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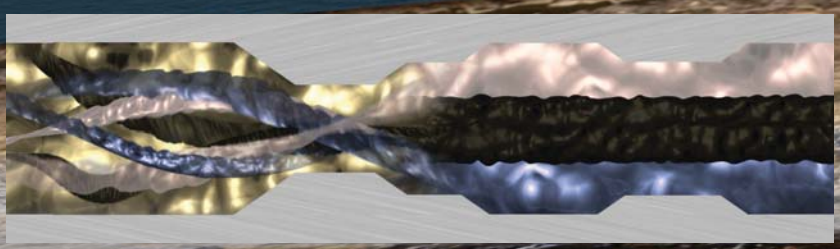

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LNGINFO

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

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

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

Producers wary as Colorado oil, gas rules become law
Scenarios validate, optimize field production
Process enhances H_2S recovery from strippers
Oblique shaft offers alternative for slope crossings

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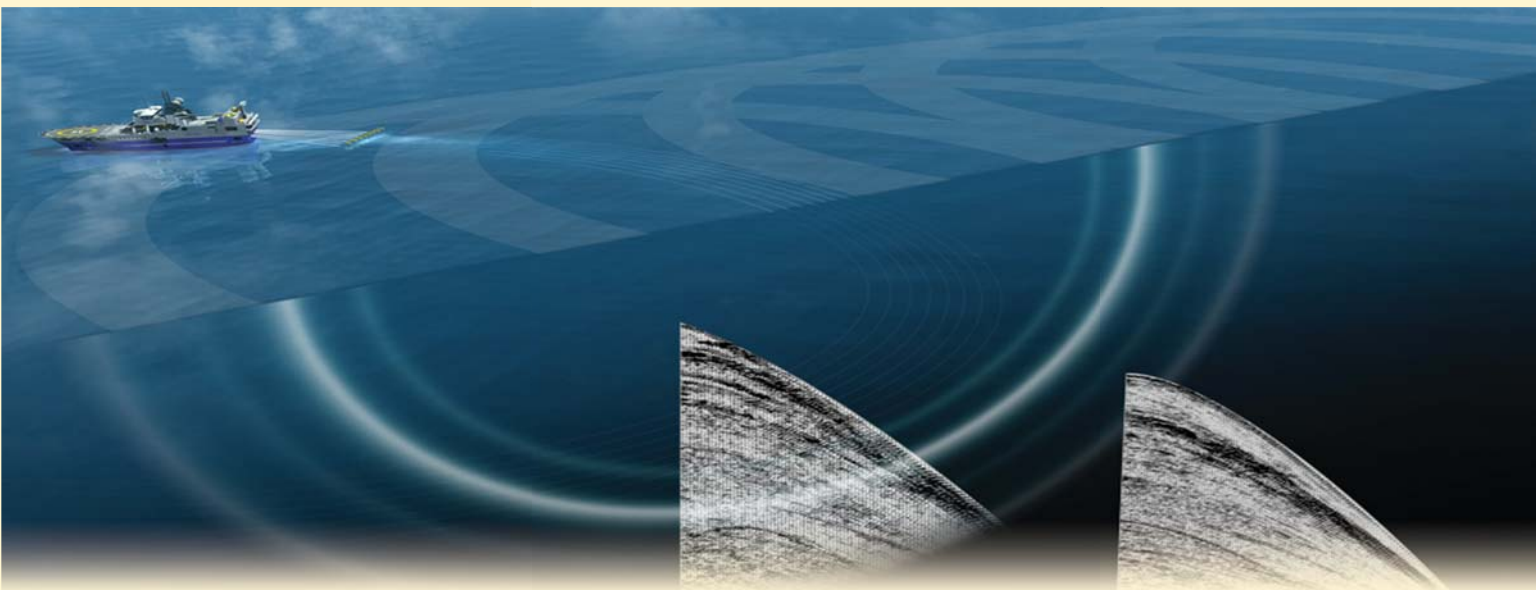
May 11, 2009
Volume 107.18

Offshore Technology Roundup



Regular Features

Cover

The global economy, energy policy, and the environment all were topics that received top billing at the Offshore Technology Conference, which celebrated its 40th anniversary this year. The special report, Offshore Technology Roundup, begins on p. 20. Shown on the cover are two technologies receiving annual awards at the conference. At left is Schlumberger Ltd.'s subC-strip and subC-collar integrity monitoring system, which was adopted by Chevron Corp. to record buckling on the operator's Tahiti development. At right (inset) is an artist's rendering of coil shooting, which acquires full-azimuth marine seismic data, as conducted by Schlumberger unit WesternGeco. Photo and image both from Schlumberger.

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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Process Notes

Why Do Many Crude/Vacuum Units Perform Poorly?

In many cases it's because the original design was based more on *virtual* than *actual* reality. There is no question: computer simulations have a key role to play but it's equally true that process design needs to be based on what works in the field and not on the ideals of the process simulator. Nor should the designer simply base the equipment selection on vendor-stated performance. The design engineer needs to have actual refinery process engineering experience, not just expertise in office-based modeling. Refinery hands-on experience teaches that fouling, corrosion, asphaltene precipitation, crude variability, and crude thermal instability, and many other non-ideals are the reality. Theoretical outputs of process or equipment models are not. In this era of slick colorful PowerPoint® presentations by well-spoken engineers in Saville Row suits, it's no wonder that units don't work. Shouldn't engineers wearing Nomex® coveralls who have worked with operators and taken field measurements be accorded greater credibility?

Today more than ever before this is important. Gone are the days when a refiner could rely on uninterrupted supplies of light, sweet, easy-to-process crudes. In troubled times fierce global competition for premium crudes means that refinery units must have the flexibility to handle heavy, viscous, dirty crudes that increasingly threaten to dominate markets. And flexibility must extend to products as well as crudes, for refinery product demand has become more and more subject to violent economic and political swings. Thus refiners must have the greatest flexibility in determining yields of naphtha, jet fuel, diesel and vacuum gas oil products.

Rather than a single point process model, the crude/vacuum unit design must provide continuous flexibility to operate reliably over long periods of time. Simply meeting the process guarantee 90 days after start-up is very different than having a unit still operating well after 5 years. Sadly few refiners actually achieve this—no matter all the slick presentations by engineers in business suits!

If you want to explore these issues in technical detail ask for Technical Papers 267 and 268.

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May 11, 2009

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General Interest — Quick Takes

Work begins on Calabar Energy City in Nigeria

Work has begun to create an energy city in Calabar, Nigeria, that will allow oil companies to fabricate some of their required material and ease their logistic and infrastructure issues.

Eyo Ekpo, special adviser on projects in Cross River, told OGJ that the 376 hectares of land in Cross River state will be funded and managed through public-private partnership. The land is swamped and the government has begun to reclaim the site at Ekorinim Peninsula for the industrial area and a portion of Pamol Rubber Estate for residential.

Ekpo said, "We have been doing modeling for the past 6-9 months [and] we're ready to go next year." He said he was holding discussions with the Oil and Gas Free Zone Authority to acquire tax breaks for companies that would establish operations in the park.

Calabar Energy City (CEC) is an initiative launched by Sen. Liyel Imoke, the governor of Cross River state. Ekpo told OGJ that there would be a 25-hectare tank farm complex with a loading jetty, a river parts complex, a heliport, a medical center, and a hotel and business complex. He said a private company would manage the park and he expects there to be strong interest from companies in using its resources.

For the first phase, oil companies will be able to secure 220-hectare plots under leases on the ecoindustrial park to carry out infrastructure and facilities. The second phase, covering 500 hectares north of Calabar, will focus on zones for residential, sporting, religious, and commercial uses. The industrial area is key to CEC, but both parts will be served by utility and infrastructure services delivered to high standards.

Cross River state is within the Niger Delta, and the project will position Calabar as a secure and viable location for the oil industry, Ekpo told OGJ. It will also create job opportunities in the region and beyond.

CEC will take advantage of the federal government's policy that requires 60% of man-hours be carried out within the operating region. This has been difficult to meet in the Niger Delta due to the violence and attacks by militants.

Salazar, Locke restore ESA consultation requirement

The US Interior and Commerce departments are revoking a George W. Bush administration order and requiring consultations with their two agencies that administer the Endangered Species Act (ESA), the two departments' secretaries announced.

Federal agencies will once again have to consult with wildlife experts at the US Fish and Wildlife Service at DOI and the National Oceanic and Atmospheric Administration at Commerce before taking any action which might affect threatened species, Interior Secretary Ken Salazar and Commerce Secretary Gary Locke said on Apr. 28.

The action rolls back an order that Salazar's predecessor, Dirk A. Kempthorne, said would simplify regulations at the two agencies by not making them review every action involving the ESA unless they considered it necessary. Kempthorne said this would make operations more efficient and let the agencies give more attention to truly pressing matters.

Salazar characterized it as another Bush administration 11th hour regulation. "By rolling [it] back, we are ensuring that threatened and endangered species continue to receive the full protection of the law. Because science must serve as the foundation for decisions we make, federal agencies proposing to take actions that might affect threatened or endangered species have to consult with biologists at the two departments," he said.

"For decades, the [ESA] has protected threatened species and their habitats. Our decision affirms the administration's commitment to using sound science to promote conservation and protect the environment," Locke said.

The two secretaries said that US President Barack H. Obama directed them in March to review the previous administration's Section 7 regulation in the ESA, which covers consultation. Congress, in the 2009 Omnibus Appropriations Act, authorized them to revoke the regulation, they added.

Locke and Salazar said the two departments would jointly review the 1986 consultation regulations to determine if any improvements are needed.

Environmental organizations applauded the move. "The Bush rules would have allowed agencies with little or no wildlife expertise to make decisions that could mean life or death for animals like the polar bear. Today's decision restores the important protections for species and their habitats offered by one of our nation's most fundamental environmental laws," said Sierra Club Executive Director Carl Pope.

"For decades, the [ESA] has used sound science as the guide to protect America's most vulnerable plants and animals. Today, the Obama administration reaffirmed that politics should not be the driver of these protections. Our nation needs to start investing in new and better infrastructure projects, and restoring this law will make sure we do so without harming our endangered plants and animals," said Rebecca Riley, a lawyer with the Natural Resources Defense Council's Endangered Species Project. ✦

Exploration & Development — Quick Takes

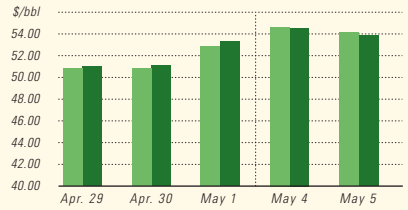
ConocoPhillips, Anadarko make NPR-A finds

ConocoPhillips and Anadarko Petroleum Corp. reported the discovery and test production from two wells in the National Petroleum Reserve-Alaska (NPR-A).

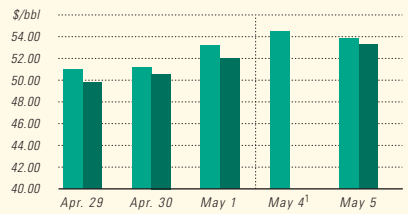
Pioneer 1, which was tested in March, and Rendezvous 2, which was tested in winter 2008, both lie in the Greater Mooses

Industry Scoreboard

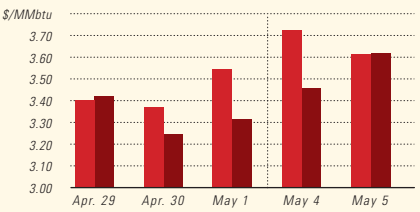
IPE BRENT / NYMEX LIGHT SWEET CRUDE



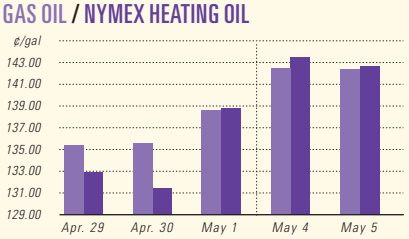
WTI CUSHING / BRENT SPOT



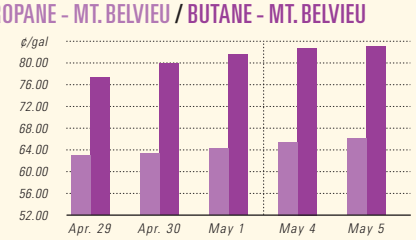
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



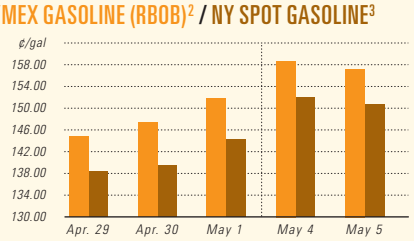
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



NYMEX GASOLINE (RBOB)[2] / NY SPOT GASOLINE[3]



[1]Not available [2]Reformulated gasoline blendstock for oxygen blending.
[3]Nonoxygenated regular unleaded.

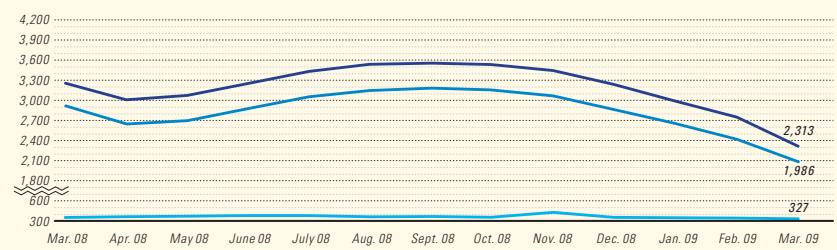
US INDUSTRY SCOREBOARD — 5/11

Latest week 4/24	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	9,064	9,109	–0.5	8,948	8,952	0.0
Distillate	3,682	4,114	–10.5	3,897	4,181	–6.8
Jet fuel	1,395	1,582	–11.8	1,393	1,549	–10.1
Residual	465	664	–30.0	563	616	–8.6
Other products	3,818	4,293	–11.1	4,180	4,558	–8.3
TOTAL DEMAND	18,424	19,762	–6.8	18,981	19,856	–4.4
Supply, 1,000 b/d						
Crude production	5,410	5,158	4.9	5,352	5,125	4.4
NGL production[2]	1,797	2,186	–17.8	1,884	2,180	–13.6
Crude imports	9,601	9,847	–2.5	9,463	9,767	–3.1
Product imports	2,855	3,259	–12.4	3,100	3,181	–2.5
Other supply[3]	1,715	1,358	26.3	1,598	1,426	12.1
TOTAL SUPPLY	21,378	21,808	–2.0	21,397	21,679	–1.3
Refining, 1,000 b/d						
Crude runs to stills	14,235	14,736	–3.4	14,235	14,645	–2.8
Input to crude stills	14,565	15,083	–3.4	14,565	14,958	–2.6
% utilization	82.6	85.8	—	82.6	85.1	—

Latest week 4/24	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	374,653	370,600	4,053	319,929	54,724	17.1
Motor gasoline	212,612	217,307	–4,695	211,089	1,523	0.7
Distillate	144,105	142,311	1,794	105,831	38,274	36.2
Jet fuel–kerosine	40,188	39,704	484	38,738	1,450	3.7
Residual	36,282	36,332	–50	39,522	–3,240	–8.2
Stock cover (days)[4]			Change, %		Change, %	
Crude	26.2	26.0	0.8	22.0	19.1	
Motor gasoline	23.5	24.0	–2.1	22.8	3.1	
Distillate	39.1	38.1	2.6	24.9	57.0	
Propane	45.8	40.5	13.1	27.5	66.5	
Futures prices[5] **5/1**			**Change**		**Change**	**%**
Light sweet crude ($/bbl)	51.07	48.48	2.59	117.95	–66.88	–56.7
Natural gas, $/MMbtu	3.38	3.46	–0.08	10.78	–7.40	–68.6

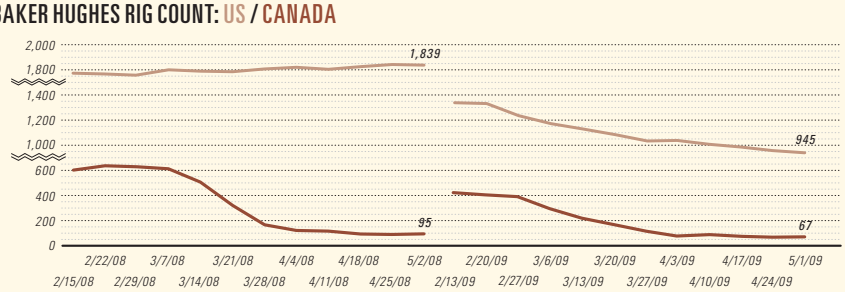
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

Tooth Unit about 20 miles southwest of the Colville River Unit development on the North Slope of Alaska.

Test production rates for these wells ranged from 500 b/d to 1,300 b/d of high-gravity oil. Gas production rates averaged 1.5 MMcfd for each well, the companies said.

"No further delineation drilling is planned for Pioneer or Rendezvous at this time," the companies said. These two accumulations will be pursued as possible satellite developments with processing at the Alpine facilities in the Colville River Unit.

Operator ConocoPhillips holds 78% interest in the Greater Mooses Tooth Unit, while Anadarko holds 22%.

Barrett probing two eastern Utah gas shales

Bill Barrett Corp., Denver, expects to learn the outcome by mid-2009 at a horizontal well spud late in the first quarter of 2009 seeking gas in Upper Mississippian Manning Canyon shale at 8,000 ft true vertical depth.

The prospect lies in northern Emery County southeast of Price, Utah, along the San Rafael Swell on the Uinta basin southwestern flank. Numerous wells as far west as Drunkards Wash coalbed methane field in Carbon County have had gas shows in Manning Canyon.

The horizontal well offsets an initial vertical well drilled in 2008 that indicated good gas shows and high gas content in core. Bill Barrett holds 50% working interest in the deep prospect.

The company has also drilled two vertical wells to 3,900 ft in the fractured Juana Lopez shale member of the Upper Cretaceous Mancos formation, in which it has 100% working interest. It plans to complete testing those wells in 2010.

StatoilHydro deems Canon find noncommercial

StatoilHydro will permanently plug and abandon its exploration well on the Canon prospect in the Norwegian North Sea after making a gas-condensate discovery that was deemed noncommercial.

The well tested the upper Brent reservoir and the deeper Statfjord sandstone level, producing gas and condensate in the former and penetrating tight sands in the latter that was probably full of water.

Tom Dreyer, StatoilHydro's vice-president, infrastructure exploration in the North Sea, said the Brent reservoir was thinner than expected.

The exploration well 30/3-10 S reached a TVD of 3,962 m in 122 m of water. StatoilHydro used the West Alpha semisubmersible rig to drill the Canon prospect, which lies 11 km west of Veslefrikk field in the North Sea. The well was drilled to prove petroleum in a fault block between the Huldra and Oseberg fields, said StatoilHydro.

The rig's charter with StatoilHydro will terminate once the well is completed.

This is the second well to be tested in the Canon structure. An exploration well drilled in 2000 provided inconclusive results about the economic potential of the structure.

StatoilHydro operates production license 052 with an 18% share. Other parters include Petoro 37%, RWE Dea Norge 13.5%, Revus Energy 4.5%, and Talisman Resources Norge 27%.

Heritage reports giant Iraqi Kurdistan find

Heritage Oil Corp. has reported the discovery of a giant oil field in Iraqi Kurdistan with 2.3-4.2 billion bbl of oil in place, of which 50-70% appears recoverable.

Exploration risk of an adjacent structure of similar size is greatly reduced, Heritage Oil said.

The company said it could start trucking production from Miran West-1 by the end of 2009, with individual flow rates likely to be 10,000-15,000 b/d/well.

A fractured gross oil-bearing interval of 710 m produced 27° gravity oil with low sulfur, no water, and a low gas-oil ratio.

The company drillstem tested Miran West-1, the first well ever drilled on the license, over a 500-m gross interval in the Shiranish, Kometan, and Qamchuqua formations. High reservoir pressures that characterize the region were not encountered in the well, Heritage said.

"Testing was severely constrained by the limitations of the downhole and surface testing equipment and the loss of over 100,000 bbl of drilling fluid and lost circulation material due to the highly fractured nature of the reservoirs," the company said.

More equipment to carry out longer term tests is expected within 6-8 weeks. Further drilling on the license is set for later in 2009.

The Miran West and East structures total 330 sq km.

Heritage Energy Middle East operates the Miran license with 75% interest, and Genel Energy International Ltd. has 25%. Heritage mapped the structures from 332 line-km of seismic shot between April and June 2008. ✦

Drilling & Production — *Quick Takes*

Tupi pilot begins production off Brazil

The extended production test of the giant presalt Tupi discovery in the Santos basin off Brazil has begun to the BW Cidade de Sao Vicente FPSO, according to Galp Energia SGPS SA, Lisbon, Portugal.

The FPSO, with a 30,000 bo/d processing capability, is moored in 2,170-m of water in Block BM-S-11, about 280 km off Rio de Janeiro's coast.

Galp Energia says that production will not exceed 14,000 bo/d during the 15-month production test of the Tupi Sul and Tupi-1 wells.

The Tupi field, discovered in October 2006, contains an estimated recoverable 5-8 billion bbl of light 28-30° gravity oil and natural gas.

Operator Petroleo Brazileiro SA has a 65% interest in the block. Partners are BG Group, 25%, and Galp Energia, 10%.

Tahiti field, gulf's deepest production, starts up

Chevron Corp. announced that oil production from Tahiti field, the deepest producing field in the Gulf of Mexico, started on May 5. Chevron expects daily production to ramp up to about 125,000 bo/d and 70 MMcfd of natural gas by yearend.

Tahiti field, discovered in 2002, is one of the largest in the gulf and contains 400-500 million boe of recoverable resources, according to Chevron. The first phase of the project cost $2.7 billion.

Tahiti lies on Green Canyon Blocks 596, 597, 640, and 641 in 4,100 ft of water about 190 miles south of New Orleans.

Primary pay sands are Lower to Middle Miocene at 23,000-28,000 ft that lie below a 8,000-15,000 ft thick salt canopy.

The deepest producing well has a depth of more than 26,700 ft, a record for the gulf, according to Chevron.

The field produces from two subsea drill centers with six subsea wells tied back to a production facility on a floating truss spar.

The operator Chevron holds a 58% working interest in the field. Partners are StatoilHydro 25% and Total SA 17%.

Chevron expects production to ramp up to 125,000 bo/d of oil and 70 MMcfd of gas by yearend from Tahiti field. Photo from Chevron.

Cased laterals pay in Mississippi Selma chalk

Penn Virginia Corp., Radnor, Pa., is producing 13 MMcfed from 20 horizontal Cretaceous Selma chalk wells in Mississippi.

The 20 wells averaged initial 30-day rates of 815 Mcfed compared with 272 Mcfed for vertical wells.

Production in the quarter ended Mar. 31 averaged 23.3 MMcfed, up 14% from the fourth quarter and 17% from the first quarter of 2008.

Results to date indicate that one horizontal well replaces two to three vertical wells and recovers four to five times the reserves of a vertical well. Laterals average 3,000 ft and have seven to eight frac stages.

Penn Virginia plans to cement casing and perforate all future completions. The first 15 wells are open-hole completion and the last five have cemented casing and perforations.

Open-hole completions averaged 761 Mcfed after 30 days and 804 Mcfed after 60 days, while cased-perforated completions averaged 1 MMcfed after 30 days and 1.2 MMcfed after 60 days.

Spud to sales averaged 41 days for the three wells drilled in the 2009 first quarter compared with 49 days for the first 17 horizontal wells. Drilling and completion cost has fallen to $2.5 million/well from $3 million. ✦

Processing — *Quick Takes*

Fire-damaged Tyler, Tex., refinery restarts

A Tyler, Tex., refinery is restarting after repairs to units damaged by a fatal fire Nov. 20.

Delek US Holdings Inc., based near Nashville, Tenn., is resuming operations of the 60,000-b/d facility.

The fire broke out in the area of the saturates gas plant and naphtha hydrotreater, killing one worker and injuring six. Those units and the control room sustained damage.

With 20,200 b/d of fluid catalytic cracking capacity and 6,500 b/d of delayed coking, the refinery yields of 90% light products and less than 2% of heavy oils from mainly light, sweet crude feedstocks.

Two refineries sought for Indonesia's Batam Island

Indonesia's Setdco Group and its partner PT Intan Megah have sought permission to build a 300,000 b/d refinery at Tanjung Sauh on Batam Island near Singapore—one of two new facilities apparently set for construction on the island.

"The crude oil will be from the Middle East," said Evita Legowo, director general for oil and gas at the Ministry of Energy and Mineral Resources. She said the government is still in the process of issuing a permit for the development of the planned refinery, and could release no further details.

Meanwhile, other reports have emerged that Gulf Petroleum Ltd., Qatar's largest oil company, also plans to build a refinery in Batam.

Gulf Petroleum is preparing documents needed to seek the investment license from the Indonesian government, according to Ismeth Abdullah, chairman of the Batam Free Trade Zone Council.

Gulf Petroleum Pres. Abdul Aziz Abdulaimi and PT Batam Sentralindo Pres. Bang Hawana recently signed a memorandum of understanding on the project.

PT Batam Sentralindo, the operator of the Batam Free Trade Zone, has agreed to provide a 250-hectare plot of land for the re-

finery project, which plans to sell its products in Indonesia and other Southeast Asian nations.

Meanwhile, reports said that a $1.5 billion refinery joint venture between Indonesia's state-owned PT Pertamina and Japan's Mitsui & Co. may stall because the Indonesian government wants an increased stake in the project.

Agreement had been reached to build a residue fluid catalytic cracking unit with a capacity of 60,000 b/d of gasoline in Pertamina's existing refinery at Cilacap in Central Java, with Mitsui holding an 80% stake and Pertamina 20%.

But the Indonesian government has advised Pertamina to review the project and seek a higher stake, a request that could sink the project altogether according to one source, who said financing for the refinery already has been approved by the Japan Bank for International Cooperation. ✦

Transportation — *Quick Takes*

EOG to rail Bakken crude to Cushing

EOG Resources Inc., Houston, is implementing a plan to use rail car unit trains to ship crude produced from the Bakken formation in North Dakota to the Cushing, Okla., terminal.

EOG Resources has finalized a strategic transportation arrangement with Burlington Northern Santa Fe railway and expects to have the rail facility operational by February 2010, said Mark Papa, chairman and chief executive officer.

The deal will afford sharply better long-term oil netbacks than it is receiving by shipping its oil by pipeline through the hub at Clearbrook, Minn., Papa said.

The company, which restricted its Bakken oil production for the first 6 months of 2009 due to marketing issues, expects to resume full production in Parshall field in North Dakota by July.

In the Williston basin, EOG Resources is running eight rigs compared with 10 in 2008, and the company has deferred almost all well completions until summer 2009 when fracs can be performed more economically and road conditions improve.

With natural gas prices languishing, EOG Resources's $3.1 billion capital budget for 2009 is directed toward liquids investments, Papa said.

The company raised its 2009 overall oil and gas production growth target to 5½% from 3%, driven by a 22% increase in liquids output. Most of the increase is to come from its Bakken and Fort Worth basin Barnett shale plays.

Changes sought in gas line flow posting rules

Calling it a small, but important, adjustment, the Natural Gas Supply Association asked the US Federal Energy Regulatory Commission to slightly change gas pipeline flow-posting requirements.

In an Apr. 30 filing, NGSA asked FERC to consider adopting a "sole-feed" exclusion. This would exempt major noninterstate gas pipelines from reporting if the pipeline has no, or very small volume endusers with total receipts of less than 15,000 million BTUs/day, or if the pipeline feeds into another major pipeline, NGSA said.

Taking this step would reduce the burden and cost of compliance for small-volume pipelines while continuing to provide clear information to regulators and the public, the trade association added.

NGSA said FERC issued in November Order No. 720, which requires certain noninterstate and interstate gas lines to post design capacity and daily scheduled gas flow information. The rule also imposed posting requirements on interstate gas pipelines that provide no-notice service.

Jenny Fordham, NGSA's energy markets and government affairs director, said the association believes FERC got the new reporting process "about 98% right" when it changed the pipeline reporting requirements last year.

"Our 'sole-feed' proposal would further simply the process and capture the same data, just a few miles further downstream. A sole-feed exclusion is consistent with the commission's desire to establish rules that will increase transparency without additional cost," she said.

Pacific Connector line moves closer to fruition

The US Federal Energy Regulatory Commission issued a final environmental impact statement (FEIS) on Pacific Connector Gas Pipeline LP's proposed 36-in. OD sendout pipeline, moving the project one step closer to fruition.

The proposed line would extend from Jordan Cove's LNG terminal—which was issued its FEIS as part of the same proceeding—about 234 miles southeast across Coos, Douglas, Jackson, and Klamath counties in Oregon to a terminus near Malin, Ore. From there the proposed line would interconnect with the existing pipeline systems of Gas Transmission Northwest Corp., Tuscarora Gas Transmission Co., and Pacific Gas & Electric Co.

The 1-bcfd Pacific Connector pipeline would include 1 compressor station, 4 meter stations, 4 pig launchers-receivers, 16 mainline block valves, 5 communication towers, and additional communications equipment at 8 existing towers.

Pacific Connector has entered into agreements with seven customers who have requested 1.49 bcfd through the proposed line. Upon finalization of LNG supply commitments at the Jordan Cove terminal, Pacific Connector will allocate, if needed, the available 1 bcfd amongst the seven customers.

Its route crosses 218 waterbodies (some multiple times) within 6 hydrological subbasins. Installation under 3 major rivers (Coos, Rogue, and Klamath) will use horizontal directional drilling, while 3 waterbodies (Kentuck Slough, Catching Slough, and the Medford Aqueduct) will be bored, 1 river (South Umpqua) will have diverted crossings, and the remainder of the waterbodies will be dry crossed, except for the open cut wet crossing of a portion of Coos Bay.

Pacific Connector's current proposed route reduced the crossing of the Coos Bay estuary to less than 2½ miles. ✦

Correction

The story "LNG supply, fuel competition pose major concerns in US" incorrectly identified the speaker for Poten & Partners (OGJ, May 4, 2009, p. 49). Speaking was Jim Briggs.

Calendar

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

OIL&GAS JOURNAL online

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

2009

MAY

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

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

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

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

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

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

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

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

Pipeline Simulation Interest Group (PSIG) Meeting, Galveston, Tex., + 966 3 873 0139, + 966 3 873 7886 (fax), e-mail: info@psig.org, website: www.psig.org. 12-15.

Iraq Oil + Gas Summit, Houston, (202) 536-5000, (202) 280-1239 (fax), e-mail: lwilson@nfemail.com, website: www.New-Fields.com. 13-14.

Louisiana Oil and Gas Symposium, Baton Rouge, (225) 578-8657, (225) 578-9257 (fax), e-mail: hammer@lsu.edu, website: www.brgs.la.org. 19-20.

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

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

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

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

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

JUNE

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

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

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

PIRA Scenario Planning Conference, Houston, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 8.

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

International Oil Shale Symposium, Tallinn, Estonia, +372 71 52859, e-mail: Rikki.Hrenko@energia.ee, website: www.oilshalesymposium.com. 8-11.

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

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

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

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

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

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

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

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

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

PIRA Scenario Planning Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 16.

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

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

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

Calendar

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

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

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

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

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

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

API Exploration & Production Standards Oilfield Equipment and Materials Conference, Westminister, Colo., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 22-26.

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

JULY

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

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.

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

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

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

SEPTEMBER

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.

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

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

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

DGMK Production and Use of Light Olefins Conference, Dresden, 040 639004 0, 040 639004 50, website: www.dgmk.de. 28-30.

IADC Advanced Rig Technology Conference, Houston, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 29.

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

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

OCTOBER

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

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

World Gas Conference, Buenos Aires, +54 11 5252 9801, e-mail: registration@wgc2009.com, website: www.wgc2009.com. 5-9.

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

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

NPRA Q&A and Technology Forum, Ft. Worth, Tex., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 11-14.

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

GPA Houston Annual Meeting, Houston, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gpaglobal.org, website: www.gpaglobal.org. 13.

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

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

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

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

SPE/IADC Middle East Drilling Conference & Exhibition, Manama, +971 4 390 3540, +971 4 366 4648 (fax), e-mail: spedal@spe.org, website: www.spe.org. 26-28.

Louisiana Gulf Coast Oil Exposition (LAGCOE), Lafayette, (337) 235-4055, (337) 237-1030 (fax), e-mail: lynette@lagcoe.com, website: www.lagcoe.com. 27-29.

Offshore Middle East Conference & Exhibition, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.offshoremiddleeast.com. 27-29.

Journally Speaking

Where's the bottom?

Bob Tippee
Editor

Everyone in the oil business wants to know when the market will reach bottom. The normal answer would be that the oil market reaches bottom when oil prices quit falling.

Well, prices have quit falling. So why is there this prevailing sense that the market hasn't yet found bedrock?

The answer: because demand continues to shrink. Next question: So why have prices quit falling? Answer: because the Organization of Petroleum Exporting Countries has cut supply.

For now, price is an unreliable indicator of the market's health. Any price level dependent on cartel discipline is precarious.

That everyone knows this explains the palpable anxiety of the oil business.

The market will not have reached bottom until demand quits falling. Before then, before the bottom will be in view, the rate of demand decline must diminish.

That hasn't happened. In its April Oil Market Report, the International Energy Agency projected average 2009 oil demand of 83.4 million b/d—down a whopping 2.4 million b/d from its estimate for 2008.

A month earlier, the agency had put the increment at 1.3 million b/d.

An OPEC rescue?

Before IEA darkened the mood, belief was growing that OPEC had rescued things.

The exporters' group by December had announced quota cuts totaling 4.2 million b/d against September production. It seemed to be lowering not just quotas but actual output as well.

Crude prices, having fallen below $40/bbl in last year's fourth quarter, recovered to slightly above $50/bbl.

They were at that level when IEA turned grumpy about demand. Sure enough, the prices of marker crudes slumped back into the 40s.

That they didn't fall further and in fact bounced quickly back to a plateau around $50/bbl is at least partly due to demand assessments cheerier than IEA's.

Within days of the 2.4-million-b/d shocker, two less pessimistic forecasts appeared.

Like IEA, OPEC and the US Energy Information Administration publish monthly oil market assessments that update demand projections for the current year.

In its April report, OPEC put 2009 demand at 84.18 million b/d, down 1.37 million b/d from its estimate for 2008. EIA estimated the demand slide at 1.35 million b/d—to an annual average 84.09 million b/d.

The mild price recovery indicates, among other things, that the market took comfort from the two later projections.

So what happens now?

OPEC's resolve is encouraging. By IEA's reckoning, the group through March had achieved 83% compliance with its aggressive quota reductions. That's unprecedented.

The exporters' group seems to have learned from its calamitous misreading of the market in the late 1990s, when it raised production quotas just as demand was contracting in response to the Asian financial collapse.

Whether the discipline can last is uncertain. Production restraint is uneven, with Saudi Arabia producing below its target and maverick OPEC members like Iran and Venezuela producing substantially above theirs. The kingdom has been known to become impatient with solo sacrifice.

Furthermore, the ability of OPEC producers to cut production is limited by more than revenue needs in relation to the arithmetic of production rates and price. Country needs for associated gas put floors at varying levels below which oil production can't languish for long.

For now, OPEC seems content with oil prices bobbing in a narrow range around $50/bbl. It will meet at the end of this month to consider next moves.

What OPEC does then will depend greatly on May demand forecasts. IEA will make its new market assessment about the time this column appears. The OPEC and EIA reports will follow.

Those projections will depend on the various agencies' readings of the global economy, about which news has been mixed.

In April, the International Monetary Fund forecast global economic contraction this year of 1.3%, with no recovery until next year. It earlier expected growth to resume in second-half 2009.

Hopeful sign?

But the Open Market Committee of the US Federal Reserve followed IMF's pessimism with a report of early signs of, if not recovery, shrinkage in the rate of contraction.

A hopeful sign in the May oil market forecasts would be a lower IEA forecast for demand contraction this year. An ominous sign would be alignment of OPEC, EIA, or both with IEA's April melancholy view.

All that's at stake here is health of one of the world's most important businesses. Who said there's no drama in economics? ✦

Editorial

A biodiesel trade fight

The US has evoked trade retaliation from Europe with a program most Americans would be shocked to learn involved international commerce. The affair shows how governmental meddling in energy markets yields perverse consequences. There will be other such lessons.

US taxpayers US subsidize biodiesel—a methyl ester made from agricultural materials—with a tax credit of $1/gal and mandates. They believe doing so supplements fuel supply and helps the environment. Those who bother to check the numbers probably derive satisfaction from reports that their country produced 700 million gal of biodiesel last year, tiny though that volume is relative to total diesel consumption.

But how many Americans know that their tax generosity has largely benefited biodiesel produced and used elsewhere?

Production surges

The Renewable Fuel Standards program established by the Energy Policy Act of 2005 mandated a volumetric biodiesel component in diesel sold in the US. The requirement is 500 million gal this year and will rise to 1 billion gal in 2012. The tax credit, mandate, and rising fuel prices made biodiesel production surge in the past 4 years. But something else happened at the same time, reports the Energy Information Administration.

"Much of the increase in production in 2007 and 2008 was not consumed within the US but was exported because of incentives provided by the biodiesel tax credit," EIA said in an Apr. 22 report. That subsidy, called the blender tax credit (BTC), initially applied to all biodiesel blended with diesel, "regardless of where it was produced or consumed." The loophole created a business called "splash-and-dash." Practitioners could bring a cargo of biodiesel produced abroad to the US, add a small amount of US diesel to exploit the BTC, and export the blend.

The imported biodiesel came from Asia and Latin America, EIA reports. Annual volumes rose from 4 million gal in 2004 to 315 million gal in 2008. US exports of biodiesel meanwhile jumped from 5 million gal to 677 million gal, mostly to Europe.

Noting the unintended consequence of its market dalliance, Congress ended BTC eligibility for imported biodiesel when it passed the Emergency Economic Stabilization Act of 2008, which extended the subsidy through the end of this year. But biodiesel produced in the US and exported still receives the benefit.

Europe, where countries subsidize their own biodiesel businesses, is fighting back. In March, the European Commission imposed temporary countervailing duties on US biodiesel. "This decision was taken on the basis of clear evidence that unfair subsidization and dumping of US biodiesel has taken place and that this is harming otherwise competitive European industry with potentially dire long-term effects," it said.

The temporary duties will be in effect for 4 months and can be followed by definitive duties, which normally last 5 years. An EC investigation found that US biodiesel accounted for 17% of the European market during April 2007-March 2008.

Deterioration of export economics slams a US biodiesel industry reeling from surges in the price of soybeans, the primary feedstock, followed by plunges in the price of diesel. The business is choking on overcapacity. Many producers have gone bankrupt. Biodiesel subsidies seem mainly to have helped operators savvy enough to spot arbitrage opportunities in US tax laws.

Energy businesses created and sustained by governments always turn out this way. Markets outmaneuver official expectations. Subsidized businesses enthusiastically overbuild capacity and need ever-increasing help. Energy targets go unmet. Opportunists find loopholes and make money. Taxpayers spend too much money on too little energy.

Increment of inefficiency

US biodiesel subsidization isn't large in volume or dollar terms relative to the energy market or the federal budget. It is nevertheless an increment of inefficiency, one blob in a belly of fat swelling as the government gorges the economy on energy wholly dependent on taxpayers. Now it's the cause of a trade battle.

The US and its trade partners should become accustomed to this kind of thing. Congress and the Executive Branch show no sign of recognizing the perverse results of their energy misjudgments. US taxpayers can expect energy disappointments and rising costs. ✦

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The oil and gas industry continues to develop new technologies to explore for, develop, and produce the energy resources needed for growing global demand. Speakers at the 40th Offshore Technology Conference in Houston May 4-7 highlighted these technologies against a backdrop of worldwide economic uncertainty and changing governmental and environmental policies.

40th OTC highlights world economy, energy policy, and environment

This report was reported and written by Alan Petzet, chief editor-exploration, Guntis Moritis, production editor, Sam Fletcher, senior writer, Paula Dittrick, senior staff writer, and Uchenna Izundu, international editor.

Despite oil prices hovering in the mid-$50/bbl range and a possible swine flu pandemic, attendance at OTC 2009 was expected at presstime last week to reach the 65,000 mark, which would be down slightly from a record high of 75,092 attendees reported last year.

Roundtable discussion

Three energy executives questioned US President Barack Obama's energy policy in a roundtable discussion of access to oil and gas resources on the US Outer Continental Shelf at OTC May 5.

In prepared remarks, Gary P. Luquette, president of Chevron North America Exploration & Production Co., said, "There are people in positions of power that want the US to move off oil as quickly as possible, and they want us to pay for it through increased taxes and fees."

Luquette noted Obama's "aggressive agenda" that could drastically reduce the industry's ability to explore, develop, and produce oil and natural gas in the US. He said, "This administration—and for that matter, a large sector of the population—think we must abandon traditional oil and gas development for the sake of the environment. This is simply not true."

Larry Nichols, chairman and chief executive officer of Devon Energy Corp., derided the myth that environmentally friendly and renewable energy sources are imminent. He questioned Obama's goal of having renewable energy resources provide 20% of US energy production by 2030. Even the Department of Energy's estimate is for only 11%.

Tim Cejka, president of ExxonMobil Exploration Co., said in prepared remarks, "Oil and gas are indeed finite resources. And alternative energy sources, such as wind, nuclear power, and biofuels, play an important and growing role in meeting global energy needs. But although oil and gas resources are finite, they are far from finished."

The US Geological Survey estimates more than 3 trillion bbl of conventional oil is ultimately recoverable worldwide. On top of that are huge unconventional resources such as heavy oil and shale oil yet to be developed. By comparison, an estimated 1 trillion bbl of crude has been produced to date in all of human history.

Based on surveys conducted by the US Minerals Management Service, the OCS holds an estimated 85 billion bbl of recoverable oil and 419 tcf of recoverable gas, with almost 18 billion bbl of oil and 76 tcf of gas in the areas previously or still off limits.

Environmentally responsible

Despite the expansion of offshore

drilling since 1980, MMS has calculated less than one one-thousandth percent of oil produced in federal waters has been spilled. The energy executives acknowledged any harmful incident "can and will be used against us by those that want to see oil and gas operations cease." Luquette said, "Let's not give them anything to work with."

The oil executives emphasized their industry repeatedly has proven over the last 25 years it has the technical capability and procedures to minimize adverse risks to the natural environment. "We can operate in an environmentally responsible manner and in a way that accommodates joint use of federal lands and waters for other activities," Luquette said.

Cejka said, "To consumers of our products, the importance of innovation to the oil industry is often not readily apparent. Gasoline may not appear as technically sophisticated as many consumer electronic goods, for example. But…technology is the lifeblood of our industry. Technology infuses the entire supply chain, from the producing reservoirs to the service station. If you just walk around the exhibit floor here at OTC, you can see the incredible depth and breadth of the technology found in the oil and gas industry."

Major and independent producers have long supported a sustained energy policy that combines conservation and development of alternative and renewable fuels along with expansion of traditional energy sources such as oil and gas.

Luquette defended the Deepwater Royalties Relief Act (DWRRA) that has been attacked as a mere subsidy to offshore oil and gas producers. He said, "Not only was DWRR a success, it was a home run that revitalized production from the Gulf of Mexico. It was passed at a time of historically low crude oil prices as a means to increase domestic production and sustain jobs in a struggling industry." Because DWRRA provided near-term royalty relief for long-term production, more than 3,000 leases were issued in 1996-2000 in water depths exceeding 200 m. It helped increase deepwater gulf production by 50% in less than a decade.

Since Chevron is one of the largest leaseholders in the gulf, Luquette said, "We are troubled by the Department of Interior's decision to delay the MMS 5-year plan process, which was designed to address the critical energy concerns facing our nation." The decision, he said, ignores the fact more than two thirds of the US public have supported in polls the development of domestic resources. He said, "This delay means that development of US offshore resources could be stalled, depriving the nation of tens of thousands of new jobs, billions of dollars in revenues to federal, state, and local governments, and greater energy security."

Environmental regulations

Separately, a Washington coalition of US oil and natural gas producers released May 6 the findings of a major research initiative that concludes new federal environmental regulations—especially related to hydraulic fracturing—could have disastrous economic consequences and increase US dependence on foreign sources of oil.

"Implementing new federal regulations that threaten domestic energy production and increase costs—without creating any additional environmental benefits—is the wrong policy course for the country, and could cost thousands of hard-working Americans their jobs," said Lee Fuller, vice-president of government relations for the Independent Petroleum Association of America, one of the coalition organizers.

The coalition said that saddling producers with new, unnecessary, and ineffective environmental regulations could put them out of business, destroy jobs, and increase US dependence on foreign sources of energy. It added that this would be especially true if lawmakers in Congress move forward with plans to target hydraulic fracturing.

Industry's public image

As the oil and gas industry struggles to manage its public image and progress is made getting legislation passed through Congress, various stakeholders can improve dialogue through expanded forums and televised debates, delegates said May 4 during an OTC panel discussion.

The panelists, who represented energy consumers, academia, oil companies, and government, debated the challenges facing the energy industry and its stakeholders.

Consumers, in particular, are underrepresented in the energy policy debate, some delegates said, and with consumers worried about energy prices and security, politicians are finding it difficult to build an overarching framework for a comprehensive, balanced national energy policy.

"The public is very busy," said Jason Grumet, executive direction of the National Council on Energy Policy. "There is a limited bandwidth to engage the public, and the price of gasoline matters to them." He called on industry participants to improve communications among themselves as well as with the public.

The industry is rapidly changing with the cost of carbon dioxide becoming a major factor, the electrification of transportation, the growth of the middle class in emerging economies, and the demise of coal. One panelist, US Senator Lisa Murkowski (R-Alas.), called for increased domestic production in the US, arguing that $1.7 trillion of revenues could be generated if operators could access areas that are currently off limits. "If we don't produce oil, prices will go up and more jobs [will move] overseas. We need to share revenues with states that allow drilling. There is a scarcity of will to produce our own oil," she said.

Panelists agreed that stakeholders have more in common that one would think, but that rhetoric continues to undermine these commonalities. "People are talking past each other and there is no constructive debate going on because there are misconceptions on both sides," added Roger Ballentine,

president of Green Strategies Inc.

Jack Gerard, president and chief executive officer of the American Petroleum Institute, said it was important to establish with the public the perceived role that industry would play in supplying future energy resources. He said consumers had failed to understand certain realities: For example, when polled, 67% of the public felt the nation's energy problems could be solved through conservation and energy efficiency, but when consumers suffered $4/gal gasoline last year, their attitude changed. After the gasoline price spike, 67% of the public then called for development of the country's resources on the OCS.

"We don't want the government to pick winners and losers in the power and fuel debate," said Bill Graves, president of American Trucking Associations. "We need to appreciate the complexity of the transition to different fuels."

Although there is increasing public pressure to move to renewables to address climate change and sustainability, this alone will not fill the gap in meeting energy demand, delegates said. Different forms of energy are discussed within vacuums, which ignores their interconnectivity. Delegates agreed that expanding US oil and gas production, alternative energy, and nuclear power were the necessary steps over the next 8 years to increase energy supplies.

Grumet said, "We're in the midst of a transition, and we all want to get there, but the challenge is that we don't have a long-term goal articulated. Climate change [mitigation] is a step in the right direction, but people are not sure what energy independence means; what does the transition look like? We need to identify goals to have productive dialogue."

Oil firms' long-term strategies

Oil and gas companies are becoming more adept at maintaining long-term business strategy in the face of short-term uncertainty stemming from oil price cycles, OTC panelists said May 4.

During a general session entitled "Coping with price volatility: how will it affect major capital projects," executives discussed cost-cutting measures that include lowering capital budgets and renegotiating contracts.

"We are getting better at going through these cycles," said Luc Messier, ConocoPhillips senior vice-president. "We must keep our options open as far as assets and properties to develop. We've adjusted our operational expenses to…remain competitive."

Messier said current oil prices remind him of 2004 levels, but he noted that operating costs have doubled since 2004. Consequently, ConocoPhillips reduced drilling in the US Lower 48 as well as Western Canada.

Matthias Bichsel, executive vice-president of Royal Dutch Shell PLC, said the company quietly renegotiated some contracts with suppliers.

A presentation by Petroleo Brasilerio SA (Petrobras) mentioned renegotiating 360 exploration and production contracts. Solange Guedes, Petrobras executive director, prepared the talk but did not attend OTC. Cesar Palagi, Walker Ridge production asset manager with Petrobras America Inc. of Houston, was a substitute speaker for Guedes.

Patrick Pouyanne, Total senior vice-president of business development, said Total's solid balance sheet enables it to sustain a long-term investment strategy throughout price cycles.

"We want to avoid a stop-and-go policy," Pouyanne said in reference to massive layoffs that the industry experienced during previous oil-price slumps. "The basics of markets are changing, but it does not affect long-term trends."

Total is becoming increasingly more internally cost disciplined as it controls daily expenses, Pouyanne said. "We have to continue to believe that cost reduction will come from technology."

Dominique de Soras of Technip's subsea division was the only panelists representing an engineering firm. He briefly discussed the cost evolution of floating production, storage, and offloading vessels as well as subsea projects.

FPSO costs last year were twice as high as in 2003, largely because of "escalating raw material" costs, De Soras said. On subsea expenses, he attributed cost increases "very much on the installation side."

Technip remains committed to quality and continues to invest in research and development, De Soras said. The company boosted its payroll 34% during 2005-08, largely to hire young engineers, he said.

Reforms in Nigeria

Nigeria's operators are urging that the major industry reforms proposed under the country's latest petroleum industry bill to be quickly implemented to ensure regulatory certainty.

Speaking May 5 at an OTC topical lunch, Adewale Tinbu, group chief executive of Nigerian oil company Oando PLC, told attendees: "The reforms are good. We want to see more companies like ours being involved in the process as the focus tends to be on the international oil companies and national oil companies."

Nigeria announced plans in 2004 to break up its national oil company, Nigeria National Petroleum Corp. (NNPC), into smaller separate and autonomous units to end its conflicting roles of operator, regulator, and national assets management. With aspirations to have a similar model to Norway's StatoilHydro or Brazil's Petroleo Brasilerio SA (Petrobras), a new, integrated IOC, Nigerian National Petroleum Co. Ltd., will be created. Currently, NNPC has been unable to contribute its share of funding for joint venture projects as the government has not provided enough money.

Tinbu noted that NNPC should give assets to local oil companies under the reforms to help them develop. "We want community relations to be improved in the delta and as a hangover, I believe from colonialism, people look at [IOCs] as 'pseudogovernments.' There is a lack of local companies in the area, and we need to see wealth transfer in the area."

Tinbu said Oando has struggled to secure gas from IOCs in Nigeria for local distribution despite spending $300

million to build domestic pipelines and called on them to allocate it as their contribution to the country.

Faithful Abiyesorhu, NNPC group executive director of engineering and technology, urged industry players to be patient with the restructuring. "We hope to get it right. It will come with pains and gains, but the pains will be transient."

Mark Ward, lead country manager of ExxonMobil Corp. subsidiary companies in Nigeria, said that technology transfer and developing local people were important in its relationship with NNPC. "We spend $1 billion/year on [research and development] on technology," he said. "We have done work on 3D seismic; directional, horizontal, and extended-reach drilling; subsea technology; and multizone simulation." But during this downturn, it was critical to recognize that both parties had a long-term relationship, he said, adding, "National content must be realistic and achievable. We have workforce development, supplier development, and strategic community investment."

Eyo Ekpo, special advisor on projects in the Cross Rivers state, said it was crucial that the reform process was handled efficiently. "The new agencies need boundaries, resources, and capital and we need to make sure that the reform is not slowed down during the transition process to keep away people who have vested interests."

Emmanuel Egbogah, special advisor to the president on petroleum matters, told delegates that public hearings are scheduled for the petroleum industry bill in May. The National Assembly has passed the legislation in its first and second hearings.

"The reform also provides for the conversion of all the existing joint ventures into incorporation joint ventures (IJVs). Each IJV will be a corporate entity to be incorporated under the laws of Federal Republic of Nigeria," Egbogah said. "The incorporation process including capitalization and restructuring will be carried out through negotiations with the respective IOCs during the reform transition period."

Other highlights of the bill include creation of the following:

- National Petroleum Directorate, a policy body that will initiate, formulate, and develop policy and be a secretariat for the petroleum minister.
- National Petroleum Inspectorate, an autonomous technical regulator that will replace the Department of Petroleum Resources.
- National Petroleum Assets Management Agency, to manage petroleum assets and commercial regulation of the industry to ensure Nigeria derives maximum value from its oil and gas resources. (Will replace NAPIMS).
- Petroleum Products Regulatory Authority, to focus on the commercial downstream sector (Will replace PPPRA).
- A research and development center, to focus on capacity-building.
- Petroleum Training Institute.
- Establishment of fund organizations, including Petroleum Equalization Fund and Petroleum Technology Development Fund.
- Frontier Exploration Services, to regulate and stimulate exploration in frontier areas, including the Anambra, Benue Trough, Bida, Chad, Dahomey, and Sokoto basins.

MMS offshore forecast

MMS's 2009-18 forecast, released May 4 at OTC, shows Gulf of Mexico oil production reaching an average 1.879 million b/d in 2013 compared with the hurricane-affected production of 1.142 million b/d in 2008.

After the 2013 peak, MMS sees oil production decreasing to an average of 1.735 million b/d in 2018.

MMS includes condensate production in its oil production numbers.

In regard to natural gas, the forecast shows production averaging 7.03 bcfd in 2009 compared with 6.43 bcfd in 2008. From a high in 2009, the forecast decreases gas production to 6.22 bcfd in 2012 before starting an increasing trend that results in gas production reaching 8.27 bcfd in 2018.

MMS's forecast depends on the successful development of announced and undiscovered resources in the gulf.

The forecast shows a continued decrease in shallow-water oil production, reaching 82,000 b/d in 2018 compared with 313,000 b/d in 2008. Likewise, shallow-water gas production decreases to 900 MMcfd in 2018 compared with 3.84 bcfd in 2008.

In 2008, oil and gas operators announced 15 deepwater discoveries in the gulf and seven new projects started production in water deeper than 1,000 ft (see table).

MMS also notes that in 2008, 57% of all gulf leases were in water deeper than 1,000 ft and the gulf had 141 projects producing from deepwater. Additionally, 73% of the tracts receiving bids in the three lease sales held in 2008 were in deepwater areas of the gulf.

Pemex's deepwater gulf plan

Carlos Morales Gil, Pemex Exploration & Production general director, said Pemex is formulating a plan to ramp up exploration in the deepwater gulf and involve international and national oil companies in the process.

Without discussing specifics, Morales Gil said deepwater participation contracts will be written by mid-2009 that will allow IOCs, NOCs, and service companies to engage in technological collaboration with Pemex and generate value for all involved. Reserves will still belong to Mexico, he noted.

Pemex will put projects out for bids in late summer and award contracts in late 2009 or early 2010, he estimated May 6 at an OTC breakfast.

Overall, Pemex has identified 1,703 exploration opportunities, and 93% of them are onshore or in shallow water, Morales Gil said.

Pemex has identified seismic amplitude anomalies in five deepwater areas. From north to south along the coastal bend, they are called the Subsalt belt, Perdido fold belt, Mexican Ridges, Gulf Salt Province, and off Veracruz the Catemaco fold belt.

PUBLICLY ANNOUNCED DEEPWATER DISCOVERIES FOR 2008

Prospect Name	Area/Block	Water depth, ft	Operator
Diamond	Lloyd Ridge 370	9,975	Murphy Oil
Hal	Walker Ridge 848	7,657	Statoil/ExxonMobil
Tortuga	Mississippi Canyon 561	6,302	Noble Energy
Freedom	Mississippi Canyon 948	6,095	BP/Noble Energy
Dalmatian	Desoto Canyon 48	5,876	Murphy Oil
Kodiak	Mississippi Canyon 771	4,986	BP
(unnamed)	Green Canyon 448	3,266	LLOG Exploration
Gladden	Mississippi Canyon 800	3,116	Newfield Exploration
(unnamed)	Mississippi Canyon 503	3,099	LLOG Exploration
Geauxpher	Garden Banks 462	2,820	Mariner Energy
Anduin West	Mississippi Canyon 754	2,696	Newfield Exploration
Sargent	Garden Banks 339	2,180	Deep Gulf Energy
(unnamed)	Mississippi Canyon 72	2,013	LLOG Exploration
(unnamed)	Viosca Knoll 821	1,030	Walter Oil & Gas
Shaft	Green Canyon 141	1,003	LLOG Exploration

South of large oil fields on the US side of Perdido, Pemex has "identified structures that might be transborder resources," he said. And it plans to shoot wide azimuth seismic to obtain better images in the Catemaco nonassociated gas province.

Pemex has shot extensive 3D and 2D seismic and drilled eight wells in its gulf deepwater basins in 2000-08, discovering two nonassociated gas fields and two extra-heavy oil fields. One of the gas fields, Lakach, is Mexico's fourth largest, he said.

Deepwater exploratory drilling is to expand northward from Cantarell, and five rigs are to be working by 2012.

Aramco aims for 70% recovery rate

Saudi Aramco wants to improve its oil recovery rate to 70% from 50% over the next 20 years by focusing on enhanced oil recovery (EOR) techniques and other new technologies, said Amin H. Nasser, Aramco senior vice-president, exploration and production.

Nasser told delegates May 4 at OTC that the company wants to expand its resources from 742 billion bbl to 900 billion bbl to address the world's future energy needs. "In the most optimistic scenario, world oil demand is placed at 125 million b/d and this would require 15-40 million b/d of additional capacity and compensation for declining fields."

Increasing Aramco's reserves will have many challenges, however, particularly developing technologies to enhance production and developing a skilled workforce, which Nasser said in light of the economic downturn was the biggest concern. "We don't want to see huge layoffs as we did in the '80s and we only reacted to that in 2000. There is a big generation gap and it took almost 20 years to restore confidence. We are hiring at Saudi Aramco and putting high school people in universities around the world."

Nasser said collaboration between service companies, academia, national oil companies, international oil companies, and technology providers was crucial in overcoming the technology hurdle to fully exploit oil resources. These have decreased significantly in size and are difficult to access due to remote locations and complex geology. Nasser estimated that the world has 4.7 trillion bbl of recoverable and potential recoverable bbl, or at least 150 years of production at present levels.

Currently, Saudi Arabia has a spare production capacity of 4 million b/d. Nasser said last year had been an unusual year with the peak of oil prices at $147/bbl. "We told journalists there was enough capacity if needed for buyers of crude." It will focus on maintaining spare capacity of 1.5-2 million b/d, which is important in stabilizing the world market. "We're ready for the future if demand picks up," Nasser added.

He told OGJ that Saudi Arabia is in negotiations with its contractors to reduce prices as costs for materials and construction had dropped. "We think it will drop further, and this will allow us to do more work in the future. We have seen a slight drop of 10-15% in some service providers, but that doesn't match the going rate in 2005." He said he would like prices to fall a "lot more," but declined to give OGJ a target.

"It depends on what kind of contract it is," he said, adding, "We have excellent relationships with our contractors in Saudi Arabia—those where we haven't started construction we are negotiating. Others we think the cost should go down to match the crude price these days."

The company has been particularly successful in its water cut: For example, the Abqaiq Arab-D reservoir, which produces 300,000 b/d, has a water cut of 35%. Oil recovery from the field is expected to increase to 70% without EOR. Ghawar's water cut is 28% and it produces 5 million b/d of oil, he said. "Horizontal wells and equalizers to reduce the pressure drawdown helped with the water cut," Nasser said. "We previously had horizontal wells and people are now talking about SMART equalizers. It's expensive up front, but good over the long term."

Natural gas development is also a major issue in Saudi Arabia. The kingdom wants to boost gas processing capacity to 9 bscfd from 6.2 bscfd by 2015, which will meet local demand and serve the petrochemicals industry.

Saudi Arabia's Khurais field

Meanwhile, the giant Khurais oil and gas field in Saudi Arabia is on schedule to start production by the end of June, according to Aramco's Nasser. The $10 billion project will come on earlier than expected as it was originally slated for completion by yearend.

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OTC Spotlight on Technology recognizes 14 technologies

Guntis Moritis
Production Editor

The 2009 Offshore Technology Conference in its Spotlight on New Technology awards recognized 14 innovations that provide benefits beyond existing technologies. To qualify for the award, companies have to have proved out the technology through either full-scale applications or successful prototype testing.

Award recipients included:

- 2H Offshore for the INTEGRistick dynamic curvature sensor to monitor the condition of deepwater subsea structures.
- Schlumberger Ltd. for the subsea subC-strip and subC-collar to monitor the condition of subsea flowlines.
- GE Oil & Gas Co. for the VetcoGray SemStar5 subsea electronics module to control subsea production.
- Baker Hughes Inc. for the TORXS expandable liner hanger system.
- Baker Hughes for the Frac-Hook multilateral system to facilite hydraulic fracturing.
- Weatherford International Ltd. for the OneTrip StarBurst multilateral system.
- Cameron-Nautronix for the NAS-MUX acoustic system to control subsea blowout preventers.
- Reelwell AS for the Reelwell Drilling Method (RDM) to facilitate managed pressure drilling.
- US Synthetic Bearings for polycrystalline diamond radial bearings for installation in mud motors, turbines, power generation, and rotary steerable tools.
- Welltec AS for the Well Cleaner PST power suction tool for cleaning sand from wells.
- ProPure AS for the compact one-shot ProSalt mixer system, used in desalting crude.
- Technip for the amplitude-LNG loading system.
- Schlumberger's WesternGeco unit for coil shooting that acquires full-azimuth marine seismic data continuously with a circular geometry, using one vessel.
- Specialized Products Co. for pulse technology-battery maintenance, conditioning and charging.

Structure, flowline monitoring

Two awards went to technologies for monitoring the state of offshore structures and flowlines.

2H Offshore's INTEGRistick dynamic curvature sensor incorporates several strain gauges inside a corrosion-resistant metal housing to measure biplanar curvature changes to subsea structures to a resolution of 1 µstrain, creep free.

The company says it can be used as a standalone battery-powered unit or as a permanent online system, such as deployed on the Chevron Corp. Tahiti steel-catenary-riser (SCR) monitoring system.

Schlumberger's subsea subC-strip and subrC-collar is another technology deployed on Chevron's Tahiti project. The 600-ft optical sensors continuously monitor the flowline for buckle shape, pipe axial, and hoop strain and temperature, providing a picture of buckle response to operational production cycles.

Data transfer is via a field umbilical using a low-power optical modem communication system to the topsides data acquisition system.

Subsea production control

One award went to VetcoGray, a GE Oil & Gas Co., for its SemStar5, a subsea electronics module for controlling subsea production. The SEM has an open architecture IP enabled communication capabilities, a modular design, and subsea plug-and-play capabilities.

The SEM supports industry-standard interfaces SIIS 1-3 and IWIS as well as full sensor interface capability.

Well completions

Three awards went to technologies to facilitate well completions.

The Baker Hughes TORXS expandable liner hanger system has a variable-diameter swage and enables the running tool to expand the liner hanger before displacing cement. Expansion

Khurais is about 90 miles east of Riyadh. The field will produce 1.2 million b/d and is the largest increment delivered in the world, Nasser said. "We have increased capacity by 20% by bringing on major increments onstream between 2004-09." By yearend, Aramco will have 12 million b/d of production capacity after it has completed all of its major development projects. Khurais, in addition to the 1.2 million b/d, is expected to produce 420 MMcfd of natural gas and 70,000 b/d of condensate (OGJ, May 8, 2006, p. 19).

The project has been challenging because during the boom period when oil prices were soaring; there was a shortage of labor and materials. Now, however, the field will start production in a very different market with oil prices in the $50/bbl range and shrinking demand because of the global recession.

Saudi officials have said Khurais, with at least 12 billion bbl of recoverable oil, is only 1.8% depleted (OGJ, Apr. 5, 2004, p. 18). This is the country's second-largest oil field and requires 310 wells to deliver the production. The drilling program was expected to take 3 years, but was finished 10 months ahead of schedule on Feb. 10 due to improvements in engineering and operations. It will typically use single horizontal lateral wells equipped with inflow control devices for water production management.

of the hanger does not reduce the system's annular flow area. Packer setting occurs after displacing cement and is not dependent on plug bump. The company says the liner hanger uses balanced hydraulics so that one can safely rotate the liner and circulate down, without risk of premature activations.

Baker Hughes's other award was for the Frac-Hook multilateral system that allows operators to pinpoint the placement of hydraulic fracturing jobs, providing greater access and control of laterals, according to the company.

Weatherford International Ltd. received an award for its OneTrip StarBurst multilateral system, which the company claims is the industry's first one-trip Level 4 multilateral system.

It says the system because of the faster installation time is particularly well suited for wells in mature fields with declining production rates.

Drilling

Four awards concerned drilling technologies.

Cameron-Nautronix's NASMUX is an acoustic system for controlling subsea blowout preventers (BOPs) and is an alternative to multiplexed control systems. The system replaces the command, control, and monitoring aspects of a control umbilical with an acoustic system that minimizes topsides equipment, the company says.

The Reelwell Drilling Method (RDM) allows accurate pressure management and improved well control through closed loop fluid circulation, making it especially attractive for managed pressure drilling, according to Reelwell.

US Synthetic Bearings says its diamond radial bearings lengthen the bearing life of drilling mud motors and turbines compared with tungsten carbide or other hard metal bearings. The company uses its patent process to form and machine the polycrystalline diamond pads.

These bearings are for bit bearing applications such as in mud motors, turbines, power generation, and rotary steerable tools.

Welltec says its Well Cleaner PST power suction tool is for cleaning out sand from wells and can replace coiled tubing or slickline bailer sand cleanouts in high angle wells. The StatoilHydro and Royal Dutch Shell Group sponsored technology, run on electric-line, can lift sand into long bailer sections and has a 1 tonne/run bailing capacity compared with a 4-9 l./run capacity of slickline bailers, the company says.

Processing

One award went to a new crude desalting process.

ProPure AS's compact one-shot ProSalt mixer system combines freshwater injection and crude-fresh water mixing by imposing a homogeneous shear stress of the dispersed fresh-crude flow.

The company says that this desalting process provides a homogeneous freshwater droplet size distribution, resulting in a more separable freshwater-crude mixture and correspondingly better use of injected fresh water.

LNG

Technip received an award for its amplitude-LNG loading system that allows the transfer of LNG in dynamic offshore conditions and involved the development and qualification of a new heavy-duty cryogenic flexible pipe systems.

The company says the flexible pipe is the key component of the loading system and expands the methods for transfer of LNG in offshore and near shore marine conditions.

Seismic

One award went to a seismic acquisition process. The WesternGeco coil shooting method acquires full-azimuth marine seismic data continuously with a circular geometry with a single seismic vessel.

Coil Shooting enhances current multi and wide-azimuth acquisition techniques that are used in complex geological areas, the company says.

Batteries

Specialized Products received an award for its pulse technology-battery maintenance, conditioning and charging that helps prevent battery failure caused by battery plate sulfation and related failure modes.

The company says that it has proved that the technology extends battery life by up to 5 times.

Smart electrical submersible pumps also will be installed.

Aramco originally planned to use 16 rigs run by three divisions over 3 years, but this was changed to 12 rigs in two divisions over a 2-year schedule. Drilling days were cut from 40 days to 25 days because of strong communication between the company and its contractors and working alongside each other in the same office.

In November 2008, Aramco inaugurated its central processing facility water injection plant (WIP), which uses combustion gas turbines. This allows 620,000 b/d of seawater injection and more pressure.

The seawater journey starts at the new treatment modules at Qurayyah seawater plant and flows to Ain Dar WIP in a 56-in. quad pipeline. Booster pumps increase the pressure at Ain Dar WIP, forcing water to flow to Khurais in the 60-in. Ain Dar Khurais-1 pipeline. The Khurais project will use five WIP trains that will inject 2.1 million b/d of treated seawater into Khurais, Abu Jifan, and Mazalij fields to maintain reservoir pressure.

Discovered 65 miles west of supergiant Ghawar field in 1957, Khurais began production in 1970 and had yielded 111 million bbl by mid-1979, when output averaged 33,000 b/d. It was later shut in, and the project to restart it began in 2005. ✦

KPMG: Executives doubt energy independence by 2030

Sam Fletcher
Senior Writer

Despite the emphasis on alternative energy sources in current and proposed government energy policies, the US cannot attain energy independence by 2030, said a majority of oil and gas executives recently surveyed by KPMG LLP's Global Energy Institute.

Most surveyed said mass production of alternative energy simply is not viable in the short term. And while there is a marked shift in their acknowledgement of global warming, the majority does not support proposed regulations to stem carbon dioxide emissions.

Since Richard Nixon, US presidents have talked about energy independence. President Barack Obama has called for this country to be independent of crude supplies from Persian Gulf producers by 2020 and from all members of the Organization of Petroleum Exporting Countries by 2025. By 2030, he hopes to see renewable energy sources taking much of the national market share from fossil fuels.

But of the 382 oil and gas financial executives polled by KPMG in April, 63% said energy independence is not possible until after 2030. Only 16% said it might happen by 2030, while an optimistic 9% said independence is possible before 2020.

Also, 63% of the respondents said Obama's plan to eliminate tax breaks for intangible drilling costs will actually push more companies to shift their drilling efforts overseas and will result in unconventional oil and gas wells not being drilled in the US, a factor that likely will slow the race toward energy independence.

"Despite the increased focus on domestic energy sources, energy infrastructure, and alternative energy sources, a realistic assessment of technology and investment in the industry suggests energy independence is not realistic for at least 2 decades," said Bill Kimble, executive director of KPMG Global Energy Institute. "The executives' perceptions of energy independence mirror their views on the viability of alternatives in the near term as well."

Oil and gas executives expect Obama's energy policy to focus primarily on alternative and renewable energy sources. However, 52% said mass production of any alternative energy just isn't feasible by 2015. That's down from 54% last year and 60% from 2 years ago.

Winners and losers

Oil and gas executives are uncertain about which of the competing energy sources will benefit most from the Obama administration's energy policy. The largest segment, 35%, expects wind energy to get the biggest boost. However, 18% favor natural gas, and 17% opted for biofuels. Conversely, 42% of the executives see coal as the biggest loser while 36% said oil will be hardest hit.

"These results clearly show the momentum wind energy has gained as a clean-energy solution," said Kimble. "But 93% of our respondents see wind generation growing to only 6% of our energy generation by 2015 and only 17% say wind energy will be viable for mass production by that year."

Next to alternative energy, the executives said the subjects that will be under the sharpest focus from the new administration will be greenhouse gas emissions and the cap-and-trade program. The Environmental Protection Agency recently concluded CO_2 emissions from burning fossil fuels are the main cause of global warming. Yet 47% of the company executives polled are still convinced global warming is only a natural weather cycle. However, that number is down from 62% in KPMG's 2008 survey.

"Our data shows a noted swing in executive perceptions on the issue of greenhouse gases and global warming," said Kimble, "but there is clear reluctance to support proposed actions and regulations to stem CO_2 emissions."

In fact, when asked if they would support a cap-and-trade or carbon tax to reduce CO_2 emissions, KPMG found 59% do not support either, 23% would support carbon tax, and 18% would support a cap-and-trade system.

In late April, a ConocoPhillips official told the US House Energy and Commerce Committee refiners will be hit harder than other US manufacturers under proposed cap-and-trade legislation. Red Cavaney, ConocoPhillips's senior vice-president of public affairs, said, unlike other manufacturers, refiners could not pass on the $68 billion the US Energy Information Administration estimated refiners would pay annually under a $25/ton carbon tax under a measure that includes collections of end-users' carbon taxes in addition to levies on refiners' greenhouse gases under the measure (OGJ Online, Apr. 23, 2009).

Spending outlook

Industry executives were pessimistic in their outlook for capital spending and key business issues. Of those surveyed, 65% expect their companies to reduce capital budgets this year, including 47% who expect spending to drop more than 10%. Only 17% expect to increase spending from 2008 levels. KPMG officials said that's a "stark contrast" to their 2008 survey when 70% of the respondents anticipated an increase in capital spending and only 5% expected a decrease.

Although oil prices have stabilized in recent weeks, KPMG found executives still rank commodity pricing as the major challenge facing their companies in the coming year. Other key business challenges in order of significance include the economy, access to capital, and regulatory concerns.

"There is no question that the economy has had an impact on US energy

companies, both in terms of pricing and capital," said Kimble. "However, with the current regulatory and legislative environment, oil and gas executives are also faced with the challenges of an evolving and dynamic industry pushing toward non-traditional energy sources."

KPMG officials plan to discuss survey results at the firm's Seventh Annual Global Energy Conference for financial executives May 12-13 at the Intercontinental Hotel in Houston. Keynote speakers will be Madeleine Albright, former US Secretary of State under President Bill Clinton; and Marvin Odum, president of Shell Oil Co.

KPMG LLP is a tax and advisory firm and the US member of KPMG International; the parent firm has more than 7,600 partners in 144 countries. ✦

House members revive bill to expand OCS activity

Nick Snow
Washington Editor

US House members who tried to legislatively repeal offshore drilling bans in previous sessions introduced a bill on May 4 to restore a 5-year Outer Continental Shelf plan, which US Interior Secretary Ken Salazar has delayed.

Rep. Tim Murphy (R-Pa.) sponsored the bill, HR 2227, with Neil Abercrombie (D-Ha.). Cosponsors are Shelley Moore Capito (R-W.Va.), Jim Costa (D-Calif.), Joe Wilson (R-SC), Timothy J. Walz (D-Minn.), and Lee Terry (R-Neb.). It was immediately referred to the Natural Resources Committee.

On Feb. 10 Salazar announced that he would delay implementation for 6 months of a 5-year OCS plan for 2010-15 that his predecessor, Dirk A. Kempthorne, had launched the previous summer in response to record retail gasoline prices.

The current secretary said he wanted the plan to include alternative and re-

Iran's trade sanctions

US trade sanctions have applied to Iran since 1996. One goal of denying that country's national oil company access to American goods, services, and technology has been to punish its government for allegedly trying to gain nuclear weapons.

Several members of Congress now want the US to be ready to turn up the heat. They've introduced bills in the House and Senate that would bar foreign suppliers of refined products to Iran from effectively doing business in the US.

HR 2194, which Rep. Howard L. Berman (D-Calif.) introduced on Apr. 30, also would apply to any non-US firm which finances, brokers, underwrites, or provides ships to help Iran import refined products. It also would apply to any foreign entity that provides goods and services for Iran's refining industry.

The country's limited refining capacity makes it necessary for it to import 25% of the products it consumes, according to Berman, who chairs the House Foreign Affairs Committee. Without these imports, much of the country's economy would grind to a halt, he said.

Won't move immediately

Berman said he doesn't plan to start his bill, which has six Democratic and Republican cosponsors, on its way through the legislative process soon because he fully supports the Obama administration's strategy of direct diplomatic strategy with Iran.

"However, should engagement with Iran not yield the desired results in a reasonable period of time, we will have no choice but to press forward with additional sanctions, such as those contained in this bill, that could truly cripple the Iranian economy," he said.

Berman introduced his bill a day after Sen. Evan Bayh (D-Ind.) introduced a similar measure on the other side of the Capitol. Bayh said his bill, S. 908, was designed to give Obama another diplomatic tool to keep Iran from getting nuclear weapons.

"This bill gives the president the express authority to target the regime's Achilles heel," said Minority Whip Jon Kyl (R-Ariz.), one of S. 908's 24 Democratic and Republican cosponsors.

'Give them a choice'

"We know who these companies are (Shell, Vito, BP, and Reliance) and we need to give them a choice: You can do business with Iran's $250 billion economy or our $13 trillion economy, but not both," Kyl said.

On May 1, Mark Dubowitz, executive director of the Foundation for Defense of Democracies in Washington, said the bills sent a strong message that Iran's nuclear weapons program won't be tolerated.

"Like Chairman Berman, we all hope the regime will see the light and that this legislation will not be needed. Congress recognizes that diplomacy is more likely to succeed if Iran's leaders understand that they will face dire consequences if they press ahead with their illegal nuclear program," he said.

But the bills probably are more symbolic than substantive since two of the multinational companies Kyl mentioned, BP and Shell, have US subsidiaries holding much of this country's refining capacity. ✦

newable energy sources. He ordered the US Geological Survey and US Minerals Management Service to prepare an evaluation of US offshore conventional and alternative resource potential, and held four public meetings to receive additional comments.

HR 2227's proposed offshore leasing provisions also provide jurisdiction for state royalty payments over a wider area by extending coastal states' boundaries to a uniform 12 miles from 3 miles. It also would repeal the 125-mile moratorium on oil and gas production in the eastern Gulf of Mexico, establish an expedited inventory of offshore energy resources, and mandate procedures to expedite judicial reviews of oil and gas leases.

Other provisions

The bill also would prohibit surface occupancy within 10 miles of the shoreline and permanent surface occupancy within 20 miles. It would open offshore resources 20 miles and further out, and mandate mitigation of offshore facilities on coastal vistas. It would mandate federal agency coordination with adjacent states on construction of pipelines to move oil and gas from the OCS. Interior also would have to coordinate leasing with the US Department of Defense and refer any unresolved issues to the president for an immediate decision.

The bill also contains provisions to share OCS oil and gas revenues, including 30% to states directly affected by activity, 20% to pay for alternative energy and conservation tax incentives, 10% for clean coal technology development, 10% for environmental restoration, 10% for the general federal treasury, 8% for conservation programs, 5% for carbon-free technology including nuclear power, 5% for water programs, and 2% for low-income home energy assistance.

The bill's second title would modify the Strategic Petroleum Reserve to reflect current refining capabilities by exchanging 70 million bbl, or 10% of its content, and dedicating the projected $400 million of proceeds to existing conservation, assistance, and energy research and development programs.

The bill's third title would extend alternative and renewable energy tax credits to 2019, while its fourth title would encourage development of electric-powered motor vehicles.

The bill's sponsors, Murphy and Abercrombie, said they met regularly with other cosponsors over several weeks to develop a comprehensive energy bill. "This legislation will be paid for: developing our own resource will bring an estimated $2.2-3.7 trillion in federal revenue," he said on May 5.

'Begin the path'

"With this bill, we truly begin the path toward a clean-energy future by investing in clean energy, creating US jobs immediately and long into the future, and cleaning the environment, all without raising taxes," Murphy said.

Wilson said the bill was particularly important to South Carolina because it contains provisions to expand and develop nuclear power. Additionally, a sizable portion of the royalties and revenues garnered from offshore oil and natural gas exploration will be returned to the coastal states; and the tourism and hospitality industry that is so vital to coastal communities will not be adversely affected because all offshore activity will take place far beyond the line of sight, he said.

American Petroleum Institute Pres. Jack N. Gerard reacted favorably to the bill's introduction, calling it a step in the right direction.

"This bipartisan bill recognizes the importance of increased access to offshore oil and natural gas resources not only to our nation's economy, in terms of generating federal, state, and local revenues and new well-paying jobs, but also to America's energy security," he said. ✦

Brazil announces 'two-pronged' energy policy

Eric Watkins
Oil Diplomacy Editor

The Brazilian government announced plans to overhaul the country's energy basket with more emphasis on renewable resources, even as it continues with oil and natural gas development plans.

Brazil's Environment Minister Carlos Minc presented his country's new balance of energy sources at the ministerial meeting of the Group of Eight countries in Siracusa, Italy, which Brazil attended as a guest.

Brazil's plan reflects "the spirit of the fifth Summit of the Americas," according to a report by the Inter Press Service (IPS), which said that earlier meeting discussed a proposal for North and South American countries to generate 50% of their energy from renewable sources by 2050.

Neither the Brazilian government nor state-run Petroleo Brasileiro SA (Petrobras) is willing to stop producing oil and natural gas or to decrease output.

Petrobras produces 1.9 million b/d of oil, but that figure is scheduled to rise to 3.1 million b/d by 2020 due to the discovery of offshore pre-salt reserves. Downstream, Petrobras is building five refineries, aiming to increase Brazil's refining capacity to 3.2 million b/d by 2020.

"We want to increase our refining capacity in order to become a large producer of refined products. We aim to make Petrobras not only a major exporter of crude, but also of oil byproducts," said Petrobras Chief Executive Officer Jose Sergio Gabrielli.

Jean Paul Prates, energy secretary

for the Brazilian state of Rio Grande do Norte, said Brazil's model for the development and marketing of traditional hydrocarbons will be "completely different from that of traditional oil exporters, like the Arab countries or Venezuela.

"It will be a model oriented toward domestic consumption, to satisfy our energy needs first, and then export the surplus. And it will still generate wealth for the country," Prates told IPS.

Renewable energy

In addition to traditional hydrocarbons, the government of President Luiz Inácio Lula da Silva will invest more heavily in other renewable energy sources including biodiesel and ethanol made from sugarcane.

The Sugarcane Industry Association (UNICA) reports 46% of the Brazilian energy mix already is based on renewable sources. Ethanol accounts for 16%.

In Brazil, 90% of new vehicles have flex-fuel engines that can run on gasoline and ethanol. New vehicles account for 25% of all cars in the country.

UNICA reports this has cut Brazil's emissions of carbon dioxide, the main greenhouse gas, by 50 million tonnes since 2003.

Ethanol production

UNICA's promotion of ethanol, however, has drawn criticism from those concerned about competition between planting crops for energy or food.

Others question the benefits of biofuels for the environment. The International Council for Science (ICSU) reported that biofuel production may even increase, rather than decrease, global warming.

ICSU said the process of farming crops like sugarcane in Brazil and corn in the US releases amounts of nitrous oxide, another greenhouse gas, that more than counteract the benefit of lowering emissions of CO_2 generated by burning ethanol instead of gasoline.

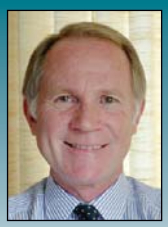
'Degraded land'

The Brazilian government said only

WATCHING THE WORLD

Eric Watkins, Oil Diplomacy Editor

Blog at www.ogjonline.com



Alberta's premier visits OPEC

Alberta Premier Ed Stelmach has the interests of his province's oil and gas industry very much at heart. He's right to do so, given Alberta's parlous state of employment.

Alberta is experiencing enormous layoffs province-wide as the development of new supplies of oil and gas—conventional and oil sands—all but grinds to a halt, according to a recent report by the Calgary Herald.

"Thousands of oil field workers have lost their jobs and most of the survivors are taking pay cuts to sustain theirs," the paper said, adding, "Many of the smaller drilling, service, and oil companies are experiencing severe financial difficulty."

Not surprisingly, the Calgary newspaper asked a highly pertinent question: "What will Ed Stelmach's response be to Alberta's economic meltdown?"

Well, one of his responses—and he may well have others we don't know about—has been to take a trip to Switzerland and Austria. It wasn't a vacation or an opportunity to check a numbered bank account.

Advocating Alberta

To the contrary, Stelmach went to advocate on behalf of Alberta's trade, investment, and energy interests with two of the world's most powerful economic organizations: the Organization of Petroleum Exporting Countries and the World Trade Organization.

"These two organizations represent the core businesses that are critical to our success—energy, investment, and trade," said Stelmach, who, among other things, planned to reinforce Alberta's commitment to responsible energy development.

"It's always important that we build relationships and position our interests with our international partners—but during these challenging economic times it's not only important, it's vital," the premier said.

On May 4, Stelmach delivered the keynote address at the Alberta Economic Forum in Geneva, telling his audience that his province "has the good fortune to be sitting on a tremendous energy treasure."

Stelmach referred to the oil sands of Northeast Alberta, which "contain proven reserves of more than 173 billion bbl of oil" and could hold "as much as 334 billion bbl" of recoverable oil.

Commitment and expertise

Not least, Stelmach said, "We have the commitment and expertise to ensure that Alberta energy is clean energy, produced in a responsible manner and employing the best science and technology available."

Stelmach also carried that message into a meeting with Bjorn Stigson, president of the World Business Council for Sustainable Development, a forum for 200 companies—among them Suncor, Chevron, Total, and Shell—to explore sustainable development and best practices.

In Vienna, Stelmach met with OPEC Sec.-Gen. Abdalla Salem El-Badri, to focus on the challenges and opportunities facing oil-producing regions, such as environmental initiatives and the global impact of oil prices, production, and supply.

All in all, it was not a bad outing for the Alberta premier, and one that clearly had his constituents' backs. With a price tag of just $52,000 (Can.) for Stelmach and two staffers, it also did not get their backs up. ✦

1% of the land suitable for agriculture in Brazil is used to grow sugarcane. As a result, the government plans to step up the recovery and use of degraded land to plant sugarcane.

Brazil and the US contribute 70% of the world's ethanol output. The Brazilian government's energy policy aims to produce 23.3 billion l./year of ethanol and to export 5 billion l. For biodiesel, the goal is to reach production of 3.3 billion l./year by 2010.

Petrobras has three new biodiesel plants and plans to produce 640 million l./year by 2013. Including ethanol, the company plans to spend $2.8 billion on biofuels up to 2013.

Gabrielli said it's important to increase exports to make Brazil one of the top players in the world ethanol market.

"Forty years of experience with ethanol in this country shows that this biofuel is not a threat to food security; on the contrary, food production has increased," Gabrielli told IPS.

Production capacity on land "appropriate for ethanol cultivation" has increased, and labor conditions for sugarcane workers have improved, Gabrielli said. "We believe it is possible to increase production of crops for biofuels in degraded areas, on land that is not being used for food production," he added. ✦

Costa Rica nixes exploration; wants Chinese refinery

Eric Watkins
Oil Diplomacy Editor

Costa Rican President Oscar Arias, reversing earlier statements of his own government, has declared his opposition to any oil and gas exploration in his country, recently described as a "biogem" by environmentalists.

"We will continue with our commitment to not permit oil exploration on Costa Rican soil," Arias said in a speech before the Costa Rican Congress. "It is a decision I made some time ago—to not have oil exploration."

The statement apparently reverses a long-standing policy of the Arias government to encourage exploration in the Central American country.

In May 2006, Arias said Costa Rica's Refinadora Costarricense de Petroleo (Recope) was in accord with Brazil's state-run Petroleo Brasileiro SA (Petrobras) "in studying the feasibility of oil exploration 50 miles off the coast."

At the time Luiz Furlan, minister for development, industry, and commerce, underlined Aria's view: "The technology for deepwater exploration is available to Costa Rica, and we will meet in order to see where we can cooperate.... Costa Rican technicians will go to Brazil in order to understand the process."

In January 2008, Environment and Energy Minister Roberto Dobles announced plans by China National Oil & Gas Exploration & Development Corp. [now known as China Southern Petroleum Exploration & Development Corp., based in Guangzhou and a subsidiary of China National Petroleum Corp.] to explore Costa Rican territorial waters.

"The matter of petroleum exploration was always one of the possibilities for us, even before the current government," Dobles said, adding that a bilateral panel was already at work drafting a formal proposal for prospecting off Costa Rica's Caribbean coast.

Dobles said any exploration would be guided by a policy mandating "any energy project must also be environmental and social" and that "no one will be able to explore in protected areas or in indigenous reserves, and high environmental standards will be demanded."

Still, Dobles said, "We cannot put the country's energy at risk." He noted unless Costa Rica discovers oil at home, it would likely be forced to import the kind of heavy crude coming out of Venezuela, which is expensive to refine and generates more pollution than lighter grades of oil.

Aria's turn-around echoes statements by Costa Rica's former President Abel Pacheco [2002-06] who declared a "moratorium on all petroleum exploration and production" and who said his country would become an "environmental leader and not a petroleum or mining enclave."

At the time, Pacheco declared, "Costa Rica's true petroleum and true gold are the water and oxygen produced" by its rainforests.

The Pacheco moratorium prompted Harken Energy Corp. to file suit against the Costa Rican government over a 1998 contract that allowed it to explore for oil in the Caribbean, an agreement that was revoked by Pacheco in 2005.

Costa Rica becomes 'biogem'

In February, the Natural Resources Defense Council named Costa Rica as a "biogem," and said it is working with government officials "to help the country meet its commitment of becoming the world's first carbon-neutral nation by 2021."

NRDC signed an agreement with Costa Rica's national electric utility Instituto Costarricense de Electricidad on energy efficiency and renewable energy projects.

In partnership with the Centro Agronomico Tropical de Investigacion y Enseanza in Costa Rica, NRDC launched a rainforest rejuvenation project to plant 30,000 trees to restore a natural rainforest. "These actions will help Costa Rica reaffirm its position as a global environmental leader and reduce pressure on its biodiversity and other natural areas," NDRC said.

While Costa Rica may eschew exploration for oil and gas, it remains in negotiation with Venezuela for admission to the PetroCaribe program under which Caracas allows countries to

receive oil at discounted prices.

Earlier this month, moreover, Costa Rica affirmed the validity of a contract signed by Chinese President Hu Jintao on a 25-year agreement to help expand Costa Rica's Moin refinery to 60,000 b/d by 2013 from the current 25,000 b/d.

Additionally, CNPC and Costa Rica's Recope are jointly evaluating plans to set up a $6 billion Costa Rican refinery with a processing capacity of 200,000 b/d (OGJ Online, Dec. 1, 2008).

According to one industry analyst, Costa Rica's agreement with China for the refinery "left the door open" for CNPC to explore for oil off Costa Rica's Caribbean coast—a door that for now at least has now been firmly shut. ✦

Scotland identifies potential UK North Sea CCS sites

Uchenna Izundu
International Editor

The UK North Sea could hold millions of tonnes of carbon emissions in saline aquifers and depleted oil and gas fields, but government must support carbon capture and storage (CCS) technology development, a report said.

The report, entitled Opportunities for Carbon Dioxide Storage Around Scotland, was prepared by the Scottish Centre for Carbon Storage, the Scottish government, and industry partners. Similar reports have been prepared by others for regions elsewhere around the world.

Scotland could play a pivotal role in the CCS sector with the creation of 10,000 jobs, and the CO_2 storage capacity is comparable with Norway and greater than the Netherlands, Denmark, and Germany combined, the study said.

It found industrial emissions, including those from electric power plants, could be injected into the northern and central North Sea, opening storage options for continental Europe. The report mentioned 10 saline aquifers and 29 hydrocarbon fields.

More than 90% of storage capacity lies within large saline aquifers positioned at several different levels and typically 1-3 km deep beneath the seabed, and often close to oil and gas fields.

Pressure is growing on member states to meet the European Union's requirement that by 2015 there are 12 demonstration sites with CCS on full-sized electric power plants. The next steps involve more detailed mapping and evaluation of specific saline aquifers.

Industry response

Experts say it is unlikely that CCS technology would be developed unless it was supported by the government. Cost estimates range from £750 million to more than £1 billion.

Utility company Scottish Power hopes to start capturing carbon within 5 years in Scotland. E.On UK plans to build a £1.5 billion coal-fired electric power station at Kingsnorth, Kent—the first in the country in more than 30 years.

Paul Golby, chief executive of E.On UK, said the company was committed to fit capture technology at the plant as long as it was properly funded. E.On hopes to send CO_2 to Hewett gas field in the southern North Sea by pipeline and is looking at different routes.

E.On proposes several fossil-fired electric power stations and other industrial sites be linked to the same carbon transportation system.

Jeff Chapman, chief executive of the Carbon Capture and Storage Association, urged government to move quickly if it wants the UK to be a pioneer. He said government must ensure that any funding mechanism is sustainable for long-term technology development.

The UK launched a competition in 2007 to support a CCS demonstration. The winner is expected to be announced at midyear. Contenders are E.On UK, Peel Power, and Scottish Power. ✦

UK chancellor offers incentives for challenging fields

Uchenna Izundu
International Editor

Operators focused on small and challenging projects in the UK North Sea that are offered investment incentives by Chancellor Alastair Darling in his 2009 budget to unlock 2 billion bbl and enhance indigenous production.

As oil prices have fallen from $147/bbl last July to a range around $50/bbl today, Darling has come under intense pressure to offer tax breaks to the industry. Recently published data by Deloitte LLP showed there was a 78% fall in exploration drilling in this year's first quarter compared with a year ago due to low oil prices, high costs, and financing difficulties. According to Deloitte, the government's tax receipts from the North Sea is expected to almost halve in 2009-10.

Darling will introduce a new "field allowance" to offset against the supplementary charge (reducing the tax rate to 30% from 50%) whereby operators would have a variable limit on tax-free income, with anything above that limit to be taxed. This measure would apply to small, and high-pressure, high-temperature, and heavy-oil fields that now can be economically developed at low oil prices. It is effective for qualifying fields given development consent on or after Apr. 22.

Jim Hannon, managing director of North Sea consultancy firm Hannon Westwood LLP, said the proposal has the "potential not only to sustain drilling on the current stock of over 300 discoveries but would have an indirect benefit on exploration drilling." Even if oil prices increase in the coming months, Hannon claimed the "field allowance scheme remained valid and capable of driving a more sustained level of investment, particularly so in a competitive world of oil and gas exploration, in which the UK has to maintain its attractiveness."

Highlights of the budget for UK North Sea operators included:

- Removing any income from change-of-use activities from the scope of the petroleum revenue tax and allowing relief against corporation tax and the petroleum revenue tax for decommissioning costs for change-of-use assets.
- Capital allowances available for cushion gas in gas storage projects.
- Chargeable gains on North Sea asset disposals to be exempt if proceeds are reinvested in the UKCS or licenses of the same value are swapped, effective from Apr. 22.
- Measures to reduce the administrative burden of the petroleum revenue tax and repeal of obsolete associated legislation.

Responses

KPMG said the tax changes will provide incentives to change the use of fields and provide for capital gains on license swap deals. But it raised concerns about the modified decommissioning rules where Darling pledged to "...ensure companies cannot access tax relief for decommissioning oil and gas infrastructure years in advance of the decommissioning actually being carried out." This approach is to stop tax avoidance schemes.

Derrick Parkes, an energy tax partner with KPMG, said: "Other detailed changes regarding change of use of existing field assets, capital gains on license swaps, and sales provide welcome clarity and relief, but the countering of arrangements to advance North Sea decommissioning relief will disappoint some."

Andrew Ogram, oil and gas tax partner at Deloitte, said although the announcements were welcome, the chancellor missed the opportunity to introduce additional incentives for exploration in the UK given the low prices and declining exploration activity.

Meanwhile, trade association Oil & Gas UK (OGUK), which has been lobbying for tax changes to stimulate investment, cautiously welcomed the package (OGJ Online, Apr. 23, 2009).

Malcolm Webb, OGUK chief executive, said the measures were a positive step for those companies trying to develop small and challenging fields in this mature, high-cost province. "However, we now need to direct our attention to sustaining and promoting investment in and around many of our older fields to prolong their lives, to stimulating exploration activity and to opening up the frontier areas west of Shetland and in that regard, we welcome the government's offer of a continued dialogue."

But OGUK was disappointed that there was no improvement for small companies to access equity markets, which is making it nearly impossible for them to continue exploration.

The government plans discussions with the industry to ensure the fiscal regime is attractive for the future of the UK North Sea. Full details on minor amendments in the budget will be explained in the finance bill, which was published on Apr. 27.

Environment issues

Darling has committed the UK to cutting carbon emissions by 34% by 2020 and offered £1.4 billion to address climate change by supporting low-carbon industries.

Darling wants the North Sea to become a hub for energy of the future—gas storage, carbon capture, and offshore wind. He proposes to achieve this by removing fiscal barriers and offering £405 million of new funding for low carbon energy and advanced green manufacturing in Britain—to drive the application of new technology and invest in small scale projects.

Some environmental and business groups dismissed the package as not going far enough to combat climate change. Adrian Wilkes, chief executive of the Environmental Industries Commission, which represents 200 environmental technology and services companies, said the budget "was timid and inadequate."

Friends of the Earth's director Andy Atkins said the targets were too weak to enable the UK to play its part in avoiding dangerous climate change. It is calling upon rich nations to cut their emissions 40% by 2020 through action at home, not offsetting: "The government has squandered a historic opportunity to kick-start a green industrial revolution and slash UK carbon dioxide emissions."

The chancellor announced support for as many as four demonstration carbon capture and storage projects instead of one. He has dedicated £90 million to pay for more research into the technology, with the European Commission likely to fund demonstration sites and a "new funding mechanism," Darling said. This is expected to be a levy on consumers' bills.

Analysts welcomed the support but warned that the government should not delay its selection of winners for the funding. Otherwise, other countries such as Germany and China would have a head start and create jobs in the sector. Key questions remain on how quickly and efficiently this funding can be made available and the conditions to secure it.

Public borrowing in the UK is to increase to £175 billion this year alone, and Darling said that he expected the economy to shrink by 3.5%. But business and economic commentators have criticized as "optimistic" his forecast of 1.25% on economic growth in 2010 and 3.5%/year of annual growth from 2011. This was because figures revealed on Apr. 24 that there was a 1.9% fall in GDP in the first quarter of this year. This was worse than analysts expected: in the fourth quarter of 2008, there was a 1.6% decline. ✦

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	Current	Historical 1996–Current
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Pipeline	E1342	E1342C
Petrochemical	E1341	E1341C
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U.S. Pipeline Study — There are 14 categories of operating and financial data on the liquids pipeline worksheet and 13 on the natural gas pipeline worksheet.
E1040

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www.ogjresearch.com

Producers wary as Colorado oil, gas rules become law

Nick Snow
Washington Editor

Colorado Gov. Bill Ritter Jr. said that new oil and gas regulations would allow the industry to grow in a sustainable way compatible with the state's economy as he signed them into law on Apr. 22. Producers remain concerned that the rules will simply create more delays and expenses.

"These rules were shaped with valuable input from people all across the state and unanimously adopted by the Colorado Oil & Gas Conservation Commission [COGCC]. They strike the right balance, a balance that recognizes the importance of a healthy industry and the importance of healthy communities, water supplies and wildlife," the governor said.

"In 1999, Colorado issued 1,000 drilling permits. Last year, the state issued more than 8,000. These new, modern rules recognize this increase in drilling activity as well as the technological changes that have occurred within the industry over the past decade. The rules also incorporate the forward-looking practices already being used by companies such as EnCana, Williams, and Gunnison Energy," he said.

'Our company decided that with these new rules, we'd move our rig over to Utah.'

The regulations took effect May 1 on federal lands and began to apply Apr. 1 on all other lands in the state.

Several producers with operations in the state did not want to comment for attribution. "We've handed this off to the Colorado Oil & Gas Association [COGA] because we're going to have work under these new rules. I could speak for a good half hour if this was off-the-record," one company's official told OGJ.

"Our primary message involved the business environment for oil and gas companies in Colorado. Obviously, with the economic downturn, the state government has created an uncertain business environment where companies might be more comfortable to Louisiana or Texas," said Nate Strauch, COGA communications coordinator.

'Second bite of the apple'

Strauch said, "Colorado's permitting already takes longer than the national average.

"Under the new rules, after the permit has been approved, different entities can come in and challenge the action. Surface owners can come in and second-guess the decision. So can the Department of Public Health and the Division of Wildlife. This gives them a second bite of the apple after being involved in the process already if they don't like the results," he told OGJ.

Strauch and Jack Ekstrom, a COGA board member, separately expressed concern about the new regulations' impacts on smaller producers.

"The investment in compliance involves whether you can afford to do it. The delays and difficulties in getting a rig and having to restart the clock because of some minor hiccup remain to be seen," said Ekstrom, who is executive director of investor relations and corporate communications at Whiting Petroleum Corp., Denver.

"You probably won't see evidence during this downturn because there are plenty of rigs available. But once there's an uptick, a company's difficulty in timing and contracting for services may be complicated by having to wait or stand by if it hasn't jumped through all the hoops perfectly," he said.

COGCC Director Dave Neslin said the agency received a wide range of input as the regulations were developed.

"We incorporated a lot of input from both large and small operators, and we will continue to work with operators to help them comply successfully with these requirements," he said.

"We intend to implement these changes in a reasonable and responsible manner. If there are issues we didn't anticipate or if further changes are needed, the commission will consider

adjustments. That's the advantage of working through a regulatory process instead of the courts," he told OGJ.

Downhole chemicals

The new regulations contain several significant provisions. Under Section 205, operators will be required to keep an inventory by wellsite of each chemical used downhole or stored for use downhole during drilling, completion, and workover operations, including fracture stimulation, in an amount exceeding 500 lb during any quarterly reporting period. They also will maintain an inventory of fuel stored at the well site in an amount exceeding 500 lb in a quarter.

When the composition of a chemical product is considered a trade secret by its vendor, operators will be required only to maintain the product's identity. The vendor or service provider will be required to supply COGCC with a list of a trade secret chemical product's ingredients when the commission's director notifies them in writing that the information is necessary to respond to a spill or release, or a property owner registers a complaint about such a release.

COGCC's director or designee may disclose such information to other staff members, but only to the extent that it is necessary for spill response assistance. The director also may disclose this information to relevant county public health directors or emergency managers, and the Colorado Department of Public Health and Environment's environmental programs director. These individuals may then share this information with staff members under similar terms.

Vendors or service providers will also be required to provide a trade secret chemical product's chemical constituents to any health professional if that professional, in submitting a written request, also executes a confidentiality agreement stating that the information will not be used for other purposes.

Oil field product manufacturers expressed concern about possibly having to disclose such ingredients, which they consider proprietary information, during a US House Oversight and Investigations Committee hearing 18 months ago. It was not immediately clear whether they think this provision in Colorado's new regulations adequately addresses this issue.

Comprehensive drilling plans

Sec. 216 of the new regulations gives operators, for the first time, the opportunity to develop a comprehensive drilling plan.

This is designed to identify foreseeable oil and gas activities in a given geographic area, facilitate discussions about potential impacts, and facilitate measures to mitigate adverse consequences. An operator's decision to initiate and enter into such a plan is voluntary.

"We're trying to encourage companies to work with us at the planning stage and effectively bundle a number of locations together for the regulatory review process. That can be more efficient both for the companies and for us as a regulator, and to better understand cumulative effects. The aim is to look at a broader landscape instead of a single well. We're trying to create incentives to use this rule, while trying to provide as much flexibility as possible so we're not create impediments to this broad planning," Neslin explained.

Several sections in the 300 series of the regulations revised the drilling permit process, he said.

"First, we have differentiated between the downhole technical issues and the surface environmental issues, which will be addressed in a separate location assessment. The idea is that Form 2-A, the second form, would be submitted for an entire drilling pad. Again, this is an effort to create efficiency. Each well would still require a drilling permit," he said.

COGCC also will provide additional notice for public comment by posting the location assessment on its website and by supplying certain information from the drilling permit application to the local government, the surface owner and nearby landowners, according to Neslin.

"In certain instances, we will consult regarding the application with the state health and wildlife departments. We have tried to limit those to where they would provide added value. Consultation with the health department, for instance, would occur when an operator is seeking a variance, while the wildlife division would be consulted when an operator proposes drilling a well in sensitive wildlife habitat," he told OGJ.

Public water systems

Section 317-B provides special protection for public water systems, Neslin continued.

"It creates a setback requirement next to drinking water tributaries and imposes operating standards for an additional half mile from the tributary. These public drinking water tributaries have been mapped with these buffer and operating standard areas. This is a new requirement that deliberately incorporated a lot of language proposed by the industry. It's a lengthy requirement, but there are opportunities for operators to obtain exceptions and variances," he said.

Sec. 608 deals with coalbed methane wells. Its provisions include a requirement for operators to assess the risk of gas or produced water leaking to the ground surface or into subsurface water resources, taking into account plugging and cementing procedures in any recompletion or plugging-and-abandonment report filed with COGCC. Other subsections address water well sampling, coal outcrop and coal mine monitoring, a static bottomhole pressure survey prior to production, bradenhead testing, and locally specific field orders.

Neslin said that another rule, Sec. 805, deals with odors. It was developed after the state and county governments in the Piceance basin received several complaints. Operators will be required to install an emissions control device on certain kinds of production equipment that emit 5 tons/year or more of

volatile organic compounds within ½ mile of schools, homes, and hospitals. Constructions of pits with that amount of VOCs yearly also will be restricted, he said.

There are three new wildlife rules in the 1,200 sections of the new regulations. One allows the state's wildlife division to consult with the COGCC, operator, and surface owner regarding wildlife impact mitigation. The agency will not be allowed to veto the drilling permit, but it can make suggestions, Neslin said. "These sensitive wildlife areas include elk winter range, big horn sheep winter range, elk calving areas, and grouse production areas," he said.

A second involves restricted occupancy areas, which the COGCC director described very small areas around the state's most critical wildlife areas such as within a half mile of a bald eagle nest or 300 ft of a cutthroat trout habitat. In these areas, operators will be required to avoid additional surface disturbance where technically and economically feasible to do so.

Not an 'NSO' requirement

Neslin continued, "If an operator can develop the resource from outside the area, we expect them to do so. If they can't, they won't be required to.

"It's not a 'no surface occupancy' requirement. Operators can also consult with the Division of Wildlife and our staff on alternative mitigation within these areas," Neslin said. The third new wildlife rule involves operating practices, many of which were proposed by producers which are using them already, he added.

"We also updated our pit requirements to reflect the best current practices, including liners, soil standards, and groundwater standards. The bonding requirements, which had not been changed in 12-14 years, were updated to reflect current costs. We have updated some of our safety requirements to reflect new information and current practices," he noted.

Neslin said COGCC thinks the new requirements strike a balance which allows the oil and gas industry to continue to operate in the state while protecting the environment and the public's safety and welfare.

"The commission is sensitive to the need to facilitate a smooth transition. It grandfathered existing permits and permit applications. We've done training across the state to educate companies about the amendments and how they apply. We've tried to explain the amended permitting process. And we're working through issues as they arise with operators, the Department of Health, and the Division of Wildlife to investigate environmental and wildlife issues," he told OGJ.

But COGA's Strauch said the new regulations fall short of what the legislature intended. "When it gave the commission authority to promulgate the rules, the directive include a requirement for them to be timely and efficient. The process proved to be neither," he maintained.

Ekstrom said, "The COGCC claimed the rules hadn't been altered for years. But if you go back through the records, there have been changes which we thought were reasoned and rational, and had the industry's input. With the latest rules, we were asked to comment and participate in a meaningful way. But it's my perception as a director of COGA that our serious and reasonable suggestions were, if not summarily dismissed, given short shrift. I found the process very disappointing.

"We talked about jobs. The western part of the state has experienced significant downturns in employment. Certainly the national financial malaise and crash in prices had something to do with it. But our company decided that with these new rules, we'd move our rig over to Utah," he told OGJ. ✦

Ethiopia

Afar Exploration Co. LLC, Tulsa, cited possible terrorist activity in terminating a planned 150 line-km seismic survey on the 3.75-million-acre Afar block in northern Ethiopia in early April 2009.

Antitank mines along a road near the border with Eritrea exploded, killing several people and destroying passenger vehicles, William C. Athens, president of Afar, reported to the Ethiopian Ministry of Mines & Energy.

Afar Exploration, which holds 100% interest, previously ran airborne gravity and magnetic surveys on the block in the Danakil depression and located structures promising for oil and gas potential, Athens said (see map, OGJ, Apr. 14, 2008, p. 39).

New Zealand

New Zealand Crown Minerals will make available 1,500 km of 5,000 km of recently shot 2D seismic in the unexplored Reinga basin in the Tasman Sea off the northern tip of the North Island.

CGG Veritas gathered the data on a nonexclusive basis. Current information suggests geology similar to the Taranaki basin, but the previously available seismic did not attract industry interest.

"The new seismic shows many possible leads including sedimentary drapes over basement highs with adjacent deep grabens and stratigraphic pinchouts. A thorough interpretation of the data by New Zealand's GNS Science will precede a blocks offer opening in late 2009," Crown Minerals said.

Oklahoma

Cimarex Energy Co., Denver, has participated in 49 wells in the Anadarko basin Woodford shale play since late 2007.

Of the 49 wells, 36 are on line and the rest are either awaiting completion or drilling. The 30-day initial average production rate, normalized for a 4,300-ft lateral, is 4.5 MMcfd.

The company's 2009 program is to drill or participate in 50 gross (23 net) wells. Cimarex holds 98,000 net acres in the play.

ASSET OPTIMIZATION—Conclusion

Scenarios validate, optimize process

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BP Trinidad & Tobago
Port of Spain, Trinidad and Tobago

Juan Carlos Rodriguez
Aspen Technology Ltd.
Barcelona

Mike Strathman
Aspen Technology Inc.
Houston

In implementing its field production optimization tool, BP Trinidad & Tobago (BPTT) ran scenarios for tuning, validating, and calibrating the models, as well as multiple optimization scenarios.

This concluding part of a two-part series of articles discusses the scenarios and their results.

Part 1 (OGJ, May 4, 2009, p. 58) covered the software components of the optimization process that includes a library of well models (PROSPER), steady-state field model and optimizer (HYSYS), Excel applications (TFO interface), a data historian (PI), and a BPTT proprietary database (MIRS).

BPTT currently has 11 offshore production platforms feeding into three offshore gas and condensate processing hubs with a 3.75-bscfd capacity.

Four gas pipelines with a 3.525-bscfd combined capacity and one liquid pipeline link the offshore platforms to Trinidad's east coast.

BPTT has contracts for supplying 2.7-bscfd natural gas to National Gas Co. of Trinidad and Tobago (NGC) and to the Liquefied Natural Gas Co. (Atlantic LNG).

Well model tuning

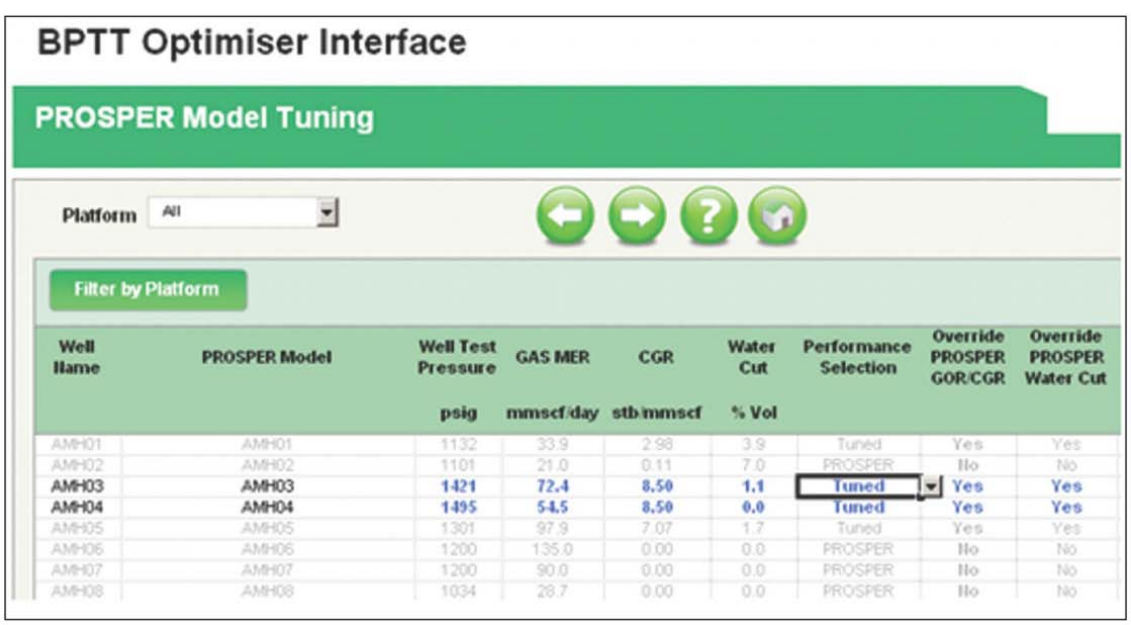
Production and allocation engineers update and calibrate PROSPER well models regularly to reflect actual well performance. The well models are critical to the predictive capability of the asset model; hence the optimization system has specific functions to check well model predictions against the latest well test data and, if necessary, refine model predictions to best match test data (Fig. 1).

For computational efficiency reasons, the process transforms the PROSPER models into polynomial expressions that relate gas flow rate with wellhead pressure. This involves the running of case studies with each PROSPER model and fitting the obtained results to the desired expression.

The Trinidad field optimizer (TFO) includes the functions and libraries that carry out this activity (Fig. 2).

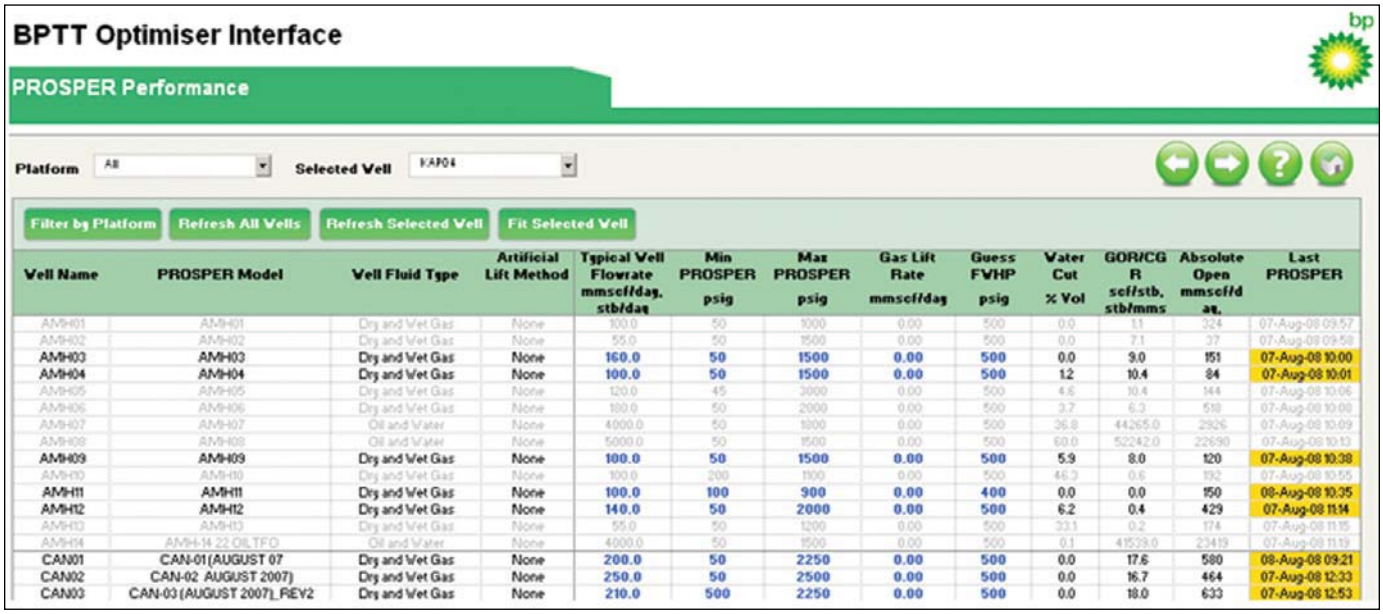
Model validation, calibration

Simulation models are a mathematical representation of the physical principles that govern the behavior of a certain process. As such, they are not powerful enough to picture all events that may happen in a real process, especially if due to outside events such as a pipeline blockage. Nevertheless, these



Well Name	PROSPER Model	Well Test Pressure	GAS MER	CGR	Water Cut	Performance Selection	Override PROSPER GOR/CGR	Override PROSPER Water Cut
		psig	mmscf/day	stb/mmscf	% Vol			
AMH01	AMH01	1132	33.9	2.98	3.9	Tuned	Yes	Yes
AMH02	AMH02	1101	21.0	0.11	7.0	PROSPER	No	No
AMH03	AMH03	1421	72.4	8.50	1.1	Tuned	Yes	Yes
AMH04	AMH04	1495	54.5	8.50	0.0	Tuned	Yes	Yes
AMH05	AMH05	1301	97.9	7.07	1.7	Tuned	Yes	Yes
AMH06	AMH06	1200	135.0	0.00	0.0	PROSPER	No	No
AMH07	AMH07	1200	90.0	0.00	0.0	PROSPER	No	No
AMH08	AMH08	1034	28.7	0.00	0.0	PROSPER	No	No

The optimization system checks well model predictions against the latest well test data (Fig. 1).



Well Name	PROSPER Model	Well Fluid Type	Artificial Lift Method	Typical Well Flowrate mmscf/day, stb/day	Min PROSPER psig	Max PROSPER psig	Gas Lift Rate mmscf/day	Guess FVHP psig	Water Cut % Vol	GOR/CGR scf/stb, stb/mms	Absolute Open mmscf/day	Last PROSPER
AMH01	AMH01	Dry and Wet Gas	None	100.0	50	1000	0.00	500	0.0	1.1	324	07-Aug-08 09:57
AMH02	AMH02	Dry and Wet Gas	None	55.0	50	1500	0.00	500	0.0	7.1	27	07-Aug-08 09:58
AMH03	AMH03	Dry and Wet Gas	None	160.0	50	1500	0.00	500	0.0	9.0	151	07-Aug-08 10:00
AMH04	AMH04	Dry and Wet Gas	None	100.0	50	1500	0.00	500	1.2	10.4	84	07-Aug-08 10:01
AMH05	AMH05	Dry and Wet Gas	None	120.0	45	3000	0.00	500	4.6	10.4	144	07-Aug-08 10:06
AMH06	AMH06	Dry and Wet Gas	None	100.0	50	2000	0.00	500	3.7	6.3	518	07-Aug-08 10:08
AMH07	AMH07	Oil and Water	None	4000.0	50	1000	0.00	500	36.8	44265.0	2926	07-Aug-08 10:09
AMH08	AMH08	Oil and Water	None	5000.0	50	1500	0.00	500	60.0	52242.0	22690	07-Aug-08 10:13
AMH09	AMH09	Dry and Wet Gas	None	100.0	50	1500	0.00	500	5.9	8.0	120	07-Aug-08 10:38
AMH10	AMH10	Dry and Wet Gas	None	100.0	200	1100	0.00	500	46.3	0.6	192	07-Aug-08 10:55
AMH11	AMH11	Dry and Wet Gas	None	100.0	100	900	0.00	400	0.0	0.0	150	08-Aug-08 10:35
AMH12	AMH12	Dry and Wet Gas	None	140.0	50	2000	0.00	500	6.2	0.4	429	07-Aug-08 11:14
AMH13	AMH13	Dry and Wet Gas	None	55.0	50	1200	0.00	500	33.1	0.2	174	07-Aug-08 11:15
AMH14	AMH-14 22 OIL TFO	Oil and Water	None	4000.0	50	1500	0.00	500	0.1	41539.0	23419	07-Aug-08 11:19
CAN01	CAN-01(AUGUST 07	Dry and Wet Gas	None	200.0	50	2250	0.00	500	0.0	17.6	580	08-Aug-08 09:21
CAN02	CAN-02 AUGUST 2007)	Dry and Wet Gas	None	250.0	50	2500	0.00	500	0.0	16.7	464	07-Aug-08 12:33
CAN03	CAN-03 (AUGUST 2007)_REV2	Dry and Wet Gas	None	210.0	500	2250	0.00	500	0.0	18.0	633	07-Aug-08 12:53

TFO includes the functions and libraries for fitting well data to the models (Fig. 2).

are valid operating scenarios, and in fact a field optimizer will demonstrate its value by providing fast and reliable answers on how to operate under those circumstances.

Equipment mechanical degradation is another factor that will affect operations. One cannot model this factor with enough rigor with first-principle engineering models.

For these reasons, equipment models typically include ad hoc adjustable parameters that one can tune to match the actual process performance. The design assumes that these parameters are fixed over a wide range of operating conditions. First-principle model equations continue being valid, but the model results are shifted with an offset calculation to mirror reality.

The values of these calibration factors have themselves an intrinsic value, as they indicate how far the operation is from the physical principles that govern its behavior. An oscillatory pressure drop offset in a gas pipeline may indicate the presence of significant pipeline dynamic effects.

In a gas operation such as BPTT's, the system hydraulics governed by the gas transportation network from offshore to the coast line and to the processing terminals onshore have a major influence in the operation of the individual platforms as well as in the overall operating margins.

The design takes special care in modeling the pipe networks as accurately as possible and in providing calibration mechanisms that can adjust those models to reflect actual system pressure drops in most scenarios. Fig. 3 shows the model's adjustable parameters for calibration.

The modeling of the pipeline segments used the Aspen HYSYS built-in pressure drop correlation. The process designers compared and checked these results against field data extracted for prolonged periods of time-on-stream. They used this information to develop empirical models that best fit all data. Each pipeline model has an offset factor that allows fine-tuning of predictions to match actual pipeline pressure readings.

Fig. 4 shows a model's predictions (black) vs. field data for a main gas pipeline in two different operating situations.

The steady-state field model and optimizer (TFOM) automatically calculates all pipe pressure drop offsets together with other process tuning factors during a calibration step to match field data with the minimal degree of model adjustment.

Pipeline tuning factor values were calculated at relatively different sets of actual process conditions during the testing phase, and important discrepancies were not observed. This indicates that the modeling and calibration approaches employed allow a correct representation of reality within the allowed operating envelopes.

Optimization

As discussed in Part 1, the BPTT gas system operation is constrained and driven by the need of producing the gas quantities contracted with the various gas consumers. Gas deliverability is therefore the key element for BPTT. A multitude of engineering and commercial issues positively or negatively affects deliverability, such as:

- Maintenance activities in platforms.
- Well testing.
- Pipelines pigging.
- Valve failures in pipes.
- Renegotiation of transportation contracts.
- Availability of new gas transportation routes.

The common factor of all these situations is that the asset must keep gas deliverability at required levels in

the best possible way with the available system capacity, as well as to react to unexpected events to recover normal production as quickly as possible.

The TFO is a:

- A day-to-day optimizer to guide the operation towards the most profitable way, for example, delivering required gas flow rates while getting the most value out of the associated condensate streams.
- As a what-if optimization system that allows finding the optimum operating strategies when major events occur.

To do so, the HYSYS optimizer's configuration has enough flexibility to allow operators to specify well status on or off, well pressure and flow rate limits, fixed and swing wells, pipeline availability, and separation equipment availability.

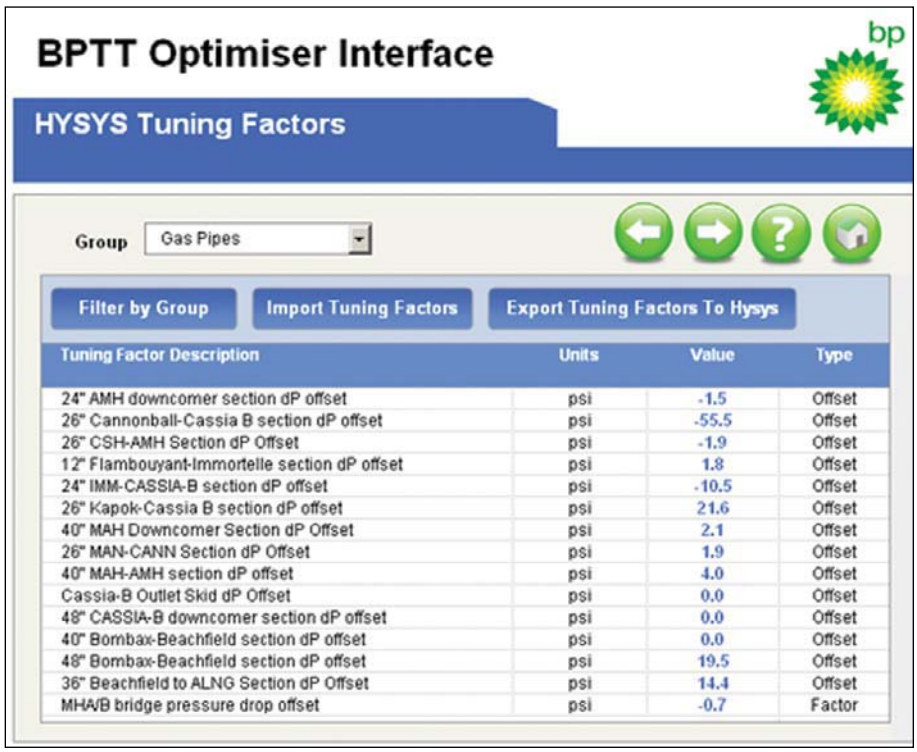
The optimizer also allows for defining the market and commercial information (gas nominations for each consumer, gas values), and the optimization target among a set of preconfigured scenarios.

The set of business scenarios that TFO can execute include:

- Meeting gas nominations while maximizing condensates recovery.
- Finding the maximum attainable operation revenue.
- Finding the maximum attainable gas production.
- Maximizing the value obtained from gas.
- Maximizing the condensates recovery.
- Finding the maximum attainable LNG gas production.
- Finding the maximum attainable gas production for domestic consumption.

Fig. 5 shows the TFO results page that compares field values with optimum set points.

This provides a great level of flexibility to the tool and allows it to address virtually all business concerns and questions that the asset typically faces. It also provides a solid engineering baseline to benchmark individual process engineer's estimates, which often strongly depend on their particular experience and preferences.

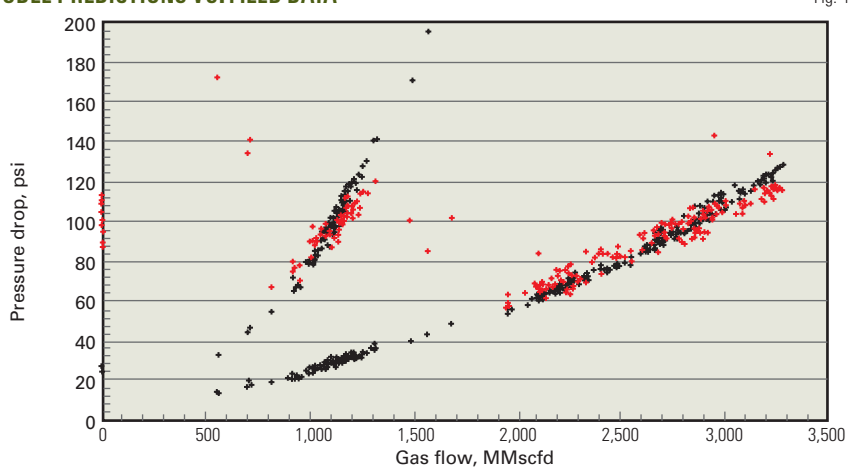


Tuning Factor Description	Units	Value	Type
24" AMH downcomer section dP offset	psi	-1.5	Offset
26" Cannonball-Cassia B section dP offset	psi	-55.5	Offset
26" CSH-AMH Section dP Offset	psi	-1.9	Offset
12" Flambouyant-Immortelle section dP offset	psi	1.8	Offset
24" IMM-CASSIA-B section dP offset	psi	-10.5	Offset
26" Kapok-Cassia B section dP offset	psi	21.6	Offset
40" MAH Downcomer Section dP Offset	psi	2.1	Offset
26" MAN-CANN Section dP Offset	psi	1.9	Offset
40" MAH-AMH section dP offset	psi	4.0	Offset
Cassia-B Outlet Skid dP Offset	psi	0.0	Offset
48" CASSIA-B downcomer section dP offset	psi	0.0	Offset
40" Bombax-Beachfield section dP offset	psi	0.0	Offset
48" Bombax-Beachfield section dP offset	psi	19.5	Offset
36" Beachfield to ALNG Section dP Offset	psi	14.4	Offset
MHA/B bridge pressure drop offset	psi	-0.7	Factor

The model includes adjustable parameters for calibration (Fig. 3).

MODEL PREDICTIONS VS. FIELD DATA

Fig. 4



Note: The black dots are the model's predictions for a main gas pipeline in two different operating situations.

Results

The model of the complete asset was checked against plant data taken during several months. The results of these runs show that the model is in good agreement with the measured plant data. The values of most of the model calibration tuning factors are relatively small, a fact that indicates a good prediction of the asset behavior.

In those cases in which certain tuning factors were unexpectedly high, they were reflecting a true operating issue such as physical restrictions in certain system pipelines or deficient data quality.[1] This is a side benefit of the full-field calibrated asset model, which

Platform AMH

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Well Name	PROSPER Model	Status	CGR/GOR stb/mmscf, scf/stb	Water Cut percent	Initial Values FWHP psig	Initial Values Gas Rate mmscf/day	Initial Values Oil Rate stb/day	Initial Values Water Rate stb/day	Optimised Values FWHP psig	Optimised Values Gas Rate mmscf/day	Optimised Values Oil Rate stb/day	Optimised Values Water Rate stb/day
AMH01	AMH01	Off	1.0	0.0	0	0.00	0	0	1000	0.00	0	0
AMH02	AMH02	On	0.1	6.3	1274	20.80	2	0	1291	20.01	0	0
AMH03	AMH03	On	8.2	0.0	1526	64.26	527	0	1543	63.41	245	0
AMH04	AMH04	Off	0.0	0.0	1526	0.00	0	0	1526	0.00	0	0
AMH05	AMH05	Off	3.2	0.0	1526	0.00	0	0	1276	0.00	0	0
AMH06	AMH06	Off	5.9	84.5	1526	0.00	0	0	1526	0.00	0	0
AMH08	AMH08	Off	10.3	78.2	1526	0.00	0	0	1526	0.00	0	0
AMH10	AMH10	On	0.0	0.0	1103	30.41	0	0	1119	24.63	0	0
AMH11	AMH11	On	0.0	0.0	1254	69.00	0	0	1271	66.66	0	0
AMH12	AMH12	On	0.0	100.0	1569	47.41	0	0	1586	46.62	0	0
AMH13	AMH13	On	0.0	100.0	1101	19.06	0	0	1118	14.46	0	0
AMH14	AMH14	On	10.8	58.1	1751	65.07	699	970	1768	64.64	356	935

The TFO results page compares field values with optimum set points (Fig. 5).

is its ability quickly to spot the areas of the production system where it deviates from the governing engineering principles.

The TFO was used to analyze several real operational scenarios that included:

- Meeting gas demands while maximizing condensates production.
- Unplanned shutdowns of Atlantic LNG trains and optimum strategies to best accommodate the operation to a lower gas demand situation.
- Planned shutdowns of Kapok and Mango wells and the effect on gas deliverability.
- Bringing on a new high yield well, such as in Mango or in Cashima, and analyzing the extra gas production potential.
- Analyzing the extra gas production attained with the Cassia-B Immortelle bypass.
- Simulating a pig blockage of the 40-in. subsea pipeline and its impact on overall gas deliverability.
- Effect of capacity restriction in the 12-in. condensate line on meeting gas market demand.
- Maximum gas deliverability as a function of Atlantic LNG terminal pressure requirements.

Typical use scenario

The main objective of TFO is in helping to meet gas market demands with the maximum associated condensates revenue.

In the most common optimization scenario, the TFO is configured to produce a given set of gas volumes for delivery to multiple gas consumers. The model is first initialized with actual field data, which includes factors such as wellhead pressures, platform pressures, pipeline flows, separator temperatures and pressures, among others.

Upon checking the accuracy of model predictions vs. actual field data or validating the model, the TFO runs will serve to find alternatives for improving how the gas nominations were met during that particular day. TFO will find the optimal gas production distribution among available fixed and swing wells, taking into account the quality and capacity constraints affecting the associated condensate production as well as the back-pressure effects on the gas transportation network that make the operation of the various offshore platforms interdependent.

Preliminary results indicate a potential of 7% more condensate production, equivalent to 1,900 bo/d.

Technology adoption

The successful implementation of optimization technologies such as TFO depends on:

- Having high-level management support.
- Willingness of production engineers and gas dispatchers to adopt it as way for improving existing operating procedures.

BPTT fully endorses both and has set up the necessary frameworks to embed TFO into the production optimization team processes.

Field trial experiments will be used to benchmark the TFO results before the tool is transferred to the gas dispatch team as a control room application.

Acknowledgments

The authors acknowledge Roland Pike and Bryn Stenhouse (BP EPTG Sunbury, UK) for their contribution to the TFO project and Scott Johnston (Ingen-Ideas, Aberdeen, UK) for his support developing the system's graphical interfaces. ✦

Reference

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Process developed for enhanced H_2S recovery from sour-water strippers

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Indian Oil Corp. Ltd. has developed a process for enhanced recovery of H_2S from sour water of refinery hydrotreaters. The process Super Sour arrests the loss of H_2S from feed the stabilization tank and result in recovery of H_2S (7-10 wt % of H_2S in feed) from sour-water strippers.

The Super Sour design configuration is being implemented at Gujarat refinery with start-up planned by yearend 2009.

The design has applications for other processes with high concentrations of H_2S in water.

Based on a presentation to the Laurance Reid Gas Conditioning Conference, Feb. 22-25, 2009, Norman, Okla.

Controlling emissions

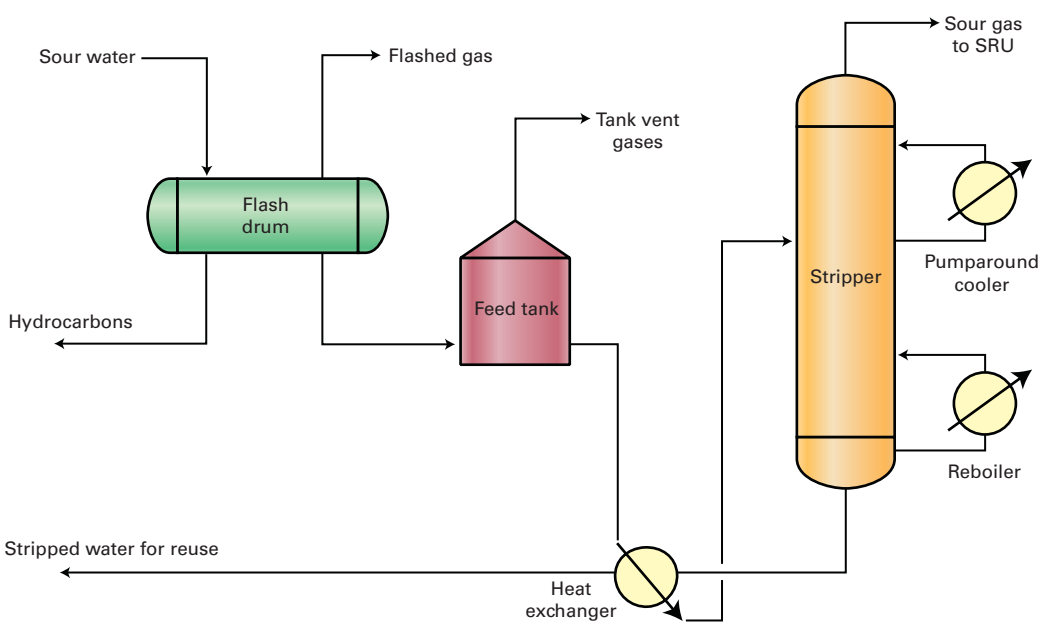
Stringent environmental regulations that emphasize controlling H_2S/SO_2 emissions in turn necessitate higher recovery of H_2S from sour water in sour water stripper unit designs. Usually some amount of H_2S is lost along with vent gases from the feed stabilization tank of stripper unit. This article describes a process design of a sour-water stripper to arrest the loss of H_2S and recover it through simple and safe design.

Typically the feed stabilization tanks are designed according to API-650/620 to operate at a low pressure of 0.015-0.02 kg/sq cm (g) (0.21-0.28 psig). At this pressure, considerable amounts of hydrogen sulfide (H_2S) are released from the tank due to its high vapor pressure. Traditionally, these vent gases from the tank are routed to the incinerator or stack of sulfur recovery units and are lost. The quantity of the unrecovered acid gas from the feed tank is around 10% of the sour-water feed's H_2S (depending on operating conditions). Some of the licensors utilize steam jet ejectors on the feed stabilization tank to suck these gases from the tank and recover H_2S after employing a small amine scrubber downstream of the ejector with precise tank pressure-control system. In such designs, steam is required continuously for operation of ejectors, and the pressure of the tank must be controlled delicately at very low pressure.

Late in 2007, the process design engineering group of Indian Oil Corp. Ltd. developed a new and safe design process called "Super Sour" for

CONVENTIONAL SOUR-WATER STRIPPING UNIT

Fig. 1



one of its refineries' new sour-water stripper plant. The new design ensures minimum H_2S loss from the unit and meets environmental regulations.

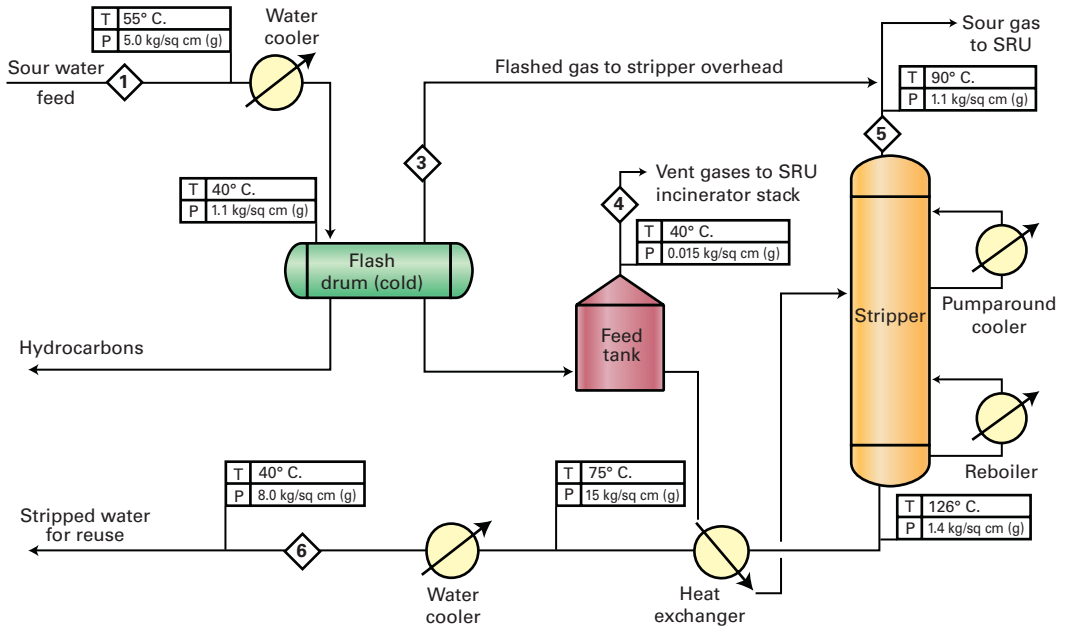
This process employs installation of an additional hot-feed flash drum upstream of the cold-feed surge drum. The H_2S rich vapors from the hot flash drum are routed to a small amine scrubber to absorb the liberated H_2S. The H_2S lean gas containing primarily hydrocarbons is then routed to the incinerator of the sulfur-recovery unit. The absorbed H_2S in rich amine is recovered in the amine regenerator and is fed to the sulfur unit for converting to sulfur. Liquid hydrocarbon will continue to be separated in the cold-feed surge drum downstream to the hot flash drum.

The purpose of the hot flash drum is to liberate enough H_2S from the feed sour water so that when the same is cooled and routed to the feed stabilization tank operating at almost atmospheric pressure, no H_2S is lost from the tank.

This process does not involve additional continuous utility consumption (i.e., ejector steam) and precise suction pressure control scheme for the tank-ejector system. This will offer an intrinsically safe, simple, and efficient solution to arrest the loss of H_2S and recover the same from feed stabilization tank.

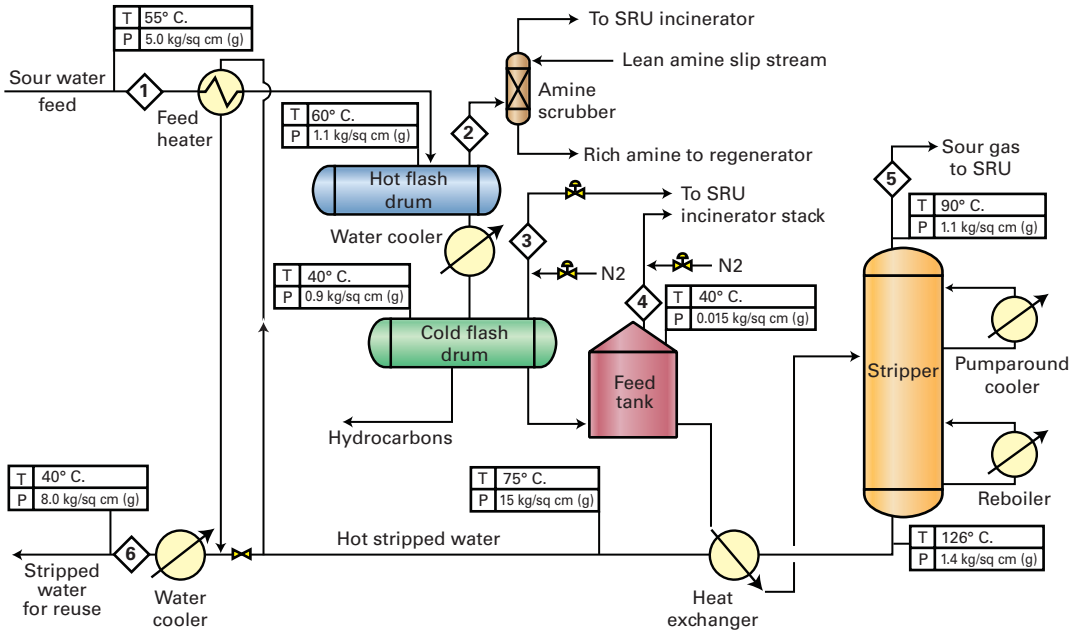
CONVENTIONAL STRIPPER: GUJARAT REFINERY

Fig. 2



SUPER SOUR UNIT CONFIGURATION

Fig. 3

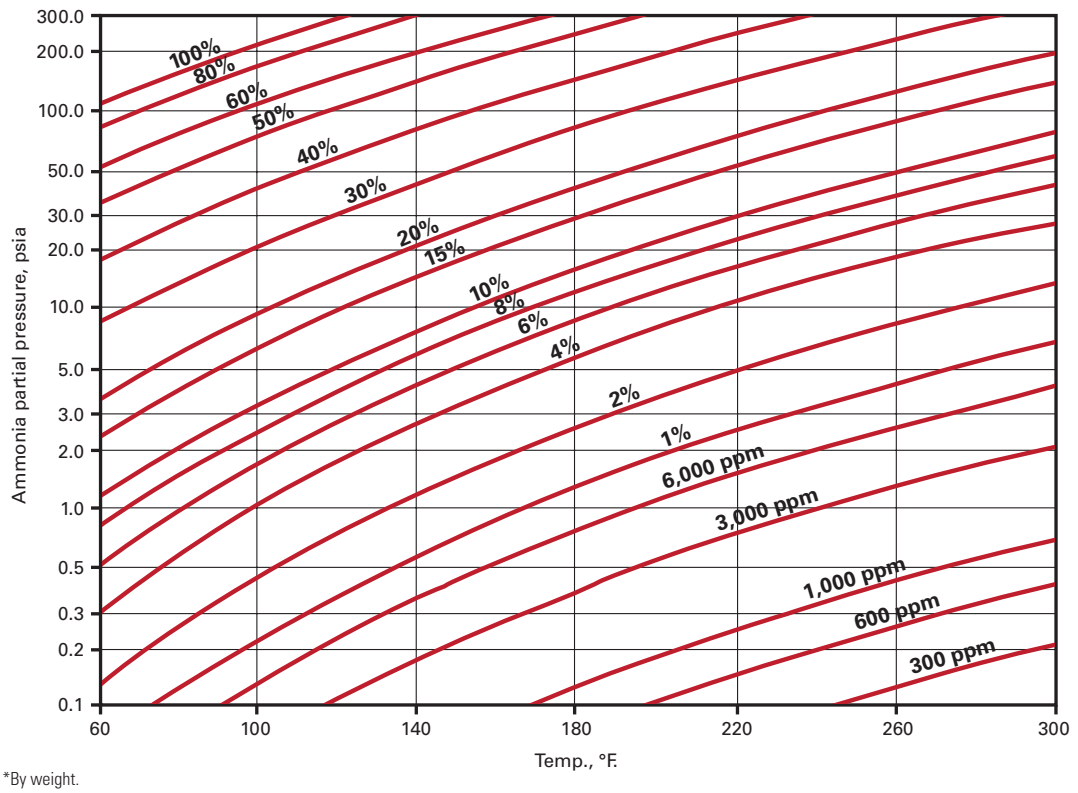


Background

Refineries that process crudes containing sulfur will liberate the sulfur in various unit operations as H_2S. Water-containing H_2S (sour water) may contain other impurities, such as ammonia (NH_3), phenol, CO_2, and

AMMONIA CONCENTRATION*

Fig. 4



*By weight.

cyanides. Sour water is produced from most of the refinery process units, such as atmospheric and vacuum distillation units, hydrotreating units, hydrocrackers, steam crackers, and fluid catalytic cracking (FCC) units. Concentrations of both H_2S and ammonia contaminants are highest in sour water generated from hydrotreating, hydrocracking, and FCC units.

Reuse or disposal of such sour water containing H_2S, ammonia, phenol, and cyanides requires removal of these contaminants from the water by the stripping process. The typical stripping process (Fig. 1) uses steam at the bottom of the stripper through a reboiler to force both the dissolved H_2S and ammonia (NH_3) out of the water into the gas phase for recovery of H_2S in a sulfur-recovery unit (SRU).

The stripped water is usually reused as process water in other parts of the refinery units or otherwise sent to the waste-water treatment plant for further treatment before reutilization.

FEED TO SOUR-WATER STRIPPER

Table 1

Stream No.	Parameters	Unit	Value
1	Temperature	°C.	55.0
2	Pressure	kg/sq cm (g)	5.0
3	Vapor fraction		0.0
4	Mole weight		18.35

FEED COMPOSITION OF SOUR-WATER STRIPPER

Table 2

Stream No.	Components	Mass flow rate, kg/hr	Wt %
1	Ammonia	1,058.10	1.84
2	H_2S	2,348.60	4.09
3	Water	53,995.30	94.07
	Total	**57,402.00**	**100.00**

Conventional process

Fig. 1 shows a typical conventional sour-water stripper design. Before the stripper tower, sour-water feed is first pumped into the flash drum. This has two purposes:

1. To remove hydrocarbon vapors.
2. To remove hydrocarbon liquids.

The flash drum typically operates at low pressure (~0.7-1.0 kg/cc (g)) to flash off the lighter hydrocarbons. The flashed vapors are routed to a low-pressure system such as stripper column overhead, incinerator stack of an SRU after burning or acid flare. The liquid hydrocarbons are separated in the flash drum by gravity separation into the drum's hydrocarbon collection compartment.

Sour water is then pumped to feed stabilization tank that is used to provide adequate residence time for additional hydrocarbon removal and for minimizing feed composition fluctuations because sour water is produced from different sources in a refinery. Significant compositional fluctuations cause poor stripping operation in the tower, resulting in either not consistently meeting product specification or wasting steam by overstripping. The constant feed composition and flow rate from the feed stabilization tank enables better control of the stripper tower and consistent stripped sour-water quality.

Sour water from the stabilization tank is heated in a feed-bottom heat exchanger by hot-stripped water from the stripper bottoms and fed to the tower as feed. As the sour water flows down the tower, H_2S and ammonia are stripped off by steam or reboiled vapor from the bottom of the tower. Use of live steam as stripping agent adds more water to the tower.

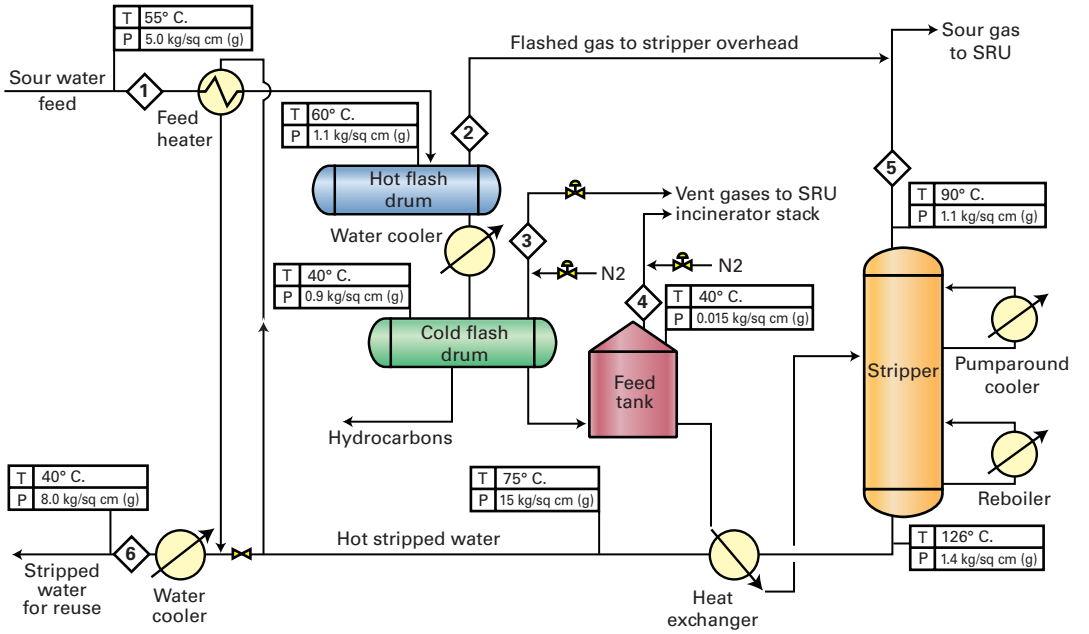
Normally low-pressure steam is used in the bottom reboiler to generate

vapor in the tower operating in the range of 0.7–1.2 kg/sq cm (g) top pressure. H_2S, ammonia, and steam rise to the tower cooling section, which is controlled at 90° C. by pumped around cooler at the top of the tower. Low overhead temperatures, less than 80° C. can cause problems due to formation of ammonium salts that may plug process lines.

Sour gases containing H_2S and ammonia from the top of the stripping tower are routed to the SRU.

SUPER SOUR UNIT CONFIGURATION - ALTERNATE

Fig. 5



The problem

Indian Oil's refinery, in the state of Gujarat, was installing a new sour-water stripper unit as a part of residue upgrade. Currently the refinery operates four old sour-water stripping units based on convectional striping process designs.

The process objective of new sour-water stripper units in the residue upgrade project was to treat the sour water generated from the diesel hydrodesulfurization unit, vacuum gas oil hydrotreater, and isomerization unit for removing H_2S and ammonia to meet stripped-water specification of less than 50 ppm (wt) H_2S and ammonia.

The new unit was to be designed to handle a total sour-water feed rate of 57,402 kg/hr (5.7 tonnes/hr) with composition as summarized in Tables 1 and 2.

Because the Gujarat refinery is already operating with four conventional units of sour-water striping process, the same was considered for the initial design of the new stripper.

Fig. 2 shows flow of the initial design configuration of sour-water stripper unit for the Gujarat refinery, according to the traditional configuration.

In the conventional design, sour-water feed to unit arrives in the flash drum after cooling to 40° C. from 55° C. The feed is cooled to reduce the vapor pressure of sour water to minimize H_2S loss from storage tank. The flash drum is floated with stripper column overhead, which is operating at pressure of 1.1 kg/sq cm (g). After hydrocarbon vapors are flashed off in the flash drum, feed enters the feed stabilization tank operating at almost atmospheric pressure condition (i.e., at 0.21335 psig pressure). The tank is designed according to API-650. At this low pressure, a considerable amount of H_2S is released from the storage tank due to its high vapor pressure. The vent gases from the tank are routed to the incinerator of SRU and are lost. The loss is around 7.5% of the feed H_2S (Table 3). Environmental regulations do not allow emissions of these vent gases containing H_2S to incinerator stack or atmosphere because it leads to higher emissions of H_2S and SO_2.

New design

The new process design developed by Indian Oil, called Super Sour, for sour-water stripping ensures minimum or no H_2S loss from the unit resulting in enhanced recovery of H_2S compared with the traditional designs.

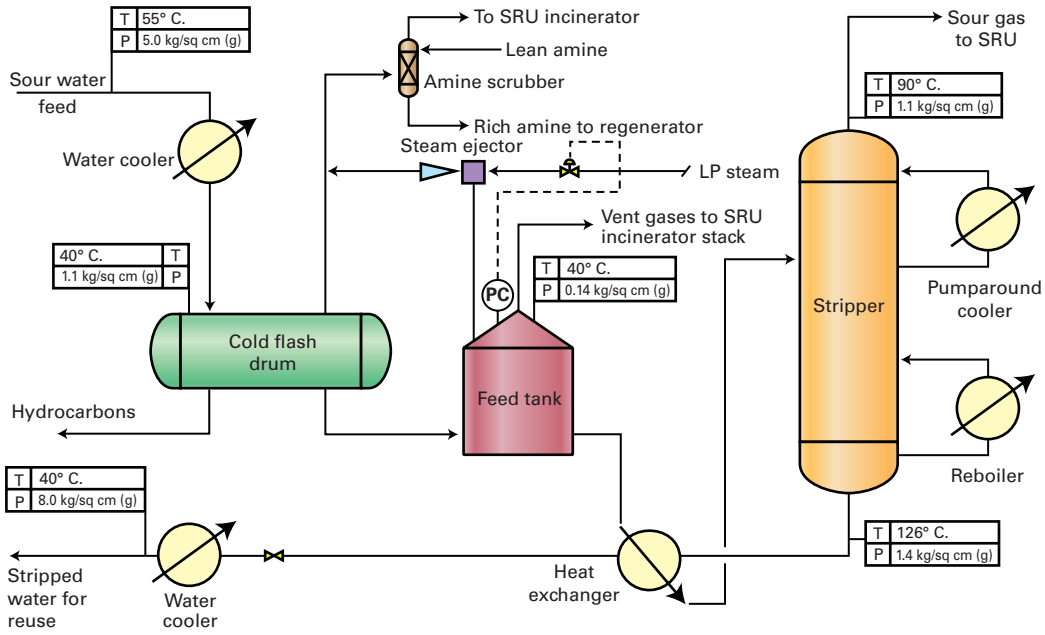
This process (Fig. 3) employs installation of an additional small-diameter hot feed flash drum (essentially, a typical vapor-liquid separator) upstream of cold-feed surge drum. The purpose of the hot flash drum is to liberate enough H_2S from the sour-water feed so that, when it is cooled and routed to the feed stabilization tank (operating at almost atmospheric pressure) there will be no bleed of H_2S from the tank, resulting in no loss of H_2S from the tank.

In this design, the hot flash drum is held at around 60° C. by heating the sour-water feed with hot-stripped water coming from the outlet of feed bottom exchanger. This requires no additional hot utility.

The H_2S rich vapors from hot flash drum are routed to a small amine scrubber to absorb the liberated H_2S. The lean gas from absorber containing primarily hydrocarbons is then routed

SOUR-WATER STRIPPER: OTHER DESIGNS

Fig. 6



to the incinerator of the SRU. The absorbed H_2S in rich amine is recovered in the amine regenerator and fed to the sulfur unit for conversion to sulfur.

Flashed feed from hot drum is cooled to 40° C. before being routed to the cold-feed surge drum for separation of hydrocarbon oil from water. This also reduces the vapor pressure of sour water. After separation of liquid hydrocarbon in cold-feed surge drum, sour water is routed to the stripper tower through the feed stabilization tank. The cold-surge drum and feed tank pressure is maintained by the nitrogen makeup.

Results

This design results in no loss of H_2S from the feed stabilization tank, as the simulated numbers of Table 4 show. The electrolyte package of Chemstations USA (Chemcad V. 6.1) was used to model and simulate the sour-water stripper unit.

At the elevated temperature of around 60° C. of hot flash drum, the ammonia going to the gas phase from the hot drum will be very marginal (stream No. 2 of Table 4) due to its high solubility in water as compared with the H_2S. Thus the ammonia buildup in the amine regenerator due to this approach will be insignificant. However, an ammonia purge stream from the amine overhead accumulator back to the cold surge drum of sour-water stripper is to knock off any ammonia buildup. Fig. 4 may be referred to for partial pressure of ammonia over aqueous solution.

In an alternative configuration, vapors from the hot flash drum containing primarily H_2S may be directly routed to the stripper overhead line for recovery of sulfur along with the stripper overhead vapors. This con-

SIMULATED RESULTS FOR CONVENTIONAL SOUR-WATER STRIPPER

Table 3

Stream No.		1 Feed	3 Flashed gas from cold flash drum	4 Vent gas from tank	5 Sour gas from stripper to SRU	6 Stripped water from sour-water unit
1	Temperature, °C.	55.0	40.0	40.0	90.0	40.0
2	Pressure, kg/sq cm (g)	5.0	1.1	0.015	1.1	8.0
	Component flow rate					
3	Ammonia, kg/hr	1,058.10	0.122	0.19	1,056.79	<50 ppm (wt)
4	H_2S, kg/hr	2,348.60	45.0	178.20	2,124.4	<50 ppm (wt)
5	H_2O, kg/hr	53,995.3	0.854	6.80	1300	52,687.65
	Total	**57,402.0**	**45.976**	**185.19**	**4,481.19**	**52,689.65**

SIMULATED RESULTS FOR SUPER SOUR UNIT

Table 4

Stream No.		1 Feed	2 Hot flash vapor to amine scrubber	3 Flashed gas from cold surge drum	4 Vent gas from feed tank	5 Sour gas from stripper to SRU	6 Stripped water from sour-water unit
1	Temperature, °C.	55.0	59.1	40.0	40.0	90.0	40.0
2	Pressure, kg/sq cm (g)	5.0	1.1	1.1	0.015	1.1	8.0
	Component flow rate						
1	Ammonia, kg/hr	1,058.10	0.380	0	0	1,056.72	<50 ppm (wt)
2	H_2S, kg/hr	2,348.60	228.0	0	0	2,119.6	<50 ppm (wt)
3	H_2O, kg/hr	53,995.3	12.0	0	0	1,300	52,683.3
	Total	**57,402.0**	**240.38**	**0**	**0**	**4,476.32**	**52,685.3**

figuration does not require installation of a small amine scrubber column for absorbing the H_2S from hot flash drum vapors. Fig. 5 shows the schematic of this configuration.

This configuration can be adopted where the likelihood of lighter hydrocarbon coming along with sour water is minimum or nil. Otherwise these hydrocarbons may find their way to the SRU, which will be detrimental to its operation. ✦

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The authors

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Ashis Nag (naga@iocl.co.in) has worked for Indian Oil for almost 32 years and at present heads its process design section. He has worked on different refinery units including reformers and hydrocrackers and carried out assignments in commissioning, operations, process design, and technical services. Nag obtained his BS (1976) in chemical engineering from Jadavpur University, Calcutta.

Oblique shaft construction offers alternative for slope crossings

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Using an oblique shaft to cross slopes in pipeline construction can protect the environment, overcome difficulties related to slope stability, and save construction costs. Based on slope stability analysis, this article will present a new method to determine design parameters for oblique shafts traversing soil slopes, establishing all designed parameters for an inclined shaft crossing a simple homogeneous slope and discussing design parameters for a complex slope.

Cases will show that the new design method is practical and concise and will allow the inclined shaft to avoid the most dangerous sliding zone of a gully or slope during the design phase and for excavation to occur without obvious impact on slope stability. The design method could effectively avoid the stress concentration of pipelines caused by landslides.

The China Petroleum Pipeline Engineering Corp. has widely used inclined shaft crossings and their parameter design method, especially in loess areas, for both the already-operating Lan-Zheng-Chang oil transport pipeline and the second West-East natural gas pipeline, currently under construction.

Background

Long-distance oil and gas pipelines in China often cross through loess gullies, loess plateaus, and other complicated and varied topographies.[1] The Lan-Zheng-Chang pipeline is the longest oil line in China and has more than 40 slopes just in the 97.4-km section in Zhengzhou district, Henan province.

Conventional burial in a loess slope environment destroys sensitive surface vegetation and causes soil erosion of the slope. Conventional burial in a loess slope is also prone to landslides, requiring advanced monitoring and integrity measures (OGJ, May 21, 2001, p. 62, and Feb. 17, 1986, p. 68). Even with such measures, however, landslides still cause heavy losses in loess slope environments engineering.

Contractors often use directional drilling to traverse high, steep slopes, but using this method in loess areas depends on topography and geological conditions. Drilling fluid can leak along cracks to the slope surface and unexpected releases of drilling mud can also damage the environment. Loess soil's sensitivity to water can collapse the loess and reduces the stability of slopes or gullies.

A manually excavated oblique shaft can address these issues while gradually crossing large and medium-sized

Manual excavation produces inclined slope-traversing pipeline shafts such as the one pictured here (Fig. 1).

Finished pipe slides into the shaft entrance once excavation is complete (Fig. 2).

gullies on a loess plateau.[2,3] Using a manually excavated oblique shaft not only protects the environment by avoiding large volume soil excavation, but also moderates slope instability and construction costs.

Inclined shaft

A Luoyang shovel allows experienced builders to excavate the oblique shaft at 4-8 m/day from slope top to slope bottom. A winch moves residual soil to the ground. Steel supports along the inclined shaft help avoid cave-ins and reduce the risks of manual excavation in bad geological conditions. Fig. 1 shows the inner view of an inclined well after manual excavation in Luoyang district, while Fig. 2 shows the pipeline entering the excavated well.

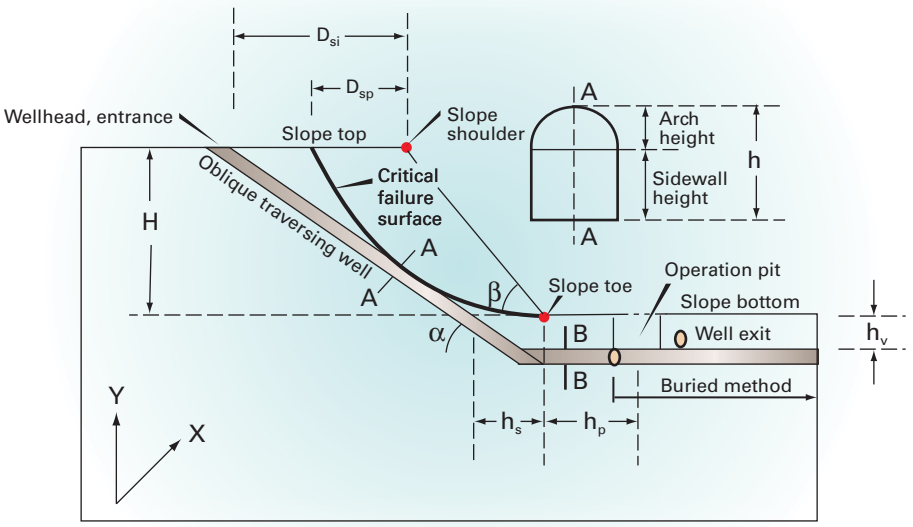
Ensuring the pipeline crosses a body-stabilized soil mass requires locating it outside the critical sliding surface. The main design parameters for spatial structure of well-traversing method include:

- Safe position of wellhead (entrance) and wellhead (exit) position at the slope top and bottom, respectively.
- Inclined shaft dip angle.
- Location of the operation pit at the bottom of slope (Fig. 3).

Reasonable design parameters ensure the security of the pipeline and the long-term stability of the slope both during construction and operation.

Crossing design

Fig. 3



Note: α = the limited designing angle of oblique well. β = slope angle. Section B-B = Section A-A.

Equations

$$(x - x_{0m})^2 + (y - y_{0m})^2 = R_{0m}^2 \quad (1)$$

$$y - y_s = x \tan \alpha \quad (2)$$

$$(1 + \tan^2 \alpha)x^2 + 2(y_s \tan \alpha - y_{0m} \tan \alpha - x_{0m})x + y_s^2 - 2y_s y_{0m} = 0 \quad (3)$$

$$(y_s \tan \alpha - y_{0m} \tan \alpha - x_{0m})^2 - (1 + \tan^2 \alpha)(y_s - 2y_{0m})y_s = 0 \quad (4)$$

Where $y_s = -h_v$ is a known value, therefore tan α can be solved by Equation 4, in which α is the dip angle of the inclined shaft.

$$D_{si} = (H - y_s)/\tan \alpha - Hn \quad (5)$$

$$\overline{SD} = (H - y_s)/\sin \alpha \quad (6)$$

Where D_{si}, H, n, and SD, respectively, denote the safety distance between inclined shaft wellhead and slope shoulder, the slope height, the reciprocal of slope ratio, and the inclined shaft length, as shown in Fig. 5.

$$D_{si} = (H - y_s)/\tan \alpha - Hn + h_v \quad (7)$$

$$F = \frac{1}{2}(\sigma_1 - \sigma_3) - (c \times \cos \phi - \frac{1}{2}(\sigma_1 + \sigma_3) \times \sin \phi) \quad (8)$$

Where F is the yield value, when $F > 0$, the soil mass falls into yield state, F value indicates the yield degree.

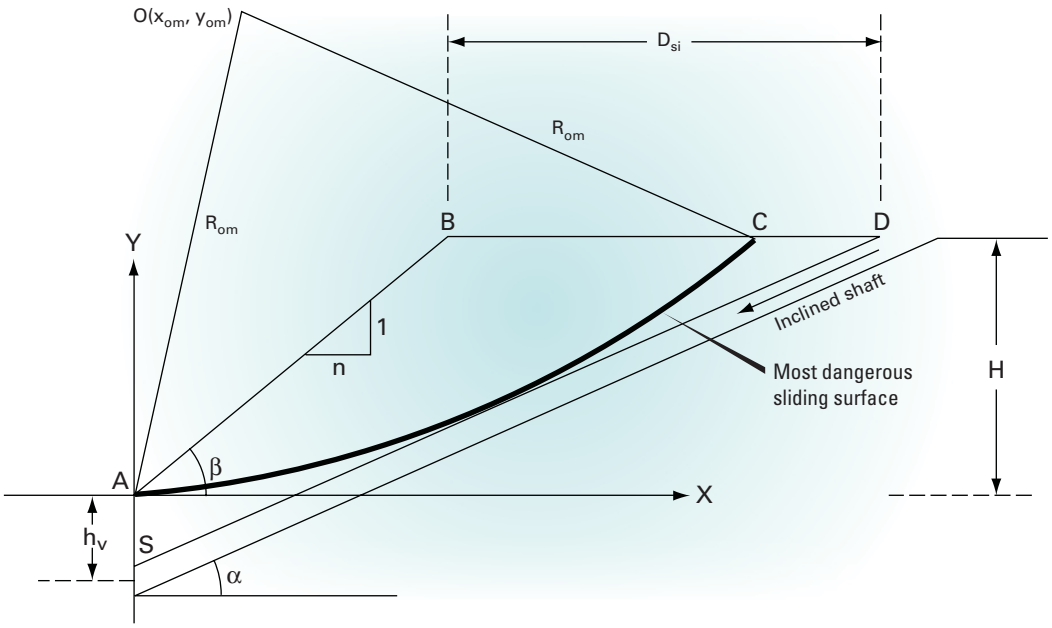
Design parameters

Soil slope stability analysis theory provides a new method for acquiring design parameters of wells traversing loess gullies or slopes. The method first determines the shape and location of the critical slip surface via slope stability analysis. Then, while avoiding the sliding block and maintaining slope stability, formulas for various design parameters of the well's spatial structure are established.

According to stability analysis theory, whether in homogeneous or nonhomogeneous slope, the slide curve is a mostly regular and non-canonical dip surface or arc-like surface. The Swedish slice method or simplified Bishop method uses slope stability analysis[4] to obtain the safety factor, center position, and radius of the critical slip surface for a homogeneous soil slope. The traditional slice method, however, cannot find the most dangerous sliding surface in

INCLINED SHAFT, MOST DANGEROUS SLIDING SURFACE

Fig. 4



complex topography.

The strength reduction method of numerical simulation can more realistically simulate gully topography and doesn't need any assumptions regarding the location and shape of the sliding surface. Continuous discount of the strength parameters yields the most dangerous sliding surface, which may be irregular in shape or composed by a number of noncanonical potential sliding surfaces,[5] allowing establishment of the formula for calculating the design parameters of the inclined shaft.

D_{sp} represents the horizontal distance from slope shoulder to the most dangerous sliding surface (Fig. 3). The distance between the wellhead at the top of slope and the slope shoulder should not measure less than 15 m.[6]

SLOPE PARAMETERS

Table 1

Parameter	Slope 1	Slope 2
Slope height; H, m	25	52.8
Slope angle; β, degrees	50	49
Density; γ, kilonewton/cu m	17.5	17.75
Cohesive force; C, kilopascals	30	48.9
Angle of internal friction; φ, degrees	25	26.35

Elasticity theory and a large amount of numerical simulation analysis[7,8] show the area of surrounding soil affected by excavation as 3-5 times the area of the excavated space size, allowing determination of h_s and h_v (Fig. 3).

Important design parameters for the inclined shaft include safe distance from the shaft wellhead to slope shoulder, dip angle and length, etc. Assuming the regular slope to be made of homogeneous materials allows conventional slope stability analysis methods to determine the circular arc of the most potentially dangerous sliding surface, with a circular center of O (x_{0m}, y_{0m}) and radius R_{0m}.

The coordinate system in Fig. 4 yields Equation 1, describing the most dangerous sliding surface.

Assuming line SD, connected by the arch crown of the inclined shaft, passes through points S(0, h_v) and D(x_s, y_s), and the included angle between line and the X axis is α, yields Equation 2 as the equation for line SD.

Equation 3 simplifies Equations 1 and 2 as line SD osculates with the most dangerous sliding surface.

Equation 4 provides the only tangential point between line SD and the most dangerous sliding surface.

The geometric relationship shown in Fig. 4 yields Equation 5 as the safety

DESIGN PARAMETERS, SAFETY FACTORS

Table 2

Parameters	Analysis method	Slope 1	Slope 2
Wellhead safety distance, m	Swedish slice method	20.52	55.53
	Bishop method	20.52	55.53
Oblique shaft length, m	Swedish slice method	50.06	115.83
	Bishop method	50.06	115.92
Oblique shaft dip angle; α, degrees	Swedish slice method	34.01	28.80
	Bishop method	34.01	28.78
Sliding arc radius, R_{0m}	Swedish slice method	49.48	106.35
	Bishop method	49.48	106.34
Sliding arc center fix, (X_{0m}, y_{0m})	Swedish slice method	(–13.45, 47.62)	(–29.37, 102.22)
	Bishop method	(–13.45, 47.62)	(–29.35, 102.21)
Safety factor, K_s	Swedish slice method	1.08	1.010
	Bishop method	1.09	1.032

PHYSICAL, MECHANICAL PARAMETERS

Table 3

c, kilopascals	φ, degrees	γ, kilonewtons/cu m	R_f	n	K_b	m
30	25	17.5	0.62	0.58	120	0.29

distance between the inclined shaft wellhead and slope shoulder and Equation 6 as the inclined shaft length.

The influence of inclined shaft excavation to the slope or gully, particularly for slope of safety factor near 1.0 (based on Equation 5's results), show the inclined shaft should be moved parallel to the stabilized soil (the sliding bed of the most dangerous slip surface) at a certain distance in the design phase to avoid affecting slope stability.

Rewriting Equation 5 as Equation 7 addresses this influence.

Examples

The inclined shaft crossing method traversed 105 slopes and gullies in the 11th, 12th, and 13th sections of the Lan-Zheng-Chang oil transport pipeline in Henan province. The longest inclined shaft length measured 140 m. Two slopes crossed illustrate the parameter design method of the inclined shaft.

Table 1 shows the slope geometry and mechanical parameters[7] of the two slopes, with analysis results shown in Fig. 5 and Table 2 for an inclined-shaft cross section height of 1.5 m.

Because the cross-section height, h, of the inclined shaft is 1.5 m, the vertical distance h_v between the inclined shaft exit and slope toe can be determined as 3.0 m (>(3~5)h/2). Keeping the inclined shaft route osculate with the critical surface allows calculation of the inclined shaft's position and the horizontal distance, h_s, between the inclined shaft and slope toe.

The slope's safety factors are close to 1.0, which is in a limit equilibrium state. The inclined pipeline shaft must therefore lie outside the potential sliding surface, and its design parameters should be adjusted with Equation 7. The safety distance between wellhead and slope shoulder increases by h_v m, and the inclined shaft overall moves parallel to the stable soil in h_v m.

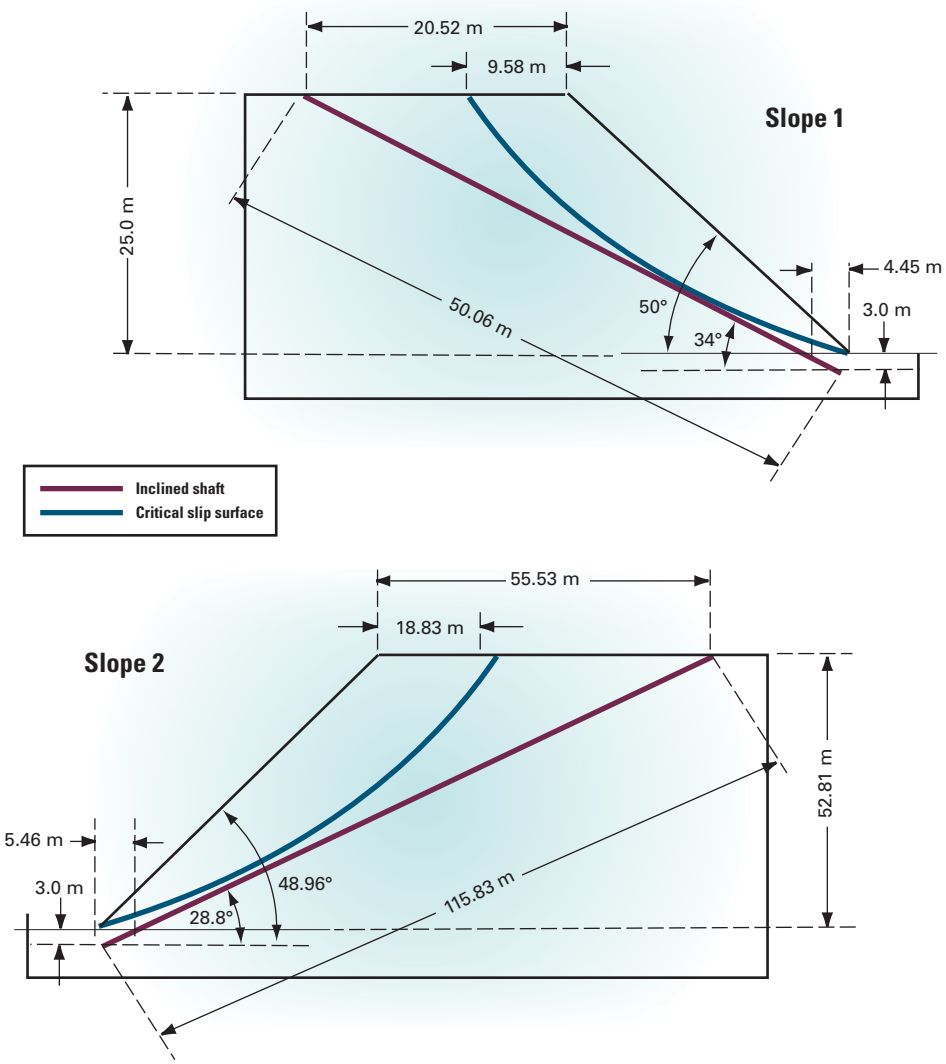
Verifying the rationality of the acquired design parameters used numerical simulation analysis on Slope 1 for inclined shaft traversing engineering. The Duncan-Chang model reasonably reflects the non-linear deformation characteristics of soil masses.[9] The Mohr-Coulomb reflects the yield degree of soil mass (Equation 8).

The limit designing dip angle of the inclined shaft measures 34°; other design parameters are shown in Table 2. The geometry model is fixed at the base and horizontal direction of the lateral face. Table 3 lists the main physical and mechanical parameter domains of the loess soil in the numerical simulations.

Fig. 6 shows the yield distribution of the slope after the inclined shaft crossing. The pipeline well lays safely outside

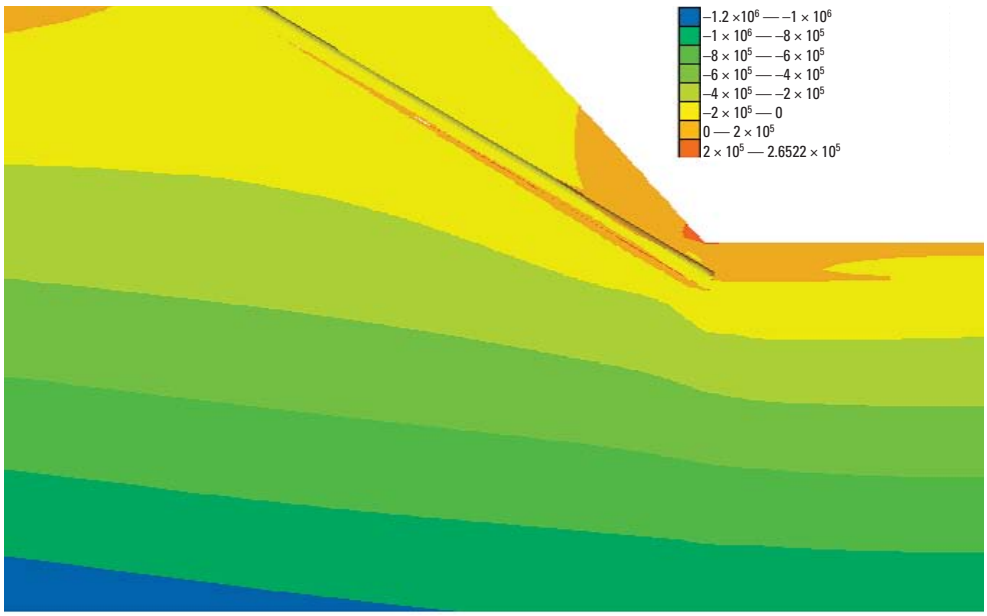
Design parameters

Fig. 5



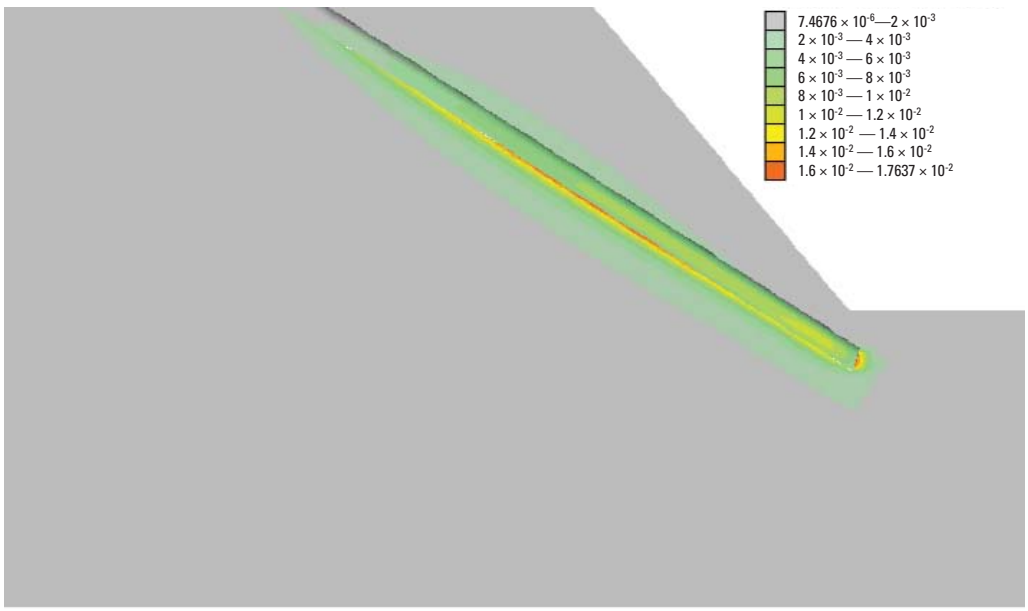
YIELD VALUE DISTRIBUTION

Fig. 6



DISPLACEMENT DISTRIBUTION

Fig. 7



the red and orange yield areas at the foot of the slope (as determined by the acquired design parameters) where the most critical slip surface lies. Figs. 6 and 7 show little effect of excavation on slope stability.

The design parameters are rational, and the method proposed to determine design parameters for pipelines traversing the slope was useful and concise. ✦

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Equipment/Software/Literature

Updated well planning, drilling engineering application

Sysdrill 2009 is an updated well planning and drilling engineering application. The 2009 version promises tighter integration, improved ease of use, and enhanced functionality.

This version allows drilling engineers to plan wells quickly, safely, and accurately to reduce drilling risk and uncertainty. Features include:

- Reduction of data entry time for engineering analyses.
- Advanced input/output interface for loading of third-party data.
- Result-driven analysis for quick identification of drilling problems.
- Incorporation of geological data for improved planning and visualization.
- Office style output for incorporation into the drilling program.

Source: **Paradigm BV**, Reimersbeek 2, 1082 AG Amsterdam, the Netherlands.

New telemetry platform

The new Orion II telemetry platform enables reliable communication with bottomhole assemblies whether drilling at high penetration rates or longer boreholes.

With Orion II, more quality data and higher resolution images can be transmitted, at greater depths, enabling better drilling decisions to be made in real time, the company notes.

The new generation telemetry platform combines new data compression technology housed in the measurement-while-drilling/logging-while-drilling tool with new surface and downhole sensors that modulate and demodulate signals and overcome interference from drilling and rig noise, even in harsh environments. Downlink commands are sent in real time while drilling without affecting delivery of measurement data to surface.

Source: **Schlumberger,** 5599 San Felipe, 17th Floor, Houston, TX 77056.

New tool helps eliminate chronic reamer problems

GaugePro XPR expandable reamer (left side of photo above) and GaugePro XPS expandable stabilizer help improve performance, reduce vibration, deliver hole quality, and increase tool reliability.

This hole-opening solution promises to eliminate chronic reamer problems. The reamer remains closed until triggered, opens on command, reams an in-gauge hole, and closes and comes out of the hole properly. With the pilot bit design synchronized to the expandable reamer in a fit-for-purpose drilling assembly, operators are achieving an exceptional downhole operating environment, the company says. The patented drop-ball method triggers an expandable reamer, eliminating premature triggering independent of weight on bit, flow, or bottomhole assembly pressure.

Source: **Hughes Christensen,** 9110 Grogan's Mill Rd., The Woodlands, TX 77380.

IDS,

Kuala Lumpur, has appointed Douwe Franssens to the newly created position of general manager, IDS Group. His initial focus will be Northern Hemisphere operations.


Franssens

Franssens previously worked as senior product manager and global real-time technology manager at Halliburton. He spent 8 years working globally in the dredging industry and then 17 years in a variety of technical and managerial positions in the oil and gas industry, with deployments to Saudi Arabia, Qatar, Malaysia, Houston, and Canada.

IDS provides intuitive, end-to-end, web-based, upstream oil and gas data reporting services. It supports the drilling project life cycle from initial concept to final decommissioning.

BJ Services,

Houston, has opened a new base in Oirschot, near Eindhoven, The Netherlands. The new base replaces the previous process and pipeline services base in Oirschot that had been operating since 2001. It also serves as the new continental Europe/North Africa region headquarters for BJ's process and pipeline services group. Designed specifically to support oil, gas, and petrochemical customers across continental Europe, the new base currently houses the largest and most diverse fleet of onshore nitrogen services equipment in Europe. It will accommodate the largest fleet of mobile pipeline recompression systems, which will arrive in summer 2009 and early 2010. In addition, mobile flaring and chemical cleaning services equipment are located at the facility, giving production facilities and pipeline operators in Europe a full complement of start-up and shutdown services. The full range of BJ Services' process and pipeline services are available from Oirschot, including but not limited to cold and hot nitrogen services, pipeline gas recompression and mobile flaring services, chemical cleaning, hydrostatic testing, nitrogen and helium leak detection, and pipe freeze isolation services, as well as pipeline and process piping cleaning and drying.

BJ Services is a leading provider of field development and production enhancement services to the energy industry.

Aker Solutions ASA,

Oslo, has opened its expanded service and maintenance base at Aagotnes outside Bergen, Norway. The 50 million-kroner (Nor.) expansion will enable the company to further improve its onshore and offshore service support for subsea customers operating off Norway. A new workshop for maintenance of subsea equipment and a new office block, which includes state-of-the-art support systems, has been set up on the existing base. The Aagotnes base provides life-of-field support for subsea equipment, including offshore installation and intervention support; onshore maintenance, refurbishment, and upgrades of subsea trees, control systems and intervention work-over systems; and maintenance, repairs, and recertification of tools. It also provides storage facilities, engineering services, and technical support.

Aker Solutions is a leading global provider of engineering and construction services, technology products, and integrated solutions to the oil and gas, refining and chemicals, mining and metals, and power generation industries.

Rhodia Novecare,

Paris, and IFP have launched a services and consulting joint venture targeting enhanced oil recovery (EOR). The objective is to offer oil companies solutions adapted to different operating conditions so as to maximize oil production. The JV will offer flexible solutions through analyzing historical reservoir production data and proposing solutions, laboratory development of chemical formulations optimized to meet oil field conditions, development and optimization of demonstration pilots and implementation on a field scale via simulation and monitoring tools, assistance for pilot implementation and development through the operational phase, and large-scale supply of the chemical solutions defined.

IFP is a Paris-based international oil and gas research organization with pioneering expertise in chemical EOR.

Rhodia is a supplier of chemical solutions for the oil industry and a leader in specialty surfactants.

Insight Management Corp.,

Orlando, Fla., and Microresearch Corp., Orcutt, Calif., have agreed to merge, retaining the name Insight Management Corp. Insight shareholders will receive 0.667 shares for each share of the new Insight. Each Microresearch share will automatically become a share of the combined company. Microresearch Pres. and CEO Jennifer Rapacki will lead the combined company.

Insight will provide technology, products, and services to the US oil and gas industry. Microresearch announced on Mar. 6 that it signed a contract to purchase Rebel Testing Inc., Gillette, Wyo. Rebel is a leading Rocky Mountain regional oil and gas service provider with a fleet of pump hoist trucks to service natural gas well pumps. It also services and pressure-tests blowout preventers.

KBC Advanced Technologies PLC,

London, has added an environmental services practice. Augmenting the existing KBC health, safety, and environmental offerings, this new, full-service environmental consulting practice provides a wide range of commercially acceptable advice and traditional services, such as environmental due diligence, environmental and social impact assessments, and contaminated land work. The environmental services team develops solutions to emerging issues across sectors, including upstream and downstream oil and gas, fossil energy production and transmission, nuclear project development, renewable energy generation and transmission, mining, and the financial investment sector, among others. Ben Sawford and Dr. Jim Wright, both former company directors at the environmental division of AMEC in the UK, have been appointed the lead this effort.

KBC consultants provide independent advice and expertise to enable leading companies in the global energy business and other processing industries to manage risk while maximizing the value from their assets.

Statistics

Imports of crude and products

	Districts 1-4		District 5		Total US		
	4-24 2009	4-17 2009	4-24 2009	4-17 2009	4-24 2009	4-17 2009	*4-25 2008
	1,000 b/d						
Total motor gasoline	841	1,106	0	11	841	1,117	1,385
Mo. gas. blending comp.	680	953	0	11	680	964	954
Distillate	123	192	0	0	123	192	273
Residual	327	291	59	92	386	383	425
Jet fuel-kerosine	41	97	15	18	56	115	114
Propane-propylene	168	63	8	6	176	69	119
Other	318	(11)	40	111	358	100	504
Total products	**2,498**	**2,691**	**122**	**249**	**2,620**	**2,940**	**3,774**
Total crude	**8,836**	**8,468**	**988**	**1,387**	**9,824**	**9,855**	**10,215**
Total imports	**11,334**	**11,159**	**1,110**	**1,636**	**12,444**	**12,795**	**13,989**

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

Purvin & Gertz LNG netbacks—May 1, 2009

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	8.14	5.45	7.40	5.35	6.75	7.33
Everett	2.72	0.98	2.43	1.09	1.42	2.96
Isle of Grain	3.07	1.31	2.56	1.22	1.75	2.58
Lake Charles	1.24	–0.28	1.06	–0.15	–0.01	1.74
Sodegaura	3.65	5.92	3.91	5.66	5.00	3.15
Zeebrugge	4.87	2.58	4.08	2.49	3.07	4.15

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

Crude and product stocks

District	Crude oil	Motor gasoline		Jet fuel, kerosine	Fuel oils		Propane–propylene
		Total	Blending comp.[1]		Distillate	Residual	
	1,000 bbl						
PADD 1	14,738	55,615	38,394	10,486	53,255	14,793	2,569
PADD 2	85,448	52,215	22,550	7,361	33,486	1,235	14,920
PADD 3	198,689	70,754	40,695	13,150	41,508	15,355	24,315
PADD 4	17,293	5,413	2,074	559	3,214	220	[1]891
PADD 5	58,485	28,615	23,021	8,632	12,642	4,679	—
Apr. 24, 2009	**374,653**	**212,612**	**126,734**	**40,188**	**144,105**	**36,282**	**42,695**
Apr. 17, 2009	**370,600**	**217,307**	**128,991**	**39,704**	**142,311**	**36,332**	**41,414**
Apr. 25, 2008[2]	**319,929**	**211,089**	**103,151**	**38,738**	**105,831**	**39,522**	**28,540**

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

Refinery report—Apr. 24, 2009

District	Refinery operations		Refinery output				
	Gross inputs	Crude oil inputs	Total motor gasoline	Jet fuel, kerosine	Fuel oils		Propane–propylene
					Distillate	Residual	
	1,000 b/d						
PADD 1	1,183	1,178	2,402	88	398	98	55
PADD 2	3,096	3,077	1,994	231	866	58	248
PADD 3	7,405	7,282	2,670	718	2,257	210	628
PADD 4	467	463	247	22	144	7	[1]74
PADD 5	2,461	2,334	1,477	383	488	103	—
Apr. 24, 2009	**14,612**	**14,334**	**8,790**	**1,442**	**4,153**	**476**	**1,005**
Apr. 17, 2009	**14,748**	**14,516**	**9,088**	**1,425**	**4,136**	**504**	**1,013**
Apr. 25, 2008[2]	**15,021**	**14,748**	**8,964**	**1,471**	**4,238**	**656**	**993**
	17,675 Operable capacity		**82.7% utilization rate**				

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

Additional analysis of market trends is available through **OGJ Online**, *Oil & Gas Journal's* electronic information source, at http://www.ogjonline.com.

OIL&GAS JOURNAL online research center

OGJ crack spread

	*5-1-09	*5-2-08	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	56.92	125.96	–69.04	–54.8
Brent crude	50.04	115.36	–65.32	–56.6
Crack spread	6.88	10.60	–3.72	–35.1
FUTURES MARKET PRICES				
One month				
Product value	58.91	128.28	–69.36	–54.1
Light sweet crude	51.07	115.34	–64.27	–55.7
Crack spread	7.84	12.94	–5.10	–39.4
Six month				
Product value	59.66	123.58	–63.92	–51.7
Light sweet crude	56.45	112.12	–55.67	–49.7
Crack spread	3.21	11.46	–8.25	–72.0

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

OGJ GASOLINE PRICES

	Price ex tax 4-29-09	Pump price* 4-29-09	Pump price 4-30-08
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	157.8	204.3	368.8
Baltimore	158.5	200.4	355.4
Boston	156.5	198.4	350.4
Buffalo	144.5	205.4	372.7
Miami	149.8	201.4	377.8
Newark	255.1	287.7	342.3
New York	129.4	190.3	358.6
Norfolk	154.1	192.5	341.8
Philadelphia	155.8	206.5	359.8
Pittsburgh	159.2	209.9	358.3
Wash., DC	177.1	215.5	366.7
PAD I avg	163.4	210.2	359.3
Chicago	156.5	220.9	282.6
Cleveland	158.5	204.9	350.8
Des Moines	160.5	200.9	347.3
Detroit	147.5	206.9	360.1
Indianapolis	140.5	199.9	357.1
Kansas City	158.9	194.9	339.8
Louisville	160.0	200.9	367.7
Memphis	159.1	198.9	345.6
Milwaukee	153.6	204.9	372.0
Minn.-St. Paul	159.9	203.9	351.1
Oklahoma City	154.5	189.9	342.1
Omaha	152.6	197.9	350.1
St. Louis	154.9	190.9	355.2
Tulsa	154.5	189.9	337.2
Wichita	152.5	195.9	341.8
PAD II avg	154.9	200.1	354.1
Albuquerque	161.5	197.9	346.2
Birmingham	156.6	195.9	351.5
Dallas-Fort Worth	154.5	192.9	352.7
Houston	154.4	192.8	348.5
Little Rock	155.7	195.9	350.2
New Orleans	153.5	191.9	347.5
San Antonio	152.5	190.9	343.1
PAD III avg	155.5	194.0	348.5
Cheyenne	161.2	193.6	334.2
Denver	156.5	196.9	363.1
Salt Lake City	149.0	191.9	345.9
PAD IV avg	155.6	194.1	347.7
Los Angeles	144.8	211.9	388.4
Phoenix	163.5	200.9	338.5
Portland	178.5	221.9	366.2
San Diego	163.6	230.7	397.1
San Francisco	168.6	235.7	404.4
Seattle	166.0	221.9	375.2
PAD V avg	164.2	220.5	378.3
Week's avg.	**158.6**	**204.2**	**357.5**
Apr. avg.	**156.7**	**202.3**	**339.3**
Mar. avg.	**147.6**	**193.2**	**319.7**
2009 to date	**145.6**	**191.2**	—
2008 to date	**273.8**	**317.4**	—

*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

	4-24-09 ¢/gal		4-24-09 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	139.03	New York Harbor	135.05
Gulf Coast	134.13	Gulf Coast	132.30
Los Angeles	151.13	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	136.96	ARA	137.45
Singapore	138.57	Singapore	132.95
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	143.53	New York Harbor	109.83
Gulf Coast	140.38	Gulf Coast	117.33
Los Angeles	158.13	Los Angeles	124.38
		ARA	102.36
		Singapore	107.93

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

BAKER HUGHES RIG COUNT

	5-1-09	5-2-08
Alabama	4	6
Alaska	4	5
Arkansas	48	43
California	17	36
Land	16	34
Offshore	1	2
Colorado	45	123
Florida	0	0
Illinois	1	0
Indiana	0	2
Kansas	17	9
Kentucky	9	10
Louisiana	135	153
N. Land	75	54
S. Inland waters	5	22
S. Land	11	20
Offshore	44	57
Maryland	0	0
Michigan	0	1
Mississippi	10	12
Montana	1	10
Nebraska	1	0
New Mexico	34	79
New York	1	8
North Dakota	37	65
Ohio	7	12
Oklahoma	88	210
Pennsylvania	27	19
South Dakota	1	3
Texas	375	882
Offshore	4	10
Inland waters	0	1
Dist. 1	11	27
Dist. 2	12	36
Dist. 3	27	60
Dist. 4	40	84
Dist. 5	92	183
Dist. 6	62	119
Dist. 7B	14	27
Dist. 7C	9	66
Dist. 8	40	133
Dist. 8A	11	25
Dist. 9	23	36
Dist. 10	30	75
Utah	15	39
West Virginia	22	26
Wyoming	34	70
Others—NV-4; TN-3; VA-4; WA-1	12	16
Total US	**945**	**1,839**
Total Canada	**67**	**95**
Grand total	**1,012**	**1,934**
US Oil rigs	196	357
US Gas rigs	741	1,473
Total US offshore	51	69
Total US cum. avg. YTD	**1,244**	**1,787**

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	5-1-09 Percent footage*	Rig count	5-2-08 Percent footage*
0-2,500	38	7.8	75	5.3
2,501-5,000	59	62.7	119	52.9
5,001-7,500	117	17.0	216	16.2
7,501-10,000	204	4.4	432	3.4
10,001-12,500	179	2.7	474	4.2
12,501-15,000	184	—	287	—
15,001-17,500	114	—	126	—
17,501-20,000	50	—	75	—
20,001-over	38	—	37	—
Total	**983**	**7.5**	**1,841**	**7.4**
INLAND	9		29	
LAND	928		1,754	
OFFSHORE	46		58	

*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]5-1-09	[2]5-2-08
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	21	21
Alaska	704	698
California	653	654
Colorado	64	65
Florida	5	5
Illinois	28	27
Kansas	103	106
Louisiana	1,450	1,297
Michigan	15	16
Mississippi	61	58
Montana	91	87
New Mexico	163	159
North Dakota	197	152
Oklahoma	175	170
Texas	1,353	1,338
Utah	57	57
Wyoming	150	148
All others	68	74
Total	**5,358**	**5,132**

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

US CRUDE PRICES

	5-1-09 $/bbl*
Alaska-North Slope 27°	42.37
South Louisiana Sweet	52.75
California-Kern River 13°	45.65
Lost Hills 30°	54.00
Wyoming Sweet	41.70
East Texas Sweet	49.25
West Texas Sour 34°	43.75
West Texas Intermediate	49.75
Oklahoma Sweet	49.75
Texas Upper Gulf Coast	42.75
Michigan Sour	41.75
Kansas Common	48.50
North Dakota Sweet	40.50

*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]	4-24-09
United Kingdom-Brent 38°	49.16
Russia-Urals 32°	47.49
Saudi Light 34°	48.20
Dubai Fateh 32°	49.54
Algeria Saharan 44°	49.43
Nigeria-Bonny Light 37°	50.46
Indonesia-Minas 34°	53.97
Venezuela-Tia Juana Light 31°	48.65
Mexico-Isthmus 33°	48.54
OPEC basket	49.26
Total OPEC[2]	48.79
Total non-OPEC[2]	47.85
Total world[2]	48.38
US imports[3]	46.67

[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]

	4-24-09	4-17-09	4-24-08	Change, %
	bcf			
Producing region	779	756	506	**54.0**
Consuming region east	668	651	596	**12.1**
Consuming region west	294	288	180	**63.3**
Total US	**1,741**	**1,695**	**1,282**	**35.8**
	Jan. 09	**Jan. 08**	**Change, %**	
Total US[2]	**2,141**	**2,055**	**4.2**	

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

Statistics

WORLDWIDE CRUDE OIL AND GAS PRODUCTION

	Feb. 2009	Jan. 2009	2 month average — production — 2009	2008	Change vs. previous year — Volume	%	Feb. 2009	Jan. 2009	Cum. 2009
	Crude, 1,000 b/d						Gas, bcf		
Argentina	630	615	623	617	6	0.9	107.6	116.4	223.94
Bolivia	40	40	40	42	–2	–4.8	38.0	42.0	80.00
Brazil	1,908	1,889	1,899	1,774	125	7.0	27.0	30.0	57.00
Canada	2,698	2,608	2,653	2,547	106	4.2	451.9	516.3	968.20
Colombia	646	617	632	559	73	13.0	21.0	22.0	43.00
Ecuador[1]	480	500	490	500	–10	–2.0	1.0	1.0	2.00
Mexico	2,663	2,685	2,674	2,943	–269	–9.1	196.3	219.8	416.05
Peru	103	110	107	73	34	46.9	7.8	9.2	17.00
Trinidad	110	110	110	115	–5	–4.6	104.0	115.0	219.00
United States	5,336	5,246	5,291	5,103	188	3.7	1,697.0	1,856.0	3,553.00
Venezuela[1]	2,100	2,180	2,140	2,425	–285	–11.8	60.0	70.0	130.00
Other Latin America	83	83	83	83	—	–0.5	5.1	5.5	10.68
Western Hemisphere	**16,797**	**16,684**	**16,740**	**16,781**	**–41**	**–0.2**	**2,716.7**	**3,003.2**	**5,719.87**
Austria	18	17	18	17	—	2.3	4.7	5.4	10.10
Denmark	283	277	280	293	–13	–4.4	24.1	30.1	54.28
France	20	17	19	21	–2	–11.7	2.8	2.8	5.60
Germany	59	59	59	64	–5	–7.5	44.0	48.0	92.00
Italy	80	87	84	111	–28	–24.8	22.0	25.0	47.00
Netherlands	30	29	30	40	–11	–26.3	365.0	400.0	765.00
Norway	2,260	2,195	2,228	2,203	25	1.1	345.6	363.5	709.10
Turkey	39	37	38	39	–1	–1.6	0.0	0.0	0.00
United Kingdom	1,468	1,432	1,450	1,490	–40	–2.7	198.6	241.8	440.35
Other Western Europe	3	3	3	4	–1	–26.0	2.9	3.2	6.01
Western Europe	**4,261**	**4,154**	**4,207**	**4,282**	**–75**	**–1.7**	**1,009.6**	**1,119.8**	**2,129.44**
Azerbaijan	850	850	850	945	–95	–10.1	36.0	40.0	76.00
Croatia	14	14	14	15	–1	–7.0	4.8	5.5	10.38
Hungary	15	14	14	14	—	0.5	8.5	8.5	16.91
Kazakhstan	1,250	1,250	1,250	1,175	75	6.4	90.0	100.0	190.00
Romania	90	90	90	95	–5	–5.3	17.0	19.0	36.00
Russia	9,730	9,740	9,735	9,780	–45	–0.5	1,750.0	1,950.0	3,700.00
Other FSU	450	450	450	400	50	12.5	350.0	400.0	750.00
Other Eastern Europe	45	45	45	49	–4	–8.4	19.8	22.1	41.93
Eastern Europe and FSU	**12,444**	**12,453**	**12,448**	**12,474**	**–25**	**–0.2**	**2,276.1**	**2,545.1**	**4,821.22**
Algeria[1]	1,250	1,270	1,260	1,390	–130	–9.4	230.0	260.0	490.00
Angola[1]	1,680	1,790	1,735	1,907	–172	–9.0	4.0	5.0	9.00
Cameroon	78	78	78	88	–10	–11.4	—	—	—
Congo (former Zaire)	25	25	25	25	—	—	—	—	—
Congo (Brazzaville)	240	240	240	240	—	—	—	—	—
Egypt	680	680	680	650	30	4.6	115.0	130.0	245.00
Equatorial Guinea	320	320	320	320	—	—	0.1	0.1	0.12
Gabon	240	240	240	235	5	2.1	0.3	0.3	0.59
Libya[1]	1,580	1,650	1,615	1,765	–150	–8.5	30.0	35.0	65.00
Nigeria[1]	1,800	1,860	1,830	2,080	–250	–12.0	70.0	80.0	150.00
Sudan	500	500	500	480	20	4.2	—	—	—
Tunisia	88	91	89	82	7	9.1	7.8	8.6	16.38
Other Africa	221	221	221	221	—	—	8.3	9.1	17.40
Africa	**8,702**	**8,965**	**8,834**	**9,483**	**–649**	**–6.8**	**465.4**	**528.1**	**993.49**
Bahrain	170	169	170	169	—	0.1	22.5	24.8	47.31
Iran[1]	3,700	3,790	3,745	4,025	–280	–7.0	255.0	290.0	545.00
Iraq[1]	2,260	2,370	2,315	2,380	–65	–2.7	17.0	20.0	37.00
Kuwait[1,2]	2,300	2,460	2,380	2,575	–195	–7.6	34.0	40.0	74.00
Oman	720	730	725	710	15	2.1	54.0	60.0	114.00
Qatar[1]	750	780	765	850	–85	–10.0	160.0	180.0	340.00
Saudi Arabia[1,2]	7,810	7,960	7,885	9,015	–1,130	–12.5	180.0	200.0	380.00
Syria	390	390	390	390	—	—	16.0	18.0	34.00
United Arab Emirates[1]	2,250	2,360	2,305	2,665	–360	–13.5	110.0	125.0	235.00
Yemen	280	290	285	320	–35	–10.9	—	—	—
Other Middle East	—	—	—	—	—	214.3	7.7	9.9	17.60
Middle East	**20,630**	**21,299**	**20,965**	**23,099**	**–2,135**	**–9.2**	**856.2**	**967.7**	**1,823.92**
Australia	485	480	482	406	76	18.8	108.7	120.0	228.70
Brunei	152	161	157	181	–24	–13.3	33.1	37.3	70.36
China	3,743	3,709	3,726	3,768	–41	–1.1	241.0	260.0	501.02
India	614	638	626	667	–41	–6.1	75.9	80.4	156.30
Indonesia	840	830	835	854	–19	–2.2	190.0	210.0	400.00
Japan	20	19	19	20	–1	–5.2	11.5	12.5	23.98
Malaysia	760	740	750	775	–25	–3.2	130.0	140.0	270.00
New Zealand	62	40	51	63	–12	–18.4	10.0	11.0	21.00
Pakistan	64	66	65	68	–3	–4.4	114.1	126.3	240.36
Papua New Guinea	40	40	40	44	–4	–9.1	0.9	1.0	1.90
Thailand	233	259	246	216	30	14.0	30.0	32.6	62.55
Vietnam	250	250	250	315	–65	–20.6	13.5	15.0	28.50
Other Asia-Pacific	35	35	35	37	–3	–7.1	96.5	96.5	193.00
Asia-Pacific	**7,297**	**7,267**	**7,282**	**7,412**	**–130**	**–1.8**	**1,055.2**	**1,142.4**	**2,197.67**
TOTAL WORLD	**70,131**	**70,822**	**70,476**	**73,532**	**–3,055**	**–4.2**	**8,379.3**	**9,306.3**	**17,685.60**
OPEC	27,960	28,970	28,465	32,430	–3,965	–12.2	1,151.0	1,306.0	2,457.00
North Sea	4,031	3,925	3,978	4,003	–25	–0.6	677.7	755.3	1,432.99

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

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'Pollutant's' new meaning threatens hydrogen vehicles

If applied consistently, the logic that treats carbon dioxide as air pollution would end whatever hope remains for hydrogen-powered vehicles.

Last month the US Environmental Protection Agency proposed to find that CO_2 and five other greenhouse gases contribute to air pollution and might endanger public health or welfare.

The agency acted under a 2007 Supreme Court ruling that greenhouse gases fit the Clean Air Act's definition of "pollutant." It didn't matter that CO_2 governs breathing of animals and sustains plants, among other things.

The ruling addressed legal wording, not scientific questions about human influence on global average temperature. But it means that if EPA makes an endangerment finding, the agency has to regulate emissions of them from motor vehicles.

So a gas essential to life plus methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride are "pollutants" by court order because they are greenhouse gases, regardless of the degree to which human emissions of them may have contributed to the uneven warming observed over the past 150 years.

By extension, this contortion of the meaning of "pollutant" bodes ill for hydrogen as a vehicle fuel.

The administration of former President George W. Bush feverishly promoted hydrogen as a vehicle fuel in direct combustion or through use as the energy carrier in onboard fuel cells.

Since then, hydrogen seems to have fallen from favor, partly for technical reasons overlooked in the initial hubbub but also because biofuels have broader political support.

But the initial appeal was strong. Hydrogen was said to be a zero-pollution vehicle fuel. Its combustion emits only water.

But wait: Water vapor's greenhouse influence is far stronger than CO_2's. Especially if the rise in global average temperature resumes after an apparent 10-year pause, more water in the environment should mean more water vapor in the atmosphere and hence more warming.

By the legal reasoning of the day, blind as it is to technicalities such as how much extra water vapor is really at stake here, that's pollution. If CO_2 endangers life, water vapor must do so many times over.

A ban on hydrogen-powered vehicles thus seems only logical.

(Online May 1, 2009; author's e-mail: bobt@ogjonline.com)

The Editor's Perspective

by Bob Tippee, Editor

Market Journal

by Sam Fletcher, Senior Writer

Possible shift in gas fundamentals

Analysts at Pritchard Capital Partners LLC in New Orleans reported a pending shift in the bearish fundamentals of the natural gas market with US production expected to drop because of a 57% decline in the US rig count and sizeable production shut-ins so far this year.

The US rig count was down to 955 rigs as of May 1. "The net declines have decelerated from 38 rigs 4 weeks ago to 30, 20, and 10 rigs over the past 3 weeks," Raymond James analysts said on May 4. "Since the 2,031 rig peak in early September, the rig count has been cut by 53%, or 1,086 rigs. The 53% rig count decline after the first 33 weeks since the peak in the 2008-09 cycle compares to a 42% drop in the 1983 cycle, a 15% fall in the 1997-98 cycle, and a 40% retracement in the 2001-02 cycle."

The June gas contract jumped 5.1% to $3.55/MMbtu on May 1 on the New York Mercantile Exchange, far outstripping combined losses from the previous two sessions. The price increase was stimulated by the Institute for Supply Management, a trade group of purchasing executives, whose manufacturing index rose to 40.1 in April from 36.3 in March. A reading below 50 indicates a contraction, and this marked the 15th consecutive month of contractions in manufacturing. However, the pace in April was slower than expected due to a rise in new orders. The private trade group's figures suggested the economic decline may be moderating, analysts said.

Crude outlook

Meanwhile, US crude inventories were at all-time highs while oil demand remained depressed, down 5.4% from year-ago levels in February. In Houston, analysts at Raymond James & Associates Inc. said oil production among members of the Organization of Petroleum Exporting Countries apparently peaked in the first quarter of 2008, with non-OPEC production having topped out in 2007.

"Of course, we cannot definitively prove that this marks the all-time peak (that is, that global oil production will never again surpass the 79.3 million b/d mark)," the analysts conceded. "That is something that will only become clear with the benefit of years of hindsight as was the case with the US in the 1970s. However, it is entirely intuitive to conclude that if both OPEC and non-OPEC production posted declines against the backdrop of $100/bbl oil—when the obvious economic incentive was to pump at full blast—those declines had to have come for involuntary reasons such as the inherent geological limits of oil fields. To summarize, we believe that the oil market has already crossed over to the downward-sloping side of Hubbert's Peak [based on the production curve model developed by geophysicist M. King Hubbert]."

Raymond James analysts said, "With demand as weak as it is now, of course, inadequate future supply is hardly what the oil market is worrying about these days. Nonetheless, reaching peak oil still represents a transformative moment in the history of the oil market, and, if we're right that this moment is already behind us, it is only a matter of time before prices begin to reflect the reality that oil scarcity may become a fact of life in the not-too-distant future."

Pritchard Capital Partners said total crude production from all OPEC members slipped 75,000 b/d, or 0.3%, to 27.58 million b/d in April, compared with March. The 11 OPEC members under quota restrictions—all except Iraq—produced 25.25 million b/d, 410,000 b/d more than their official target of 24.84 million b/d. Nevertheless, OPEC members generally are "staying tight and abiding by their quotas," said Pritchard Capital analysts.

They reported Saudi Arabia reduced its production by 25,000 b/d to 7.92 million b/d, under its official target of 8 million b/d. UAE cut production 40,000 b/d to 2.16 million b/d in April, 63,000 b/d lower than its target. According to industry reports, Abu Dhabi's export allocation of its Murban, Lower Zakum, and Umm Shaif crudes to customers in Asia will stay 15% below contract volumes through May—10% less of Upper Zakum crude than contracted this month and 18% less in June of Umm Shaif, Lower Zakum, and Murban crude.

Kuwaiti production fell 20,000 b/d to 2.09 million b/d, the lowest production level since August 2003, and 127,000 b/d lower than its quota, said Pritchard Capital Partners. On the other hand, they reported Nigeria raised production 50,000 b/d to 1.84 million b/d. Angola increased its output by 10,000 b/d to 1.63 million b/d. Algeria and Iran also increased crude production an unspecified amount last month, analysts said.

(Online May 4, 2009; author's e-mail: samf@ogjonline.com)

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