred despite the change in systems and temporary joint use of both at the same time.

Rosberg turned the 4-week shutdown period originally stipulated by Wingas into 3 days of restricted opera-

REHDEN STORAGE WELLS

Fig. 2



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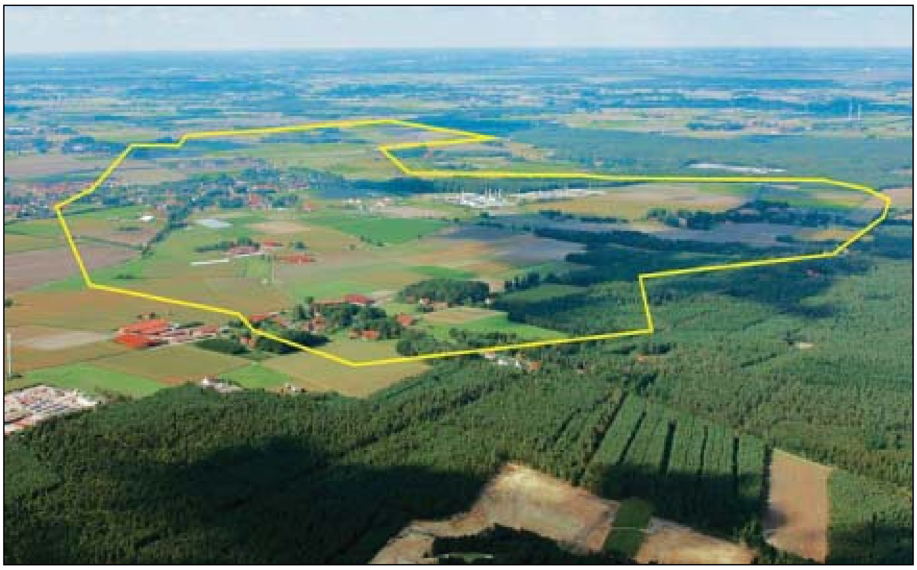

The natural gas storage facility covers 8 sq km in Rehden, Lower Saxony, Germany. Gas is stored at roughly 2,000 m (Fig. 3).

tions, completing the project entirely without shutdown time and within stipulated cost and specifications.

Rehden now runs a modern and completely integrated process control

Rehden natural gas storage facility

Storage area:	8 sq km
Storage volume:	7 billion cu m
Working gas:	4.2 billion cu m
Cushion gas:	2.8 billion cu m
Storage depth:	1,900-2,100 m
Working pressure:	110-280 bar
Maximum discharge rate:	2.4 million cu m/hr

system with the field-level equipment already on hand. A central control room now runs and monitors all aspects of storage facility operations via seven operator stations. In addition to the compressors, the DCS controls probes, gas processing and drying, protection and security systems, 30-kv switchgear, and the fire alarm system; processing and recording more than 4,000 process values (about 30,000 process variables).

The telecontrol application, implemented in accordance with IEC 60870 and integrated into the process control system, allows secure access to the storage facility for central dispatching from Wingas headquarters in Kassel. Operator interface with equipment is the same whether they are inside or outside the facility.

Rosberg specialists used a standard chemistry software library for Rehden, adapting components only where absolutely necessary and keeping as close to the standard as possible. This has improved profitability by removing the need for reconfiguration during upgrades. Using DCS Simatic PCS 7 also prepared the facility—in a future step—to move between gas injection and offtake in the same day, a process that used to take several weeks. ✦

Reference

1. International Gas Union (2006): Working Committee 2, www.igu.org/html/wgc2006/WOC2database/index.htm.

The authors

Betrand Viala (bertrand.viala@siemens.com) is PCS 7 partner manager at Siemens AG's industrial automation systems business unit. He holds mechanical engineering degrees from the University of Karlsruhe and the ENSAM in France.

Bernd Rastatter (bernd.rastatter@roesberg.com) is general sales manager at Rosberg Engineering GMBH's automation and IT division.

Equipment/Software/Literature

New system provides oil field rescue

Here's the new Rollgliss R500 rescue and escape device, a system that offers controlled descent, self-rescue, emergency evacuation, and assisted rescue with lifting capabilities.

To ensure quick and safe rescue, the R500 features controlled descent speeds of 2-3 fps. Its bidirectional design allows one end of the lifeline to descend while the other ascends to prepare for another rescue. The compact and lightweight device can be positioned and installed quickly, and easy operation enables efficient and effective rescue, the firm notes.

The system is suited for self-rescue, multiple evacuations, and assisted rescue on offshore and onshore oil field locations.

For maximum durability and performance, the device is designed with high-quality and corrosion resistant materials, as well as 9.5 mm superstatic kernmantle rope available in 25 ft increments between 50 and 1,000 ft in length. The rope is configured with connecting hardware at each end of the lifeline for bidirectional rescue. The system can be used at heights of as much as 1,000 ft for a single user weighing 310 lb or less or 330 ft for two users totaling 550 lb or less.

The R500 meets all applicable industry standards, including OSHA and ANSI Z359.4-2007, and is available in five models. Each model includes the Rollgliss R500 descender, rope, three anchoring slings, three carabiners, pulley, edge protector, rope grab, and carrying bag. Additional options are a rescue hub, ladder bracket, and humidity-resistant case.

Source: **Capital Safety,** 3833 Sala Way, Red Wing, MN 55066-5005.

New oil field seal

This new seal is designed to help increase uptime and efficiency by as much 150% in oil field equipment.

The seal consists of a spring-energized, graphite-reinforced PTFE sealing ring coupled with a high-temperature engineered thermoplastic antiextrusion element and a metal locking ring. The maker says the seal has been successfully tested and proved to deliver superior performance in progressive cavity pumps. Other potential applications include top drives, mud pumps, downhole tools, and high-speed rotary devices.

Its all-in-one configuration protects it against wear and extrusion and helps make it resistant to oil field fluids and gases, the firm points out.

Source: **Bal Seal Engineering Inc.,** 19650 Pauling, Foothill Ranch, CA 92610.

IMPORTS OF CRUDE AND PRODUCTS

	Districts 1–4 6-12 2009	Districts 1–4 6-5 2009	District 5 6-12 2009	District 5 6-5 2009	Total US 6-12 2009	Total US 6-5 2009	Total US *6-13 2008
	1,000 b/d						
Total motor gasoline	925	960	24	45	949	1,005	1,310
Mo. gas. blending comp.	643	695	24	45	667	740	916
Distillate	159	203	49	0	208	203	211
Residual	383	454	44	34	427	488	216
Jet fuel–kerosine	75	60	27	13	102	73	162
Propane–propylene	86	128	2	4	88	132	111
Other	515	515	(25)	11	490	526	349
Total products	**2,786**	**3,015**	**145**	**152**	**2,931**	**3,167**	**3,275**
Total crude	**8,448**	**7,873**	**1,198**	**905**	**9,646**	**8,778**	**9,786**
Total imports	**11,234**	**10,888**	**1,343**	**1,057**	**12,577**	**11,945**	**13,061**

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

PURVIN & GERTZ LNG NETBACKS—JUNE 19, 2009

Receiving terminal	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	Liquefaction plant, $/MMbtu					
Barcelona	6.74	4.72	5.95	4.62	5.28	5.87
Everett	3.33	1.55	2.99	1.65	1.89	3.59
Isle of Grain	2.95	1.24	2.40	1.17	1.65	2.41
Lake Charles	1.50	–0.07	1.32	0.08	0.25	2.03
Sodegaura	3.41	5.48	3.67	5.21	4.55	3.07
Zeebrugge	4.67	2.52	4.04	2.41	3.11	4.09

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

CRUDE AND PRODUCT STOCKS

District	Crude oil	Motor gasoline Total	Motor gasoline Blending comp.[1]	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane–propylene
	1,000 bbl						
PADD 1	14,394	52,575	35,465	11,057	59,846	16,699	4,120
PADD 2	84,676	47,182	21,590	8,099	32,313	1,233	19,643
PADD 3	190,743	70,246	39,714	12,336	42,265	17,519	26,357
PADD 4	17,218	5,592	1,931	673	2,916	382	[1]1,117
PADD 5	58,946	27,607	21,836	9,208	12,696	4,299	—
June 12, 2009	**365,977**	**203,202**	**120,536**	**41,373**	**150,036**	**40,132**	**51,237**
June 5, 2009	**363,111**	**203,417**	**120,128**	**40,449**	**148,375**	**38,468**	**49,352**
June 13, 2008[2]	**306,757**	**209,090**	**103,474**	**39,751**	**111,704**	**38,166**	**38,002**

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

REFINERY REPORT—JUNE 12, 2009

District	Refinery operations Gross inputs	Refinery operations Crude oil inputs	Refinery output Total motor gasoline	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane–propylene
	1,000 b/d		1,000 b/d				
PADD 1	1,279	1,283	2,306	62	367	139	50
PADD 2	3,251	3,230	2,033	185	875	42	263
PADD 3	7,417	7,118	2,820	645	2,153	279	662
PADD 4	561	558	285	27	153	12	[1]63
PADD 5	2,735	2,536	1,353	415	504	129	—
June 12, 2009	**15,243**	**14,725**	**8,797**	**1,334**	**4,052**	**601**	**1,038**
June 5, 2009	**15,040**	**14,733**	**9,378**	**1,439**	**4,036**	**552**	**1,072**
June 13, 2008[2]	**15,785**	**15,480**	**9,113**	**1,566**	**4,506**	**710**	**1,126**
	17,672 Operable capacity		**86.3% utilization rate**				

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

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

OGJ CRACK SPREAD

	*6-19-09	*6-20-08	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	79.80	146.91	–67.10	–45.7
Brent crude	69.75	133.67	–63.92	–47.8
Crack spread	10.06	13.24	–3.18	–24.0
FUTURES MARKET PRICES				
One month				
Product value	81.63	150.08	–68.45	–45.6
Light sweet crude	70.61	134.37	–63.76	–47.5
Crack spread	11.02	15.71	–4.69	–29.9
Six month				
Product value	80.08	148.23	–68.15	–46.0
Light sweet crude	73.96	135.85	–61.89	–45.6
Crack spread	6.12	12.38	–6.26	–50.6

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

OGJ GASOLINE PRICES

	Price ex tax 6-17-09	Pump price* 6-17-09	Pump price 6-18-08
		¢/gal	
(Approx. prices for self-service unleaded gasoline)			
Atlanta	204.1	250.6	414.2
Baltimore	206.7	248.6	403.1
Boston	210.6	252.5	405.9
Buffalo	202.6	263.5	421.1
Miami	216.8	268.4	423.3
Newark	207.1	239.7	395.7
New York	197.5	258.4	413.0
Norfolk	201.2	239.6	395.4
Philadelphia	208.9	259.6	413.9
Pittsburgh	206.9	257.6	403.3
Wash., DC	221.3	259.7	414.2
PAD I avg	207.6	254.4	409.4
Chicago	244.7	309.1	442.7
Cleveland	230.9	277.3	396.8
Des Moines	228.0	268.4	397.6
Detroit	233.7	293.1	408.7
Indianapolis	220.8	280.2	398.4
Kansas City	216.5	252.5	394.6
Louisville	234.4	275.3	402.3
Memphis	210.8	250.6	387.1
Milwaukee	234.9	286.2	411.2
Minn.-St. Paul	227.4	271.4	399.8
Oklahoma City	220.0	255.4	384.1
Omaha	220.0	265.3	394.0
St. Louis	215.5	251.5	392.2
Tulsa	213.1	248.5	382.3
Wichita	213.1	256.5	375.4
PAD II avg	224.2	269.4	397.8
Albuquerque	215.6	252.0	387.5
Birmingham	207.7	247.0	395.3
Dallas-Fort Worth	212.5	250.9	400.2
Houston	208.6	247.0	392.3
Little Rock	204.8	245.0	393.7
New Orleans	208.7	247.1	397.2
San Antonio	202.8	241.2	390.3
PAD III avg	208.7	247.2	393.8
Cheyenne	213.0	245.4	390.9
Denver	214.6	255.0	402.5
Salt Lake City	208.1	251.0	400.2
PAD IV avg	211.9	250.5	397.9
Los Angeles	221.5	288.6	453.8
Phoenix	212.2	249.6	420.2
Portland	227.6	271.0	429.4
San Diego	223.7	290.8	462.7
San Francisco	231.7	298.8	458.1
Seattle	228.8	284.7	438.3
PAD V avg	224.3	280.6	443.8
Week's avg.	**216.4**	**262.0**	**406.7**
May avg.	**179.0**	**224.6**	**372.9**
Apr. avg.	**156.7**	**202.3**	**339.3**
2009 to date	**159.6**	**205.2**	—
2008 to date	**292.9**	**336.3**	—

*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

Spot market product prices

	6-12-09 ¢/gal
Motor gasoline (Conventional-regular)	
New York Harbor	200.25
Gulf Coast	198.75
Los Angeles	212.25
Amsterdam-Rotterdam-Antwerp (ARA)	203.25
Singapore	190.29
Motor gasoline (Reformulated-regular)	
New York Harbor	206.75
Gulf Coast	201.25
Los Angeles	222.75

	6-12-09 ¢/gal
Heating oil No. 2	
New York Harbor	180.25
Gulf Coast	178.38
Gas oil	
ARA	182.97
Singapore	187.50
Residual fuel oil	
New York Harbor	144.95
Gulf Coast	156.02
Los Angeles	160.19
ARA	146.61
Singapore	147.14

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

BAKER HUGHES RIG COUNT

	6-19-09	6-26-08
Alabama	5	3
Alaska	4	6
Arkansas	44	47
California	24	43
Land	23	43
Offshore	1	0
Colorado	44	113
Florida	1	1
Illinois	1	0
Indiana	2	1
Kansas	16	9
Kentucky	8	11
Louisiana	137	172
N. Land	79	67
S. Inland waters	6	21
S. Land	11	26
Offshore	41	58
Maryland	0	1
Michigan	0	1
Mississippi	9	13
Montana	0	12
Nebraska	0	0
New Mexico	37	80
New York	2	7
North Dakota	36	70
Ohio	8	13
Oklahoma	77	207
Pennsylvania	40	20
South Dakota	0	2
Texas	330	916
Offshore	1	12
Inland waters	0	2
Dist. 1	14	26
Dist. 2	15	29
Dist. 3	25	65
Dist. 4	28	96
Dist. 5	77	178
Dist. 6	49	122
Dist. 7B	12	27
Dist. 7C	12	70
Dist. 8	47	138
Dist. 8A	9	28
Dist. 9	17	39
Dist. 10	24	84
Utah	15	42
West Virginia	20	26
Wyoming	31	76
Others—HI-1; NV-2; VA-5;	8	14
Total US	**899**	**1,906**
Total Canada	**143**	**259**
Grand total	**1,042**	**2,165**
US Oil rigs	196	384
US Gas rigs	692	1,514
Total US offshore	46	71
Total US cum. avg. YTD	**1,148**	**1,813**

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	6-19-09 Rig count	6-19-09 Percent footage*	6-26-08 Rig count	6-26-08 Percent footage*
0-2,500	44	9.0	89	3.3
2,501-5,000	66	62.1	147	48.2
5,001-7,500	110	17.2	253	14.6
7,501-10,000	200	7.0	483	3.5
10,001-12,500	171	4.6	476	2.7
12,501-15,000	154	0.6	322	—
15,001-17,500	106	—	127	—
17,501-20,000	49	—	73	—
20,001-over	30	—	35	—
Total	**930**	**9.3**	**2,005**	**7.0**
INLAND	11		32	
LAND	883		1,917	
OFFSHORE	36		56	

*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]6-19-09	[2]6-20-08
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	20	21
Alaska	685	662
California	650	648
Colorado	62	66
Florida	6	5
Illinois	27	26
Kansas	100	107
Louisiana	1,440	1,286
Michigan	15	16
Mississippi	61	60
Montana	94	85
New Mexico	165	162
North Dakota	195	157
Oklahoma	174	170
Texas	1,339	1,356
Utah	56	58
Wyoming	150	143
All others	66	78
Total	**5,305**	**5,106**

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

US CRUDE PRICES

	6-19-09 $/bbl*
Alaska-North Slope 27°	40.78
South Louisiana Sweet	69.50
California-Kern River 13°	61.15
Lost Hills 30°	66.90
Wyoming Sweet	59.05
East Texas Sweet	65.50
West Texas Sour 34°	60.00
West Texas Intermediate	66.00
Oklahoma Sweet	66.00
Texas Upper Gulf Coast	59.00
Michigan Sour	58.00
Kansas Common	65.00
North Dakota Sweet	56.50

*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]	6-12-09
United Kingdom-Brent 38°	69.41
Russia-Urals 32°	69.10
Saudi Light 34°	66.73
Dubai Fateh 32°	69.55
Algeria Saharan 44°	69.94
Nigeria-Bonny Light 37°	71.25
Indonesia-Minas 34°	72.64
Venezuela-Tia Juana Light 31°	69.21
Mexico-Isthmus 33°	69.10
OPEC basket	69.34
Total OPEC[2]	68.58
Total non-OPEC[2]	67.81
Total world[2]	68.24
US imports[3]	65.98

[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]

	6-12-09	6-5-09	6-12-08	Change, %
		bcf		
Producing region	985	957	667	**47.7**
Consuming region east	1,164	1,091	997	**16.8**
Consuming region west	408	395	279	**46.2**
Total US	**2,557**	**2,443**	**1,943**	**31.6**

	Apr. 09	Apr. 08	Change, %
Total US[2]	**1,903**	**1,436**	**32.5**

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

Statistics

Imports of crude and products

	Districts 1-4 6-19 2009	Districts 1-4 6-12 2009	District 5 6-19 2009	District 5 6-12 2009	Total US 6-19 2009	Total US 6-12 2009	Total US *6-20 2008
	1,000 b/d						
Total motor gasoline	955	1,045	16	45	971	1,090	1,162
Mo. gas. blending comp.	655	746	2	38	657	784	756
Distillate	289	191	0	0	289	191	107
Residual	179	247	27	70	206	317	335
Jet fuel-kerosine	78	38	20	13	98	51	114
Propane-propylene	93	120	2	3	95	123	79
Other	13	239	55	38	68	277	743
Total products	**2,262**	**2,626**	**122**	**207**	**2,384**	**2,833**	**3,296**
Total crude	**8,370**	**7,784**	**914**	**1,253**	**9,284**	**9,037**	**10,251**
Total imports	**10,632**	**10,410**	**1,036**	**1,460**	**11,668**	**11,870**	**13,547**

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

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

OIL&GAS JOURNAL online research center.

OGJ crack spread

	*6-26-09	*6-27-08	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	74.28	147.61	–73.33	–49.7
Brent crude	67.98	137.15	–69.17	–50.4
Crack spread	6.30	10.46	–4.16	–39.8
FUTURES MARKET PRICES				
One month				
Product value	76.58	151.66	–75.08	–49.5
Light sweet crude	68.85	137.63	–68.78	–50.0
Crack spread	7.74	14.03	–6.29	–44.9
Six month				
Product value	77.21	150.61	–73.40	–48.7
Light sweet crude	72.06	138.47	–66.41	–48.0
Crack spread	5.15	12.14	–7.00	–57.6

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

Purvin & Gertz LNG netbacks—June 26, 2009

Receiving terminal	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	Liquefaction plant $/MMbtu					
Barcelona	6.74	4.72	5.95	3.93	5.28	5.87
Everett	3.14	1.34	2.81	1.44	1.84	3.40
Isle of Grain	2.83	1.21	2.38	1.11	1.65	2.39
Lake Charles	1.37	–0.29	1.18	–0.14	0.05	1.87
Sodegaura	3.78	5.49	4.04	5.21	4.55	3.18
Zeebrugge	4.64	2.49	3.99	2.39	3.06	4.04

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

Crude and product stocks

District	Crude oil	Motor gasoline Total	Motor gasoline Blending comp.[1]	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane-propylene
	1,000 bbl						
PADD 1	14,085	54,761	36,605	10,233	62,152	15,754	3,837
PADD 2	81,673	49,756	24,255	7,766	32,458	1,266	23,014
PADD 3	184,664	69,899	39,299	14,086	42,777	15,969	29,102
PADD 4	17,053	5,915	2,089	578	3,041	215	[1]1,228
PADD 5	56,378	28,574	23,196	9,065	11,675	4,532	—
June 19, 2009	**353,853**	**208,905**	**125,444**	**41,728**	**152,103**	**37,736**	**57,181**
June 12, 2009	**357,721**	**205,034**	**123,387**	**41,800**	**150,026**	**37,824**	**53,529**
June 20, 2008[2]	**301,758**	**208,757**	**102,465**	**40,500**	**119,421**	**39,253**	**39,694**

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

Refinery report—June 19, 2009

District	Refinery operations Gross inputs	Refinery operations Crude oil inputs	Refinery output Total motor gasoline	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual	Propane-propylene
	1,000 b/d		1,000 b/d				
PADD 1	1,420	1,389	2,464	92	407	132	59
PADD 2	3,349	3,326	2,156	218	845	56	266
PADD 3	7,330	7,235	2,838	665	2,101	263	707
PADD 4	619	616	368	30	194	9	[1]62
PADD 5	2,666	2,465	1,398	438	522	137	—
June 19, 2009	**15,384**	**15,031**	**9,224**	**1,443**	**4,069**	**597**	**1,094**
June 12, 2009	**15,180**	**14,677**	**9,131**	**1,388**	**3,915**	**613**	**1,078**
June 20, 2008[2]	**15,588**	**15,258**	**9,057**	**1,614**	**4,588**	**573**	**1,086**
	17,672 Operable capacity		**87.1% 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 6-24-09	Pump price* 6-24-09	Pump price 6-25-08
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	211.6	258.1	414.7
Baltimore	214.2	256.1	404.0
Boston	218.2	260.1	406.9
Buffalo	210.2	271.1	422.0
Miami	224.5	276.1	424.0
Newark	214.6	247.2	396.2
New York	205.2	266.1	413.9
Norfolk	212.1	250.5	396.1
Philadelphia	216.4	267.1	414.6
Pittsburgh	215.1	265.8	404.0
Wash., DC	228.8	267.2	414.7
PAD I avg	215.5	262.3	410.1
Chicago	242.6	307.0	443.5
Cleveland	228.6	275.0	397.5
Des Moines	225.7	266.1	398.5
Detroit	231.6	291.0	409.5
Indianapolis	218.6	278.0	399.1
Kansas City	212.1	248.1	395.5
Louisville	232.1	273.0	402.7
Memphis	210.3	250.1	387.6
Milwaukee	232.7	284.0	411.7
Minn.-St. Paul	225.1	269.1	400.5
Oklahoma City	209.7	245.1	384.6
Omaha	207.1	252.4	394.6
St. Louis	210.4	246.4	392.7
Tulsa	204.7	240.1	383.0
Wichita	208.0	251.4	375.7
PAD II avg	219.9	265.1	398.5
Albuquerque	222.9	259.3	388.1
Birmingham	215.0	254.3	396.0
Dallas-Fort Worth	219.8	258.2	401.0
Houston	215.9	254.3	393.0
Little Rock	212.1	252.3	394.5
New Orleans	215.9	254.3	398.0
San Antonio	209.9	248.3	391.0
PAD III avg	215.9	254.4	394.5
Cheyenne	222.7	255.1	393.6
Denver	222.5	262.9	406.4
Salt Lake City	216.0	258.9	402.7
PAD IV avg	220.4	259.0	400.9
Los Angeles	229.0	296.1	457.2
Phoenix	219.7	257.1	424.0
Portland	234.9	278.3	432.4
San Diego	231.1	298.2	466.2
San Francisco	239.1	306.2	461.3
Seattle	236.3	292.2	441.4
PAD V avg	231.7	288.0	447.1
Week's avg.	**219.8**	**265.4**	**408.0**
June avg.	**214.6**	**260.2**	**404.2**
May avg.	**179.0**	**224.6**	**372.9**
2008 to date	**162.0**	**207.6**	—
2007 to date	**295.6**	**339.3**	—

*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

	6-19-09 ¢/gal
Spot market product prices	
Motor gasoline (Conventional-regular)	
New York Harbor	187.27
Gulf Coast	184.52
Los Angeles	188.65
Amsterdam-Rotterdam-Antwerp (ARA)	191.92
Singapore	188.31
Motor gasoline (Reformulated-regular)	
New York Harbor	193.77
Gulf Coast	186.52
Los Angeles	199.90

	6-19-09 ¢/gal
Heating oil No. 2	
New York Harbor	174.75
Gulf Coast	174.50
Gas oil	
ARA	178.17
Singapore	187.02
Residual fuel oil	
New York Harbor	142.93
Gulf Coast	159.00
Los Angeles	160.19
ARA	146.61
Singapore	153.00

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

Baker Hughes rig count

	6-26-09	6-27-08
Alabama	5	4
Alaska	6	6
Arkansas	44	54
California	22	43
Land	22	43
Offshore	0	0
Colorado	43	113
Florida	1	1
Illinois	1	1
Indiana	4	1
Kansas	19	10
Kentucky	9	11
Louisiana	135	178
N. Land	77	76
S. Inland waters	12	20
S. Land	7	30
Offshore	39	52
Maryland	0	1
Michigan	0	1
Mississippi	9	13
Montana	0	12
Nebraska	0	0
New Mexico	38	80
New York	2	5
North Dakota	37	71
Ohio	8	13
Oklahoma	79	200
Pennsylvania	43	21
South Dakota	0	2
Texas	338	915
Offshore	1	10
Inland waters	0	2
Dist. 1	12	24
Dist. 2	15	30
Dist. 3	25	60
Dist. 4	33	94
Dist. 5	73	185
Dist. 6	47	121
Dist. 7B	13	33
Dist. 7C	16	66
Dist. 8	53	138
Dist. 8A	8	29
Dist. 9	17	41
Dist. 10	25	82
Utah	16	42
West Virginia	20	26
Wyoming	30	76
Others—HI-1; NV-2; VA-5	8	13
Total US	**917**	**1,913**
Total Canada	**148**	**356**
Grand total	**1,065**	**2,269**
US Oil rigs	219	375
US Gas rigs	687	1,530
Total US offshore	43	64
Total US cum. avg. YTD	**1,139**	**1,817**

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 6-26-09	Percent footage* 6-26-09	Rig count 6-27-08	Percent footage* 6-27-08
0-2,500	40	5.0	91	3.2
2,501-5,000	69	60.8	147	46.9
5,001-7,500	114	20.1	252	15.8
7,501-10,000	203	5.4	477	3.1
10,001-12,500	178	7.8	481	2.7
12,501-15,000	147	—	329	—
15,001-17,500	111	—	132	—
17,501-20,000	49	—	83	—
20,001-over	29	—	38	—
Total	**940**	**9.7**	**2,030**	**6.8**
INLAND	11		33	
LAND	892		1,936	
OFFSHORE	37		61	

*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]6-26-09	[2]6-27-08
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	20	21
Alaska	667	655
California	647	647
Colorado	62	66
Florida	6	5
Illinois	28	26
Kansas	100	107
Louisiana	1,431	1,278
Michigan	15	15
Mississippi	60	60
Montana	93	85
New Mexico	164	162
North Dakota	190	157
Oklahoma	172	170
Texas	1,328	1,361
Utah	56	59
Wyoming	150	143
All others	66	76
Total	**5,255**	**5,093**

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

US crude prices

	6-26-09 $/bbl*
Alaska-North Slope 27°	40.78
South Louisiana Sweet	69.00
California-Kern River 13°	60.75
Lost Hills 30°	69.10
Wyoming Sweet	58.66
East Texas Sweet	65.25
West Texas Sour 34°	59.75
West Texas Intermediate	65.75
Oklahoma Sweet	65.75
Texas Upper Gulf Coast	58.75
Michigan Sour	57.75
Kansas Common	64.50
North Dakota Sweet	54.75

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

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

World crude prices

$/bbl[1]	6-19-09
United Kingdom-Brent 38°	69.70
Russia-Urals 32°	69.46
Saudi Light 34°	67.70
Dubai Fateh 32°	70.79
Algeria Saharan 44°	70.45
Nigeria-Bonny Light 37°	71.49
Indonesia-Minas 34°	74.03
Venezuela-Tia Juana Light 31°	70.04
Mexico-Isthmus 33°	69.93
OPEC basket	70.09
Total OPEC[2]	69.47
Total non-OPEC[2]	68.98
Total world[2]	69.25
US imports[3]	67.56

[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]

	6-19-09	6-12-09	6-19-08	Change, %
	bcf			
Producing region	997	985	682	**46.2**
Consuming region east	1,234	1,164	1,050	**17.5**
Consuming region west	420	408	288	**45.8**
Total US	**2,651**	**2,557**	**2,020**	**31.2**
	Apr. 09	**Apr. 08**	**Change %**	
Total US[2]	**1,903**	**1,436**	**32.5**	

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

Statistics

PACE REFINING MARGINS

	Apr. 2009	May 2009	June 2009	June 2008	– 2009 vs. 2008 – Change	Change, %
	$/bbl					
US Gulf Coast						
West Texas Sour	5.94	5.87	7.42	14.07	–6.66	–47.3
Composite US Gulf Refinery	3.93	5.30	6.93	13.66	–6.73	–49.2
Arabian Light	1.43	4.33	6.34	12.48	–6.15	–49.3
Bonny Light	3.04	3.66	6.17	3.71	2.46	66.4
US PADD II						
Chicago (WTI)	6.12	9.62	13.44	16.73	–3.29	–19.7
US East Coast						
NY Harbor (Arab Med)	3.70	10.73	10.57	9.33	1.24	13.3
East Coast Comp-RFG	3.35	5.92	6.45	7.62	–1.17	–15.3
US West Coast						
Los Angeles (ANS)	16.62	15.38	16.16	12.07	4.09	33.9
NW Europe						
Rotterdam (Brent)	1.81	1.66	0.97	1.10	–0.13	–11.5
Mediterranean						
Italy (Urals)	2.57	1.62	0.58	7.31	–6.73	–92.1
Far East						
Singapore (Dubai)	3.53	2.42	0.76	6.77	–6.01	–88.8

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

US NATURAL GAS BALANCE DEMAND/SUPPLY SCOREBOARD

	Apr. 2009	Mar. 2009	Apr. 2008	Apr. 2009-2008 change	Total YTD 2009	Total YTD 2008	YTD 2009-2008 change
	bcf						
DEMAND							
Consumption	1,736	2,155	1,814	–78	8,894	9,284	–390
Addition to storage	354	199	295	59	732	550	182
Exports	69	107	79	–10	400	398	2
Canada	43	79	47	–4	287	249	38
Mexico	24	24	28	–4	101	136	–35
LNG	2	4	4	–2	12	13	–1
Total demand	**2,159**	**2,461**	**2,188**	**–29**	**10,026**	**10,232**	**–206**
SUPPLY							
Production (dry gas)	1,732	1,796	1,679	53	3,938	6,764	–2,826
Supplemental gas	6	6	5	1	23	16	7
Storage withdrawal	107	296	106	1	1,653	1,997	–344
Imports	312	325	321	–9	1,319	1,424	–105
Canada	256	292	289	–33	1,170	1,313	–143
Mexico	0	1	0	0	7	3	4
LNG	56	32	32	24	142	108	34
Total supply	**2,157**	**2,423**	**2,111**	**46**	**6,933**	**10,201**	**–3,268**

NATURAL GAS IN UNDERGROUND STORAGE

	Apr. 2009	Mar. 2009	Feb. 2009	Apr. 2008	Change
	bcf				
Base gas	4,252	4,246	4,242	4,223	29
Working gas	1,903	1,656	1,761	1,436	467
Total gas	**6,155**	**5,902**	**6,003**	**5,659**	**496**

Source: DOE Monthly Energy Review.
Data available in OGJ Online Research Center.

WORLDWIDE NGL PRODUCTION

	Mar. 2008	Feb. 2008	3 month average production 2009	3 month average production 2008	Change vs. previous year Volume	Change vs. previous year %
	1,000 b/d					%
Brazil	81	83	82	87	–5	–5.3
Canada	639	663	649	693	–44	–6.3
Mexico	374	364	368	367	1	0.3
United States	1,850	1,792	1,788	1,820	–32	–1.8
Venezuela	200	200	200	200	—	—
Other Western Hemisphere	210	209	207	201	6	3.1
Western Hemisphere	**3,354**	**3,312**	**3,294**	**3,368**	**–74**	**–2.2**
Norway	300	306	291	299	–8	–2.8
United Kingdom	149	151	146	183	–37	–20.0
Other Western Europe	10	10	10	10	—	–2.7
Western Europe	**460**	**467**	**447**	**492**	**–45**	**–9.2**
Russia	402	402	403	421	–18	–4.2
Other FSU	150	150	150	150	—	—
Other Eastern Europe	15	15	15	16	–1	–5.2
Eastern Europe	**567**	**567**	**568**	**587**	**–18**	**–3.2**
Algeria	338	341	343	352	–9	–2.5
Egypt	70	70	70	70	—	—
Libya	80	80	80	80	—	—
Other Africa	131	131	131	135	–4	–2.6
Africa	**619**	**622**	**624**	**636**	**–12**	**–1.9**
Saudi Arabia	1,345	1,311	1,320	1,440	–120	–8.3
United Arab Emirates	250	250	250	250	—	—
Other Middle East	835	835	835	874	–38	–4.4
Middle East	**2,430**	**2,396**	**2,405**	**2,564**	**–158**	**–6.2**
Australia	61	60	61	58	3	4.8
China	650	650	650	620	30	4.8
India	—	—	—	—	—	—
Other Asia-Pacific	169	169	169	181	–12	–6.4
Asia-Pacific	**880**	**879**	**880**	**859**	**21**	**2.5**
TOTAL WORLD	**8,309**	**8,243**	**8,219**	**8,505**	**–286**	**–3.4**

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

OXYGENATES

	Apr. 2009	Mar. 2009	Change	YTD 2009	YTD 2008	Change
	1,000 bbl					
Fuel ethanol						
Production	19,220	19,837	–617	76,722	65,098	11,624
Stocks	14,845	15,652	–807	14,845	11,539	3,306
MTBE						
Production	1,485	1,526	–41	5,758	6,358	–600
Stocks	1,142	1,066	76	1,142	1,727	–585

Source: DOE Petroleum Supply Monthly.
Data available in OGJ Online Research Center.

US HEATING DEGREE-DAYS

	May 2009	May 2008	Normal	2009 % change from normal	Total degree-days July 1 through May 31 2009	Total degree-days July 1 through May 31 2008	Total degree-days July 1 through May 31 Normal	% change from normal
New England	266	319	281	–5.3	6,645	6,317	6,545	1.5
Middle Atlantic	188	258	217	–13.4	5,840	5,395	5,872	–0.5
East North Central	204	273	238	–14.3	6,566	6,366	6,447	1.8
West North Central	215	259	208	3.4	6,839	6,914	6,701	2.1
South Atlantic	45	61	61	–26.2	2,885	2,530	2,846	1.4
East South Central	55	58	76	–27.6	3,541	3,389	3,597	–1.6
West South Central	21	20	17	23.5	2,099	2,161	2,286	–8.2
Mountain	163	236	233	–30.0	4,678	5,015	5,127	–8.8
Pacific	88	191	182	–51.6	2,918	3,249	3,152	–7.4
US average*	**126**	**176**	**159**	**–20.8**	**4,431**	**4,329**	**4,485**	**–1.2**

*Excludes Alaska and Hawaii.
Source: DOE Monthly Energy Review.
Data available in OGJ Online Research Center.

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

Japan
ICS Convention Design Inc., Plama Bldg. 2F, 2-13-8, Nihonbashi Kayabacho, Chuo-ku, Tokyo 103-0025, Japan, Tel: 81.3.5645.1271, Fax: 81.3.5645.1272; Manami Konishi, E-mail: manami.konishi@ex-press.jp; Masaki Mori, E-mail: masaki.mori@ex-press.jp

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

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

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

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

A new government foray: commerce in highway rest areas

The Editor's Perspective

by Bob Tippee, Editor

Government is encroaching into private affairs in ways other than the big-headline issues like automaker takeovers and fuel selection. It's even sneaking up on interstate highways. Businesses that sell fuel, food, and services along US highways worry about pressure to commercialize interstate rights-of-way.

When Congress created the interstate highway system in 1956, local communities naturally worried about harm to commerce. So lawmakers prohibited the offer of commercial services in rest areas built on interstate highways after Jan. 1, 1960. Some states want that to change. This year a transportation agency in Virginia approved a resolution supporting sales of food and fuel at rest areas.

California, Oregon, and Washington, are considering an "alternative-fuels corridor" along Interstate 5 and want to be able dispense fuel from government-run facilities in rest areas. And past highway bills have contained proposals for a pilot program allowing as many as 10 states to test commercial activities in rest areas.

Existing businesses adjacent to interstate highways oppose these initiatives, of course. They'd suffer competitive disadvantages from fuel and food stops more easily accessible by motorists than their own. And they know their new competitors would extract other favors from state patrons.

One idea for the alternative-fuel corridor, for example, is to excuse state-sponsored rest-area businesses from rent payments until they're profitable.

A group called Partnership to Save Highway Communities is working to keep rest-area commercialization out of highway reauthorization legislation being drafted by the House Committee on Transportation and Infrastructure.

Another group opposed to commercialization, NATSO, representing travel plazas and truckstops, estimates that more than 60,000 businesses, employing at least 2 million people, have developed along interstate highways. It cites a 2003 University of Maryland study estimating commercialization would close as many as half those businesses. To anyone confident about free markets, commercialization is repugnant.

As they appeal for public support, though, opponents would help their cause by encouraging roadside businesses to perform better than many of them do at keeping restrooms clean, windshield rinses clear, and towel dispensers full.

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Market Journal

by Sam Fletcher, Senior Writer

Lack of peace boosts prices

Crude prices are sure to rise since "world peace isn't breaking out," said analysts in the Houston office of Raymond James & Associates Inc.

They said, "A geopolitical risk premium of some magnitude looks set to remain in oil prices on a permanent basis. As the market comes to recognize this reality, combined with improving visibility on global oil demand, we look for oil prices to continue drifting higher to the $80-plus level towards the end of 2010. And if war with Iran becomes inevitable, then oil goes a lot higher."

The near-month price for benchmark US crude occasionally bobbed above $70/bbl on the New York Mercantile Exchange in late June due to disruptions of oil exports from Nigeria. Oil was up in early trading June 29 on reports Royal Dutch Shell PLC closed a major oil field in Nigeria after several production wells were attacked, following earlier claims by the rebel Movement for the Emancipation of the Niger Delta of wellheads being bombed in Shell's Afremo oil field. Even earlier, Shell confirmed militant attacks damaged a pipeline carrying benchmark Bonny crude to the key export terminal in Nigeria.

Olivier Jakob at Petromatrix, Zug, Switzerland, said attacks on oil facilities in the delta have likely reduced Nigeria's current production to 1.3-1.4 million b/d, down from 1.9 million last July and 1.8 million in the first quarter of this year. "The attacks on the pipeline infrastructure are also having an impact on the running of the local refineries; Warri and Port Harcourt are said to be shut, and Kanuda [is reported] running on stocks, which will run out in…weeks and provide some support to the Atlantic Basin light-end products," he said.

He questioned if the market has priced enough of a risk premium on Nigeria. He said, "If you are a refiner on the US East Coast running on Nigeria light crude oil, you do not change your slate overnight to Arabian Heavy, and Saudi Arabia will anyway not move [to increase production] before global stocks have been reduced. One way or another, Nigerian disruptions should lead to an acceleration in the reduction of light, sweet crude oil stock, and this provides a risk for an acceleration in the reduction of the futures contango" (OGJ Online, June 26, 2009).

Jakob is "cautious" in his outlook for the Nigerian government's offer of amnesty to militants. "There is money involved, hence some militants might go for that; but the ones that lay down their arms only leave the territory and its associated business to the ones that don't, so we will remain skeptical about the whole deal," he said.

Iranian discord

Raymond James analysts also noted continuing discord in Iran. "There are two roads ahead for the Iranian nuclear standoff. One road leads to a peaceful solution, a diplomatic compromise under which Iran fully complies with its obligations, presumably in exchange for some 'carrots' from Europe or others. The second road leads to higher oil prices. At best, this second road includes the imposition of meaningful economic sanctions, and if that doesn't work, potentially, military action," they said.

"If President Mahmoud Ahmadinejad stays in office, Iran is clearly set to continue heading down the second road, but even if he is replaced by a more moderate figure like Mir Hossein Mousavi, that route remains a real possibility. Assuming we are already headed down the second road, the question then shifts to timing. We think the odds of imminent military action are slim as President Barack Obama struggles to find his place as a world leader. That said, we think the odds of an Iranian oil problem begin to rise rapidly through 2010 as Iran presumably approaches the 'point of no return' for nuclear weapons capability."

As for other disruptions, Raymond James analysts said, "Russia has long been playing hardball with international oil companies. Venezuela has expropriated foreign-owned oil properties (and, more recently, oil service equipment)."

In New Orleans, analysts at Pritchard Capital Partners LLC noted China's push to build crude reserves through loans to Petroleo Brasilerio SA in Brazil and OAO Rosneft in Russia, as well as its purchase of Addax Petroleum Corp. "The Chinese are aggressively increasing the size of their energy footprint in order to meet future demand growth. China also plans to increase its strategic crude oil reserves by 160% to 270 million bbl over the next 5 years, and will begin building a second group of stockpiling bases as early as this year, at a cost of $4.39 billion," they said.

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