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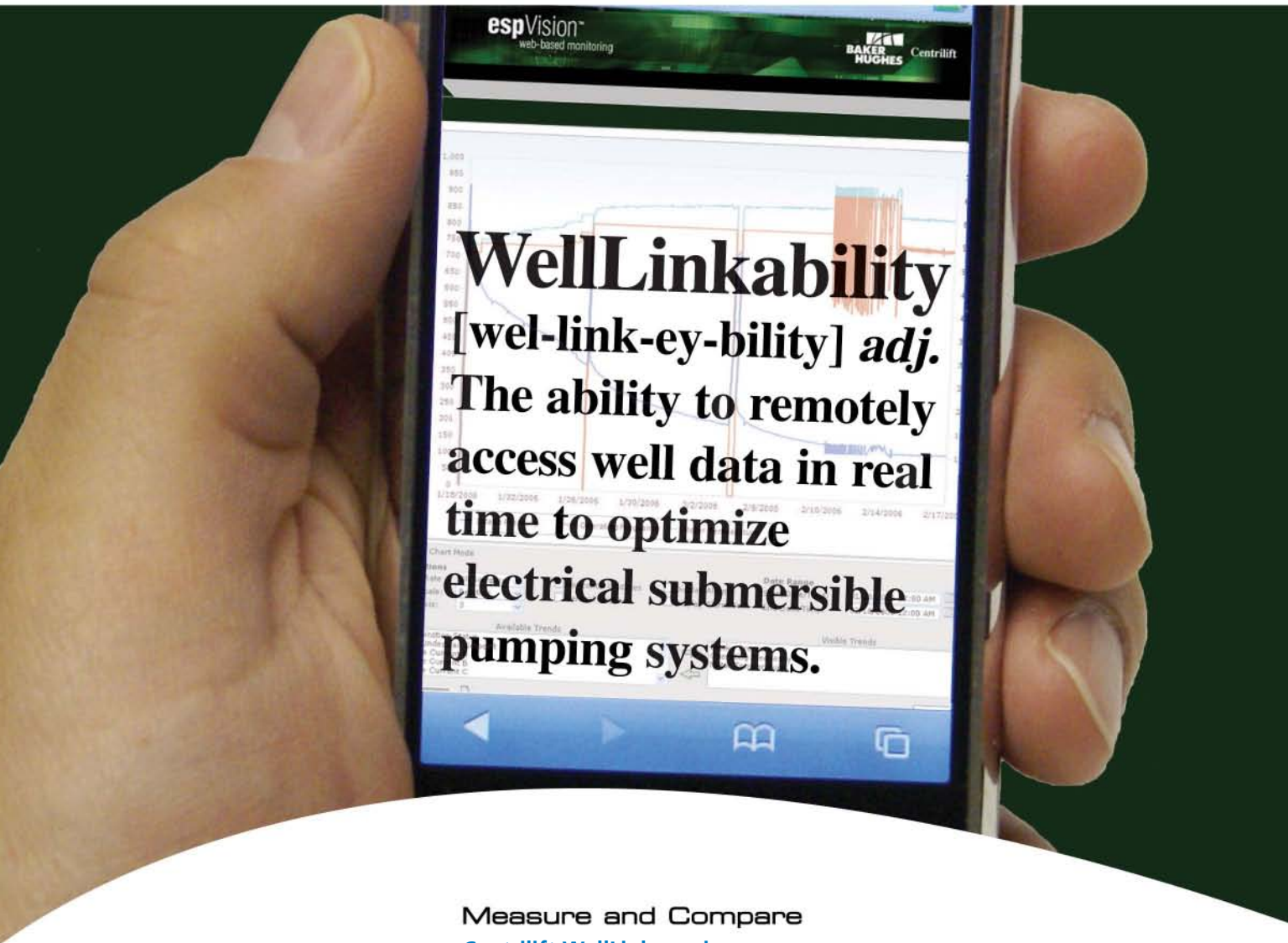

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Condensate coming into its own

Condensate, one of the two groups defined as Natural Gas Liquids (NGLs), is finally coming of age in world trade, marketing, refining and petrochemicals. Condensate sales are moving from a niche marketing specialty to a mainstream segment of crude and products trade, and nowhere is this more evident than in the Mideast Gulf and Asia Pacific.

This report explains how the protean nature of condensate allows it to be used in a wide range of sectors: as a refinery slate component; in specialized distillation towers called condensate splitters; in direct feed to ethylene crackers; in gasoline blending and as a substitute for gas in turbine power generation. It can be defined as a base material, a blending component, a feedstock or a boiler feed.

See website for Table of Contents and sample tables, charts and graphs.

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Automating the Oil Field

Obstacles bedevil EISA's RFS biofuels mandate
Exploration maturity key to ranking search areas
Demand for low-cost feeds to hike trade of high-acid crudes
Neutron diffraction-based tools aid failure forecasting

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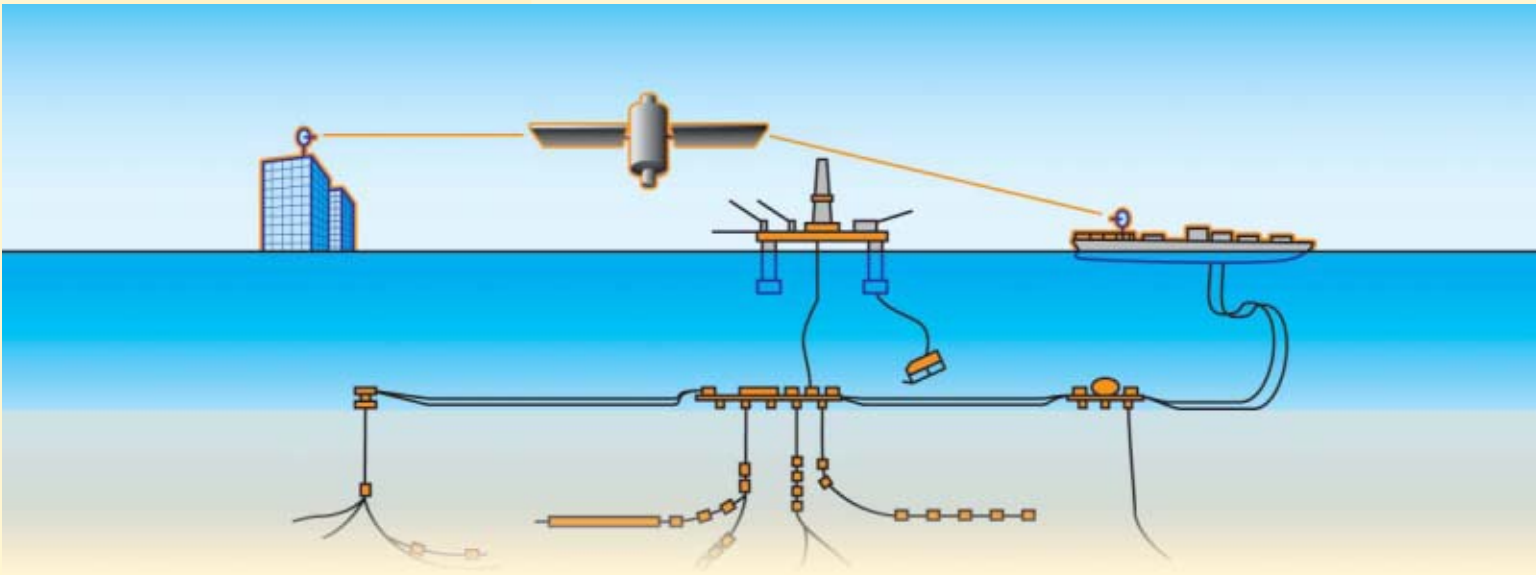
Mar. 17, 2008
Volume 106.11

AUTOMATING THE OIL FIELD



REGULAR FEATURES

COVER

The Atlantis semisubmersible platform, shown on the cover, began oil and gas exports toward yearend 2007. BP PLC operates the platform, which is moored in 7,070 ft of water in the Gulf of Mexico. Atlantis has a design capacity to process 200,000 bo/d and 180 MMcfd of gas. This project, as well as most oil and gas projects, benefits from the many advances being made in automation and communications. The first article in the special section, starting on p. 41, describes the upgrading of downhole control and communications in a subsea well off Norway while the second article covers the all-electric subsea trees installed off Netherlands that have several advantages over trees controlled with electrohydraulic actuators. Photo from BP.

Is CP worthless?

What kind of question is this? Most in the pipeline industry agree that cathodic protection (CP) is the smart way to provide backup corrosion protection on underground pipelines.

But consider: If you use solid film backed corrosion coatings, you may be wasting money by adding CP to the pipeline.

There is a common sense reason for this statement. CP systems protect pipelines by delivering electrical current to the steel surface. Solid film back corrosion coatings have the property of *resistivity*, which means they *block* electrical current. This blocking effect is called *cathodic shielding*.

The phenomenon of *cathodic shielding,* or blocking of protective CP current, has been the subject of dozens of technical papers since the mid 1980's. You can review a cross section of these papers on Polyguard's website.You can also view a 10 minute explanation of the cathodic shielding process.

Worldwide, we estimate that over half of pipelines are being coated with solid film back coatings, such as shrink sleeves, tapes, and 2 or 3 layer systems. Most of these lines have CP systems. These are the operators who may be wasting their money on CP. Moreover, many install shielding coatings on girth welds, the most vulnerable area for corrosion.

Two corrosion coatings are proven to be non-shielding, and allow passage of protective CP currents. One of these coatings is FBE. The other is Polyguard RD-6.

NACE SP0169-2007 states: *"Materials … that create electrical shielding should not be used on the pipeline"* [1].

49 CFR §192.461 states: *"External protective coating …must …have properties compatible with any supplemental cathodic protection."* [2]

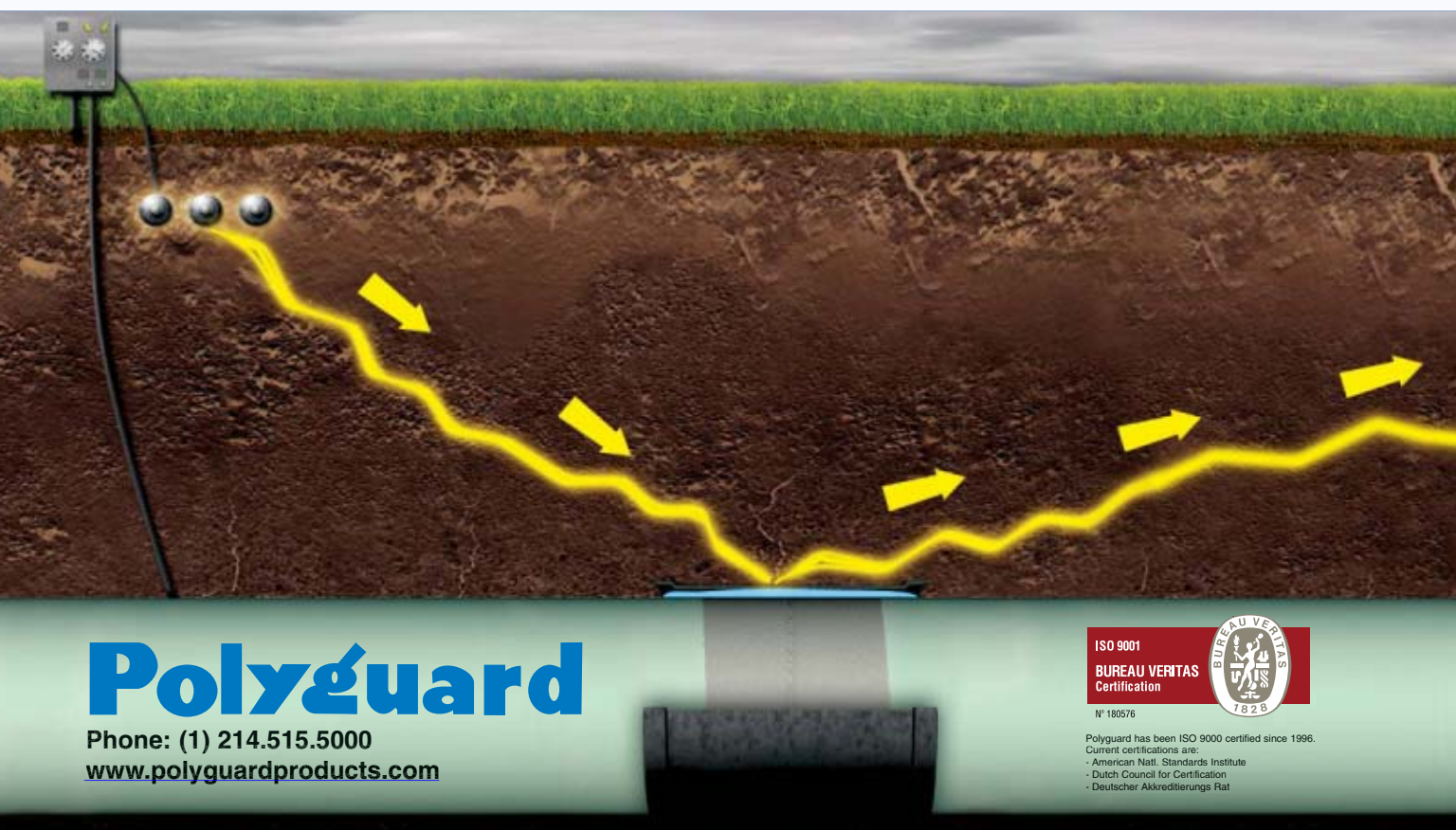
If you are concerned that your organization is behind this curve, we recommend:

1. **Visit polyguardproducts.com/failsafecoating.htm and review the large body of information about shielding problems.**

2. **Talk to operators who have used Polyguard's RD-6 system. *(There are many)* Ask them if they know of any serious corrosion or SCC ever found under RD-6. *(We don't, even after 19 years and thousands of installations).***

3. **Have someone in your organization attend the NACE course *"Coatings in Conjunction with Cathodic Protection"*.**

1. NACE SP0169-2007 *"Control of External Corrosion on Underground or Submergeed Metallic Piping Systems"*.
2. 49 CFR Ch.1 (§192.461 see also §195.559)



General Interest

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Drilling & Production

Processing

Transportation

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General Interest — Quick Takes

Markey summons majors for oil-price hearing

Responding to record crude oil prices, US Rep. Edward J. Markey (D-Mass.) announced Mar. 11 that the House Select Committee on Energy Independence and Global Warming, which he chairs, will summon chief executives from the five biggest major oil companies to testify at an Apr. 1 hearing.

"The American people deserve answers from Big Oil. The top five oil companies made record profits last year, and yet are continuing to hold on to tax breaks that could be used to advance the clean fuels of the future," said Markey.

The committee has scheduled the hearing for Apr. 1, the first date available after Congress returns from its planned spring district recess.

"It's time for these top oil company CEOs to look Americans in the face and tell them why they can't support new solutions," Markey said.

The House on Feb. 27 passed HR 5351, which would continue funding for alternative and renewable energy projects by denying oil and gas companies $18 billion in incentives. The bill faces an uncertain future in the Senate, and President George W. Bush has threatened to veto it.

Also on Mar. 11, the US Energy Information Administration issued its latest short-term energy outlook. The forecast retained its estimate that monthly average retail gasoline prices should peak around $3.50/gal in May but added, "There is a significant possibility that prices during some shorter time period, or in some region or subregion, will cross the $4/gal threshold."

China lawmakers propose energy regulatory body

China plans to establish a full cabinet-level regulatory body aimed at consolidating and overseeing all of the fuel-related responsibilities now assigned to differing agencies.

The new commission, to be called the State Energy Commission, will be responsible for about 10 ministerial or subministerial agencies covering oil, gas, and other forms of energy such as the Energy Bureau of the National Development and Reform Commission, China National Petroleum Corp., and China Petrochemical Corp.

Conflicting interests and a lack of coordination among various ministries and commissions have made it difficult for the central government to regulate the sector from the perspective of national energy security.

"Such a body is urgently needed to oversee strategic oil reserves and overcome the country's shortages of energy," according to one industry source who said the change has come because of worries about energy security, especially as China's dependence on imported oil edges towards 50% and oil prices reach $100/bbl or more.

Nearly 60% of China's oil imports come from the Middle East, which makes the mainland vulnerable to any disturbance in international markets.

But the government estimates that it will need to import 70% of its oil and 50% of its gas by 2020.

Iraq still not recognizing KRG, IOC deals

Iraq has repeated its refusal to recognize any agreements for oil or gas signed between the country's Kurdish Regional Government and international oil companies.

Iraq's oil minister Hussain al-Shahristani said, "The central government is in charge of the administration of natural resources, and agreements not approved by the central government will not be recognized."

KRG, against the wishes of the central government, already approved several contracts with international oil companies, including Crescent Petroleum, Sharjah; Reliance Industries Ltd., Mumbai; OMV AG of Austria; and a consortium led by South Korea's state-run Korea National Oil Corp.

The Iraqi oil ministry considers such agreements illegal and has threatened to exclude and blacklist participating IOCs from future opportunities in the country.

As of Dec. 31, 2007, the Iraqi oil ministry suspended SK Energy's term contract to import Basra oil because it refused to abandon its exploration project in the Kurdish region as part of the KNOC consortium. Last month, KRG Prime Minister Nechirvan Barzani planned to lead a delegation to Baghdad for talks with Iraqi Prime Minister Nuri al-Maliki on the status of the Oil and Gas Law, as well as recent and pending contracts KRG signed with international oil companies (OGJ Online, Feb. 8, 2008).

IOC in talks for equity in Canadian oil sands

In an attempt to secure oil supplies for its refineries and strengthen India's energy security, state-owned Indian Oil Corp. (IOC) reported it is looking to acquire equity in oil sands blocks in Canada. IOC has initiated talks with BP PLC and Shell Canada Ltd.

An Indian delegation was in Canada last month to discuss the proposed investment. Other Indian firms interested in acquiring oil sands assets in northeastern Alberta include state-run Oil & Natural Gas Corp. and Oil India Ltd.

IOC has made several unsuccessful attempts to acquire equity stakes in overseas exploration and production blocks. The company doubts now that it will meet its 2012 target of sourcing 2 million tonnes/year of oil from its own overseas blocks. ✦

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Industry Scoreboard

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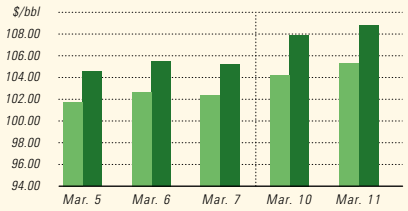
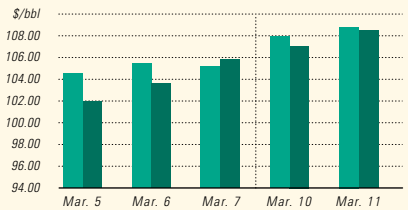
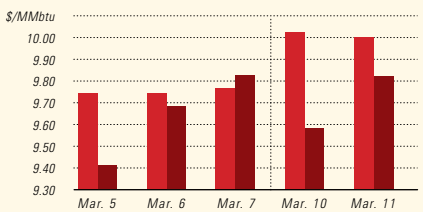


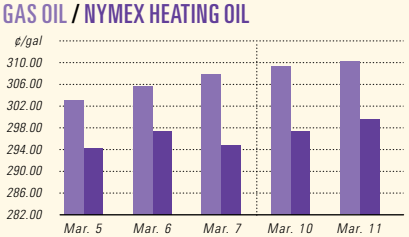
WTI CUSHING / BRENT SPOT



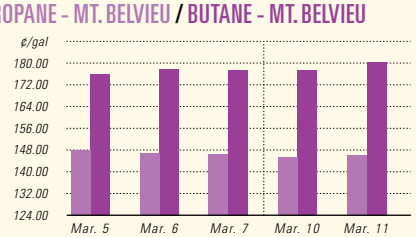
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



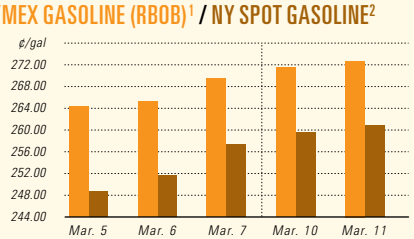
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



[1]Reformulated gasoline blendstock for oxygen blending.
[2]Non-oxygenated regular unleaded.

US INDUSTRY SCOREBOARD — 3/17

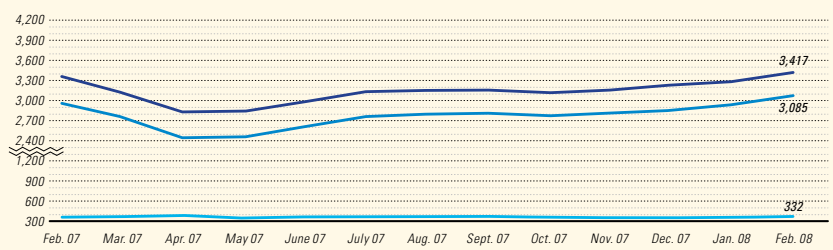
Latest week 2/29	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	9,065	9,025	0.4	9,056	8,958	1.1
Distillate	4,398	4,601	–4.4	4,306	4,434	–2.9
Jet fuel	1,560	1,636	–4.6	1,552	1,626	–4.6
Residual	615	944	–34.9	706	848	–16.8
Other products	4,917	5,065	–2.9	5,048	5,049	—
TOTAL DEMAND	20,555	21,271	–3.4	20,667	20,915	–1.2
Supply, 1,000 b/d						
Crude production	5,043	5,147	–2.0	5,032	5,172	–2.7
NGL production[2]	2,657	2,219	19.7	2,491	2,235	11.4
Crude imports	9,809	9,049	8.4	10,017	9,650	3.8
Product imports	3,405	3,119	9.2	3,446	3,283	5.0
Other supply[3]	834	1,045	–20.2	996	1,046	–4.8
TOTAL SUPPLY	21,748	20,579	5.7	21,982	21,386	2.8
Refining, 1,000 b/d						
Crude runs to stills	14,814	15,880	–6.7	14,814	14,712	0.7
Input to crude stills	14,983	15,729	–4.7	14,983	15,087	–0.7
% utilization	85.9	90.4	—	85.9	86.4	—

Latest week 2/29	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	305,449	308,505	–3,056	324,156	–18,707	–5.8
Motor gasoline	234,276	32,619	1,657	216,425	17851	8.2
Distillate	117,625	119,952	–2,327	123,172	–5,547	–4.5
Jet fuel-kerosine	39,342	40,083	–741	40,236	–894	–2.2
Residual	36,508	36,672	–164	35,625	883	2.5
Stock cover (days)[4]			Change, %		Change, %	
Crude	20.9	21.2	–1.4	22.1	–5.4	
Motor gasoline	25.8	25.8	—	23.7	8.9	
Distillate	26.7	27.5	–2.9	26.4	1.1	
Propane	18.4	19.3	–4.7	16.6	10.8	

Futures prices[5] 3/7			Change		Change	%
Light sweet crude, $/bbl	103.42	100.84	2.58	61.66	41.76	67.7
Natural gas, $/MMbtu	9.59	9.23	0.36	7.38	2.21	29.9

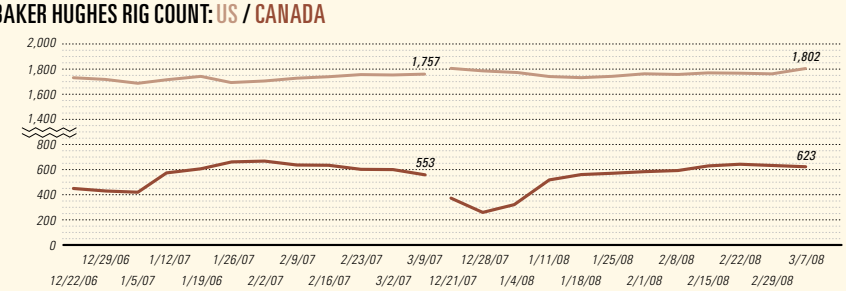
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

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



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

Eni makes oil discovery in Timor Gap

Eni SPA's Australian subsidiary Eni Australia, Perth, made an important oil discovery in the Joint Petroleum Development Area (Timor Gap) administered by Australia and East Timor.

Wildcat well Kitan-1, drilled on Permit JPDA 06-105 in the far northeast corner of the Timor Gap, flowed 6,100 b/d of oil on test.

"The data will now be interpreted to assess the potential dimension of the discovery," reported Eni.

Kitan lies in the vicinity of the now-depleted Elang and Kakatua fields, about 500 km north of Darwin. The well was drilled to 3,568 m TD.

Eni is operator of the permit with 40%. Other interest holders are Inpex of Japan 35% and Talisman Resources Pty. Ltd. 25%.

Eni has a number of interests in the Timor Sea, including 100% of the Blacktip gas field under development in the Bonaparte Gulf, a 10.99% share in the Bayu-Undan gas-condensate field in the Timor Gap, and 80% in each of five exploration permits in East Timor waters to the north of the Gap boundary.

OMV wins another exploration license in Norway

OMV AG has secured another offshore exploration license in the Norwegian Sea, bringing its total allocation to five under the recent Awards in Predefined Areas licensing round.

OMV (Norge) AS will operate Block PL 471 and will work with Sagex Petroleum Norge AS on a 50-50 basis.

Helmut Langanger, OMV executive board member responsible for exploration and production, said the license strengthens the company's E&P position in this core region. OMV described the block as being in a prospective area.

Exall tests Gilwood oil north of Edmonton

Exall Energy Corp., Calgary, said its Marten Mountain horizontal oil discovery in Alberta 140 miles north-northwest of Edmonton flowed 1,585 b/d of 40° gravity sweet oil and 575 Mcfd of gas at 850 kpa flowing pressure.

Exall, operator with 59.338% working interest before payout and 66% after payout, plans to drill a second horizontal well from the same pad and a vertical well nearby as soon as surface access permits, likely to be in the third quarter. The company has 66% interest in 6,080 surrounding acres.

The well, in 102/14-1-75-6w5, averaged 1,135 b/d and 475 Mcfd from Devonian Gilwood on a 21.7-mm choke. The Alberta allowable for the well is expected to be 285 b/d. The well penetrated 420 m of Gilwood sand.

MEO's Timor Sea Blackwood finds gas sands

MEO Australia Ltd., Melbourne, has encountered a 98-m gross gas-saturated sand interval in its Blackwood-1 wildcat in the Timor Sea.

This exceeded the anticipated most-likely predrill estimate of 57 m. However the significance has yet to be determined in a production test.

The Blackwood gas appears to have low carbon dioxide content.

This success could relieve some disappointment of the company's earlier program at Heron-2, which also found gas but failed to flow commercial volumes to surface.

Blackwood, like Heron, lies within the large Epenarra structure, which is a broad, low-relief anticline with a mapped closure of 1,200 sq km. The contingent gas resource of Epenarra is said to be about 6 tcf.

If Blackwood flows at commercial rates, it could revive MEO's plans for an artificial island with an LNG and methanol plant planned for nearby shallow water at Tassie Shoals 300 km north of Darwin, for which environmental approval has been obtained.

AED, Sinopec form JV for Timor Sea assets

AED Oil Ltd., Melbourne, has agreed to form a joint venture with Sinopec International Petroleum Exploration & Production Corp. of China in which Sinopec will acquire 60% of AED's assets in the Timor Sea.

These involve permits AC/P22, AC/L6, and AC/RL 1, which include producing Puffin oil field and Talbot oil field held under retention license.

Sinopec will become operator of the JV under the new arrangement, which will become effective Mar. 31.

The transaction, which values AED's hitherto wholly owned assets at $1 billion (Aus.), is subject to government approvals, including that of Australia's Foreign Investment Review Board.

AED said it will use the funds to retire debt, settle creditors, and fund its JV interest and ongoing development and exploration opportunities in the permits. The company owes Norwegian oil services firm AGR Group $41.5 million (Aus.) for production services and lease of the Puffin field floating production, storage, and offloading vessel.

AED's Puffin production is less than the originally anticipated 30,000 b/d of oil from the two producing wells, Puffin-7 and Puffin-8. Flow was limited to 10,000 b/d due to downhole problems now attributed to drilling and completion flaws.

Redcliffe gauges Halfway oil find at Wapiti

Redcliffe Exploration Inc., Calgary, tested a Triassic Halfway sour oil and gas discovery at Wapiti in the Peace River arch area of west-central Alberta.

Redcliffe, operator with 72% working interest, said the well will go on production in the second quarter and that it will maximize producing rates "due to the current royalty rate and incentive program that are proposed to be changed effective Jan. 1, 2009."

On a 4-day initial production test, the well stabilized at 750 b/d of 48° gravity oil and 2.6 MMcfd of gas on a 20/64-in. choke with more than 1,900 psig flowing tubing pressure, considered to be virgin reservoir pressure.

The company plans to drill at least one more well into the pool this year. ✦

Drilling & Production — *Quick Takes*

Pakistan firm signs rig deal

Petroleum Exploration (Pvt.) Ltd., operator, signed a long-term contract with Weatherford Drilling International for a new National Oilwell Varco 1,500-hp IDEAL drilling rig.

The rig is in Houston and will be shipped to Pakistan following its expected Apr. 7 commissioning. The spud date for the first exploration well of the proposed drilling program on the Jura concessions in Pakistan is expected in July, depending on shipping availability.

In the last year, 1,523 km of 2D seismic data were shot over the Jura concessions. In addition, more than 1,600 sq km of 3D data are available over the Badin IV North and Badin IV South blocks.

ConocoPhillips to decommission Ekofisk units

ConocoPhillips let a contract to Heerema Marine Contractors to decommission its nine Ekofisk platforms in the Norwegian and UK sectors of the North Sea by 2013.

Heerema will work with Norwegian demolition and recycling company AF Decom Offshore to carry out the work. The award includes options to remove other platforms and installations as well.

Decommissioning of the platforms, which gathered production from Ekofisk, Eldfisk, Embla, and Tor, will occur in phases so that Heerema can fully utilize the Hermod and Thialf semisubmersible crane vessels.

"The Ekofisk topsides and jackets will be removed and taken to a yard in Vats, Norway, for recycling and disposal. An estimated 96-98% of the material recovered will be recycled by 2014," Heerema said.

The value of the decommissioning contract, which covers engineering, offshore preparation, removal, and onshore recycling, was reported to be $1 billion.

ConocoPhillips has begun decommissioning its 25,000 Ekofisk storage tank with its topsides and is preparing for in-place disposal finishing by yearend. ✦

Processing — *Quick Takes*

Chevron tests heavy oil hydrocracking technology

Chevron Corp. plans to build a precommercial plant at its 330,000 b/d Pascagoula, Miss., refinery to test the technical and economic viability of a technology to upgrade heavy oil.

This proprietary vacuum resid slurry hydrocracking (VRSH) technology has the potential to increase yields of gasoline, diesel, and jet fuel from heavy and ultraheavy crude oil and could be used to increase and upgrade production of heavy oil resources, said company officials.

"Given the increasing role of heavy oil in meeting the world's growing energy demand and our significant heavy oil resources, this technology could provide a unique pathway to increase supplies of clean-burning fuels for the marketplace," said Mike Wirth, executive vice-president of global downstream operations for Chevron.

The Pascagoula precommercial plant will have a capacity of 3,500 b/d. All necessary permits have been secured, and construction is expected to begin later this year.

Chevron has been developing VRSH technology since 2003. The patented process has undergone successful preliminary testing on a wide range of feedstocks in multiple pilot plants at Chevron's research center in Richmond, Calif.

The company's research shows that the technology can achieve up to 100% conversion of the heaviest feedstock versus less than 80% conversion by the best current commercial refining technology.

The Pascagoula refinery, Chevron's largest wholly owned petroleum refinery, has been operating for more than 40 years.

Total lets contract for Port Arthur refinery

Total SA let a $1.9 billion contract to Fluor Corp. for engineering, procurement, and construction of certain units at Total's Port Arthur, Tex., refinery.

The EPC contract covers a 50,000-b/d coker and desulfurization, vacuum distillation, and related units at Total's 231,000 b/d Port Arthur refinery.

The $2.2 billion increase in the refinery's deep-conversion capacity will boost output of ultralow-sulfur automotive diesel by 3 million tonnes/year. Commissioning is scheduled in 2011.

The new contract follows Fluor's completion of front-end engineering and design work at the Port Arthur refinery.

ExxonMobil lets Singapore plant contract

ExxonMobil Asia Pacific Pte. Ltd. authorized John Wood Group subsidiary Mustang Engineering to begin detailed engineering, design, and construction management for the process control of a second world-scale steam cracker complex in Singapore.

The project will be integrated with the existing Singapore site, providing feedstock, operating, and investment synergies with both the chemical plant and refinery.

The petrochemical project will employ ExxonMobil's latest proprietary technologies, enabling a broad range of feedstocks to be processed and converted into higher-value products.

The project will include a world-scale, 1 million tonne/year ethylene cracker, two 650,000 tpy polyethylene units, a 450,000 tpy polypropylene unit, a 300,000 tpy specialty elastomers unit, an aromatics extraction unit to produce 340,000 tpy of benzene and an oxo-alcohol expansion of 125,000 tpy. Project start-up is expected in early 2011.

Mustang also was awarded the upgrade of the process controls of the existing steam cracker complex. In 2006, Mustang completed the front-end engineering design contract for process control, which was used to launch the detailed design of this project. ✦

Chevron approves Platong Gas II project

Chevron Corp. and its partners have approved construction of the Platong Gas II natural gas project in the Gulf of Thailand at a cost of some $3.1 billion with startup scheduled for first quarter 2011.

The Platong Gas II development, which lies in shallow water 200 km offshore, is designed to add 420 MMcfd of gas processing capacity. The project feeds the growing demand for gas in the domestic market.

In December Chevron signed an agreement with Thailand's Ministry of Energy to increase its contract quantity of gas by 500 MMcfd to 1.2 bcfd by 2012 from offshore Blocks 10, 11, 12, and 13.

Platong Gas II is expected to be the major source of this increase in production. In October 2007, the company received 10-year lease extensions until 2022 for Blocks 10-13. Chevron has ownership interests in these blocks ranging from 60-80%.

Chevron is operator of Platong II and holds a 69.8% participating interest with Mitsui Oil Exploration Co. Ltd. 27.4%, and PTT Exploration & Production PCL 2.8%.

Fayetteville-Greenville expansion gets final EIS

Texas Gas Transmission LLC's proposed Fayetteville-Greenville expansion project would have limited adverse environmental impacts if recommended mitigation measures are used, the Federal Energy Regulatory Commission's staff concluded in a final environmental impact statement on Mar. 8.

The Owensville, Ky., company's proposal involves construction of two 36-in. natural gas pipeline laterals in central Arkansas and central Mississippi, according to company information.

It said the Fayetteville lateral would extend 167 miles from Conway County, Ark., to Texas Gas's main line in Coahama County, Miss., and would have 1.1 bcfd of capacity. The 750 MMcfd Greenville lateral would start near the company's compressor station near Greenville, Miss., and end at a Gulf South Pipeline Co. LP line near Koskiusko, Miss.

FERC said the proposed project also would include a 10,560 hp compressor station near Koskiusko and related aboveground facilities along both laterals. It said the Fayetteville lateral would use existing rights of way for about 90.5 miles, or 54%, of its length.

Texas Gas indicated that it will use recommended plans and procedures covering erosion control, water body crossings, storm water pollution controls, and other measures to control the project's environmental impact, according to FERC. "Horizontal directional drill construction methods would be used to cross many sensitive resources," it said.

FERC said commissioners would consider the final EIS and staff recommendations before issuing the final permit for the project. Texas Gas said this could occur during second-quarter 2008 after which it would soon begin construction.

Service is projected to begin in the third quarter on the Fayetteville lateral segment from Grandview to Latona, Ark., and during first-quarter 2009 on the Greenville lateral and the segment from Latona to Lula, Miss.

Chevron to develop Wheatstone as LNG

Chevron Australia Pty. Ltd. reported plans to develop its wholly owned 2004 Wheatstone gas field discovery on the North West Shelf as a stand-alone LNG project with facilities placed on the northwest coast of mainland Western Australia.

The company says the initial plan is to establish a 5 million tonne/year LNG facility and allow for later expansion of additional trains. The plant would also produce gas for the domestic market.

Preliminary engineering and design on the project is under way, and front-end engineering and design should commence next year.

Wheatstone field, which has estimated gas reserves of 4.5 tcf, lies on retention lease WA-17R about 145 km off Dampier in 200 m of water.

The news of a stand-alone development has puzzled the industry in Australia because discovery of the field had been touted more as a potential gas-to-liquids project than LNG.

Its close proximity to the North Rankin and Goodwyn fields also makes it a logical addition to the Woodside-operated North West Shelf LNG project (of which Chevron is a participant) rather than a new greenfield LNG project in the same vicinity.

In addition, at one point Wheatstone was suggested as a candidate for development alongside Woodside's nearby Pluto field, possibly as a supply of gas for Pluto 2's second train LNG development.

Chevron appears to have rejected those options.

The company says it is preparing design studies at Wheatstone for development and production, site evaluation, and further field appraisal work.

CFE lets LNG terminal to Japanese-Korean group

Mexico's Federal Electricity Commission (CFE) has awarded a $900 million contract for the construction and operation of an LNG receiving terminal on Mexico's Pacific coast to Terminal KMS de GNL, a consortium of Mitsui & Co. 37.5%, Samsung Corp. 37.5%, and Korea Gas Corp. 25%.

The terminal, to be built at the Port of Manzanillo, will be comprised of two LNG tanks, a regasification facility, and a pier. Commercial start-up is scheduled for midyear 2011.

The company will manage and operate the facilities for 20 years based on a service contract with CFE. The partners said they will charge a regasification fee of 40¢/Mcf to process the gas.

After starting at 90 Mcfd in 2011, supply to the facility will be scaled up to 500 Mcfd by 2015 in increments of 180 Mcfd, 360 Mcfd, and 400 Mcfd. The gas from Manzanillo will feed the 3 Gw of capacity CFE intends to install in the region.

CFE earlier awarded Repsol Comercializadora de Gas a 15-year, $15 billion contract in September 2007 to supply the Manzanillo terminal with Peruvian gas (OGJ, Mar. 10, 2008, Newsletter.) ✦

Letters

Oil supply and investment

In the letter entitled "World decline rate," the authors quoted a Cambridge Energy Research Associates forecast for a world oil *supply* of 112 million b/d by 2017 (OGJ, Feb. 4, 2008, p. 12). Taking the average world oil production of 86 million b/d in 2007 gives a daily supply increase from 2008 to 2017 of about 2.6 million bbl. Putting this more oil volume in relation to daily world oil production in 2007 gives about 3%.

For comparison, Chevron projected in 2007 in an advertisement that world oil *demand* could reach 115 million b/d in 2030 from 82 million b/d in 2004. In this case the daily oil demand increase would be about 1.3 million bbl and makes in relation to daily world oil production in 2004 about 1.5%.

Since average world oil production has been 86 million b/d and 82 million b/d in 2007 and 2004, the daily increase was 1 million b/d/year, or closer to Chevron's forecast.

Which is more realistic—1.5% or 3%—is difficult to tell. But for me, there is nothing suspect about any of these percentages. Maybe CERA has forecasted the increased supply by adding how much more oil the world would need plus how much "new oil" the exploration and production industry has to produce to replace production declines. This new oil has to come from new discoveries, greenfields, brown and mature fields, improved and enhanced oil recovery, unconventional oil, etc. However, I question CERA's story that the world's oil production is declining at 4.5%/year.

To satisfy rising world oil demand, and at the same time replace production declines (both have "intelligently" to go hand-in-hand) requires fresh money to invest. The authors give an example for an investment volume: Saudi Arabia will invest $50 billion to increase production capacity by 2 million b/d (or $25,000/b/d). I think that this dollar-per-barrel figure is low to cover all needed capital expenditure for the work to be done from the reservoir to the pipeline.

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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.

2008

MARCH

NACE International Conference & Expo, New Orleans, (281) 228-6200, (281) 228-6300 (fax), website: www.nace.org. 16-20.

Offshore Asia Conference & Exhibition, Kuala Lumpur, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.offshoreasiaevent.com. 17-19.

Sub-Saharan Oil, Gas & Petrochemical Exhibition & Conference, Cape Town, +27 21 713 3360, +27 21 713 3366 (fax), e-mail: expo@fairconsultants.com, website: www.fairconsultants.com. 17-19.

Turoge and Black Sea Oil & Gas Exhibition & Conference, Ankara, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 18-20.

AAPG Prospect & Property Expo (APPEX), London, (918) 560-2679, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org. 24-26.

AAPG Pacific Section Meeting, Bakersfield, Calif., (918) 560-2679, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org. Mar. 29-Apr. 2.

NPRA International Petrochemical Conference, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. Mar. 30-Apr. 1.

SPE Middle East Petroleum Engineering Colloquium, Dubai, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. Mar. 30-Apr. 2.

PIRA Understanding Global Oil Markets Conference, Tokyo, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. Mar. 31-Apr. 1.

ERTC Sustainable Refining Conference, Brussels, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. Mar. 31—Apr. 2.

APRIL

SPE/ICoTA Coiled Tubing & Well Intervention Conference & Exhibition, The Woodlands, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 1-2.

ERTC Biofuels+ Conference, Brussels, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 2-4.

GIOGIE Georgian International Oil & Gas Conference & Showcase, Tbilisi, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 3-4.

Middle East Petroleum & Gas Conference, Doha, +65 6222 0230, +65 6222 0121 (fax), e-mail: mpgc@cconnection.org, website: www.cconnection.org. 6-8.

Australian Petroleum Production & Exploration Association (APPEA) Conference & Exhibition, Perth, +61 2 9553 1260, +61 2 9553 4830 (fax), e-mail: appea2008@saneevent.com.au, website: www.appea2008.com.au. 6-9

ACS National Meeting & Exposition, New Orleans, 1 (800) 227-5558, e-mail: natlmtgs@acs.org, website: www.acs.org. 6-10.

American Institute of Chemical Engineers (AIChE) Spring National Meeting, New Orleans, (212) 591-8100, (212) 591-8888 (fax), website: www.aiche.org. 6-10.

CIOGE China International Oil & Gas Conference, Beijing, + (44) 020 7596 5000, + (44) 020 7596 5111 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 7-8.

API Pipeline Conference & Cybernetics Symposium, Orlando, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 7-10.

EAGE Saint Petersburg International Conference & Exhibition, Saint Petersburg, +7 495 9308452, +7 495 9308452 (fax), e-mail: eage@eage.ru, website: www.eage.nl. 7-10.

IADC Well Control Europe Conference & Exhibition, Amsterdam, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 9-10.

ENTELEC Annual Conference & Expo, Houston, (888) 503-8700, website: www.entelec.org. 9-11.

North Caspian Regional Atyrau Oil & Gas Exhibition & Petroleum Technology Conference, Atyrau, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 9-11.

✦CERI World Oil Conference, Calgary, Alta., (403) 220-2380, (403) 289-2344 (fax), e-mail: jstaple@ceri.ca, website: www.ceri.ca. 13-15.

API Spring Refining & Equipment Standards Meeting, New Orleans, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 14-16.

API/NPRA Spring Operating Practices Symposium, New Orleans, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 15.

SPE Gas Technology Symposium, Calgary, Alta., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 15-17.

SPE International Health, Safety & Environment Conference, Nice, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 15-17.

Base Oils & Lubricants in Russia and the CIS Conference, Moscow, +44 207 067 1800, +44 207 430 0552 (fax), e-mail: e.polovinkina@theenergyexchange.co.uk, website: www.wraconferences.com/Overview.html. 16-17.

GPA Midcontinent Annual Meeting, Okla. City, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 17.

Calendar

AAPG Annual Convention & Exhibition, San Antonio, 1 (888) 945 2274, ext. 617, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org/sanantonio. 20-23.

SPE Improved Oil Recovery Symposium, Tulsa, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 20-23.

ERTC Coking & Gasification Conference, Rome, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 21-23.

West Asia Oil, Gas, Refining, & Petrochemicals Exhibition & Conference, Oman, +968 24790333, +968 24706276 (fax), e-mail: clemento@omanexpo.com, website: www.ogwaexpo.com. 21-23.

International Pump Users Symposium, Houston, (979) 845-7417, (979) 847-9500 (fax), website: http://turbolab.tamu.edu. 21-24.

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

MAY

IOGCC Midyear Meeting, Calgary, Alta., (405) 525-3556, (405) 525-3592 (fax), e-mail: iogcc@iogcc.state.ok.us, website: www.iogcc.state.ok.us. 4-6.

PIRA Canadian Energy Conference, Calgary, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 5.

API International Oil Spill Conference, Savannah, Ga., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 5-8.

Offshore Technology Conference (OTC), Houston, (972) 952-9494, (972) 952-9435 (fax), e-mail: service@otcnet.org, website: www.otcnet.org. 5-8.

GPA Permian Basin Annual Meeting, Odessa, Tex., , (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 6.

PIRA Understanding Global Oil Markets Conference Calgary, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 6-7.

ERTC Asset Maximization Conference, Lisbon, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 12-14.

Oil and Gas Pipelines in the Middle East Conference, Abu Dhabi, +44 (0) 1242 529 090, e-mail: c.pallen@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk/mepipes8/mepipes8register.html. 12-14.

International School of Hydrocarbon Measurement, Oklahoma City, (405) 325-1217, (405) 325-1388 (fax), e-mail: lcrowley@ou.edu, website: www.ishm.info. 13-15.

Uzbekistan International Oil & Gas Exhibition & Conference, Tashkent, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 13-15.

NPRA National Safety Conference, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. 14-15.

IADC Drilling Onshore America Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 15.

SPE Digital Energy Conference, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: service@spe.org, website: www.spe.org. 20-21.

Mediterranean Offshore Conference & Exhibition (MOC), Alexandria, Egypt, + 39 0761 527976, + 39 0761 527945 (fax), e-mail: st@ies.co.it, website: www.moc2008.com. 20-22.

NPRA Reliability & Maintenance Conference & Exhibition, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. 20-23.

Society of Professional Well Log Analysts (SPWLA) Annual Symposium, Edinburgh, (713) 947-8727, (713) 947-7181 (fax), website: www.spwla.org. 25-28.

Middle East Refining and Petrochemicals Conference & Exhibition, Bahrain, +973 1755 0033. +973 1755 3288 (fax), e-mail: mep@oesallworld.com, website: www.allworldexhibitions.com. 26-28.

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

SPE International Oilfield Scale Conference, Aberdeen, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 28-29.

The CIS Oil and Gas Summit, Paris, +44 (0) 207 067 1800, +44 207 430 0552 (fax), e-mail: l.hannant@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk/summit8/summit8register.html. 28-30.

JUNE

ERTC Management Forum, Copenhagen, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 2-4.

Caspian Oil & Gas Exhibition & Conference, Baku, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 3-6.

Oklahoma Independent Petroleum Association (OIPA) Annual Meeting, Dallas, (405) 942-2334, (405) 942-4636 (fax), website: www.oipa.com. 6-10.

SPEE Society of Petroleum Evaluation Engineers Annual Meeting, Hot Springs, Va., (713) 651-1639, (713) 951-9659 (fax), e-mail: bkspee@aol.com, website: www.spee.org. 7-10

PIRA Scenario Planning Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 9.

Asian Geosciences Conference & Exhibition, Kuala Lumpur, +44 (0) 20 7862 2136.

+44 (0) 20 7862 2119, e-mail: geoasia@oesallworld.com, website: www.geo-asia.com. 9-11.

Independent Liquid Terminals Association (ILTA) Annual Operating Conference & Trade Show, Houston, (202) 842-9200, (202) 326-8660 (fax), e-mail: info@ilta.org, website: www.ilta.org. 9-11.

SPE Tight Gas Completions Conference, San Antonio, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 9-11.

EAGE/SPE EUROPEC Conference & Exhibition, Rome, +31 30 6354055, +31 30 6343524 (fax), e-mail: eage@eage.org, website: www.eage.nl. 9-12.

ASME Turbo Expo, Berlin, (973) 882-1170, (973) 882-1717 (fax), e-mail: infocentral@asme.org, website: www.asme.org. 9-13.

PIRA London Energy Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 10.

Asian Oil, Gas & Petrochemical Engineering Exhibition, Kuala Lumpur, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: oga@oesallworld.com, website: www.allworldexhibitions.com. 10-12.

Global Petroleum Show, Calgary, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 10-12.

IADC World Drilling Conference & Exhibition, Berlin, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 11-12.

PIRA Understanding Global Oil Markets Conference, London, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 11-12.

Asia's Subsea Conference & Exhibition, Kuala Lumpur, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: subsea@oesallworld.com, website: www.subseaasia.org. 11-13.

CIPC/SPE GTS Joint Conference, Calgary, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 16-19.

American Association of Professional Landmen (AAPL) Annual Meeting, Chicago, (817) 847-7700, (817) 847-7704(fax), e-mail: aapl@landman.org, website: www.landman.org. 18-21.

LNG North America Summit, Houston, (416) 214-3400, (416) 214-3403 (fax), website: www.lngevent.com. 19-20.

IPAA Midyear Meeting, Colorado Springs, Colo., (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 19-21.

PIRA Scenario Planning Conference, Houston, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 23.

API Tanker Conference, San Diego, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 23-24.

API Exploration & Production Standards on Oilfield Equipment & Materials Conference, Calgary, Alta., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 23-27.

PIRA Understanding Global Oil Markets Conference, Houston, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 24-25.

Russian Petroleum & Gas Congress, Moscow, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 24-26.

NEFTEGAZ Exhibition, Moscow, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 24-26.

Calendar

PIRA's Globalization of Gas Study Conference, Houston, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 25.

PIRA Understanding Natural Gas Markets Conference, Houston, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 26-27.

World Petroleum Congress, Madrid, +34 91 745 3008, +34 91 563 8496 (fax), e-mail: info@19wpc.com, website: www.19wpc.com. June 29- July 3.

JULY

International Offshore & Polar Engineering Conference,Vancouver, (650) 254 2038, (650) 254 1871 (fax), e-mail: meetings@isope.org, website: www.isope.org. 6-11.

Annual Rocky Mountain Natural Gas Strategy Conference & Investment Forum, Denver, (303) 861-0362, (303) 861-0373 (fax), e-mail: conference@coga.org, website: www.coga.org. 9-11.

IADC Lifting & Mechanical Handling Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 15-16.

Oil Sands and Heavy Oil Technology Conference & Exhibition, Calgary, Alta., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilsandstechnologies.com. 15-17.

AUGUST

ACS National Meeting & Exposition, Philadelphia, 1 (800) 227-5558, e-mail: natlmtgs@acs.org, website: www.acs.org. 17-21.

IADC/SPE Asia Pacific Drilling Technology Conference, Jakarta, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 25-28.

Offshore Northern Seas Exhibition & Conference, Stavanger, +47 51 59 81 00, +47 51 55 10 15 (fax), e-mail: info@ons.no, website: www.ons.no. 26-29.

Summer NAPE Expo, Houston, (817) 306-7171, (817) 847-7703 (fax), e-mail: info@napeexpo.com, website: www.napeonline.com. 27-28.

SEPTEMBER

China Power, Oil & Gas Conference & Exhibition, Guangzhou, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.chinasenergyfuture.com. 2-4.

ECMOR XI-European Mathematics of Oil Recovery Conference, Bergen, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 8-11.

IADC Drilling HSE Europe Conference & Exhibition, Amsterdam, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 9-10.

Rocky Mountain GPA Annual Meeting, Denver, (918) 493-3872, (918) 493-3875 (fax), email: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 10.

API Fall Refining & Equipment Standards Meeting, Los Angeles, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 15-17.

Rio Oil & Gas Conference & Expo, Rio de Janeiro, 55 21 2112 9078, 55 21 2220 1596 (fax), e-mail: riooil2008@ibp.org.br, website: www.riooilegas.com.br. 15-18.

API/NPRA Fall Operating Practices Symposium, Los Angeles, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 16.

GEO India South Asia's Geosciences Conference &

Exhibition, New Delhi, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: geo@oesallworld.com, website: www.geo-india.com. 17-19.

SPE Annual Technical Conference & Exhibition, Denver, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 21-24.

ERTC Petrochemical Conference, Cannes, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. Sept. 29- Oct. 1.

International Pipeline Exposition, Calgary, Alta., 403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. Sept. 30-Oct. 2.

Unconventional Gas International Conference & Exhibition, Ft.Worth, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.unconventionalgas.net. Sept. 30-Oct. 2.

OCTOBER

NPRA Q&A Forum, Orlando, Fla., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 5-8.

GPA Houston Annual Meeting, Kingwood, Tex., (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessor.com. 7.

KIOGE Kazakhstan International Oil & Gas Exhibition & Conference, Almaty, + (44) 020 7596 5000, + (44) 020 7596 5111 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 7-10.

IADC Drilling West Africa Conference & Exhibition, Lisbon, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 8-9.

International Gas Union Research Conference, Paris, +31 50 521 30 78, +31 50 521 19 46 (fax), e-mail: igrc2008@gasunie.nl, website: www.igrc2008.com. 8-10.

ERTC Lubes and Additives Conference, Berlin, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 13-15.

Middle East Plant Maintenance Conference, Abu Dhabi, +44 207 067 1800, +44 207 430 0552 (fax), e-mail: d.michalski@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 13-15.

Calendar

API Fall Petroleum Measurement Standards Meeting, Long Beach, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 13-17.

Central and Eastern European Refining & Petrochemicals Roundtable, Warsaw, +44 207 067 1800, +44 207 430 0552 (fax), e-mail: c.taylor@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 14-16.

ISA EXPO, Houston, (919) 549-8411, (919) 549-8288 (fax) website: www.isa.org. 14-16.

Oil & Gas Transportation in the CIS & Caspian Region Conference, Moscow, +44 (0) 207 067 1800, +44 207 430 0552 (fax), e-mail: j.golodnikova@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk/cispipes10reg ister.html. 14-16.

PIRA New York Annual Conference, New York, (212) 686-6808, (212) 686-6628 (fax), e-mail: sales@pira.com, website: www.pira.com. 16-17.

Petchem Arabia Conference, Abu Dhabi, +44 207 067 1800, +44 207 430 0552 (fax), e-mail: c.verma@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 20-22.

SPE Asia Pacific Oil & Gas Conference & Exhibition, Perth, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 20-22.

SPE International Thermal Operations & Heavy Oil Symposium, Calgary, Alta., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 20-23.

Permian Basin International Oil Show, Odessa, Tex., (432) 367-1112, (432) 367-1113 (fax), e-mail: pbioilshow@pbioilshow.org, website: www.pbioilshow.org. 21-23.

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

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

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

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

NOVEMBER

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

Abu Dhabi International Petroleum Exhibition & Conference (ADIPEC), Abu Dhabi, website: www.adipec.com. 3-6.

Deepwater Operations Conference & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepwateroperations.com. 4-6.

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

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

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

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

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

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

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

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

IADC Well Control Middle East Conference & Exhibition, Muscat, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 24-25.

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

DECEMBER

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

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

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

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

International Petroleum Technology Conference (IPTC), Kuala Lumpur,

+971 (0)4 390 3540, +971 (0)4 366 4648 (fax), e-mail: iptc@iptcnet.org, website: www.iptcnet.org. 3-5.

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

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

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

AAPG Annual Convention & Exhibition, San Antonio, 1 (888) 945 2274, ext. 617, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org/sanantonio. 20-23.

XSPE Improved Oil Recovery Symposium, Tulsa, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 20-23.

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

2009

JANUARY

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

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

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

FEBRUARY

ASEG International Conference & Exhibition, Adelaide, +61 8 8352 7099, +61 8 8352 7088 (fax), e-mail: ASEG2009@sapro.com.au. 22-26.

MARCH

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

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

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

MAY

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

JUNE

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.

OCTOBER

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

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Opening doors

Judy R. Clark
Senior Associate Editor

About 15 years ago, when it became evident that a great bank of senior personnel in oil and gas production, refining, and petrochemicals would soon be nearing retirement age and exiting the industry, enlightened management initiated actions to forestall the approaching intelligence drain and employee shortage.

Some companies quickly developed programs to document and archive all procedures, methods, and specialty knowledge within their companies while their skilled experts were still on board.

Some cross-trained existing employees for competency in numerous areas, giving monetary incentives for the number of skills learned and amount of flexibility achieved.

Many created scholarships, offered internships, and developed more complete in-house training programs for interns and new hires.

Consultants became very popular.

All in this together

But more had to be done.

Because this was an industry-wide problem, it was clear that combining assets and working together to attract an army of talent to the industry would be needed over a period of time, especially as the industry would be competing for talent with other industries and also needed to enhance its image.

So industry partners formed associations to promote the more-widespread teaching of process technology and to recruit future skilled workers. These efforts are especially helpful for independents and small firms without the resources of larger companies.

The associations provided online web-based courses, job banks, and advice and assistance for students. They also supplied materials, direction, and company input for educators starting process technology (PTEC) programs and coordinated with industry to ensure internships and job placement on completion of the requisite programs.

CAPT—the Center for the Advancement of Process Technology (www.captech.org)—is the primary umbrella association comprised of regional associations and other partners in industry, educational institutions, and vendors such as consultants.

On its web site, CAPT lists 33 oil, gas, and chemical company partners; 9 regional associations; 28 associate members (vendors); and 49 educational partners—colleges and universities that offer 2-year PTEC degrees.

These educators work with member companies to place students upon successful completion of their programs.

At first, college-age or older recruits were targeted, and colleges across the US were approached about adding PTEC programs.

CAPT itself offers web-based courses covering Introduction to Process Operations, HS&E, Quality, Equipment, Systems, and Instrumentation.

Expanding the scope

It became evident that this was to be a long-term endeavor and that even students in high school and younger could be introduced to the industry to whet interest for future recruitment.

CAPT offers materials to high schools for forming "PTEC in High Schools" programming and provides a guide for forming a 1-week summer Science and Technology Preview Institute as a recruiting tool for high school females, as one of the organization's goals is diversity.

ConocoPhillips has gone a step further, having just announced a partnership with the National Energy Education Development for 1-day workshops for K-12 teachers in 24 US cities. The workshops will equip teachers with tools and information to incorporate into daily classroom activities and "improve their students' energy knowledge." ConocoPhillips said it also will sponsor training for educators at national and regional educator conferences throughout 2008 with the same goal.

Diversity is also evident in a separate program that has a twofold goal: (1) to help solve the military's problem with heavy unemployment of servicemen and women following their release from active duty and (2) to assist the oil industry with its need for intelligent, strong, and disciplined personnel.

In a sort of leathernecks-to-roughnecks program, Troop Transition Inc. (TTI) has just begun its first 10-week class in rig operations and safety ("Troops 2 Roughnecks") at the Marine base at Camp Pendleton, Calif. Marines expecting to leave the service in 6-12 months can take the course at no personal cost, compliments of Uncle Sam's tuition-assistance program.

TTI, which has had good success in Troops 2 Truckers, Teachers, Mechanics, etc., and its Direct 2 Management program for officers, hired International Association of Drilling Contractors-accredited Randy Smith Training Solutions to teach the course and is working with exploration companies to provide job opportunities and further training for these Marines upon successful course completion and receipt of their rig passes.✦

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VP, Chevron

Program-at-a-Glance

Tuesday May 20th				
7:00 - 8:30 AM	Registration in Hotel Lobby Area / Continental Breakfast in Exhibit Area			
8:30 - 9:30 AM	Introductions: Mehrzad Mahdavi		Welcome: Allen Shook, SPE-GCS Chairman **Introductory Keynote: Don Paul, VP, Chevron**	
9:30 - 10:00 AM	Networking in Exhibit Area			
10:00 - 11:30 AM	*Unlocking the Value of Data (KM)	*Integrated Operations and Remote Operations Centers	*Work Processes / Workflows in Digital Oilfields	*Remote Computing / Visualization (thin clients)
11:30 - 12:10 PM	Lunch			
12:10 - 12:45 PM	Introductions : Don Moore Announcement: RPSEA IT Technical Advisory Committee: Michael Ming **Luncheon Keynote: Arjun N. Murti, Managing Director and Partner, Goldman Sachs**			
12:45 - 1:15 PM	Networking in Exhibit Area			
1:15 - 2:45 PM	*Unlocking the Value of Data (KM)	*Integrated Operations and Remote Operations Centers	*Work Processes / Workflows in Digital Oilfields	*Remote Computing / Visualization (thin clients)
2:45 - 3:15 PM	Networking in Exhibit Area			
3:15 - 4:30 PM	Concluding Keynotes Moderator: Don Paul **Concluding Keynotes: Donna Crawford, Associate Director for Computation, LLNL and John Gibson, President and CEO, Paradigm**			
4:30 - 5:00 PM	Networking Reception in Exhibit Area			
Wednesday May 21st				
7:00 - 8:30 AM	Registration in Hotel Lobby Area / Continental Breakfast in Exhibit Area			
8:30 - 9:30 AM	Introductions: Roger Hite		**Morning Keynotes: Ashok Belani, CTO, Schlumberger Brian Russell, Co-founder Hampson-Russell Software Services Ltd and Past President SEG**	
9:30 - 10:00 AM	Networking in Exhibit Area			
10:00 - 11:30 AM	*Reliability and Maintenance of Systems	*RTO for Mature Fields	*The Renaissance Man: Bridging the Silos of E & P	*Benefits and Issues for Seafloor Seismic Monitoring
11:30 - 12:00 PM	Networking in Exhibit Area			
12:00 - 1:30 PM	*Riding the IT Curve: Advances in Software *Host: Murthy Divakaruni, Larson & Toubro*	*Riding the IT Curve: Interface Technologies *Host: Art Schroeder, Ultra-deepwater Technology Manager, RPSEA*	*Riding the IT Curve: High Performance Computing *Host: Herb Yuan, Shell Co-Host: Philippe Flichy, Merrick Systems*	
1:30 - 2:00 PM	Networking in Exhibit Area			
2:00 - 3:30 PM	*Information Integrity and Reliability	*RTO for Mature Fields	*Safe Operations in Digital Oilfields	*Shared Earth Modeling
3:30 - 4:45 PM	**CIO / CTO Roundtable - Now what?** Moderators: Don Paul, CTO, Chevron, Don Moore, CIO, Occidental and Washington Salles, CIO, Petrobras			
4:45 - 5:00 PM	Closing Remarks and Prize Drawing Moderator: Herb Yuan, Shell			

**For agenda details please visit the website at http://specgcs.org/DEC_2008*

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Editorial

Energy and the poor

Politicians who favor governmental solutions to energy problems often make two statements that those more committed to market solutions tend to avoid. One of the statements is that rising energy prices hurt poor people most. The other is that government-sponsored energy development creates jobs.

The statements are related in ways that should weaken energy agendas centered on governments.

The first statement, that rising energy costs hurt the poor most, doesn't need expression. It's self-evidently true. Vulnerability to preeminent hardship when necessities rise in price is the sad essence of poverty. To point this out as though it were some grand insight about a point requiring debate is condescending, if not outright annoying. The point requiring debate is how best to avoid hurting the poor.

Fuel choices

Here, supporters of governmental solutions to energy problems stumble. The solutions they favor require the government to make fuel choices. These choices invariably raise costs. They do so directly with mechanisms such as taxes on disfavored energy forms and price supports for politically preferred alternatives. And they do so indirectly through hidden subsidies and general inefficiency.

Proponents of such manipulations deny the costs and structure their initiatives to make it appear that companies or governments pay them. But companies and governments are just economic conduits. Only people—individual taxpayers and consumers—can bear the costs of governmental actions. When governments try to engineer energy patterns, taxes and energy prices ultimately rise, and taxpayers and consumers carry the whole load. Needless as it is to say again, the costs hurt poor people most.

Promises of job creation camouflage the costs of energy forced into the market by governments. Yet job creation becomes a talking point when, for example, Democrats seeking their party's presidential nomination propose to spend $150 billion on noncommercial energy or to tax oil and gas companies to fund subsidies of hydrocarbon substitutes. It can seem sensible: Government money creates an industry, companies of which hire workers. So subsidizing energy creates jobs. What's to argue?

The problem with this analysis is that the government doesn't create the money it uses to promote an industry. It takes or borrows the money from taxpayers—ultimately individuals, not companies—elsewhere in the economy. In those parts of the economy, spending, profits, and investment decline under the new burden. Job creation does, too.

The government, therefore, doesn't create jobs when it manipulates energy. It just moves them around. What's more, it moves jobs from parts of the economy profitable enough to be paying taxes into some favored part that would be unprofitable without an inflow of other people's money. So resources flow from efficient, low-cost activities into inefficient, high-cost sectors. There's no way to do this without generating cost. And everyone knows who suffers most from added cost.

This is not an argument against regulation. Some government moves raise costs legitimately. Oil-product standards toughened to fight air pollution raise the costs of making fuel for a good reason—as long as the new standards really cut emissions and pursue genuine environmental benefit, which isn't always the case. The argument here is that concern for costs, and their effects on the poor, should be a prominent factor in environmental policy-making. It should start as recognition that toughened product specifications do raise costs that people must pay—because refiners either pass along the costs or absorb them and cut investment, limiting supply. Both options represent costs to consumers.

Political decisions

The tactics governments use to implement fuel preferences raise costs more generally than this and often more insidiously. Decisions about them are inescapably political, not economic, scientific, or charitable. Suppliers of the subsidized fuels benefit, and everyone else pays from the consequent reductions in profits and job, tax hikes, and imposed inefficiencies. And the beneficiaries seldom include the poor, who tend not to make heavy political contributions.

The indisputable suffering that rising energy costs impose on the poor should induce governments to avoid mistakes that make those costs rise unnecessarily. That it seldom does is a bitter hypocrisy of modern politics. ✦

COMMENT

Obstacles bedevil EISA's RFS biofuels mandate

Tim Sklar
Sklar & Associates
Murrells Inlet, SC

Is it possible for 36 billion gal/year of renewable fuels to be produced in 15 years, and if so, would it bring energy independence and security to the US?

In this election year, the public is being offered numerous solutions to the energy problems that the US and the world must address.

One such proposal being actively promoted is to replace transportation fuels refined from imported oil with fuels such as biodiesel, bioethanol, and other advanced biofuels.

Often presented in the popular media and in political discourse is the notion that one of the most effective strategies to reduce our national dependence on imported oil is to have large quantities of biofuels produced from things that grow, and that somehow the private sector will embrace this strategy and produce all of the renewable fuels that will be needed.

The latest buzz is about using waste materials instead of food crops, because soaring corn prices have distorted the prices we pay for food as well as for corn ethanol.

The public is being told this second generation of biofuels could be produced from agriwaste, such as corn stover and wheat straw; from fast-growing cellulosic crops, such as switch grass; from forest residue and other wood waste; and from municipal solid waste retrieved from land fills.

Unfortunately, not being mentioned are the impracticalities of producing large quantities of fuels from these materials. Not being addressed are other impediments, such as bringing together the varied and often competing interests into biofuels projects, the technological hurdles that must be overcome, the vast amount of capital investment that will be needed, and the incentives the public will need to create a new industry.

For the last several years our company has been assisting clients in the development of biofuels projects. It is dismaying that the realities encountered in developing renewable biofuels are often not even mentioned, let alone discussed. Assumptions upon which so much hope is being placed are often wrong or shortsighted.

The latest example of oversimplification is the presumption built into the Renewable Fuels Standards (RFS), which is a component of the Energy Independence and Security Act of 2007 (EISA). RFS is a legislative mandate requiring increased national production of renewable biofuels—to 36 billion gal/year by 2022 from 9 billion gal/year in 2008— without addressing how this can be done. It therefore is in serious need of a reality check.

As shown in Fig. 1, the RFS mandates that US corn ethanol production reach a production peak by 2015 and not increase thereafter. This will require that cellulosic biofuel and all other advanced biofuels play a larger role in meeting the RFS mandate, increasing to 58% of the total RFS mandate by 2022 from less than 1% today, with corn ethanol dropping from its current 99% of the total to 42% in 15 years (Fig. 2).

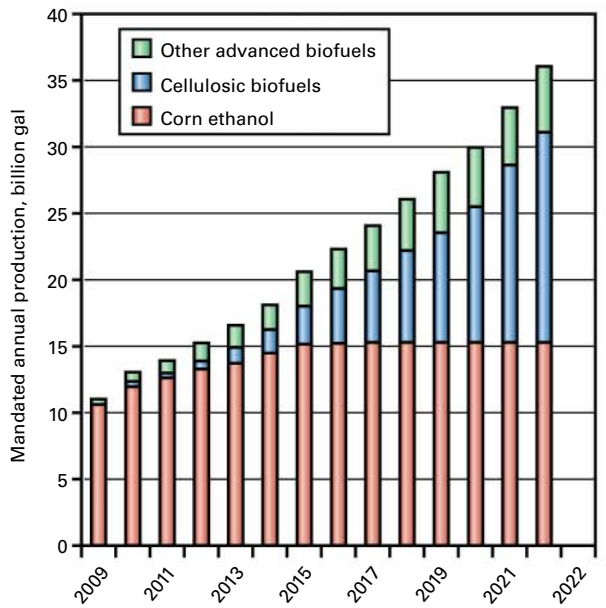
The fundamental question that one must ask is whether it is reasonable to assume that EISA's RFS mandate for the private sector is realistic. Based on what is known today, it is not. If nothing is done to assist the private sector, a mandated 36 billion gal/year of renewable fuels within 15 years is wishful thinking. There may be a chance that this could happen but only if extensive, costly government support programs are put into place.

What is likely?

Although EISA may have accurately projected a need for 36 billion gal of renewable biofuels by 2022, its depen-

EISA RFS* FOR BIOFUELS PRODUCTION

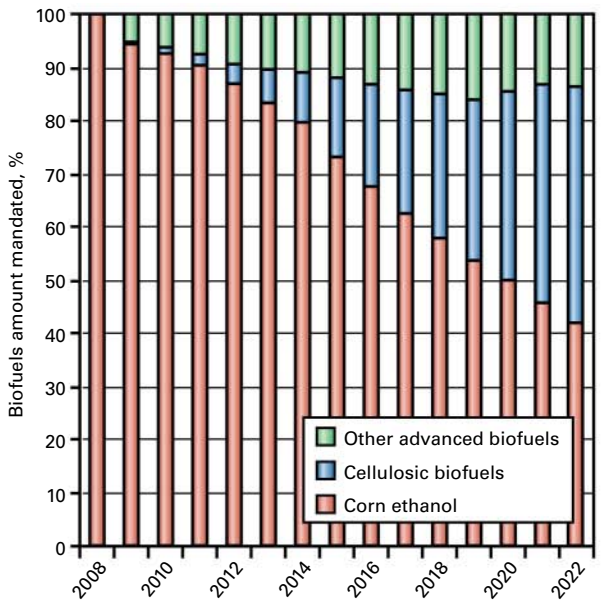
Fig. 1



*Renewable Fuels Standards.

BIOFUELS' INCREASING ROLE IN TOTAL RFS* UNDER EISA

Fig. 2



*Renewable Fuels Standards.

dence on private enterprise to fill this need is unrealistic for several reasons:

- The renewable fuels industry is fragmented, with only modest participation by large corporate interests.

Biodiesel currently is being produced from soybean oil in 20 biodiesel processing plants, owned by small corporations. A recent National Biodiesel Board survey indicated that a number of small biodiesel companies were raising equity for about 30 new biodiesel plants. Soybean oil used by these plants is obtained from 60 crushing plants in 21 states. Outside of a few growers' cooperatives, ownership is concentrated with major agribusiness giants, such as Archer Daniels Midland, Bunge, and Cargill.

These crushing operations obtain soybeans from local soybean growers' cooperatives. There are more than 300,000 farms in the US that grow soybeans on 75 million acres, most of them alternating with corn in a 50:50 rotation. About 75% of the soybean crop is grown in the Upper Midwest and Midwest, with the balance coming from the Southeast and Southwest. Crushers in these regions produce about 75% of the soybean oil and soybean meal. Vegetable oil produced from other oilseed crops such as canola is not now being used in making biodiesel.

Outside of a few small cellulosic ethanol plants that are just becoming operational on a commercial scale, all of the fuel ethanol is now being produced in 160 corn ethanol processing plants. As with biodiesel, most of these processing plants are operating in the Corn Belt states and are owned by small companies or growers' cooperatives. The companies active in developing cellulosic ethanol plants also are mostly small companies. But a few major oil companies and paper companies are now participating in cellulosic ethanol development projects.

- With the exception of processes now used to convert cornstarch into ethanol, technologies for producing advanced renewable fuels are still in the research and development or pilot plant stage.
- There are only a handful of plants currently being developed to produce cellulosic ethanol on a commercial scale. One is a plant in Japan that has been producing commercial quantities of cellulosic ethanol from wood chips and wood waste for the past 2 years. Another is a project, well under way, in which a paper mill is being converted into a biofuels production facility using wood chips and black liquor as feedstock.

In addition, two funded projects are emerging from pilot operations and are being scaled up to produce cellulosic ethanol from municipal solid waste. And there is an exciting project under way in which a 2-stage thermal process is being used to convert forest residue and wood waste into cellulosic ethanol on a commercial scale.

However, there is still a long way to go before the RFS mandate can be met, as additional R&D of biofuels processes remain in progress to perfect and improve process efficiency, obtain higher biofuels yields, and make a wider range of advanced biofuels from the cellulosic waste.

Enormous investment

To meet the RFS mandate, capital investment in advanced biofuels plants must reach $11 billion in 4 years, increasing to $46 billion in 10 years and $105 billion in 15 years. Added to these amounts is the capital cost of increasing corn ethanol output to the 15 billion

EISA RFS REQUIREMENTS FOR BIOFUELS TO 2022

	2008	2012	2017	2022
			Mandated amounts, %	
Corn ethanol	100.0	86.8	62.5	41.7
Cellulosic biofuel	0.0	3.3	22.9	44.4
Other advanced biofuels	0.0	9.9	14.6	13.9
			RFS annual mandate, billion gal	
Corn ethanol	9.0	13.2	15.0	15.0
Cellulosic biofuel	0.0	0.5	5.5	16.0
Other advanced biofuels	0.0	1.5	3.5	5.0
			No. of 55-million gal/year biofuels plants operating	
Corn ethanol	164	240	273	273
Cellulosic biofuel	0	9	100	291
Other advanced biofuels	0	27	64	91
Total No. of plants for RFS	**164**	**276**	**436**	**655**
			Plant investment, billion $ (@ $5/installed gal)	
Corn ethanol	45	66	75	75
Cellulosic biofuel	0	3	28	80
Other advanced biofuels	0	8	18	25
Total	**45**	**76**	**120**	**180**

gal/year level at an added capital cost of $75 billion. In other words, the RFS mandate calls for private capital investment in renewable fuels plant capacity of $180 billion over the next 15 years (see table).

Added to this are the additional amounts that must be invested to improve the technology, provide supporting pipelines and storage terminal capacity, and upgrade distribution facilities to handle new fuels. Clearly, all of this private investment is just not going to happen as a result of a legislative mandate.

With respect to RFS projections, it may be realistic to expect corn ethanol production to increase to 15 billion gal/year over the next 10 years from 9 billion gal/year, assuming that current support programs remain in effect and corn crops are increased without further market distortion.

But it is unrealistic to assume that the RFS projections for advanced biofuels production could match corn ethanol production in 10-15 years. Cellulosic ethanol and biodiesel production is now just a "drop in the bucket." In 4 years, the RFS mandate calls for 2 billion gal of cellulosic biofuel, biodiesel, and other advanced biofuels to be produced, increasing to 9 billion gal 10 years from now, and 21 billion gal 15 years from now.

This growth in advanced biofuels production will require at least 35 new 55-million gal/year biofuels plants to be operating by 2012, 164 by 2017, and 382 by 2022. New capital investment in advanced biofuels plants of this size could exceed $11 billion by 2012 and require an additional $34 billion by 2017 and $59 billion more by 2022. EISA does not provide funding or incentives for this massive investment it is mandating.

Barriers to investment

Further, there are a number of perceived or actual barriers to attracting the amount of investment needed to this infant industry:

- The market for new advanced biofuels, such as butanol and dimethyl ether as gasoline replacements, face market resistance. In the case of recently introduced biofuels such as biodiesel and E85, the oil industry is still not fully convinced that it should be making substantial investments that will be required in building biofuels processing plants, in establishing new biofuels distribution networks, or in undertaking new biofuels marketing campaigns.
- Growers of soybeans have not yet been convinced to abandon wheat or corn as a second crop in order to produce canola or other oil seed crops in the hope that biodiesel producers will expand and create a demand for vegetable oil that does not now exist. Likewise, crushers are reluctant to increase capacity to support yet-to-be-planted oilseed crops or to produce vegetable oil for yet-to-be-built biodiesel plants.
- Grain elevator operators and farm cooperatives that generate large quantities of agricultural waste are not eager to organize and invest in joint ventures for collection, preprocessing, and storage operations in anticipation of attracting investors to build new agriwaste-to-ethanol plants,
- Pulp and paper mills that have access to large amounts of pulp wood and wood waste are not fully convinced that they should produce cellulosic ethanol or other advanced fuels, as they have never been in the fuels business. They also are reluctant to upset the cost they now pay for wood and wood waste, or to modify their pulp mill operations if it could in any way adversely impact their paper-making operations.
- And no one is running out to build biofuels plants at a cost of $125-275 million each.

Other problems with RFS

The RFS mandate does little to meet EISA's legislative goal of providing energy independence and energy security, as the 36 billion gal/year renewable fuel target is designed to provide less than 6% of the nation's transportation fuel needs in 15 years.

Nor does the RFS mandate do much to reduce greenhouse gas emissions. Today, corn ethanol is the dominant renewable biofuel.

The most optimistic assessment is that corn ethanol reduces greenhouse gasses by only 20% compared with conventional fuels. And even though cellulosic ethanol and other advanced biofuels offer higher reductions (50-60%), these fuels will not be produced in significant quantities for years, even if the RFS mandate is met.

At best, advanced biofuels are expected to be 13.2% of all renewable fuels produced in 2012, increasing to 37.5% in 2017 and 58.3% in 2022. This is only

3.5% of all transportation fuels to be consumed in the US in 2022.

On top of the other deficiencies associated with EISA, the RFS mandate is probably not enforceable, as the mechanism for enforcing it is weak and ill-defined. The responsibility for seeing that mandates are met is left to the US Environmental Protection Agency administrator, who has to negotiate with state governments…and grant exceptions when mandates prove impossible to meet.

At best, EISA provides political cover to politicians. The added biofuels to be produced under the RFS mandates would be only a small part of the energy independence solution EISA seeks to address.

Costly government aid

What could the government do other than a mandate? Meeting the RFS mandates would require a combination of extensive added government aid in the form of R&D grants, tariff protections, low-cost project financing, and loan guarantees to stimulate private investment in biofuels plants and ancillary facilities.

In addition, the government would have to provide tax incentives for biofuels operators during ramp-up and possibly price subsidies and other measures. ✦

The author

Tim Sklar (sklarincdc@aol.com) is president of Sklar & Associates, a consulting firm specializing in biofuels project development. He is a CPA with expertise in project finance, due diligence investigations, viability assessments, and business plans. He has extensive consulting and operational experience in business turnarounds and operational management and restructuring, having served on the management consulting division of accounting and consulting firms PriceWaterhouseCoopers and KPMG on US and international assignments. Sklar served as chief financial officer of regional manufacturer GFC Inc, leading a major business turnaround effort.

He has held positions in the federal government as research director of a presidential commission charged with developing policy recommendations on educational finance reform and as director of regulatory enforcement in the Federal Energy Administration. Sklar has developed courses for CPAs and attorneys on due diligence for acquisitions and sales of closely held companies, high risk ventures, and emerging growth companies. He also provides liaison services for project sponsors, private investors, and concessionaires in dealings with international institutional lenders such as the World Bank, IDB, Ex-Im Bank, and OPIC.

Energy project experience includes petroleum refineries, power plants, power distribution systems, hybrid remote power generation systems, integrated oil seed crushing-biodiesel processing plants, and integrated pulp mill-cellulosic ethanol processing plants.

Yergin: Renewables becoming competitive in energy markets

Renewable energy is becoming competitive in energy markets yet must overcome problems of economics, technology, and scale, said Daniel Yergin, chairman of Cambridge Energy Research Associates (CERA) and executive vice-president of IHS Inc., at the Washington International Renewable Energy Conference in Washington, DC.

"Renewables are already a significant business in terms of tens of billions of dollars in investment per year," Yergin said. "But the scale of the existing energy business is enormous, and we'll only start to see the real impact in terms of market share in the next 5-10 years."

High energy prices, issues of climate change and energy security, and a major shift in public opinion are converging to drive the development of renewable energy. "All of this is supported by the growing conviction that new carbon policies will reshape the competitive landscape of the global energy business," Yergin said.

As a result, he said, "We are going through a period of what I call the 'great bubbling,' a high degree of innovation all across the energy spectrum. This is boosting the competitiveness of renewables and efficiency and is also evident in terms of conventional energy." According to the worst-case and best-case scenarios of a new CERA study, renewable power could be supplying 7-16% of the world's electric needs by 2030.

CERA's study assesses the prospects of various clean energy technologies and defines key risks and opportunities. The technologies include biofuels, renewable power, carbon capture and storage, nuclear power, and hydropower. According to the study, clean energy investment—including renewables as well as nuclear and hydro—could reach a cumulative total of $7 trillion by 2030.

"There is a broad range of opportunities and benefits, as well as risks and pitfalls as the modern energy industry increasingly moves to adopt clean technologies that will be part of the alternative, low-carbon pathway to the energy future," Yergin told the conference. The changing energy future will be shaped both by traditional technology and engineering firms, electric power companies, and oil and gas companies, and by new entrants such as innovators, entrepreneurs, venture capital firms, and high-tech companies, he said.

"Governments around the world—prompted by dual concerns about energy security and climate change—will also play a significant role," Yergin said. "As governments move forward to further encourage renewables development, they do need to pay attention to key considerations about costs, scale, reliability, timing, and unintended consequences. Another key issue is the additional investment needed to support and tie renewables into existing energy systems."

Yergin added, "A major reason for the recent leap to $100/bbl [for benchmark crude] is the economy, but now a weak US economy and the credit

crunch, rather than the strong global economy that has been so important the last few years. A slowing US economy, rate cuts by the Federal Reserve and expectations of more, and a weak US dollar, along with the reappearance of inflation around the world, are driving investors into oil and other commodities. Instead of the traditional 'flight to the dollar' during times of uncertainty, we are seeing a 'flight to oil.' At the same time, rising costs in the oil field have put a higher floor under oil prices."

According to the CERA study:

• Renewable power technologies are poised for substantial growth. Wind will make the largest gains, followed by solar power and biomass, despite near-term bottlenecks in wind turbine manufacturing, supply shortages in silicon, and competitive pressures from escalating component costs.

• Government policy remains a key driver for clean energy advancement. Putting a price on CO_2 emissions, setting mandates, and providing subsidies all work to kick-start clean energy technologies by meeting the economic competitiveness and cost advantages of conventional technologies. "The challenge in the years ahead is to provide subsidies in a way that ensures that these technologies get off the drawing board and are able to wean themselves from support—allowing for a phase-out rather than an increase in subsidies—as they become commercially viable on their own. It is also important that mandates be set at achievable levels and with care so as not to create unexpected pressures from higher prices," the report said.

• A full range of clean technologies along with the demand side responses will be necessary to address the challenge of redirecting global greenhouse gas emissions trends. While many clean technologies are commercially available, more work is needed to develop and demonstrate a broader set of technologies, including advanced coal systems.

• Nuclear and hydroelectric generation will account for almost half the gross clean power additions by 2030. The coal resource base and utilization in the US and China will create a powerful drive to develop "clean coal" technologies.

• Rapid economic growth may push Asian energy needs from 30% of current global demand to 40% by 2030; combined with its manufacturing cost-competitiveness, this could make Asia a nexus for clean energy technology research, development, and equipment production.

• Economic growth affects energy demand and carbon emissions as well

as the political and financial support for research and development of new clean energy technologies.

The study concluded that the "Big Three" of energy consumption—the US, the European Union, and China—will have a major impact on development of clean energy, along with certain other countries, particularly Japan, India, and Brazil. Some 5,000 people attended the conference hosted by the US government. Among the participants were cabinet-level officials from more than 70 countries. ✦

Ziff: Royalty hike worsens Alberta gas industry troubles

A looming royalty increase is aggravating a "recession" in Alberta's conventional oil and gas industry, according to a veteran Calgary consultant.

The province's conventional industry is dominated by natural gas, drilling for which is plummeting, says Paul Ziff, chief executive officer of Ziff Energy Group (Fig. 1).

The Alberta government last October announced what it called a New Royalty Framework, rejecting a special tax on oil sands recommended by a review panel but lifting royalty rates overall (OGJ, Nov. 5, 2007, p. 34).

For natural gas, the framework raises the maximum royalty to 50% from 35% and eliminates tiers, starting in 2009. It retains and will revamp programs for special production categories such as deep formations and marginal wells.

"Based on the much lower price for natural gas than oil and today's higher drilling and operating costs," Ziff says in a recent report, "the new royalties on natural gas production are coming at a lousy time and are contributing to a sharp drop in current and future gas drilling activity."

Prices, costs

The consultant notes that prices for natural gas in Alberta are half those of oil on an energy-equivalent basis and that most of the profits reported by big energy companies come from oil produced from mature fields (Fig. 2).

He also points to a "dramatic escalation in the cost to find new gas reserves."

His firm estimates that the full-cycle cost of new gas supplies increased to $4.70/Mcf (Can.) in 2006 from $1.50/Mcf in 1995.

Of the 1995 estimate, $0.85/Mcf represents finding and development costs, including drilling, seismic work, land, and facilities; $0.40/Mcf reflects operating costs; and $0.25/Mcf is administrative cost. The 2006 cost breakout: $3.05/Mcf finding and development, $1.30 operating, and $0.35 administrative.

"Adding the producer's return or profit, royalty, and taxes since 2006, the price of natural gas is not high enough to justify average new gas exploration," Ziff says.

Spending drops

After announcement of the new royalty framework, he adds, "Conventional industry spending has dropped sharply," while in neighboring Saskatchewan and British Columbia, it's "booming."

Gas drilling in the US, where the gas price is similar to that in Alberta but where costs and royalties are lower, continues to increase, Ziff says. In Western Canada (mainly Alberta), the annual average rig count fell 40% last year.

Even before the new royalty rate, producers faced rapidly rising costs, especially for labor, which is in short supply because of surging oil sands development. In addition, Ziff says, the strong Canadian dollar has cut about $3/Mcf from the Canadian gas price.

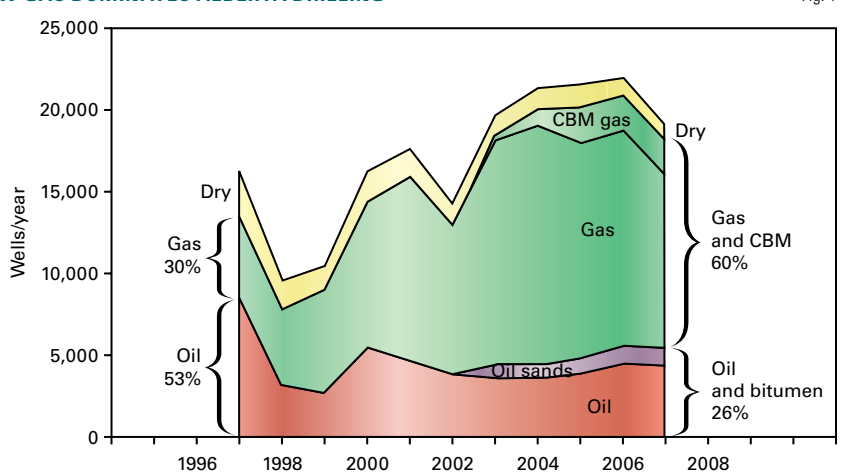
Many Canadian companies have said they're cutting spending in Alberta, and many non-Canadian companies are quietly shifting spending away from the province.

"Ziff Energy estimates at least 80% of companies active in Alberta have reduced their planned conventional spending since the new royalty announcement," the consultant says.

Most affected by the spending cuts are deep gas in western and northwest-

How gas dominates Alberta drilling

Fig. 1



Source: Ziff Energy Group

ern Alberta and shallow gas and coalbed methane in the central and southeastern areas.

Layoffs begin

Some operators have announced layoffs in Alberta, and Ziff Energy expects more. Many service companies are laying off workers. Underutilized equipment is moving to the US and Russia.

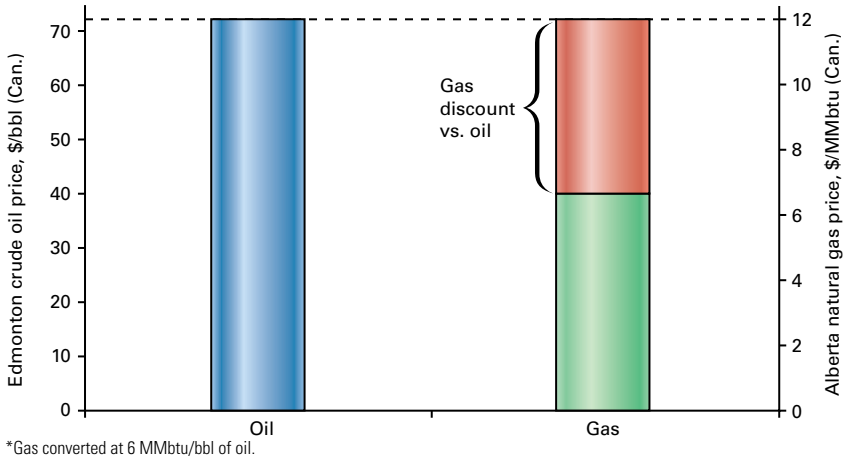
According to Ziff, biweekly sales of crown land have dropped to their lowest level in almost a decade in a trend that will cut Alberta's future royalty receipts.

The province's slowdown jeopardizes the government's target of a $1.4 billion increase in royalty revenue.

"Unless the proposed royalty program is revised, conventional gas activity will decline sharply, creating a 'made-in-Alberta' recession in 2008 outside of the oil sands," Ziff says. "The increase in provincial net revenues of $1.4 billion in 2009 is a house of cards ready to tumble." ✦

THE ALBERTA GAS PRICE DISCOUNT*

Fig. 2



*Gas converted at 6 MMbtu/bbl of oil.
Source: Ziff Energy Group

Luthi: OCS oil and gas leasing must move beyond gulf

Nick Snow
Washington Editor

More federal Outer Continental Shelf areas must be opened for oil and gas leasing if the US expects to limit its energy imports, said US Minerals Management Service Director Randall B. Luthi.

Effecting such a change "won't happen overnight," he said in opening remarks to the US Department of Interior agency's 2007 OCS Policy Committee Mar. 5 in Herndon, Va. "It will require substantial education. State and local governments could be the key. MMS is anxious to work with them,"

Oil and gas industry executives on the committee agreed. "There aren't many new places left to look in the US offshore," William A. Van Wie told OGJ. "We should at least consider the natural gas that might be available off the East Coast." Van Wie is vice-president and general manager of exploration at Devon Energy Corp. in Houston.

"Certainly, it's imperative to increase our domestic energy supplies," said James E. Carlton III, manager of land in the Lower 48 at ConocoPhillips Co. in Houston. "We need to work around congressional moratoria and presidential withdrawals. From an industry perspective, there are very few new places we can go despite our record of safe and reliable production.

A lease sale off Virginia's coast in 2011 is part of the 5-year OCS plan that began July 1, but it will take place only if a congressional moratorium is lifted and a presidential withdrawal ended. That would need to happen "in the very near future" for MMS to complete all the necessary preleasing steps, according to Renee Orr, leasing division chief in the agency's offshore minerals management division.

A very narrow window

"The window of opportunity is very narrow," Orr told the committee. MMS has not officially been approached by any southeastern coastal states about being included in the federal OCS program as Virginia did last year, she added. Others at the meeting told OGJ that at least one other state's legislature passed a bill during its 2008 session similar to Virginia's, however.

"We can start discussing what areas make sense," Luthi told reporters following his remarks. He said he expects revenue sharing to be part of any OCS leasing in new areas, with a split similar to the 37.5% split four Gulf Coast states will receive from new federal leases under the 2006 Gulf of Mexico Energy Security Act.

"Many people in this country have gotten used to thinking we can get energy elsewhere if we don't produce it here. That's changing, particularly with demand growing in China, India, and other countries that are closer to the resources," he told the committee.

"After the 2005 hurricanes, it became apparent that we're putting a lot of our eggs in one basket. That's why it's important to consider areas beyond the Gulf of Mexico," Luthi added.

He told reporters that the US Department of Justice should decide "in

WATCHING GOVERNMENT

Nick Snow, Washington Editor

What Congress needs to hear

Oil and gas producers face formidable technical challenges as they venture into deeper water. The money that's involved can be considerable.

That message became apparent as two officials from companies heavily involved in Gulf of Mexico ultradeepwater projects addressed the US Minerals Management Service's Outer Continental Shelf Policy Advisory Committee Mar. 6 in Herndon, Va.

"It can cost $250 million to drill a single well, money which could be lost if it is not successful. That's the kind of financial risk oil companies are taking," said Cesar Palagi, Walker Ridge production asset manager at Petrobras America Inc. in Houston.

That doesn't include expenses for equipment, services, and crews, added J. Keith Couvillion, deepwater land manager for Chevron North America Exploration & Production Co. in Houston. "We've seen increases in costs that have matched increases in oil prices. It costs $250,000/day just to rent a deepwater rig, not including services," he said.

'We detail every foot'

Ultradeepwater E&P in the gulf poses many challenges: water as deep as 8,000 ft, a salt canopy that covers most of the Lower Tertiary trend, and significantly higher pressure and temperatures, Couvillion told the committee. "Some of our wells take a year or longer before we actually start drilling. We detail every foot we drill and use real-time monitoring," he said.

There's still a lot to learn, he emphasized. "Especially in ultradeep water, we don't have the kind of data points to drill the kind of wells we find on the shelf. There are cliffs and canyons out there which can make it difficult to place a platform and production system," he said.

Petrobras plans to bring the floating production, storage, and offloading system technology it developed for Brazil's offshore Campos basin to the gulf for the first time in the Cascade and Chinook fields 250 miles southwest of New Orleans, Palagi said.

Edge of technology

Wells that are planned there will be in 8,000 ft of water and reach as far as 28,000 ft, which essentially is the edge of current technology, Palagi said. "We don't have a regulatory framework to develop with some of the technologies that are being developed, so we are working closely with MMS to make certain the appropriate regulations are ready," he said.

"We don't have all the answers. We're just beginning to learn the questions. But we also have some of the brightest people in the world working on it. If there's crude oil out there, we'll find a way to produce it safely, reliably, and with minimal environmental impact," Couvillion said.

Following the presentation, the committee's chairman, Victor G. Carillo, oil and gas division director at the Texas Railroad Commission, noted that several federal lawmakers have complained that companies' profits are excessive and need to be taxed further.

"I wish every member of Congress could have heard what you told us today," he told Couvillion and Palagi. ✦

the next few days or weeks" if it will pursue an appeal which MMS requested of a federal court's decision that Kerr-McGee Corp. should not be required to pay $12-23 billion of royalties from its deepwater leases in the Gulf from 1996 through 2000. Anadarko Petroleum Corp. acquired Kerr-McGee on Aug. 10, 2006.

If the decision stands, he continued, "it would dwarf the royalty relief issues surrounding the 1998 and 1999 leases" which were issued without price ceilings. Six other producers that have voluntarily renegotiated terms for leases during those 2 years would not be held to the new agreements if the decision stands, he added. ✦

Gastech: Meeting gas demand to require partnerships, technology

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

Industry keynote speeches opening Gastech 2008 in Bangkok centered on the bright future of natural gas, especially LNG; the need for cooperation among international oil companies, national oil companies, and resource-host governments; and the critical role technology will play in industry's growth to 2030.

One speaker later in the day offered a view of the LNG industry that runs counter to the prevailing view of the dominance of Asia-Pacific markets.

Delivering keynotes were Chevron Asia Pacific Exploration & Production Co. Pres. Jim Blackwell, ExxonMobil Gas & Power Marketing Co. Pres. Andy Swiger, and Jon Chadwick, executive vice-president, Asia-Pacific, for Shell Gas & Power. An industry-contrarian view was presented by Stefan Judisch, chief executive officer for RWE Gas Midstream.

The keynote also announced advance of an offshore project in the Gulf of

Thailand from Chevron and initiation of new technologies from Shell.

Gastech 2008, held Mar. 10-13, drew more than 2,000 delegates and 3,000 exhibitors and other visitors, according to conference officials. They touted this year's event as the largest in its 35-year history.

Principles, partnerships

Meeting anticipated growth in gas demand to 2030, according to Blackwell, requires three principles to strengthen industry partnerships: shared respect, shared capabilities, and shared rewards.

He named the Angola LNG project as an example in which partners—elements of NOC Sonagol and the various IOC companies—have worked in shared respect to overcome inherent conflicts of interest to achieve common goals. Partners in the project announced a final investment decision at yearend 2007.

Blackwell cited Chevron's nearly 30-year contract with PetroChina to develop major fields in the country for which Chevron, exemplifying shared capabilities, called on its expertise in handling sour gas as key to project success.

To illustrate his principle of shared rewards, Blackwell announced the advance to FID for construction of the Platong Gas II natural gas project in the Gulf of Thailand (OGJ Online, Mar. 10, 2008). Total development cost of the field is about $3.1 billion with start-up set for first quarter 2011, he said.

The shallow-water Platong Gas II development, 120 miles offshore, will add 420 MMcfd processing capacity and feed growing Thailand gas demand. Chevron operates the field and holds a 69.8% participating interest with Mitsui Oil Exploration Co. Ltd. (27.4%) and PTT Exploration & Production PCL (2.8%).

ExxonMobil's Swiger reviewed the company's growth prospects for gas generally and LNG specifically. Overall energy growth to 2030 will advance by 1.3%/year with fossil fuels being indispensable to meeting that growth and natural gas advancing to meet 25% of demand, up from 20% in 2007.

Technology advances will be critical for supply to meet demand by, importantly, enabling higher gas production as LNG to move from remote sites.

Perhaps most importantly, according to Swiger, is the need for strong, sustaining partnerships among IOCs, NOCs, and governments in emerging countries that host new gas developments.

Technology advances

Underscoring the role technology is to play in helping LNG to maintain and expand its role in

bringing new gas supplies to markets, Shell's Chadwick announced two new technologies that are advancing toward implementation.

One is Shell's Automated Cool-Down that monitors and controls cooling in liquefaction plants' main cryogenic heat exchangers. The tool addresses the occasional problem of bundle tube leaks in the MCHE. The leaks, he said, can cause unexpected unit shutdowns. Further, the tool "leads to rapid start-up and less flaring."

Shell also announced in Chadwick's remarks that it was proceeding with development of floating LNG aboard a vessel 400 m by 75 m wide and capable of producing 3.5 million tonnes/year. The design also embodies hydrocarbon liquids handling capabilities.

Although he avoided tagging the FLNG plans with cost estimate or production timetable, Chadwick said that within 4 months, the company would issue an international tender to selected consortia consisting of Japanese and Korean shipyards and EPC contractors.

Contrarian view

In an afternoon address, Judisch stated that the immediate future of LNG is not one of Asia-Pacific drawing away all supply. That, he said, is conventional wisdom. In fact, in the "next few months," several capacity additions are due for Asia and the Middle East, culminating in 2010 with as much as 96 million tonnes/year coming to the marketplace.

His central message was that "markets work", and he cited as an example how Woodside has been building new LNG trains every 2 years.

Moreover, he said recent history shows US Henry Hub and Europe's National Balancing Point above Japanese Crude Cocktail (JCC) pricing; "it can happen again," he said, as the number of short-term cargoes increases and LNG supply and market flexibility grow.

"We now have an overbuild of regasification with more than half existing terminals empty," Judisch said. Floating LNG is "an answer" to managing the imbalance between production and regasification. ✦

Gastech: Market factors to slow global LNG evolution

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

Against a rapidly changing environmental and geopolitical backdrop, the global LNG industry appears rapidly evolving, said Martin Houston, executive vice-president and managing director for BG Group PLC. This evolution has brought the industry to a critical juncture in its development as its members met last week at Gastech in Bangkok.

In his second-day keynote speech, Houston said the "road ahead looks very different from our road already traveled; old and new orders are rebalancing, costs and prices are re-equilibrating, and margins are migrating as the balance of power shifts."

Past, present

Over its first 35 years, the LNG industry showed steady but unspectacular growth, said Houston. Its relatively high cost base ensured that it remained a regional and niche fuel. Cost-reduction efforts in the early 1990s, however, extended LNG's market reach and increased its competitiveness.

Specifically, this evolution allowed the US gas market, the world's largest, to push wider industry growth. Record US LNG imports of 16.2 million tonnes in 2007 only presaged the more than 70 million tonnes/year contracted into the US by 2012, he said.

The wave of US LNG import contracts signed by BG Group and others in 2003-05 not only ensured growth, said Houston, but also guaranteed structural change. These deals laid the foundation for evolution to a "more globally connected, flexible, and integrated market from largely regional, bilateral trade."

Rapidly increasing commodity prices since then have created further uncertainty in both supply and demand as LNG starts to drive globalization of natural gas and to experience the effects of this globalization in a high-priced, supply-tight world.

These events have pushed LNG into the geopolitical spotlight, said Houston. As industry has become more interconnected, he said, both "internally as a global trade system and externally with geopolitics and national agendas," it has become more difficult to predict how the global system will function.

Future

Houston said three fundamentals will define the LNG industry: price, market efficiency, and volatility.

In terms of price, economic growth, entrance of new players, supply security, and environmental concerns are pushing strong LNG demand. On the other hand, cost escalation, construction capacity, and domestic priorities are slowing the arrival of new LNG.

This supply-demand discrepancy, he said, has driven up prices for both term and spot volumes. And while it is good for sellers, its effect on the LNG industry is less certain.

The "dash for gas" over the past 2 decades was driven largely by the economics of the combined cycle gas turbine. Previous oil prices made natural gas the economic as well as environmental fuel of choice. The environmental advantage remains, but high prices threaten gas's "most-favored fuel" status for power generation.

By market efficiency, Houston means the ability of supply to react efficiently

to demand signals. Over the past years, LNG evinced many features of a commodity: It has become globally fungible, and increasing trade flexibility is allowing LNG in some cases to respond to price signals and flow to the highest value markets worldwide.

Spare transport and import infrastructure are emerging to enable this, he said. And there appears to be increasing competition within the flexible position of the trade as the volume and number of flexible LNG holders grow.

Houston cautioned, however, that elements remain to inhibit industry's becoming a fully efficient and competitively traded global market. These include constrained market and resource access, infrastructure costs, existing long-term agreements, company business models, capabilities, and lack of price discovery.

Despite increasing flexibility, Houston believes that true liquidity, transparent market indices, or direct-trade instruments are unlikely near term. Most critically, he said, excess production capacity is unlikely to emerge in the system any time soon.

Houston and BG Group believe that, even in an evolution towards greater global price convergence, external factors will inject volatility into short-term markets. Simply put, he said, "'stuff happens' and prices will react." The July 2007 earthquake in Japan is evidence of that.

A more fundamental question is whether LNG will form a stable and "volatility dampening" trade system or whether it will in fact add to global trade volatility. While increasingly flexible volume should over time smooth the fluctuations of individual markets, the US market is about to "take up the burden" of balancing seasonal demand for the rest of the globe.

He said there will be periods when "global volatility [will be] transmitted to the NYMEX rather than the NYMEX smoothing global volatility." Add to this are the increasing national political agendas being layered on. ✦

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Beyond petroleum

Beyond petroleum is the direction various companies are headed these days, as many of them turn to the production of biofuels, especially second-generation.

Brazil's Petroleo Brasileiro SA (Petrobras) and biotechnology firm Kior Inc., Menlo Park, Calif., last week signed a cooperation agreement over the development of second-generation biofuels.

Petrobras wants to use plant waste materials to produce bio-oil using Kior's biomass catalytic cracking technology. "Second-generation biofuels don't compete with foodstuff plants," Petrobras said, underlining a point of great significance these days.

Many governments and companies have had to temper their enthusiasm for biofuels after howls of protest were raised last year about their ill effects on the price and availability of food.

Cautious and circumspect

While some folks have actually denied any such ill effects on food, others—more cautious or circumspect—have taken heed. Instead of risking adverse publicity about adding to food scarcity or upward pricing, they are seeking nonfood sources of feedstock for biofuels.

That explains the relationship between Petrobras and Kior. One could almost say that the interest by Petrobras is focused on a single fact: Kior has been studying biofuel production from sugarcane bagasse since 2006.

Brazil is a leading producer of biofuels from sugarcane. In fact, it is the world's second-largest producer of ethanol and its biggest exporter.

But other folks are getting in on the biofuels act, too, such as Chevron Corp. and Weyerhaeuser Co., which have launched Catchlight Energy LLC, a 50-50 joint venture to develop the next generation of renewable transportation fuels from nonfood sources (OGJ Online, Mar. 4, 2008).

In contrast to the Petrobras venture, which will use sugar as feedstock, the Catchlight JV will make use of timber, surely a plentiful nonfood commodity in the US Pacific Northwest that Weyerhaeuser calls home.

Catchlight catches on

Chevron and Weyerhaeuser will contribute resources, including funding, background technology, and employees, to Catchlight, which will research and develop technology for converting cellulose-based biomass into what they hope will be economical, low-carbon biofuels.

Catchlight's formation is the first milestone of a biofuels alliance Chevron and Weyerhaeuser made last year, and it reflects the companies' shared view that nonfood biofuels will play an important role in diversifying the nation's energy supply.

"Catchlight Energy brings together two leaders in their industries and leverages their strengths—from feedstocks to fuel manufacturing to marketing—to create a sustainable, economic, nonfood biofuels business at commercial scale," said Mike Wirth, Chevron executive vice-president, global downstream.

According to Miles Drake, Weyerhaeuser senior vice-president, research and development and chief technology officer, "Catchlight Energy represents an imaginative approach to releasing this potential as we work to develop a sustainable solution to the world's energy needs."

The idea is clearly growing. ✦

Exploration maturity key to ranking search areas

E.D. Attanasi
P.A. Freeman
US Geological Survey
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This article describes a scheme for summarizing visually the spatial distribution, intensity, and productivity of oil and gas drilling for areas outside the US and Canada.

The article is extracted from a US Geological Survey circular, "Statistics of Petroleum Exploration outside the United States and Canada."[1]

This circular updates USGS circulars 981 and 1096 and extends the coverage of those studies to China, Eastern Europe, and the Former Soviet Union. As with the earlier editions, the data are based on IHS Inc.'s International Petroleum & Exploration Production database.[2]

The analytical approach in USGS Circular 1288 focuses on exploration maturity as a key to ranking search areas. Efficient exploration strategies typically rank areas by exploration maturity. However, exploration maturity is multifaceted.

The locations and results of past and current drilling reflect the industry's accumulated geologic knowledge of an area, but well counts alone are an incomplete measure of exploration intensity.

For example, in partially explored areas, information from a few wildcat wells can potentially condemn a large area if the data show that the occurrence of commercial discoveries is unlikely because of the timing of hydrocarbon generation, the absence of available traps, poor or defective seals, or because of the absence of reservoir-quality rocks. The degree of exploration maturity is determined by the spatial attributes of past drilling.

Exploration maturity should be defined relative to a density of drilling that, in turn, implies an approximate threshold size of an undiscovered oil or gas accumulation. An area is mature relative to a threshold size if the drilling is sufficiently dense that there is little chance that accumulations at least as large as the threshold size remain undetected in the exploration area.

Characterizing maturity

Locations in a country or basin are described mathematically as a set of grid points that represent corners of square cells that cover the country or province.

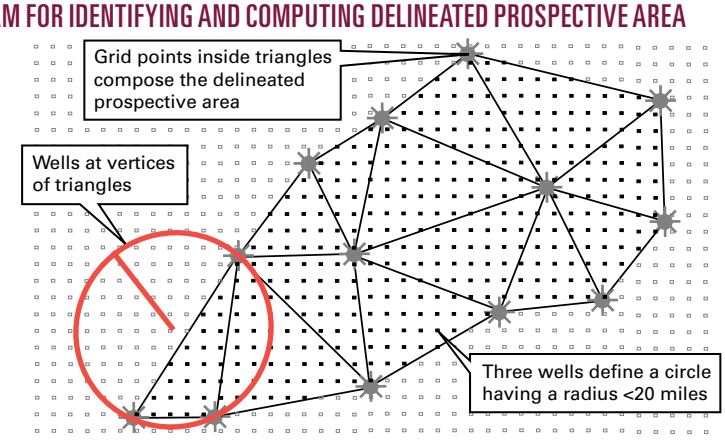
For purposes of visual presentation, each cell is scaled to cover 8 sq miles, making the corner points 2.83 miles apart. Each grid point is identified by a longitude and a latitude location. The delineated prospective area is described as the set of all (grid) points inside the area drilled that are reasonably close to wells (producing or dry).

The scheme for assigning grid points to the delineated prospective area is based on well locations. Any three noncolinear wells (that is, not in a straight line) can form a triangle where the wells are the vertices, and the nonoverlapping triangles can be drawn for any set of wells (Fig. 1).

A grid point is said to be in the delineated prospective area if that grid point is located within a triangle that is small enough to fit inside a circle that has a radius of 20 miles. The delineated prospective area, in square miles, is computed as the combined area of those triangles having a well at each vertex and fitting inside a circle with a radius of 20 miles. Delineated prospective areas are displayed on maps as

DIAGRAM FOR IDENTIFYING AND COMPUTING DELINEATED PROSPECTIVE AREA

Fig. 1



Grid points are corners of square cells with area 8 sq miles. If three noncolinear wells define a circle having a radius of less than 20 miles, then the triangle connecting the wells defines the delineated prospective area that consists of grid points that lie within the triangles.

closed polygons.

The 20-mile radius was chosen in earlier studies because it corresponded to a convenient scale for visual presentation.[3,4] The 20-mile radius is also consistent with the precision of the data on the locations of the wells and discoveries.

The delineated prospective area may expand rapidly if exploration is successful and additional wildcat wells are sited at the outer limits. The area may stabilize later as yields to drilling decline sufficiently in the newly added area or if technological barriers stop further expansion. After stabilization of a delineated prospective area, most exploratory drilling is characterized as follow-up drilling (that is, additional drilling in an already delineated prospective area).

MAP SHOWING THE DELINEATED PROSPECTIVE AND EXPLORED AREAS THROUGH 2001 IN NIGERIA

Fig. 2

The explored area is defined as the area consisting of the points in a delineated prospective area that are within 2 miles of a well. For example, when two wells are exactly 2 miles apart, the largest circular field that could occur between the wells would have a surface area of 3.14 sq miles. The circle would have a diameter of 2 miles, and so the radius would be 1 mile. The area would then be 3.14 sq miles.

The expected recovery from petroleum accumulations having that surface area of 3.14 sq miles varies with pay thickness and with reservoir properties. Some similar size petroleum accumulations in the US Permian Basin and Gulf of Mexico range from 12 million to 24 million bbl of oil.

For some provinces, much of the delineated prospective area may never become part of the explored area because the delineated prospective area is unproductive and not worth further evaluation. As an example, Fig. 2 shows the delineated prospective and explored areas for Nigeria as of the end of 2001.

Grid points are assigned dates that indicate the year that each grid point entered the respective prospective area and explored area categories. With these data, profiles can be made that show graphically the additions to the delineated prospective area and explored area as a function of wildcat wells.

A slowdown in the expansion of the delineated prospective area appears when the rate of increase in that area is reduced causing a profile to "roll over" (Fig. 3). This profile rollover happens when exploration is concentrated within the existing delineated prospective area rather than directed at opening new areas.

Measuring productivity

Discovery rates describe yields of petroleum per unit of exploration.

These rates are commonly calculated as the aggregate volume of oil or gas in new discoveries divided by the number of exploration wells drilled during a specific time interval. For a single play having a fixed boundary, the discovery rate typically declines as progressively smaller accumulations are found.

In basins that contain several plays, if there is a sustained decline in discovery rates, then analysts will extrapolate the discovery rates to predict future finds, finding costs, and volumes of undiscovered recoverable resources. However, if the area of interest includes multiple sedimentary basins, then discoveries from new areas may offset declining discovery rates in old areas, and the overall discovery rate for the entire region may not decline during the historical data period. In this situation, extrapolation of discovery rates may not be useful.

The assignment of discovery data to grid points within the delineated prospective area can separate the confounding effects of a declining discovery rate in an old area vs. a different and perhaps increasing discovery rate in a new area. According to this procedure, each grid point in the delineated prospective area is labeled with a prospective area date, which is the year that the point became part of the delineated prospective area.

The volume of oil and gas for each discovery is assigned to the closest grid point in the delineated prospective area. The year that these grid points become part of the delineated prospective area typically precedes the discovery date of the field.

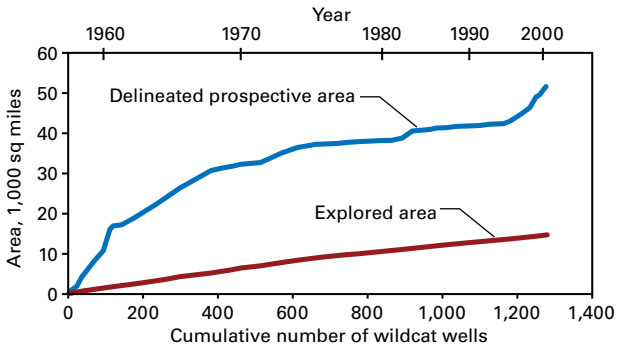
The association of oil and gas volumes to grid points and years (when the point became prospective) allows the comparison of the quality (in terms of petroleum volumes) of the new and older prospective areas. Thus, yields to drilling in old areas can be compared with yields to drilling in new areas, in order to decide whether future drilling should target sites already inside the delineated prospective area or sites in new areas.

Reported volumes of oil and gas discoveries are assigned to the grid points that are closest to the location of the reported discovery or discovery well. Then reported volumes of cumulative recoverable oil and gas are plotted against the delineated prospective area, where the increments of the prospective area are ordered by time.

If all areas are equally productive (and if follow-up drilling is assumed to be instantaneous), then the graph of cumulative oil or gas discovered vs. cumulative delineated prospective area ordered by time is a straight line. If the earlier delineated prospective area has a better endowment than the later delineated prospective area, then the shape of the graph will be concave down. Alternatively, if the later delineated prospective area has a better endowment than earlier delineated prospective area, then the shape of the graph will be concave up.

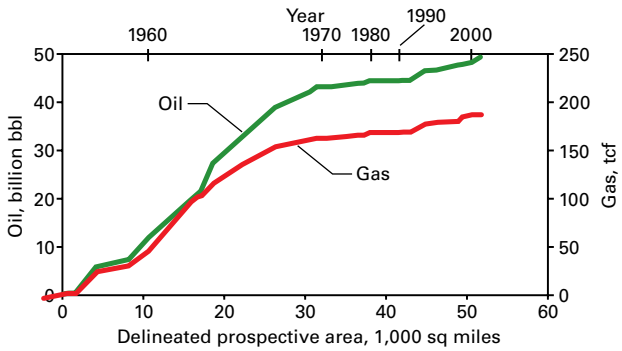
A caveat is that care should be taken when interpreting graphs that show later delineated prospective areas as less productive than early delineated prospective areas. For recently added areas, an apparent decline in the volume of discoveries per unit area could be exaggerated because of insufficient time for follow-up drilling. However, if sufficient time has elapsed without significant discoveries or follow-up drilling, then the reduced yields to drilling probably reflect the petroleum endowment accurately.

GROWTH IN NIGERIA DELINEATED AND EXPLORED AREAS* Fig. 3



*Graphed by the year that the area became prospective or explored.

CUMULATIVE NIGERIA RECOVERABLE OIL AND GAS FINDS* Fig. 4



*Graphed by the year the field location became part of the delineated prospective area.

Example: Nigeria

As an example from USGS Circular 1288, Fig. 2 shows the delineated prospective area and the explored area in Nigeria based on drilling through 2001. In this figure, the delineated prospective area amounts to about 51,600 sq miles and the explored area is about 14,600 sq miles.

Fig. 3 shows the rapid additions to delineated prospective area in Nigeria from 1953, the year of first discovery, through 2001.

The profile of cumulative oil discoveries graphed by the year that the field location became part of the delineated prospective area shows an upturn in the discoveries (quality) of the areas associated with newly delineated areas during the latter 1990s when deeper offshore area exploration started (Fig. 4). Through 2001, fewer than 1,300

wildcat wells had been reported for Nigeria.

Summary

The study area of US Geological Survey Circular 1288, the world outside the US and Canada, was partitioned into 44 countries and country groups.

Map figures such as Fig. 2 and graphs similar to Figs. 3 and 4 provide a visual summary of maturity of oil and gas exploration. From 1992 through 2001, exploration data show that in the study area the delineated prospective area expanded at a rate of about 50,000 sq miles/year, while the explored area grew at a rate of 11,000 sq miles/year.

The delineated prospective area established by 1970 accounts for less than 40% of total delineated prospective area but contains 75% of the oil discovered to date in the study area. From 1991 through 2000, offshore discoveries accounted for 59% of the oil and 77% of the gas discovered in the study area. ✦

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Venezuela

The Baripetrol SA joint venture's $60 million 2008 budget for the Colon Block in western Venezuela calls for drilling four development wells in La Palma field, a 165 sq km 3D seismic shoot in Socuavo field, and 20 workovers in Los Manueles and Rosario fields. Baripetrol's gross production is 10,500 b/d of oil and 5 MMcfd of gas, and the yearend 2008 target is 15,000 b/d and 10 MMcfd. A drilling rig under contract to Baripetrol through 2011 is to begin operations in April.

PetroFalcon Corp., Caracas, has a 5% interest in the Baripetrol joint venture.

Alberta

Stealth Ventures Ltd., Calgary, is pursuing what it calls Alberta's first commercial shale gas development at Wildmere, 120 miles east-southeast of Edmonton. The company has completed 10 wells of a planned 80-well program in 2008 for biogenic gas in Upper Cretaceous Colorado Group shales.

Stealth said it booked 12.4 bcf of proved and probable reserves in 2007 from 39 gross (29 net) wells across 15 townships. The 2P reserve life index is 15.7 years. The company holds 122 gross (83 net) sections of land at Wildmere.

The wells are expected to be classified as low-productivity, thereby qualifying for lower government royalties starting in 2009.

Newfoundland

Shoal Point Energy Ltd. has spud the directional Shoal Point et al. 2K-39 well on the northern tip of Shoal Point toward a subsurface target under Port au Port Bay in western Newfoundland.

The primary target is the Ordovician Aguathuna formation of the St. George's Group that produces 51° gravity oil and gas at Garden Hill field. The well is to terminate 2,200 m, or a few degrees west of due north of the point. Planned TD is 4,040 m, or 2,700 m true vertical depth, in the Watt's Bight formation.

The well is to test a large, seismically defined structure genetically related to the Hunt-PanCanadian Port au Port-1 discovery at Garden Hill South.

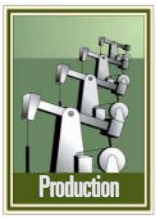
Mississippi

EOG Resources Inc. plans to start the first meaningful gas production from horizontal development of the Cretaceous Selma chalk in 2009 in Jefferson Davis County southeast of Jackson.

It put horizontal recovery potential at a net 200 bcf of gas or 60% recovery on 14,000 net acres. Recovery factor was 15% from the company's vertical drilling in the area. EOG has drilled three horizontal wells into the upper and lower chalk.

Upgrade expands Visund subsea well communications

Lars Egil Mathisen
Weatherford International Inc. SICOM
Trondheim, Norway



Upgrading of communications from subsea wells producing to the Visund platform required a threefold solution that involved retrofitting new communication cards in canisters that attach to existing subsea trees, using existing power lines for communication, and integrating the data topside.

The upgrade improves monitoring of subsea wells so that production from the field's complex reservoirs can be optimized.

Visund

StatoilHydro operates Visund oil and gas field in Blocks 34/8 and 34/7, 22 km northeast of Gullfaks field in the Tampen area of the Norwegian North Sea.

The field came on stream in 1999 and production is through a semi-submersible processing, drilling, and quarters platform (Fig. 1).

The subsea-completed wells in the field are tied back to the floater with flexible risers. Oil is piped to Gullfaks for storage and export while gas is piped to Europe, with gas exports having started in 2005.

The platform controls 32 subsea wells that produce an average 32,000 b/d and 1.49 billion cu m/day.

Partners in the field are StatoilHydro AS, 53.2%; Petoro AS, 30.00%; Norske ConocoPhillips AS, 9.10%, Total E&P Norge AS, 7.70%.

Interface card

The subsea wells were equipped with four electric pressure-temperature downhole gauges each and integrated into the production control system. StatoilHydro needed to expand the gauges to eight/well, but this required a new generation of downhole interface card.

The card selected was an Intelligent Well Interface Standard (IWIS) card from Roxar ASA that was not compatible with the existing control system. The card also is implemented as an ISO standard, Reference ISO 13628-6.

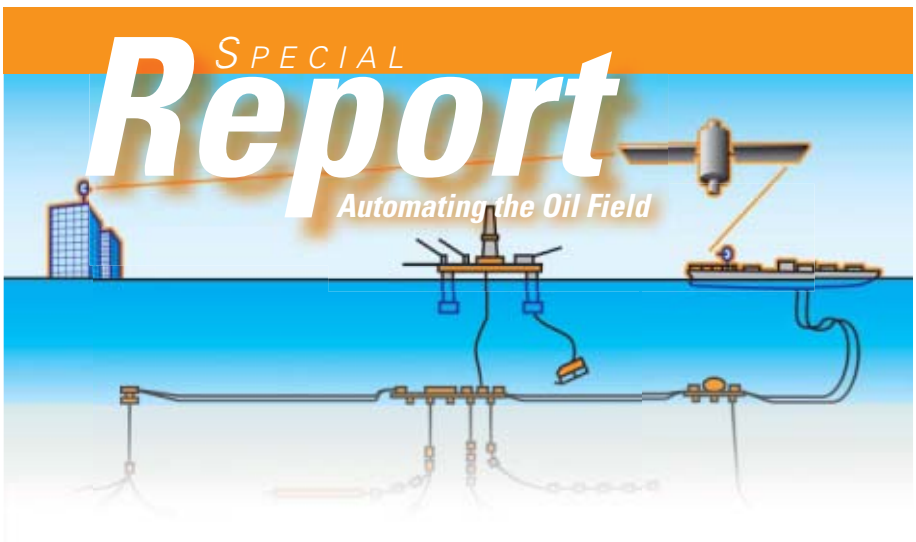
The subsea industry developed jointly the open interface (mechanical, electrical, and data communication) standard. IWIS provides a transmission control protocol-internet protocol (TCP-IP) link to subsea electronics, and ensures interchangeability of downhole vendor equipment.

Upgrade installation

StatoilHydro faced several obstacles for installing the upgrade. Besides working with a system that did not have built-in expandability, the existing control module did not have room for a new downhole communications card.

Additionally, the upgrade was limited to the existing number of communication wires in the umbilical and on the seafloor that were already at capacity.

To install the additional downhole gauges with minimal effects on the existing control system, StatoilHydro used a retrofit solution from SICOM, now a Weatherford International company.



The SICOM solution required installation of a new subsea canister with a remotely operated vehicle (ROV). The modem within the new canister communicates on the existing umbili-

Subsea wells producing Visund field flow to a semisubmersible processing, drilling, and quarters platform (Fig. 1).

cal cables and integrates the new data seamlessly into the management system on the rig.

SICOM's i100 power-line modem provides TCP/IP and Ethernet communication with a bandwidth of up to 400 kbits/sec. The former system at Visund and most other North Sea installations run at speeds up to 1.2 kbits/sec.

The upgrade used the existing communication wires, but rather than as single channel lines, the wires form a part of a multiplexed system that handles information for several wells. The multiplexed data are similar to a digital subscriber line (DSL) on a home phone line that allows transmissions without interrupting phone calls.

The process sends data packets through the power lines in an unused frequency band. At the other end of the line, the i100 modem captures and decodes the packets, as well as facilitating finding the optimum frequencies for each communication channel based on interference from power and other communication impulses.

This system permits as many as eight wells to communicate simultaneously on one line.

Because the existing control modules did not have additional capacity to accept an IWIS communication card, the upgrade required fabrication and installation of a new canister that fit on the existing subsea tree (Fig. 2).

The ROV-installed canister contains the IWIS card and the modem that controls communication on the power lines. The new system bypasses the former system with new jumpers that connect the new canister to the new downhole gauges.

The canisters were installed easily on the guideposts of the infrequently used remote tie-in system (RTS) on the subsea tree. The canisters can be removed for servicing if needed.

The RTS guideposts are used for tie in of flexible risers between the subsea tree and floating production unit.

The modems connect to the power lines and use the minimal power needed for communications. They pass the electricity onto the control system with virtually no loss or interruption to the control system. The multiplex communication on the power lines provides the communication channels for the required number of gauges in the wells. The modems can handle communication protocols for the major subsea communication systems, assuring an open system in the future if additional upgrades are needed.

Topsides server

A topside server now handles communication with the subsea modules and integrates the data received into the existing software systems on the rig. These include the safety automation system (SAS) based on Teleperm programmable logic controllers (PLCs) and the information management system consisting of an Aspentech IP21 database for storage of all historic data.

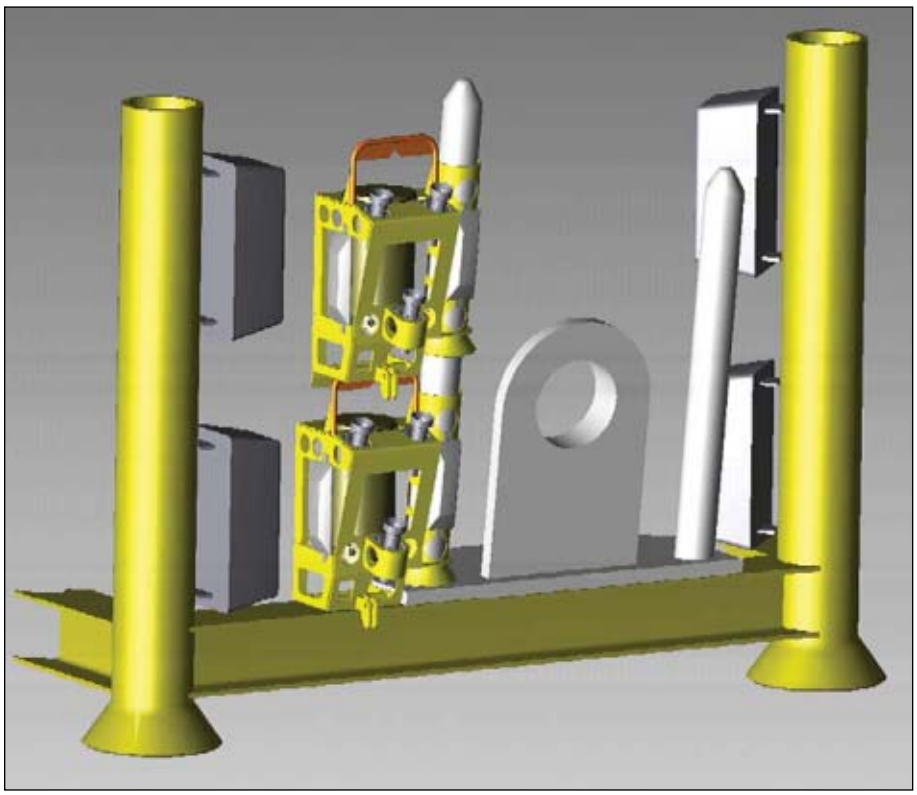
The software includes an open OPC DA interface for data exchange with external systems including all major databases.

The information management system gives the user the opportunity to analyze reservoir data in detail and optimize production. The additional four pressure-temperature gauges in the well provide the data resolution needed for more detailed analysis.

Benefits

The project organization made it possible to install an upgrade in an already existing design by implementing state of the art communication and control systems. The work also demonstrated the potential for retrofitting communications on existing assets.

The new system adds redundancy



The upgrade work mounted the new canisters on an existing guidepost of the subsea trees (Fig. 2).

by allowing the installation of eight gauges/well instead of the original four gauges/well. This means that the operator can now monitor performance in wells with more complex reservoir structures.

Communications with wells are now faster and more reliable. Rather than one well/communication channel, the new system provides up to eight wells/communication channel. The system increased communication speed to 390 kbits/sec from 1.2 kbits/sec.

The operator also now can access the information remotely, through the internet. Information monitored and serviced remotely means that service is prompt and cost effective.

With the success of this project, StatoilHydro may expand the monitoring capabilities of downhole gauges to other wells in this field and in other subsea fields. ✦

Acknowledgment

The project required the cooperation and efforts of Per-Ole Ingebrigtsen, StatoilHydro controls and operations, Olav Westrheim, StatoilHydro well and drilling, and Frode Haugen, StatoilHydro topside instrumentation.

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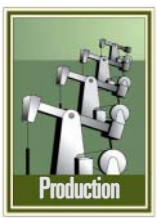
All-electric actuated subsea system qualified, implemented

Jan van den Akker
Cameron
Celle, Germany

John Burdick
Cameron
Houston



After about 8 years of design, testing, and qualifying, the all-electric actuated subsea system is now ready for is first commercial installation on gas wells off the Netherlands.

The benefits of the all-electric system compared with hydraulically actuated systems include improved reliability, availability, and enhanced functionality and performance of subsea controls.

The system also eliminates the environmental concerns of venting or the leakage of control fluids to the sea. Coupled with savings in high-cost control fluids and equipment, the all-electric system offers operators a cleaner, more economical alternative to hydraulic-based systems.

The all-electric system can also facilitate control of ultralong distance offset wells, subsea-to-beach installations, and complementary technologies such as subsea separation and processing.

Based on a presentation to Deep Offshore Technology International, Feb. 12-14, 2008.

System design

Cameron, perceiving the trend in subsea completions toward increased step-outs and water depths, recognized the limitations of electrohydraulic control and initiated work on an all-electric system in 1999. From the earliest conceptual design stages, it considered such requirements as increased reliability, availability, maintainability, cost savings, standard equipment interface and footprint, low power consumption, ease of use, and simplified hardware.

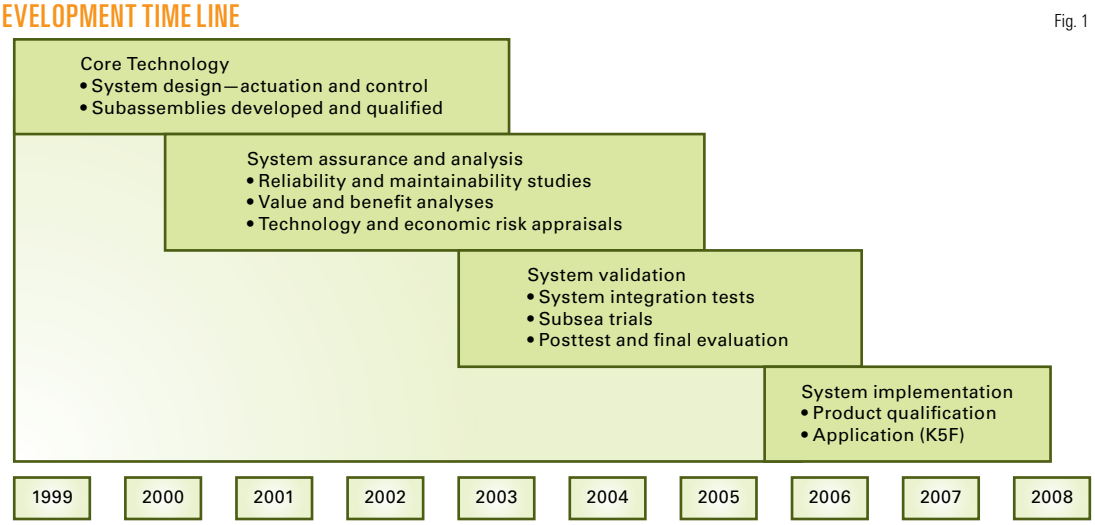
As an unintended bonus, complete removal of hydraulic fluid makes the all-electric system environmentally friendly as well.

The time line in Fig. 1 provides an overview of the development, testing, and implementation program. Note that early in development several analyses assessed the robustness and economic viability of the design, and the results of these studies led to updated design parameters and modifications. The first years of the program established several fundamental design criteria.

To overcome long-distance power transmission problems, the program selected DC power. It can facilitate step-out distances beyond 400 miles with high transmission efficiency.

DEVELOPMENT TIME LINE

Fig. 1



For communications, the current system uses a coaxial cable at a 19 kbit/sec data rate. In the future, fiber optics will provide greater bandwidth and allow longer step-outs.

The most reliable means of storing energy for the fail-safe gate-valve actuators is by compressing a large spring and, because of this, the design maintains this technology. With the energy stored in the springs, batteries and the troublesome battery connections and cabling become unnecessary, making the system fail-safe.

Two high-torque brushless DC motors drive the valve open and compress the spring, while two small low-power consumption stepper motors hold the valve open by loading a wrap-spring clutch. Any power loss or failure at any point in the system results in the valve closing via the powerful spring module.

The motor redundancy, along with a dual-channel position sensor, ensures trouble-free operation and high availability under normal operation. The position sensor measures exact stem position to an accuracy and resolution of 0.1 mm, providing assurance of full valve travel.

Also, the system stores in a database such data as power consumption, valve position, and motor rpm during each valve actuation. The retrieved data provide trending capability throughout the life of the actuator and can prove invaluable for troubleshooting and preventive or predictive maintenance.

The all-electric choke actuator has full dual redundancy, fail-in-position operation, fully rotational non-stepping action, high-precision stem position sensing, and parametric data storage. These attributes make choke operations user friendly.

Full stem travel can occur in as little as 60 sec. Intermediate positioning involves inputting an absolute value in mm or a percentage of travel and the actuator will automatically travel to that position and stop. Additionally, the system allows automatic control of flow rate or pressure through use of the choke as the final control element in a proportional-integral-derivative (PID) control loop. This obviously is more difficult with a conventional hydraulic stepping choke actuator.

This system includes an equally competent control system. All-electric subsea production control has advantages in most scenarios but especially when the field is in deep water or at a long step-out distance from the host facility. Electric motors maintain their high level of efficiency and full torque capability regardless of water depth unlike hydraulic pressure that must overcome hydrostatic seawater pressure.

High voltage DC for long-distance power transmission is much more efficient than either AC power or hydraulic pressure. Even at distances of more than 500 km, the efficiency of DC power is between 80-90% compared with less than 20% for low-frequency AC. This greater efficiency reduces the required conductor size in the umbilical. In addition, DC reduces the total number of conductors need.

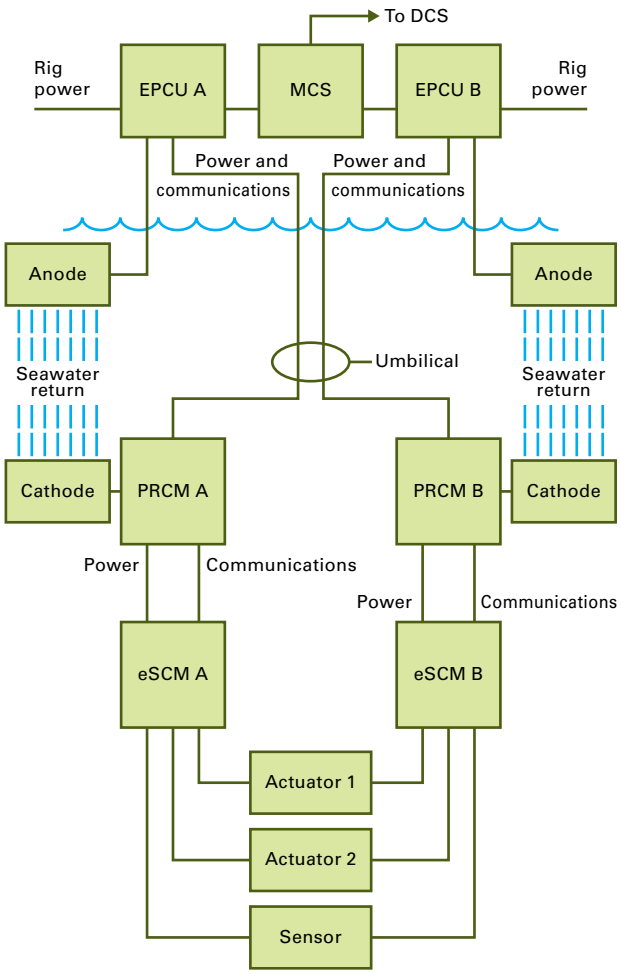
Three conductors are needed for three-phase AC compared with only one conductor for DC if the system incorporates a seawater return.

The removal of hydraulic tubing from the umbilical and the fewer, smaller conductors needed have several advantages. The all-electric umbilical has a smaller cross section that allows for the manufacture and spooling of longer continuous lengths. Overall umbilical weight is less and therefore may allow for the use of a smaller installation vessel. On long step-outs, splices in the umbilical will be either less or avoided altogether. Purchase and installation cost savings are the greatest advantage of a smaller, simpler all-electric umbilical. Cost is further reduced and deck space gained, by elimination of the control fluid and a high-pressure unit (HPU).

Delivering more electrical power subsea than is being consumed is inefficient and shortens the life of subsea

Main components

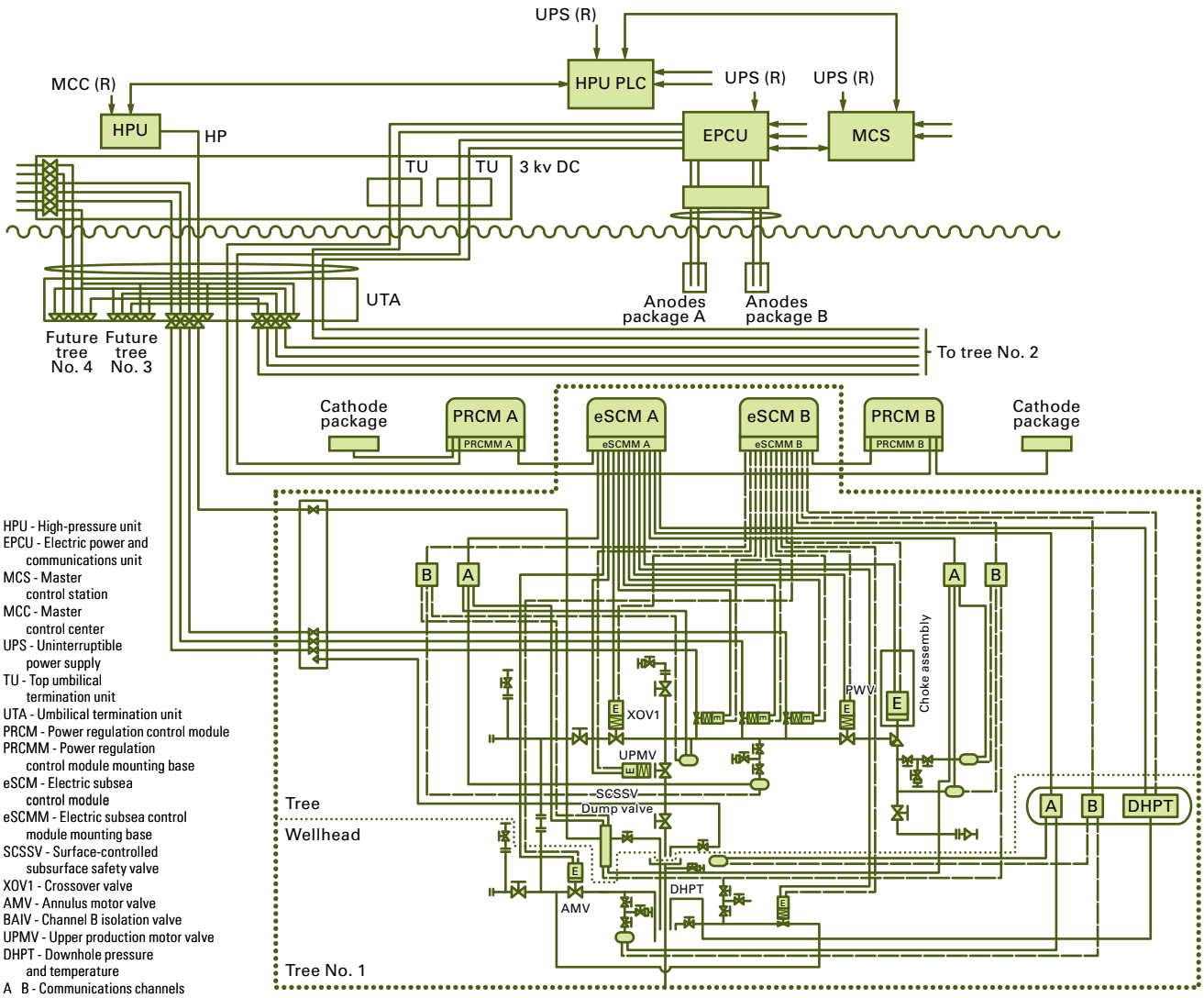
Fig. 2



EPCU - Electric power and communications unit
MCS - Master control station
PRCM - Power regulation control module
eSCM - Electric subsea control module
DCS - Distributed control system

IMPLEMENTED SYSTEM

Fig. 3



regulation equipment. The Cameron DC surface-power-supply output voltage and current levels can both be adjusted independently. The output voltage is set automatically at a level to deliver 3 kv at the input to the subsea regulation module regardless of losses through the cable and connectors.

The output current varies depending on load requirements. At idle, when only the subsea electronics and sensors are being powered, the current level is low. Whenever demand increases, as when a valve is opening, the current level increases and stabilizes during the opening sequence, which is typically about 1 min in duration, and then reduces again upon its completion.

Redundancy at the surface is evident both within the power cabinet, in the form of dual modular supplies running in parallel, and by providing two surface units in a Channel A and B configuration. This parallel independent channel configuration carries through to the actuator itself, ensuring operability of the system despite any single-point failure. Additionally, either channel can be taken offline for any reason while the other continues to function normally.

Two subsea modules serve to regulate power and control tree and manifold functions. Remotely operated vehicles (ROVs) can retrieve both subsea modules.

The first module reduces and regulates the 3-kv input to 300 v DC and separates the communication signal from the power conductor. The reduced voltage and independent communication signal then go to the electric subsea control module. This unit controls valve functions, logs actuator parametric data, receives sensor information, and communicates with surface control equipment.

A fully populated control module currently can operate 16 functions.

Fig. 2 shows the main components along with the master control station, redundant paths, and seawater return.

Qualification

The system is not only a new product line but also an entirely new technology in subsea completions. Because of this, Cameron employed a comprehensive qualification program.

Three levels of testing covered all equipment from the smallest electronic circuit board to large main assemblies. Actual tests carried out and range of test parameters followed international standards where applicable or past experience and good engineering practice where no standard applied.

In some instances, the qualification tests surpassed the guidelines within the standards such as the case with electronic printed circuit boards. The standard stipulates testing of either each individual board or testing of circuit board assemblies. Cameron did both. Because all-electric control is new technology, many of the components are not covered by any standard so that the testing was at a very high level to set a benchmark.

The first level of testing was on the electronic printed circuit board, in accordance with ISO-13628-6 at Q1 level. The guidelines of this testing are:

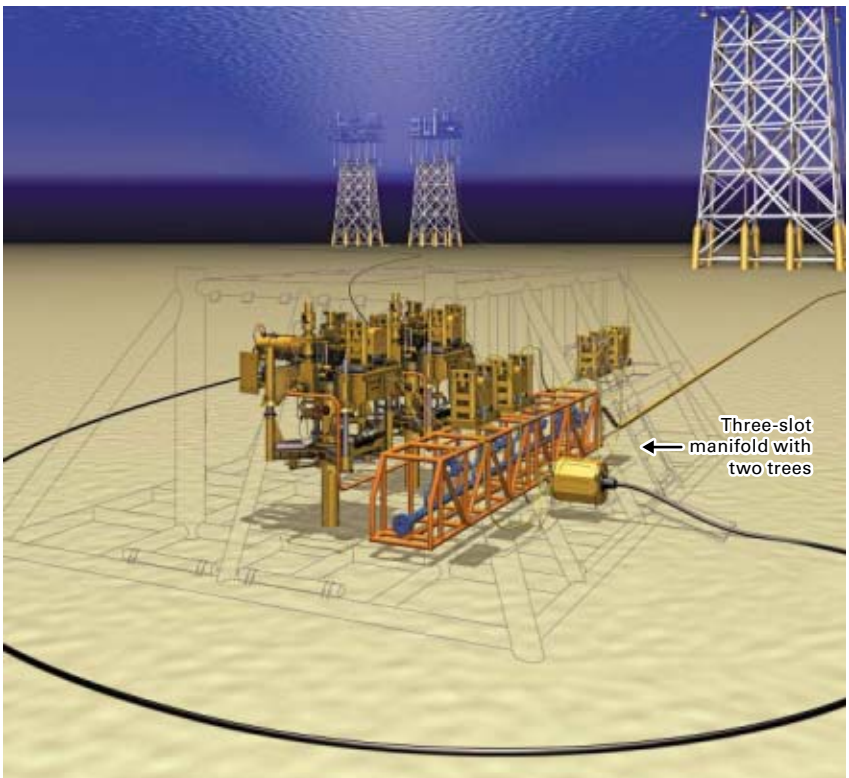
- *Shock*—30 g acceleration, 11 ms half sine in six directions along three perpendicular axes
- *Vibration*—25 hz ±2 mm displacement, 1 octave/min max, double sweep, 25-1,000 hz 5 g acceleration, 1 octave/min, double sweep, vibration tests repeated for all three perpendicular axes, 2-hr random vibration within following parameters: 20-80 hz at 3 db/octave rise, 80-350 hz at 0.04 g^2/hz, and 350-2,000 hz at 3 db/octave roll-off.
- *Thermal*—48-hr soak at −18° C., and 48-hr soak at 70° C.

The second level of testing was at the subassembly level. This included multiple printed circuit boards mounted in a rack or stacked and other smaller assemblies used to build the major assemblies. The level of testing for these units also was according to ISO-13628-6 but at Q2 level. The testing was similar to the above but at slightly less stressful levels as follows:

- *Shock*—10 g acceleration, 11 ms half sine in six directions along three perpendicular axes
- *Vibration*—25 hz ±2 mm displacement, 1 octave/min max, double sweep, 25-150 hz 5 g acceleration, 1 octave/min, double sweep, vibration tests repeated for all three perpendicular axes, 2 hr random vibration within following parameters: 20-80 hz at 3 db/octave rise, 80-350 hz at 0.04 g^2/hz, and 350-2,000 hz at 3 db/octave roll-off.
- *Thermal*—48-hr soak at low design temperature of −10° C. closed housing and −18° C. open housing, and 48-hr

K5F FIELD DEVELOPMENT

Fig. 4



ALL-ELECTRIC TREE

Fig. 5

soak at high design temperature of 40° C. closed housing and 70° C. open housing.

Shock and vibration levels are lower because the mass of the equipment under test is higher and the main purpose of this test is to verify integrity of assembly means and connections.

The third level of testing included each major assembly, such as each size of gate valve, choke, power regulation and communication module (PRCM), and the electric subsea control module (eSCM). Also included in this classification were the electrical connectors and jumper assemblies. Testing for these assemblies took the form:

- Seal test.
- Function test.
- Fail-safe close test (gate valve only).
- Overload test (1.5 × maximum stem force).
- Temperature cycle test (–2° C. minimum, 65° C. maximum).
- Hyperbaric to 3,000 m.
- Gate valve endurance cycle test (1,000 open/close cycles).
- Choke endurance cycle test (200 open/close cycles in 5 mm steps to simulate 1,000,000 steps of electrohydraulic choke actuator).
- Shock and vibration (shock: 5g 9 ms half sine four times in six directions, vibration: 10-100 hz 0.6 g rms in three axes, 1.8 g maximum, 4 × 15 min).

Connectors and jumpers were fully tested by the manufacturer to the same international standard.

After fully qualifying all equipment, Cameron ran in stages a series of integration tests to ensure interoperability and verify software operation.

The first stage, called Phase 1A, involved a surface power supply and surface modem driving through a cable length simulator to a variable electronic load and subsea modem in a nonredundant configuration.

Upon completion of 1A, Phase 1B replaced the simulated load with actual subsea equipment including the PRCM, eSCM, and electric actuators still in a single channel.

The final level of testing, Phase 2, duplicated all the power and control elements forming a fully dual-redundant system in a channel A and channel B configuration. Although not officially part of the qualification program, this additional testing was crucial for proving the fully qualified components functioned properly when integrated together.

To document this comprehensive series of tests fully, Cameron created a qualification program dossier with the following documents:

- Qualification program overview that provides a short, concise summary of equipment tested, levels of testing, results and effectiveness of testing, and mitigating steps taken.
- Qualification philosophy that provides references international standards where applicable and justifies types and levels of testing where no standard applies.
- Qualification test plan that includes system description, testing performed before final product qualification, test status table, comprehensive reference to international standards used, and other relevant information covering the full qualification program.
- Failure mode effects and criticality analysis-technical risk assurance process (FMECA-TRAP) summary that lists the studies performed and the results of these studies in both text and tabular form.

Implementation

After completion of the field trails in 2004, Cameron started to market the product and in June 2006 received its first order for supplying two trees, including associated all-electric production controls, to be installed inside a three-slot manifold (Figs. 4 and 5). The order was from Total E&P Nederland BV for their K5F field in 121 ft of water off the Netherlands.

In addition to the requirement of controlling the first two tree assemblies, the order also required the subsea production controls be prepared for a future third tree inside the manifold as well as for a future step out of a fourth tree assembly. The distance between the host platform and the manifold is 20 km.

The DC current path uses the coaxial cable inside the control umbilical for supplying power and communications and uses the seawater as its return path. This required four anodes at the platform and four cathodes at the manifold.

Four electrical power and communication units (EPCU) provide full redundant (Channel A and B) supply for the four power regulation control units (PRCM), which in return send the power and communication signals after regulating it down from 3 kv DC to

Cameron's site integration test (SIT) program included a water basin filled with seawater for simulating the electrical current return path (Fig. 6).

300 v DC, to the four electrical subsea control modules (eSCM), responsible for controlling the valves, choke and tree instrumentation (Fig. 3).

A natural consequence on the implementation of the all-electric production controls is that Cameron also had to design, build, and test an all-electric installation and workover control system (IWOCS). This system's general specifications make it fit for use on other applications as well.

The all-electric DC IWOCS is available on a rental basis and allows either:

- Direct control of the individual actuators by means of connecting at the backend of the actuators.
- Control a complete tree through the eSCM by connecting up to the diver interface panel at the front of the tree.

For this control, the process includes a simplified topside power and communication system consisting of a single channel communication and power supply, as well as an uninterruptible power supply (UPS) to allow stable power supply and a 5-hr standby time with the tree fully open. The design features an IWOCS reel assembly that ends at an IWOCS umbilical termination unit (I-UTA), which in effect is a simplified eSCM.

Aside from the tree being all electric, the downhole safety valve (DHSV) is still an element within the first project that operates in a traditional hydraulic manner. A tree-mounted solenoid valve assembly directly controlled by eSCM operates the DHSV.

Cameron, however, is in communication with various DHSV suppliers and current indications are that the first fully qualified all-electric DHSV will be available in fourth-quarter 2008 or first-quarter 2009.

The two major execution challenges on the first project were:

1. Move the product from a research and development into an industrial production environment.
2. Manage the first project, while product qualification is ongoing, with improvements and changes implemented on equipment already in production.

These challenges required working closely with a group of selected vendors, already used by the R&D group, through special purchasing agreements for securing production slots and more importantly ensuring that specific knowledge gained by the vendors during the product qualification process would not get lost.

In addition, the project placed special emphasis on identifying critical long-lead items early in and put priority on design freezes for these items. Also the dedicated purchase agreements allowed for the possibility to make changes without having to go through the typical vendor approach whereby there is defined scope agreed and variation orders are used to manage change, which typically take up critical time.

To ensure that the maximum of equipment is tested before going offshore, Cameron has decided for an extensive factory acceptance test (FAT) and a site integration test (SIT) program, which includes two 5-km long coaxial cables simulating the production control umbilical, as well has implemented a water basin filled with seawater, in which to allow simulation of the electrical current return path (Fig. 6).

Installation offshore of the first components started in February 2008. ✦

The authors

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Refiner demand for discounted feeds will increase trade of high-acid crudes

Refiners looking for discounted crude supplies will import and use greater volumes of high total acid number (TAN) crudes, according to a study from Asia Pacific Energy Consulting (APEC).

The study states that incremental high-TAN crude output should rise by 1.8 million b/d during 2005-10, with 61% of that gain expected in West-of-Suez production regions. High-TAN crude production, trade, and use will increase globally and Asia-Pacific will be the focus of interregional acidic crude trade through the next decade, according to the study.

This study is different from previous forecasts because it does not include acidic crudes that do not affect markets or trade balances.

Asia-Pacific's need for low-sulfur crude that produces a high volume of gas oil and residual fuel will be one "pull" factor attracting high-TAN output from West-of-Suez regions. The discount on high-TAN crudes will is another "pull" factor for Asian buyers, particularly as refiners look for less-expensive sweet crudes.

The study stated that "push" factors that will increase arbitrage sales to Asian refiners include a disproportionate buildup of high-TAN output in West Africa, Sudan, and Latin America; a lack of refining capacity, particularly that suited to handle high-TAN crudes in this area; and political supports, including Venezuela's effort to increase sales to China and Asia-Pacific.

Crude markets

APEC believes that crude prices in a steady range of $90/bbl or greater are unsustainable, although short-term spikes of $100/bbl are likely and may occur on more than one occasion. The study assumes a medium-term average range through 2010 of $65-75/bbl for Brent crude, with increased price volatility in the short term.

A substantial crude production capacity buffer will emerge in the coming decade, and Asia-Pacific will continue to depend on ever-increasing volumes of crude imports, mainly from the Mideast Gulf, according to the study.

The further rise in crude prices during second-half 2007 to $90/bbl levels has begun to erode demand growth in OECD markets. The first signs of demand slowing in Asia-Pacific, both in advanced economies and developing markets, appeared in second-half 2007.

Although OECD markets have seen an absolute decline in oil demand, particularly in transport fuels, Asia-Pacific has experienced slower demand growth, even though overall consumption continues to rise moderately. APEC believes that world markets, even in Asia-Pacific, have entered a demand "killing zone," with a moderating effect on crude prices.

Slowing demand growth, combined with substantial new refining capacity due to start up by 2010, will shift Asia-Pacific from a region in which oil prices were led by products' availability, to that of markets, such as the Atlantic Basin, led by crude availability and price.

The Mideast Gulf, mainly OPEC producers, will continue to provide most extraregional crude supplies to Asia-Pacific, according to the study. A substantial minority share of imports, however, will continue to be low sulfur, medium-weight to heavy crudes. These crudes will be needed to meet Asia-Pacific's tightening product specifications, to meet the high proportion of gas oil (diesel) consumption, to fill incremental crude needs in face of stagnant Asia-Pacific crude output, and to fill slates for less-sophisticated Asian refineries.

Acidic crude basics

High-TAN or acidic crudes are grades that contain substantial naph-

thenic acid. The amount of potassium hydroxide (KOH) needed to neutralize acidity is the measure of a crude's acidity.

The study assumed that a crude with more than 1.0 mg KOH/g is a high-TAN grade because at this point, Atlantic Basin high-TAN crudes begin to be discounted heavily and move toward East-of-Suez markets. The only common element in acidic crudes is the high-TAN content; they can vary extensively in most other physical characteristics.

Although most high-TAN crudes have medium to heavy gravities (all less than 29° API), they are usually are low in sulfur content (with the notable exception of Venezuelan grades) and often produce a disproportionate gas oil yield when refined.

Although high-TAN crude output occurs in every oil-producing region of the world, this study focused on internationally traded acidic grades and their effect on Asia-Pacific markets.

High-TAN crude output

According to the study, China has been the big gainer in high-TAN crude production in recent years and will continue to dominate output through 2015. China's output of high-TAN crude will increase to 736,000 b/d in 2015, from 330,000 b/d in 2006. Substantial production increases from the foreign-equity fields QHD and Penglai will occur by 2010.

Australia, which produces minimal acidic crude output from Wandoo field, will add substantial high-TAN output with the start-up of the Vincent, Crosby, and Van Gogh crudes, all moderately high-TAN grades that will be exported. Total high-TAN crude output from Australia will reach 180,000 b/d by 2015.

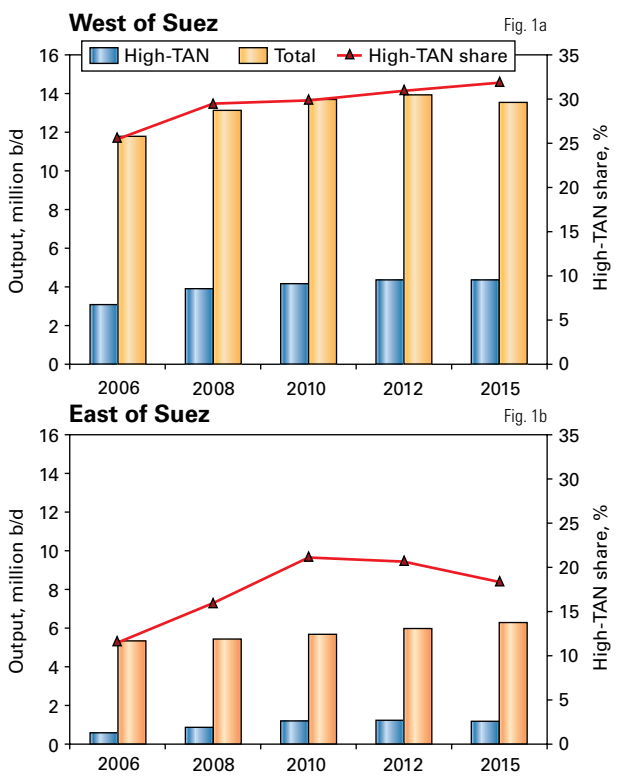
Domestic use of Indonesia's Duri crude will increase and the country will remain relatively constant in terms of high-TAN crude output. Duri remains the closest thing to a regional high-TAN crude marker even though it is only mildly acidic.

West Africa added many new high-TAN grades since 2004 and, although only a few additional acidic crudes will be commissioned through 2010, overall high-TAN output will continue to grow. The region will increase high-TAN crude output to 1.155 million b/d in 2015 from 435,000 b/d in 2006.

In 2006, Angola, Chad, and Sudan (which the study included in the West-of-Suez region) were the major African countries with high-TAN production, Sudan will expand substantially its acidic crude output, a rise of nearly 325,000 b/d by 2012 compared with 2006 levels, particularly for the highly acidic Fula grade. A lack of refining capacity in most of these African countries will spur exports of high-TAN output, according to the study.

HIGH-TAN CRUDE EXPORTERS

Fig. 1



Although total North Sea production will decline, the UK and Norway will see marginal gains in high-TAN output, increasing to 585,000 b/d in 2015 from 553,000 b/d in 2006. Most acidic crude produced will be used in Northwestern Europe, although the US market receives regular imports of Norwegian cargoes. Only some small-volume new high-TAN grades may emerge in this region by 2012.

Latin America's high-TAN output will have more of an effect on Asia-Pacific by 2010. Venezuela will push sales to China and Brazil already has bought its first refinery in the region. Although PDVSA's impetus for increased exports is political and Petrobras' is commercial, the net result will be the same—a sharp increase in interregional sales of mainly acidic crude grades.

Although Venezuela will struggle to maintain crude output through 2010, Brazil will steadily add new crude grades to its production list and steadily increase overall oil output, according to the study. Latin America will increase high-TAN output to 2.91 million b/d in 2015 from 2.37 million b/d in 2006.

Iran's Norwuz will likely remain the only high-TAN crude grade produced in the Middle East. APEC expects that Central Asian and US high-TAN crude output will remain within the respective country and will not be exported as high-TAN grades. If exported, acidic crude output will be blended off into moderate-TAN crude streams to allow for pipeline exports.

Total vs. acidic crude

The study only considered tradable high-TAN crude production and regions producing and exporting high-TAN grades. Overall, in countries

already producing and marketing acidic crudes, the proportion of high-TAN crude to overall output will rise substantially through 2010, reaching a high of 25%, up from less than a fifth of all output in 2006.

When compared against total regional crude production in Asia-Pacific, Africa, Europe, Latin America, and the Mideast Gulf, acidic crude will rise to 10.7% in 2010 from an 8% share of overall oil output in 2006. West-of-Suez producers will add more total volume of high-TAN crude through 2015 and consistently will produce a larger percentage of world traded high-TAN crude than East-of-Suez producers.

High-TAN crude's share of output for the West African countries in the study (Angola, Cameroon, Chad, Congo, Gabon, Ivory Coast, and Sudan) will increase to 27.5% of total crude, up from 16.0% in 2006.

Brazil, Venezuela, and Trinidad and Tobago's proportion of high-TAN crude will increase to 56.2% in 2015 from 51.4% in 2006, the study reported. China's proportion of high-TAN to total crude output will increase to 16.7% from 8.5% during 2006-15.

Potential Suez arbitrage

The study examined the potential for arbitrage of high-TAN crudes for East and West of Suez. It excluded the Mideast Gulf because it is a swing production area, selling to both regions.

Acidic crude made up 25.4% of West-of-Suez crude supply in high-TAN exporting countries in 2006; in contrast, it made up 11.4% of crude output in high-TAN exporting countries worldwide (Figs. 1a and 1b).

Although East of Suez high-TAN output will rise sharply by 2010, it will likely peak at less than a quarter of total East-of-Suez output in high-TAN exporting countries. In contrast, West of Suez high-TAN production will grow, albeit at an uneven pace, to make up nearly a third of the oil production in West-of-Suez acidic crude exporting countries by 2015, according to the study.

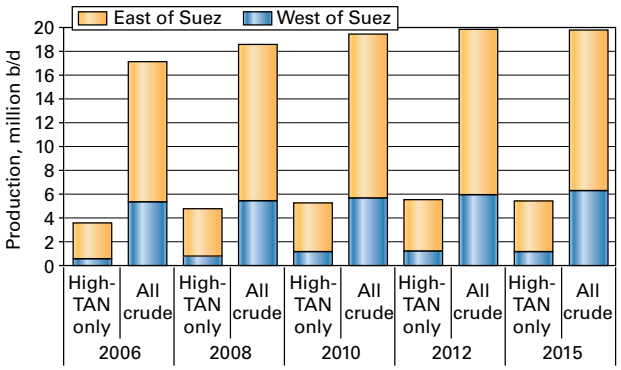
Acidic crude production, measured against total Asia-Pacific output, peaks at slightly more than 15% between 2010 and 2012. In contrast, West of Suez high-TAN production will continue to rise as a proportion of total oil output through 2012 and in that year will peak at 41.4% of all oil production, according to APEC.

Fig. 2 shows total high-TAN output divided into East and West of Suez. West-of-Suez output consistently is far greater than East-of-Suez output and continues throughout the time frame of the study to dominate the world's total of internationally traded acidic crude.

In the past, few acidic crude grades from Asia-Pacific made their way to West-of-Suez markets and, for the most part, consisted of Indonesian Duri as well as some Chinese crude, according to the study. Yet East-of-Suez refiners were consistent importers of high-TAN crude from West-of-Suez producers.

Although APEC believes there may be an increase in the export of high-TAN grades from China to West-of-Suez refiners, mainly ConocoPhillips and Chevron Corp. if they desired to bring in equity production from China, in addition to Duri, the tendency will be for high-TAN crudes to move from western producers eastward.

REGIONAL PRODUCTION, HIGH-TAN PRODUCERS ONLY Fig. 2



High-TAN prices

West-of-Suez crudes, including Sudanese exports, are usually marked off of Brent, and most Asia-Pacific crudes still tend to use Duri as the basis. Many Asia-Pacific crudes are, however, valued more for their specialty utilization than a relationship to Duri, mainly in fuel-oil blending, lubes, and asphalt manufacture.

According to the study, some western high-TAN crudes, while maintaining a price relationship to Brent, such as Chad's Doba, are in reality much more affected by low-sulfur fuel oil prices in Northwest Europe and low-sulfur waxy residual. Venezuelan exports to Asia are somewhat difficult to value but may depend on factors besides Brent linkage and for asphalt-production grades, such as Boscan, and may well have no relationship to any crude marker.

Producers of high-TAN crude with extensive downstream systems have a price advantage vs. acidic crude producers without their own refining capacity.

The emergence of any major new high-TAN grade tends to discount all acidic crudes. This is most noticeable when a high-TAN crude begins export from a producing country with little alternative but to sell output abroad, according to the study.

Future price trends

Price and domestic demand increases will be primary factors in Brazilian efforts to increase sales to Asia-Pacific. Brazil's sharp oil output rise in recent years has been mainly in medium to heavy sweet grades, a good percentage of which has been in high-TAN grades.

Domestic refiners need more light sweet crude; Petrobras has been trading out heavy sweet grades, often acidic, to Asia-Pacific, gaining a premium for the sweet character of these exports, while balancing its domestic refining by importing more light crude from the Atlantic Basin.

Three exporting countries will substantially influence prices in the medium term: Brazil, Sudan, and Australia. Brazil will export more Marlim, Albacora Leste, Roncador, and possibly Polvo to Asia-Pacific through 2010, using its new Okinawa refinery as a crude break bulk and reexport facility for East Asian sales, according to the study.

Sudan's growing diplomatic isolation will make it depend more on close economic ties with China. APEC feels that most Fula output, as well as a substantial portion of Dar production, will move to China, though Indian and Malaysian buyers may also take a great share of export sales.

Australia has three substantial high-TAN crude grades starting up by 2010 and because both are in Western Australia, most output will be exported to Asian buyers. Smaller, but regular volumes of West African crudes will appear in Asian markets in the medium term and, if PSVSA meets its stated goals, much high-TAN crude will be sold to China as well as smaller-volume exports to other Asian markets.

Product quality

According to the study, product quality will be a more important support for the import of high-TAN crudes East of Suez. Although reducing sulfur will be a primary refining goal for gasoline and residual, the key pressure remains to reduce and then virtually eliminate sulfur in gas oil, particularly road diesel.

By 2010-11, most major Asia-Pacific countries will have sulfur limits approaching 50 ppm for road diesel and refiners will be hard-pressed to meet this standard without running at least some sweet crude. Many grades of acidic crude yield large volumes of low-sulfur gas oil.

Most crude grades produce gas oil with a relatively low cetane value, implying that diesel derived from high-TAN crudes would have to be blended. Yet acidic crudes also have blending value in residual, both for viscosity and for their low sulfur content, when blended with high-sulfur residual, according to the study.

High-TAN crude refiners

The study identified different groups as potential high-TAN crude buyers:

- Refineries with specialized metallurgy.
- Large refineries that can dilute acidic crude and use it as trim.
- Those refiners with sufficient specialized facilities to handle high-TAN crudes when discounted.
- Specialized, nonprocessing utilizations.
- Risk-adverse refiners that will only occasionally experiment with high-TAN grades.
- Large and sophisticated refineries buying discounted acidic crude in the hope of a double-dip in profits, using residual from high-TAN grades as cat-cracker feedstock.

Refiners can handle acidic crudes safely using three different methods: dilution (blending with nonacidic crude), chemical injection to neutralize acidity, and through the selection and use of specialized materials in the refinery, particularly special alloy steels.

Extensive refining capacity designed to handle high-TAN crude has been operating in Northwest Europe and the US gulf and Atlantic Coast regions for some time.

In high-TAN exporting countries in Latin America and Africa, however, refining capacity for acidic crude is either antiquated and needs renovation (Venezuela); is inadequate for increased domestic high-TAN production (Brazil); or total refining capacity is inadequate for domestic needs, whether running high-TAN grades or not (most of West Africa). Sudan has made an effort to build refining capacity capable of handling its surge of incremental high-TAN output, but growing acidic crude output is outpacing new special-build refining capacity, according to the study.

With the exception of Brazil, most new capacity to handle acidic crude will be built in Asia-Pacific by 2010. China is adding two new refineries specially built for high-TAN crude slates. In India, the new Reliance refinery will be able to handle large volumes of high-TAN crude, and Petronas and ConocoPhillips had approved a substantial revamp of its Melaka plant at yearend 2007, according to APEC.

Other refiners have considered plans to revamp their refineries to handle acidic crudes, notably in China, South Korea, and Thailand.

China will continue to dominate high-TAN production, consumption, and imports for Asia-Pacific at least through the medium term. APEC expects, however, a significant increase in high-TAN use by South Korea, Taiwan, Malaysia, Singapore, and India. Chinese exports to the US West Coast may also rise, depending on system needs of Chevron and ConocoPhillips. ✦

Neutron diffraction-based tools aid failure forecasting models

Pablo Genta
Saudi Aramco
Dhahran

Massimo Rogante
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Neutron diffraction and small-angle neutron scattering techniques can assess residual stress in and the microstructure of hydrocarbon pipelines. Forecasting tools based on predictive failure models incorporating these techniques can produce such tangible benefits as improved material selection and pipeline design, greater standardization of material, and more thoroughly examined welding requirements.

They can also allow a more comprehensive understanding of ideal wall thickness, taking into account that thinner pipe walls can reduce RS gradients that cause failures while also reducing installation and material costs. Such tools will also help operators prioritize maintenance, repair, and rehabilitation needs.

Neutron techniques are also complementary to other testing methods, extending their benefit to pipeline operators by revealing hidden cause-effect relationships leading to pipeline failures and identifying potential weaknesses in protection systems.

This article explains how ND and SANS techniques can address problems in current pipeline-integrity assessment methodologies.

Based on presentation to the Pipeline Rehabilitation & Maintenance conference, Manama, Bahrain, Dec. 11-13, 2007.

Background

Guaranteeing pipeline structural integrity requires pipeline operators to maintain a low likelihood of failures while at the same time keeping operating and maintenance costs under control. The operator's ability to prevent failures through effective predictive models and appropriate inspection determines whether a low failure rate will be achieved.

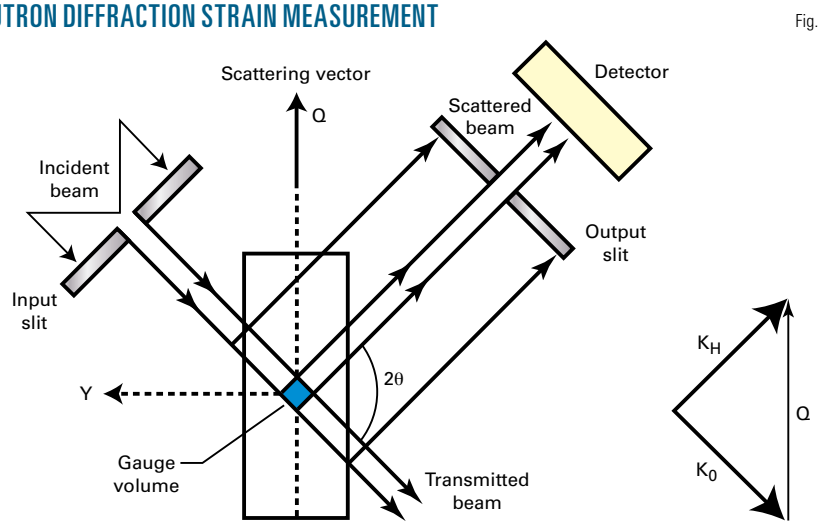
The presence of a microcrack due to the welding process can lead to failure of the entire structure. An accurate method of assessing residual stress in pipelines can help address this and achieve desired safety and reliability levels.

Knowledge of RS levels and other microstructural factors (e.g., inhomogeneities, precipitates, microvoids, etc.) can help in selecting pipe manufacturers, specifying quality of materials, establishing safe operating pressures, and planning maintenance and rehabilitation programs.

RS in pipelines generally arises from

NEUTRON DIFFRACTION STRAIN MEASUREMENT

Fig. 1



material history, production, ground movement, and in-service damage. Extrusion, filament winding, thermal treatment, and welding processes are able to induce RS, which subsists without applying external load to the material. Estimating the real total stress when a material is subjected to external loads requires accounting for the underlying RS state. Some components of combined total stress may exceed a particular design stress limit of the material, risking an early structural failure.

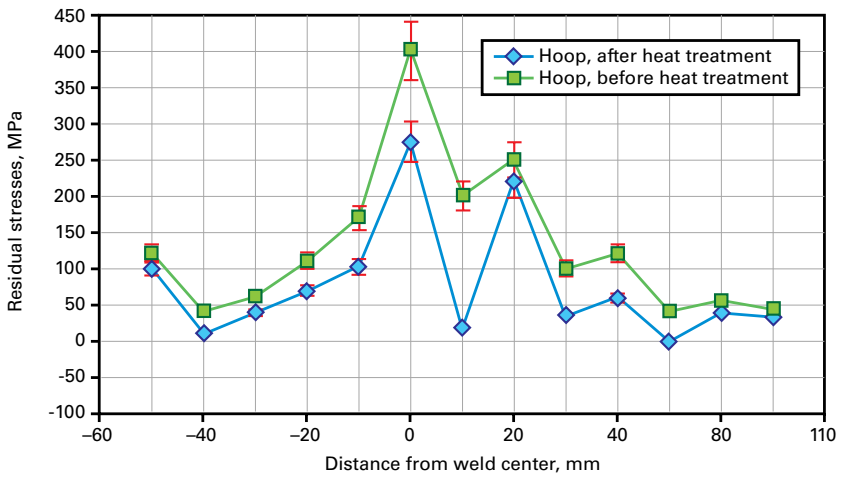
Knowledge of spatial and directional RS distribution in pipelines becomes necessary to determine their influence on the material. The assessment of RS levels reveals, through ND and SANS tools, the cause-effect relationships between the current condition of a given pipeline material and its potential future failure modes under operating conditions.

Understanding such relationships permits predicting what types of failure modes are likely and the resistance of the pipeline material to crack propagation under operating conditions. Building a valid predictive failure model, however, requires considering valid methods of collecting material samples, cataloguing, and data analysis, which exceed the purpose of this article.

SANS should complete information obtained by the ND tool as it provides additional data characterizing defect type, amount, and size. SANS allows microbeam scanning and detection of nanopores (nanocracks) in sample materials. SANS analysis of samples exposed to different mechanical loads provides information on the nanoscopic and microscopic development of defects—from dislocations to voids and cracks—and their relationship to applied stress. Comparative analysis between the SANS cross sections of freshly prepared and aged samples also provides information on size distribution and concentration of new defects induced by treatment of the material.[1,2]

Hoop RS, Cr1Mo ferritic pipe

Fig. 2



Experimental procedure

Strain measurement diffracts a collimated neutron beam (having a wavelength λ) with a polycrystalline sample, and then passes it through a second collimator before reaching the detector. Both collimators' slits define the investigated volume (Fig. 1), whose cross section normally can be as small as 1 sq mm or, in individual cases, smaller.

The Bragg law (Equation 1) allows determining the interplanar distance d_{hkl}. Equation 2 provides the corresponding lattice strain.

Analysis of triaxial stress requires particularly accurate values describing unstressed lattice spacing. A strainless sample of the material avoids systematic errors in the d_0, and therefore in the strain value as well. Various experimental and analytical methods exist for the determination of d_0,[3] with Reference 1 discussing the representative geometry of diffraction related to pipelines (triaxial stress states).

Knowing the elastic constants of the material and applying the relations shown in Equation 3 yield the stress values.

Analysis of the shape of broadened diffraction profiles guides investigation of microstrains.[3-5]

RS measurement by ND present is nondestructive and provides precise statistical information by averaging measurements across a macroscopic sample volume. Investigation of a specimen can occur various times after exercise or heat treatment, and the small absorption of neutrons often allows measurement of centimeter-thick materials.

Operators can perform the same measurement on pipelines before and after heat treatment or welding process, and after different exercise periods, and points of the

Equations

$$n\lambda = 2d_{hkl} \sin\theta \quad (1)$$

Where the integer n is the diffraction order, 2θ the ample takeoff angle related to the maximum of the Bragg diffracted intensity peak, and hkl the Miller indices of investigated lattice planes.

$$\varepsilon_{hkl} = \frac{d_{hkl} - d_0}{d_0} \quad (2)$$

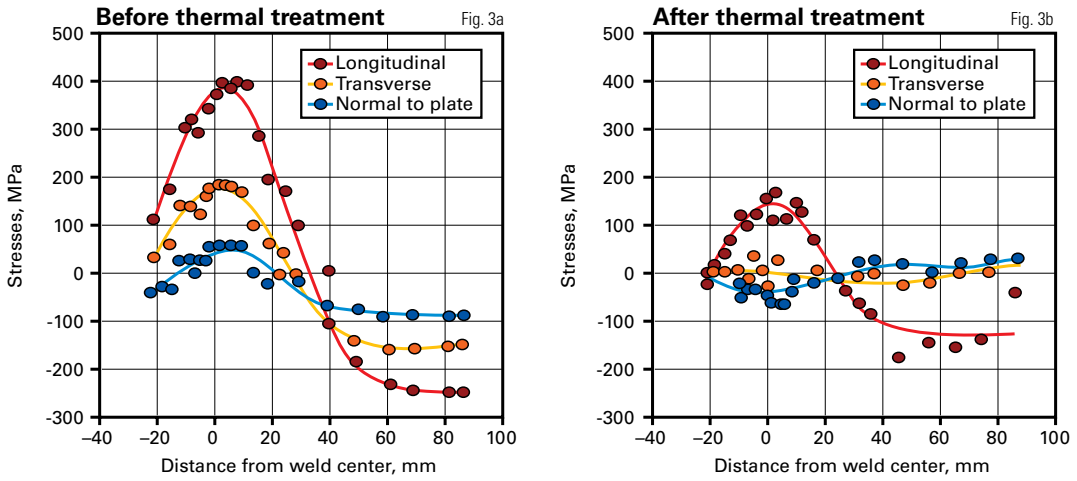
Where d_0 is the hkl interplanar distance (lattice spacing) in a stress–free reference material.

$$\sigma_{ii} = \varepsilon_{ii}\left(\frac{E(1-\nu)}{(1+\nu)(1-2\nu)}\right)_{hkl} + (\varepsilon_{jj} + \varepsilon_{kk})\left(\frac{\nu E}{(1+\nu)(1-2\nu)}\right)_{hkl} \quad (3)$$

Where i, j, k = 1, 2, 3.

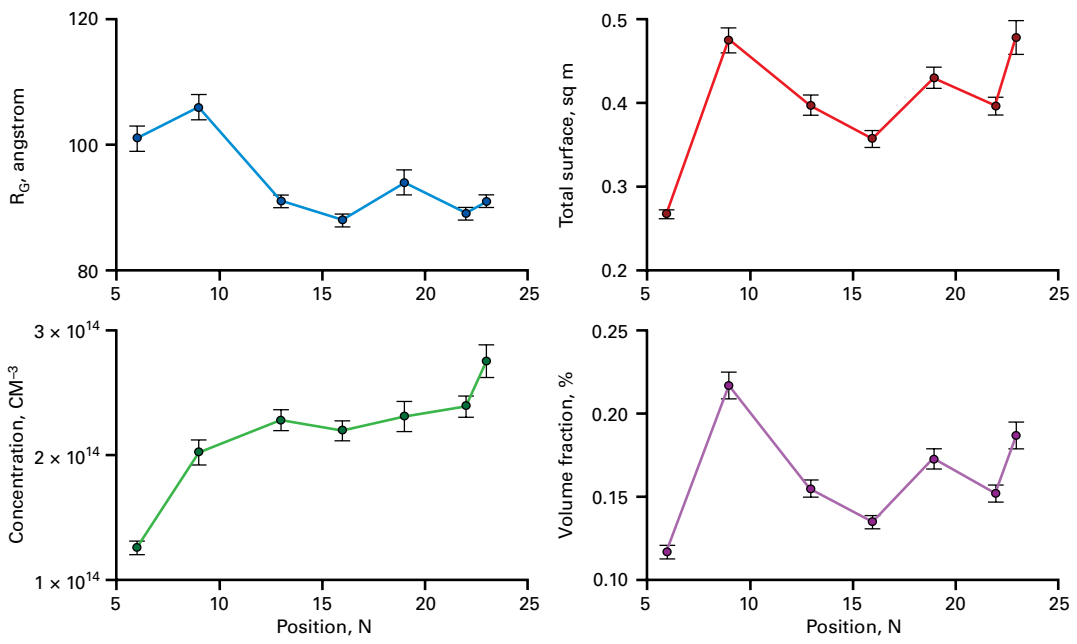
AISI 304 WELDED PLATE STRESS

Fig. 3



NiCrMoV COMPONENT MICROPHASE PARAMETER VARIATIONS

Fig. 4



pipe can be investigated at different depths. The neutron beam can also perform deformation tests in situ, enabling both tensile and compressive tests up to a certain maximum loading.

SANS technique allows characterizing materials in the nanoscale (0.001-0.1 μm), is nondestructive, and provides precise statistical information by averaging data across a macroscopic sample volume. The specimen can be investigated various times after more exercise or heat treatments, and the small absorption of neutrons, often allows the measurement of centimeter thick materials.

Thermal treatment due to welding produces growth of inclusions (precipitates). SANS obtains their characteristics (number and size distribution) by knowing their chemical nature (e.g., carbides, etc.). Once a sample is investigated from the original material, investigating other samples taken after the material has been exercised, including the welded part, can check for microstructural changes (nanodefects, voids, etc.).

Obtainable results

Fig. 2 represents hoop RS measured by neutron diffraction in a 2.25 Cr1Mo ferritic arc welded pipe before and after relaxation heat treatment (5-mm depth). The gap between the RS curves explains the resulting deviation trend between heat-treated and nonheat-treated samples.

The predictive model attempts to characterize the measured deviations between RS curves for different installation and operating conditions of the samples studied in the case of thermal-related failures. The gradient of the difference between RS curves, along with factors such as cycling fatigue caused by operating conditions, also factors into these deviations.

Fig. 3 represents the stress status in AISI 304 welded plate along the three main directions and plate thickness before and after a 620° C. thermal treatment.

Stress failure modes fall into two

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

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Refinery	E1340	$395.00 US	E1340C	$1,495.00 US
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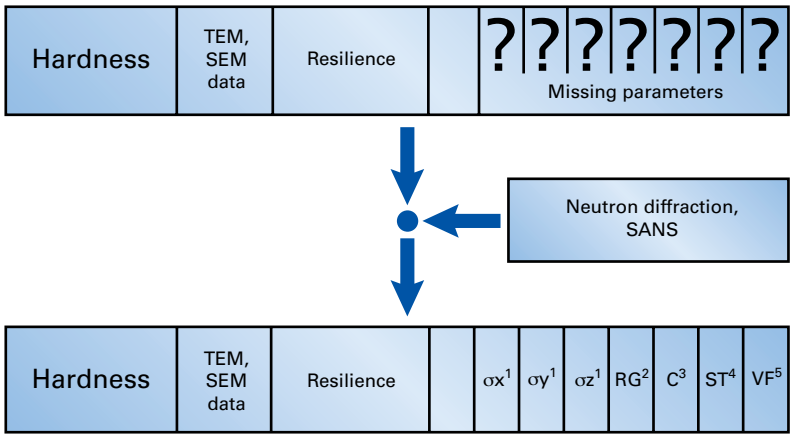
PARAMETERS FROM NEUTRON-BASED METHOD

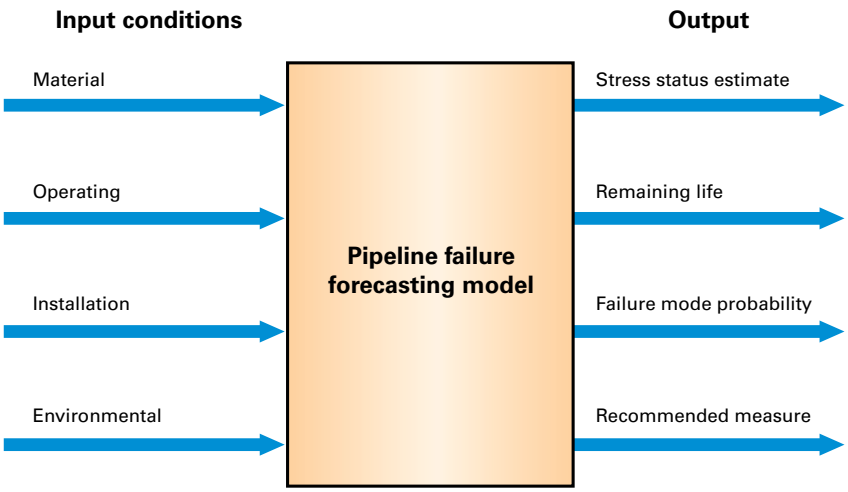
Fig. 5



Notes: [1]RS along main directions. [2]Precipitate gyration mean radius. [3]Precipitate concentration. [4]Unit-volume metal-precipitate interface area. [5]Precipitate volume fraction.

NEUTRON DIFFRACTION STRESS ASSESSMENT

Fig. 6



groups: thermal and mechanical. These categories, however, are not exclusive. In the case of welded pipes, for example, both thermal and mechanical-related stress exists, accelerating ageing. Any predictive failure model needs to account for the combined effects of thermal and mechanical-related failures, as well as their causes.

SANS provides much information on the nanostructure of a metal and its joints, and the results obtained help predict joint quality changes.[1,2]

Fig. 4 shows variations of microphase parameters obtained by SANS in a very thick NiCrMoV steel component (94% Fe). Analysis of precipitates' gyration mean radius, concentration, metal carbide interface area per unit volume, and volume fraction, can help determine the behavior of the exercised (exposed to thermal and mechanical stresses) material. These parameters represent the degradation level of materials, also relevant in determining the root causes of stress.

Thermal treatment during manufacturing for example—heating at high temperatures, especially for a relatively long time—partially dissolves the material's particles, saturating the solid solution. Cooling prompts growth of the precipitates from the saturated solution. The particles' growth caused by high temperature can induce a coarsening of microstructure and further growth of the precipitates. Evaluating the shape and size of such precipitates therefore can prove particularly useful in locating areas of maximum thermal alteration and evaluating the velocity of said alteration.

The most important problems related to a material's strength deal with welded metals, the fracture risk of which seems to be much higher than the base metal. Nonuniform mechanical stress and other aging factors (thermal treatment, fatigue, corrosion, etc.) create the higher risk of fracture in joints.

Current concepts of metal fracture, including welded joints, are based primarily on optical and electron microscopy data of surface structures or defects in thin slices. Research in fractography has focused on scanning electron microscopy to quantify features in the nonplanar fracture surface. The characteristics that unlock these quantitative data, however, are the true fracture surface areas.

Experimental procedures have advanced for obtaining the surface area (e.g., analysis of the resulting profiles related to the fracture surface). Fracture studies have also focused on the fractal properties of profiles and surfaces.

Fractal dimensions stemming from these analyses of observed nanoscale structures appear to be normally applicable to natural irregular nonplanar surfaces. Two main classes of fractal structures exist: aggregated clusters of small particles (volume fractals) and systems with irregular interfaces and grain boundaries (surface fractals). SANS measurements verify the fractal nature of structures and find their fractal dimensions.

Parameters usually adopted by the pipeline operator to ensure safe operations through the plant's life suffer from a lack of data. Outstanding mechanical properties of the materials depend strongly on precipitates morphology and applied heat treatment. Transmis-

sion electron microscopy serves as the standard means of studying the morphology, although this and other standard methods of materials science do not allow for characterizing the microstructure completely.

Precursory use of ND and SANS tools allows control of the micro and nanostructure determination of pipeline materials, enriching the available data set by supplying fundamental parameters. Fig. 5 shows the additional parameters that help understand and ultimately predict the degradation of materials, their possible fracture, and anticipated lifetime.

The proposed forecasting failure model will determine RS and remaining material life with relatively simple pattern matching techniques of actual pipeline data against the previously identified patterns. The two main sources of the model's data are design data and data obtained from the ND and SANS tests.

The model allows prediction of behavior of the considered material under different scenarios. If current mechanical stress conditions continue, for example, the material will suffer a particular defect; or the cycling fatigue process coupled with thermal-related RS can cause a material fracture if cycling conditions continue.

Characterizing the gap between stress status estimates and maximum allowable stress values for the material with different scenarios also allows determination of remaining life. Other important features of the proposed predictive model include identification of probable causal factors of failures and the ability either to eliminate such causal factors or mitigate the resulting problem.

Fig. 6 shows a schematic diagram of the proposed forecasting failure model for pipelines.

The proposed forecasting model consists of a relational database formed by catalogued material parameters obtained from ND and SANS from samples that represent, statistically, the population of pipelines on which the forecasting tool will be used. Extended parameters obtained from ND and SANS include σ_x, σ_y, σ_z, R_G, C, S_T, and V_F, which are cataloged along with conventional inspection TEM and SEM parameters and the operating, installation, and environmental conditions of both fresh and exercised (aged) pipe materials.

Studying and characterizing deviations between fresh and exercised samples yield a set of deviation patterns. Characterization includes recording and analysis of trend and inflexion points of the data curves to determine possible failure modes and remaining life.

The forecasting failure model considers material conditions, including material composition, measured wall thickness, corrosion level, presence and amount of welded joints; operating conditions, including presence and magnitude of applied forces, fluid pressure, historical accumulated stress (default value as a function of time), fluid properties, corrosion inhibitor chemicals, presence and magnitude of mechanical vibration; and installation conditions, including depth of burial, soil load, coating type, and cathodic protection, if any.

Environmental conditions considered include soil type, seismic level, rain, washouts, and maximum-minimum ambient temperature values. ✦

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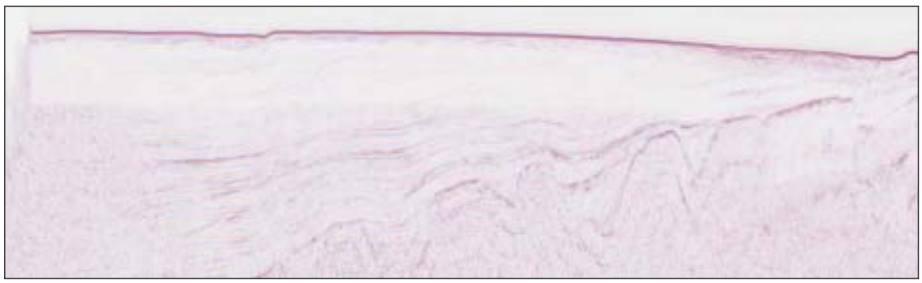
Equipment/Software/Literature



New seismic data acceleration software

A newly launched seismic data acceleration solution promises a multifold performance increase to reduce lengthy processing times and deliver faster results to make drilling decisions.

The company says its software solution harnesses the massively parallel processing capabilities of GPU accelerators to increase the efficiency of data centers and reduce total cost of IT ownership. The firm says this technique is designed for 2D and 3D land and marine data where a typical processing job can compute from several days to months and solves a bottleneck in the seismic processing industry today. The photo shows increased resolution available with the new software.

Migration is a commonly used seismic data processing method used to recover subsurface images of the earth's interior using surface-recorded data volumes obtained from seismic reflection surveys. This company's solution is designed to speed up the Kirchhoff prestack time migration method in seismic data processing. By accelerating the computation within this method, the company says it uncovers potential for increased resolution, faster turnaround, and better quality confidence while handling larger data sets of increasing complexity. By accelerating the computations involved in seismic migration, the firm notes that it uncovers the benefits of more dense packaging and improved economics in power and cooling.

Source: **Acceleware Corp.,** 1600 37th St. SW, Calgary, Alta. T3C 3P1.

New deepwater wellhead system

The new MS-800 full bore subsea wellhead system is designed for deepwater applications. With the capacity to withstand 8 million lb of load on the wellhead, the MS-800 is designed to help drillers reach deepwater targets in such regions as the US Gulf of Mexico and offshore Brazil. The new system increases the casing load capacity to 2 million lb for the first position casing hanger and the 16-in. casing hanger, while also increasing the pressure capacity for the 16-in. hanger to 10,000 from 6,500 psi.

Source: **VetcoGray,** 3010 Briarpark Ave., Suite 300, Houston, TX 77042.

Services/Suppliers

Paradigm,

Machnizh

Houston, has appointed Jorge Machnizh president and COO. He will relocate to London under the company's strategy of distributing executive leadership team members close to its global customer base. Machnizh succeeds John W. Gibson Jr., who remains CEO. He has more than 27 years of experience in the energy industry, beginning his career with the seismic division of Schlumberger and later serving as vice-president of operations for Halliburton's Landmark Graphics division. Prior to joining Paradigm, Machnizh served as president and COO of Input/Output's Imaging Systems Group. He has a BS in geology from the University of Southern California.

Paradigm offers solutions in seismic data processing and subsurface imaging, prospect interpretation and modeling, reservoir characterization, and well planning and drilling.

InterMoor Inc.,

Ruiz

Houston, has named Joao Carlos Ruiz de Oliveira engineering manager for InterMoor do Brasil. He had been senior engineer, special projects. Based in Rio de Janeiro, Ruiz will oversee project execution as well as organizing engineering and administrative activities. Prior to joining InterMoor in May 2007, he was a subsea engineer for Petrobras. He has a degree in mechanical engineering from Federal Fluminense University in Rio de Janeiro.

InterMoor, an Acteon company headquartered in Houston, is a leading supplier of mooring technology providing innovative solutions for rig moves and mooring services, including engineering and design, fabrication, and subsea installation.

EPiC Energy Resources Inc.,

The Woodlands, has acquired Epic Integrated Solutions LLC (no prior affiliation to EpiC Energy Resources), Houston, in a stock and cash transaction valued at $4.3 million.

EPiC Energy Resources provides energy engineering and consulting services along with acquiring, developing, and optimizing energy assets. Epic Integrated Solutions provides the oil and gas industry with specialized training, operations documentation, and data management services for the start-up and operation of production facilities.

Tetra Technologies Inc.,

The Woodlands, Tex., has appointed Philip N. Longorio senior vice-president, responsible for managing Tetra's global fluids and production testing business. He worked for Halliburton for more than 28 years in both operations and sales positions, ending as the vice-president of Sperry-Sun Drilling Services. Thereafter he was president and CEO of WellDynamics BV, a joint venture of Halliburton and Shell Technology Ventures to market intelligent completion technology.

Tetra is an oil and gas services company, including an integrated calcium chloride and brominated products manufacturing operation that supplies feedstocks to energy markets, as well as other markets.

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Condensate coming into its own

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This report explains how the protean nature of condensate allows it to be used in a wide range of sectors: as a refinery slate component; in specialized distillation towers called condensate splitters; in direct feed to ethylene crackers; in gasoline blending and as a substitute for gas in turbine power generation. It can be defined as a base material, a blending component, a feedstock or a boiler feed.

See website for Table of Contents and sample tables, charts and graphs.

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Imports of crude and products

	Districts 1-4		District 5		Total US		
	2-29 2008	2-22 2008	2-29 2008	2-22 2008	2-29 2008	2-22 2008	*3-2 2007
	1,000 b/d						
Total motor gasoline	745	1,281	55	73	800	1,354	788
Mo. gas. blending comp.	455	820	5	23	460	843	569
Distillate	186	194	—	—	186	194	432
Residual	257	181	45	—	302	181	332
Jet fuel-kerosine	87	79	—	53	87	132	188
Propane-propylene	121	254	9	27	130	281	109
Other	1,119	526	58	33	1,177	559	320
Total products	**2,970**	**3,335**	**172**	**209**	**3,142**	**3,544**	**2,738**
Total crude	**8,520**	**8,938**	**917**	**1,020**	**9,437**	**9,958**	**8,872**
Total imports	**11,490**	**12,273**	**1,089**	**1,229**	**12,579**	**13,502**	**11,610**

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

Purvin & Gertz LNG netbacks—Mar. 7, 2008

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	7.76	6.23	7.59	6.11	6.88	7.50
Everett	8.88	6.49	8.45	6.55	7.14	9.26
Isle of Grain	8.64	6.14	8.23	6.02	6.79	7.82
Lake Charles	6.91	4.73	6.65	4.92	5.25	7.64
Sodegaura	6.61	8.42	6.63	8.43	7.68	5.64
Zeebrugge	7.84	5.73	7.21	5.69	6.21	7.21

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	14,606	66,191	34,388	8,528	41,397	14,326	3,847
PADD 2	61,887	57,067	18,496	8,200	32,451	1,418	8,553
PADD 3	162,779	71,623	35,211	12,967	28,043	15,058	16,121
PADD 4	12,925	7,045	2,261	547	2,937	384	[1]928
PADD 5	53,252	32,350	26,137	9,100	12,797	5,322	—
Feb. 29, 2008	**305,449**	**234,276**	**116,493**	**39,342**	**117,625**	**36,508**	**29,449**
Feb. 22, 2008	**308,505**	**232,619**	**116,074**	**40,083**	**119,952**	**36,672**	**31,583**
Mar. 2, 2007[2]	**324,156**	**216,425**	**98,072**	**40,236**	**123,172**	**35,625**	**28,747**

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

Refinery report—Feb. 29, 2008

District	Refinery operations		Refinery output				
	Gross inputs	Crude oil inputs	Total motor gasoline	Jet fuel, kerosine	Fuel oils		Propane-propylene
					Distillate	Residual	
	1,000 b/d						
PADD 1	1,465	1,482	1,643	93	492	117	61
PADD 2	3,235	3,201	2,523	204	935	68	217
PADD 3	7,047	7,002	3,076	677	1,814	285	706
PADD 4	567	563	307	22	159	14	[1]143
PADD 5	2,665	2,620	1,493	396	605	146	—
Feb. 29, 2008	**14,979**	**14,868**	**9,042**	**1,392**	**4,005**	**630**	**1,127**
Feb. 22, 2008	**14,765**	**14,624**	**8,778**	**1,496**	**3,888**	**628**	**1,061**
Mar. 2, 2007[2]	**14,935**	**14,757**	**8,590**	**1,424**	**4,024**	**697**	**1,053**
	17,436 operable capacity		**85.9% 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

	*3-7-08	*3-9-07	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	112.15	76.96	35.19	45.7
Brent crude	102.97	60.59	42.38	69.9
Crack spread	9.17	16.36	–7.19	–43.9
FUTURES MARKET PRICES				
One month				
Product value	115.19	76.76	38.43	50.1
Light sweet crude	103.42	60.85	42.57	70.0
Crack spread	11.77	15.91	–4.14	–26.0
Six month				
Product value	113.31	77.42	35.89	46.4
Light sweet crude	100.63	65.02	35.61	54.8
Crack spread	12.68	12.39	0.29	2.3

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

OGJ GASOLINE PRICES

	Price ex tax 3-5-08	Pump price* 3-5-08	Pump price 3-7-07
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	286.4	326.1	244.4
Baltimore	273.7	315.6	243.3
Boston	270.4	312.3	241.1
Buffalo	274.5	334.6	260.4
Miami	289.0	339.3	261.0
Newark	265.3	298.2	236.2
New York	254.0	314.1	251.4
Norfolk	274.5	312.1	234.8
Philadelphia	269.3	320.0	259.9
Pittsburgh	267.4	318.1	247.0
Wash., DC	283.0	321.4	247.6
PAD I avg.	273.4	319.2	247.9
Chicago	291.0	341.9	272.0
Cleveland	258.9	305.3	244.7
Des Moines	268.3	308.7	238.4
Detroit	258.5	307.7	249.0
Indianapolis	267.7	312.7	248.3
Kansas City	268.0	304.0	237.9
Louisville	288.5	325.4	244.7
Memphis	267.9	307.7	235.1
Milwaukee	254.2	305.5	248.7
Minn.-St. Paul	261.0	301.4	246.1
Oklahoma City	268.5	303.9	236.2
Omaha	265.5	311.9	249.7
St. Louis	254.4	290.4	238.9
Tulsa	264.9	300.3	234.1
Wichita	256.2	299.6	239.1
PAD II avg.	266.2	308.4	244.2
Albuquerque	271.5	307.9	240.2
Birmingham	278.0	316.7	235.3
Dallas-Fort Worth	272.2	310.6	237.0
Houston	271.6	310.0	234.0
Little Rock	273.0	313.2	236.6
New Orleans	271.7	310.1	238.7
San Antonio	265.7	304.1	228.5
PAD III avg.	272.0	310.4	235.8
Cheyenne	259.9	392.3	224.7
Denver	266.8	307.2	238.8
Salt Lake City	266.9	309.8	228.3
PAD IV avg.	264.5	303.1	230.6
Los Angeles	284.4	342.9	298.5
Phoenix	263.1	300.5	252.3
Portland	294.2	337.5	274.6
San Diego	295.8	354.3	304.0
San Francisco	309.3	367.8	323.0
Seattle	294.4	346.8	277.3
PAD V avg.	290.2	341.6	288.3
Week's avg.	**272.4**	**315.9**	**249.1**
Feb. avg.	**259.5**	**303.1**	**228.0**
Jan. avg.	**260.9**	**304.5**	**225.3**
2008 to date	**261.5**	**305.1**	—
2007 to date	**185.2**	**228.8**	—

*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

	2-29-08 ¢/gal		2-29-08 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	247.88	New York Harbor	280.63
Gulf Coast	254.93	Gulf Coast	277.70
Los Angeles	273.71	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	241.35	ARA	290.82
Singapore	266.26	Singapore	281.26
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	247.00	New York Harbor	174.71
Gulf Coast	257.21	Gulf Coast	172.33
Los Angeles	277.71	Los Angeles	212.96
		ARA	190.10
		Singapore	185.13

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

BAKER HUGHES RIG COUNT

	3-7-08	3-9-07
Alabama	3	3
Alaska	9	13
Arkansas	39	43
California	35	31
Land	34	29
Offshore	1	2
Colorado	115	99
Florida	0	1
Illinois	0	0
Indiana	2	1
Kansas	9	14
Kentucky	11	11
Louisiana	155	198
N. Land	56	60
S. Inland waters	18	24
S. Land	28	37
Offshore	53	77
Maryland	0	0
Michigan	1	2
Mississippi	11	18
Montana	11	20
Nebraska	1	0
New Mexico	71	77
New York	3	8
North Dakota	59	30
Ohio	13	13
Oklahoma	201	187
Pennsylvania	20	15
South Dakota	2	1
Texas	884	813
Offshore	7	9
Inland waters	4	1
Dist. 1	24	25
Dist. 2	34	33
Dist. 3	55	51
Dist. 4	95	93
Dist. 5	182	159
Dist. 6	122	124
Dist. 7B	37	45
Dist. 7C	49	55
Dist. 8	129	105
Dist. 8A	19	25
Dist. 9	42	37
Dist. 10	85	51
Utah	41	44
West Virginia	24	29
Wyoming	71	77
Others—NV-4; TN-4; VA-3	11	9
Total US	**1,802**	**1,757**
Total Canada	**623**	**553**
Grand total	**2,425**	**2,310**
Oil rigs	337	287
Gas rigs	1,456	1,465
Total offshore	61	89
Total cum. avg. YTD	**1,762**	**1,731**

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	3-7-08 Percent footage*	Rig count	3-9-07 Percent footage*
0-2,500	83	3.6	70	5.7
2,501-5,000	108	53.7	110	61.8
5,001-7,500	189	21.6	216	20.3
7,501-10,000	451	2.8	418	3.5
10,001-12,500	424	4.9	415	4.0
12,501-15,000	319	0.3	273	0.7
15,001-17,500	95	—	119	1.6
17,501-20,000	79	—	75	—
20,001-over	39	—	34	—
Total	**1,787**	**7.6**	**1,730**	**8.7**
INLAND	35		42	
LAND	1,696		1,623	
OFFSHORE	56		65	

*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]3-7-08 1,000 b/d	[2]3-9-07
(Crude oil and lease condensate)		
Alabama	15	19
Alaska	693	750
California	652	666
Colorado	44	38
Florida	5	6
Illinois	26	25
Kansas	97	96
Louisiana	1,325	1,312
Michigan	15	16
Mississippi	50	58
Montana	92	93
New Mexico	163	162
North Dakota	114	115
Oklahoma	170	172
Texas	1,339	1,335
Utah	44	52
Wyoming	143	145
All others	64	69
Total	**5,051**	**5,129**

[1]OGJ estimate. [2]Revised.

Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

US CRUDE PRICES

	3-7-08 $/bbl*
Alaska-North Slope 27°	80.63
South Louisiana Sweet	108.25
California-Kern River 13°	92.55
Lost Hills 30°	100.80
Southwest Wyoming Sweet	96.65
East Texas Sweet	101.25
West Texas Sour 34°	94.25
West Texas Intermediate	101.75
Oklahoma Sweet	101.75
Texas Upper Gulf Coast	98.25
Michigan Sour	94.75
Kansas Common	100.75
North Dakota Sweet	95.25

*Current major refiner's posted prices except North Slope lags 2 months. 40° gravity crude unless differing gravity is shown.

Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

WORLD CRUDE PRICES

	2-29-08 $/bbl[1]
United Kingdom-Brent 38°	99.69
Russia-Urals 32°	94.91
Saudi Light 34°	95.07
Dubai Fateh 32°	92.41
Algeria Saharan 44°	100.14
Nigeria-Bonny Light 37°	101.40
Indonesia-Minas 34°	98.56
Venezuela-Tia Juana Light 31°	94.92
Mexico-Isthmus 33°	94.81
OPEC basket	96.76
Total OPEC[2]	95.40
Total non-OPEC[2]	94.85
Total world[2]	95.15
US imports[3]	91.74

[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]

	2-29-08	2-22-08 bcf	2-29-07	Change, %
Producing region	535	571	587	–8.9
Consuming region east	760	852	837	–9.2
Consuming region west	189	196	229	–17.5
Total US	**1,484**	**1,619**	**1,653**	**–10.2**
	Dec. 07	**Dec. 06**	**Change, %**	
Total US[2]	**2,879**	**3,070**	**–6.2**	

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

Statistics

INTERNATIONAL RIG COUNT

Region	Feb. 2008 Land	Feb. 2008 Off.	Feb. 2008 Total	Feb. 07 Total
WESTERN HEMISPHERE				
Argentina	85	—	85	87
Bolivia	2	—	2	2
Brazil	21	25	46	41
Canada	619	1	620	635
Chile	1	—	1	1
Colombia	42	—	42	28
Ecuador	7	—	7	12
Mexico	65	29	94	95
Peru	6	—	6	8
Trinidad	1	4	5	8
United States	1,709	56	1,765	1,736
Venezuela	67	16	83	76
Other	2	—	2	2
Subtotal	**2,627**	**131**	**2,758**	**2,731**
ASIA-PACIFIC				
Australia	11	13	24	18
Brunei	1	2	3	2
China-offshore	—	22	22	18
India	54	31	85	85
Indonesia	43	24	67	48
Japan	1	—	1	1
Malaysia	—	10	10	16
Myanmar	7	1	8	11
New Zealand	4	2	6	5
Papua New Guinea	3	—	3	3
Philippines	—	—	—	1
Taiwan	—	—	—	—
Thailand	2	7	9	11
Vietnam	—	6	6	7
Other	1	3	4	5
Subtotal	**127**	**121**	**248**	**231**
AFRICA				
Algeria	22	—	22	24
Angola	—	6	6	5
Congo	1	1	2	4
Gabon	1	1	2	3
Kenya	—	—	—	—
Libya	13	1	14	13
Nigeria	2	4	6	6
South Africa	—	—	—	—
Tunisia	2	2	4	3
Other	1	1	2	6
Subtotal	**42**	**16**	**58**	**64**
MIDDLE EAST				
Abu Dhabi	9	2	11	12
Dubai	1	—	1	1
Egypt	43	8	51	39
Iran	—	—	—	—
Iraq	—	—	—	—
Jordan	—	—	—	1
Kuwait	11	—	11	13
Oman	53	—	53	44
Pakistan	19	—	19	17
Qatar	2	9	11	11
Saudi Arabia	69	10	79	74
Sudan	—	—	—	—
Syria	21	—	21	26
Yemen	14	—	14	13
Other	1	—	1	1
Subtotal	**243**	**29**	**272**	**252**
EUROPE				
Croatia	1	—	1	1
Denmark	—	2	2	2
France	—	—	—	—
Germany	6	1	7	4
Hungary	3	—	3	3
Italy	5	—	5	4
Netherlands	—	3	3	6
Norway	—	11	11	17
Poland	2	—	2	2
Romania	17	3	20	2
Turkey	5	—	5	4
UK	1	15	16	25
Other	6	—	6	4
Subtotal	**46**	**35**	**81**	**74**
Total	**3,085**	**332**	**3,417**	**3,352**

Definitions, see OGJ Sept. 18, 2006, p. 42.
Source: Baker Hughes Inc.
Data available in OGJ Online Research Center.

OIL IMPORT FREIGHT COSTS*

Source	Discharge	Cargo	Cargo size, 1,000 bbl	Freight (Spot rate) worldscale	$/bbl
Caribbean	New York	Dist.	200	202	1.72
Caribbean	Houston	Resid.	380	139	1.33
Caribbean	Houston	Resid.	500	157	1.49
N. Europe	New York	Dist.	200	250	3.42
N. Europe	Houston	Crude	400	169	3.42
W. Africa	Houston	Crude	910	130	2.88
Persian Gulf	Houston	Crude	1,900	92	3.79
W. Africa	N. Europe	Crude	910	129	2.12
Persian Gulf	N. Europe	Crude	1,900	95	2.84
Persian Gulf	Japan	Crude	1,750	103	2.50

*February 2008 average.
Source: Drewry Shipping Consultants Ltd. Data available in OGJ Online Research Center.

WATERBORNE ENERGY INC. US LNG IMPORTS

Country	Mar. 2008	Feb. 2008	Mar. 2007	Change from a year ago, %
	MMcf			
Algeria	—	—	8,670	—
Egypt	—	—	14,760	—
Equatorial Guinea	—	—	—	—
Nigeria	—	—	9,070	—
Norway	2,980	3,030	—	—
Qatar	—	—	—	—
Trinidad and Tobago	25,710	22,050	54,330	–52.7
Total	**28,690**	**25,080**	**86,830**	**–67.0**

Source: Waterborne Energy Inc.
Data available in OGJ Online Research Center.

PROPANE PRICES

	Jan. 2008	Feb. 2008	Jan. 2007	Feb. 2007
	¢/gal			
Mont Belvieu	150.58	142.52	89.35	97.55
Conway	146.37	148.92	86.96	96.77
Northwest Europe	171.81	159.06	92.58	100.83

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

MUSE, STANCIL & CO. REFINING MARGINS

	US Gulf Coast	US East Coast	US Mid-west	US West Coast	North-west Europe	South-east Asia
	$/bbl					
Feb. 2008						
Product revenues	108.75	102.39	101.87	110.94	104.95	102.06
Feedstock costs	–95.43	–97.42	–90.54	–87.96	–94.22	–97.99
Gross margin	13.32	4.97	11.33	22.98	10.73	4.07
Fixed costs	–2.08	–2.40	–2.34	–2.73	–2.34	–1.82
Variable costs	–2.42	–1.55	–2.13	–3.65	–3.31	–1.02
Cash operating margin	**8.82**	**1.02**	**6.86**	**16.60**	**5.08**	**1.23**
Jan. 2008	5.87	0.82	8.39	10.04	2.09	2.64
YTD avg.	7.35	0.92	7.63	13.32	3.59	1.94
2007 avg.	12.36	6.36	18.60	20.89	5.75	2.26
2006 avg.	12.39	6.13	14.91	23.69	5.88	1.06
2005 avg.	12.53	6.98	12.31	20.55	5.51	1.52

Source: Muse, Stancil & Co. See OGJ, Jan. 15, 2001, p. 46
Data available in OGJ Online Research Center.

MUSE, STANCIL & CO. GASOLINE MARKETING MARGINS

Jan. 2008	Chicago*	Houston	Los Angeles	New York
	¢/gal			
Retail price	314.86	296.96	323.13	321.32
Taxes	57.81	38.40	61.23	52.32
Wholesale price	239.59	242.61	245.99	249.94
Spot price	222.88	230.54	236.14	230.15
Retail margin	17.41	54.95	15.91	19.06
Wholesale margin	16.71	12.07	9.85	19.79
Gross marketing margin	**34.12**	**22.02**	**25.76**	**38.85**
Dec. 2007	29.30	30.97	25.58	40.73
YTD avg.	34.12	22.02	25.76	38.85
2007 avg.	26.96	23.12	19.05	31.10
2006 avg.	19.74	20.34	18.03	27.90
2005 avg.	19.77	16.26	20.39	27.13

*The wholesale price shown for Chicago is the RFG price utilized for the wholesale margin. The Chicago retail margin includes a weighted average of RFG and conventional wholesale purchases.
Source: Muse, Stancil & Co. See OGJ, Oct. 15, 2001, p. 46.
Data available in OGJ Online Research Center.
Note: Margins include ethanol blending in all markets.

MUSE, STANCIL & CO. ETHYLENE MARGINS

	Ethane	Propane	Naphtha
	¢/lb ethylene		
Feb. 2008			
Product revenues	69.85	113.70	135.86
Feedstock costs	–39.19	–81.13	–126.14
Gross margin	30.66	32.57	9.72
Fixed costs	–5.38	–6.36	–7.19
Variable costs	–5.80	–6.87	–9.27
Cash operating margin	**19.48**	**19.34**	**–6.74**
Jan. 2008	14.32	14.86	–6.27
YTD avg.	16.90	17.10	–6.51
2007 avg.	14.41	14.14	–7.42
2006 avg.	19.53	22.44	1.34
2005 avg.	14.43	20.68	1.28

Source: Muse, Stancil & Co. See OGJ, Sept. 16, 2002, p. 46.
Data available in OGJ Online Research Center.

MUSE, STANCIL & CO. US GAS PROCESSING MARGINS

Feb. 2008	Gulf Coast	Mid-continent
	$/Mcf	
Gross revenue		
Gas	8.04	7.06
Liquids	1.52	4.24
Gas purchase cost	8.95	9.48
Operating costs	0.07	0.15
Cash operating margin	**0.54**	**1.67**
Jan. 2008	0.71	2.05
YTD avg.	0.63	1.86
2007 avg.	0.44	1.48
2006 avg.	0.26	0.97
2005 avg.	–0.06	0.25
Breakeven producer payment % of liquids	62%	60%

Source: Muse, Stancil & Co. See OGJ, May 21, 2001, p. 54.
Data available in OGJ Online Research Center.

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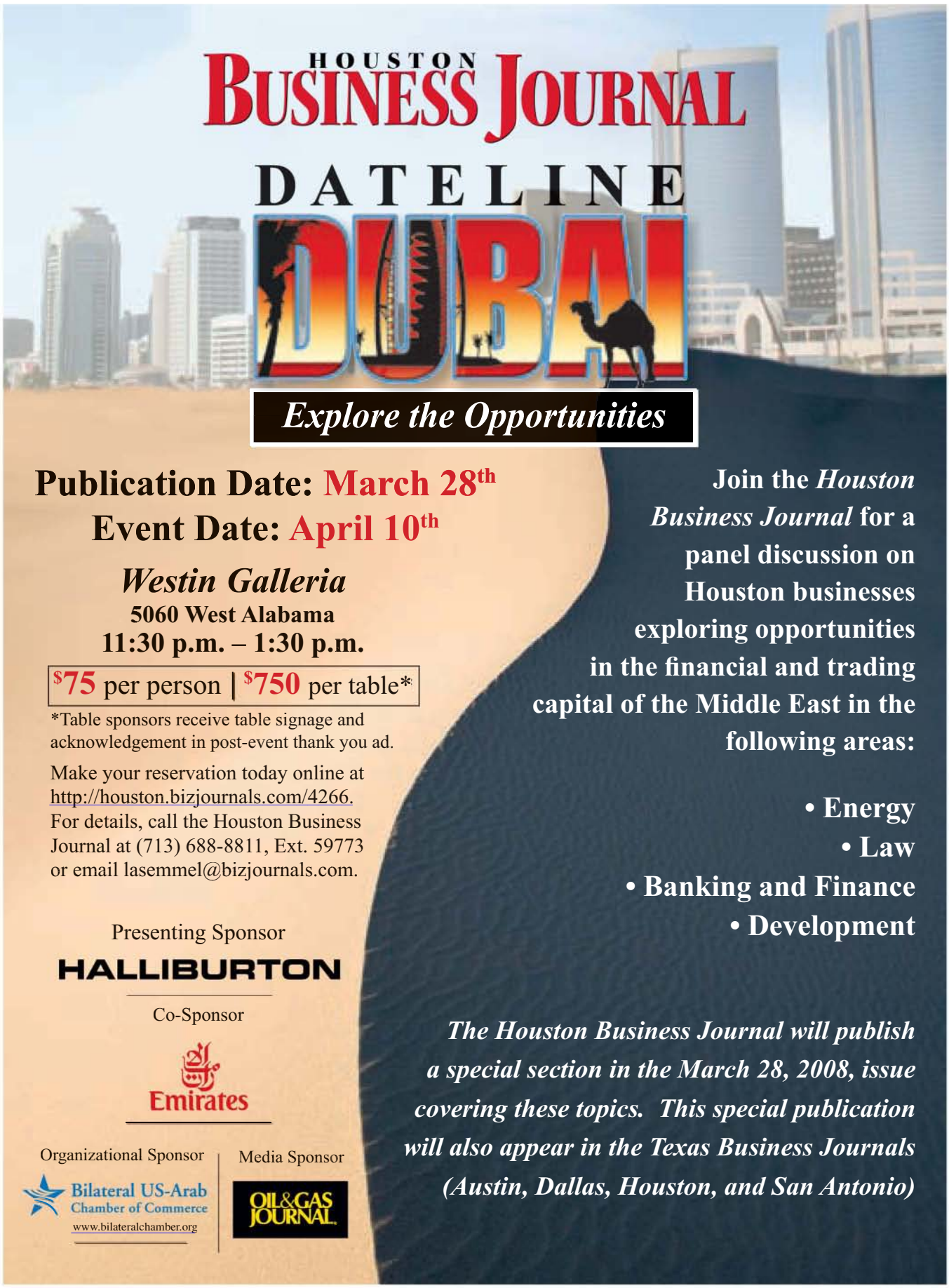

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OPEC blames rising crude oil prices on US 'mismanagement'

The Organization of Petroleum Exporting Countries drew first blood in a spat with US President George W. Bush.

After a Mar. 4 meeting with King Abdullah of Jordan in Washington, DC, Bush reprised for reporters his January appeal for more oil from OPEC (OGJ, Jan. 28, 2008, p. 72).

"I think it's a mistake to have your biggest customer's economy slow down or your biggest customers' economics slowing down as a result of high energy prices," Bush said the day before an OPEC meeting.

The Editor's Perspective

by Bob Tippee, Editor

After OPEC met, leaving production targets unchanged, President Chakib Khelil blamed high oil prices on "mismanagement of the US economy."

Khelil, Algeria's energy minister, said: "If the prices are high, definitely they are not due to a lack of crude. They are due to what's happening in the US."

While OPEC may be exercising more caution than is necessary, Khelil is right.

Low inventories cited by the Bush administration to demonstrate a need for more OPEC oil don't explain crude prices above $100/bbl. They're not that low.

Demand growth is slowing. Major production projects will come on stream this year. Prices should be falling.

OPEC knows this and legitimately worries about a second-quarter demand slump that might be deeper than usual.

Crude prices are high and rising not because a weakening market has too little supply but because oil, like other commodities, is serving as a haven for cash frightened away from other investments.

Much of that phenomenon does reflect US mismanagement of its economy.

The housing credit fiasco shouldn't have happened. The US shouldn't be aggravating food-price increases by burning corn-based ethanol for fuel. It should worry about runaway federal spending and the weakening dollar. It should allow oil and gas leasing of locked-up federal land.

And Bush should quit spouting impossible dreams that would be economically ruinous to pursue.

"America has got to change its habits," he told a renewable-energy conference Mar. 5. "We've got to get off oil."

He wants more oil now but no oil later. No wonder markets are shaky. No wonder OPEC's getting testy.

(Online Mar. 7, 2008; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Fundamentals don't support $105 oil

An unexpected drop in US crude inventories made front-month crude jump $5 to a record closing of $104.52/bbl Mar. 5 on the New York Mercantile Exchange, although many of the industry's biggest participants and closest observers reported no new changes in either supply or demand to justify that fly-up.

Crude prices climbed to new heights in the next trading session, driven not by the ebb or flow of oil but by the flow of money from pension and hedge funds and speculators into energy commodities. The market hit a high of $106.54/bbl Mar. 7 before closing at $105.15/bbl, down 32¢ for the day yet up $3.21/bbl for the week, after the Labor Department reported 63,000 fewer US jobs during February, the biggest drop in 5 years.

The US dollar dropped to a new low against the euro that same day. "The weak dollar should make for a soft landing of demand erosion in non-dollar countries," said Olivier Jakob at Petromatrix, Zug, Switzerland, "but it will not create a demand booster. With record high crude oil and record high gas oil crack as well as high diesel premium, driving in Europe is not getting cheaper."

ExxonMobil Corp. Chief Executive Officer Rex Tillerson said the weak dollar, geopolitical uncertainties, and speculation were equally responsible for the run up in energy prices. Ministers of the Organization of Petroleum Exporting Countries cited essentially the same market forces Mar. 5 in voting to maintain current production levels. They said the deepening credit crisis in financial markets and a potential economic slowdown in the US economy make it likely that world demand for oil will decline in the second quarter.

Jakob said, "OPEC has proven again that the days when it was a market maker are definitely over. The oil market is about financial flows, not oil flows. The only way for OPEC to regain its previous status would be to wake up today's world and start using futures to hedge its production."

US inventories

The Energy Information Administration said crude inventories fell 3.1 million bbl to 305.4 million bbl in the week ended Feb. 29, vs. Wall Street expectations of a 2.1 million bbl build. US gasoline stocks escalated 1.7 million bbl to 234.3 million bbl in the same period, outstripping financial analysts' consensus of a 500,000 bbl gain. Distillate fuel inventories for the same week decreased by 2.4 million bbl to 117.6 million bbl, vs. consensus of a drop of 1.9 million bbl.

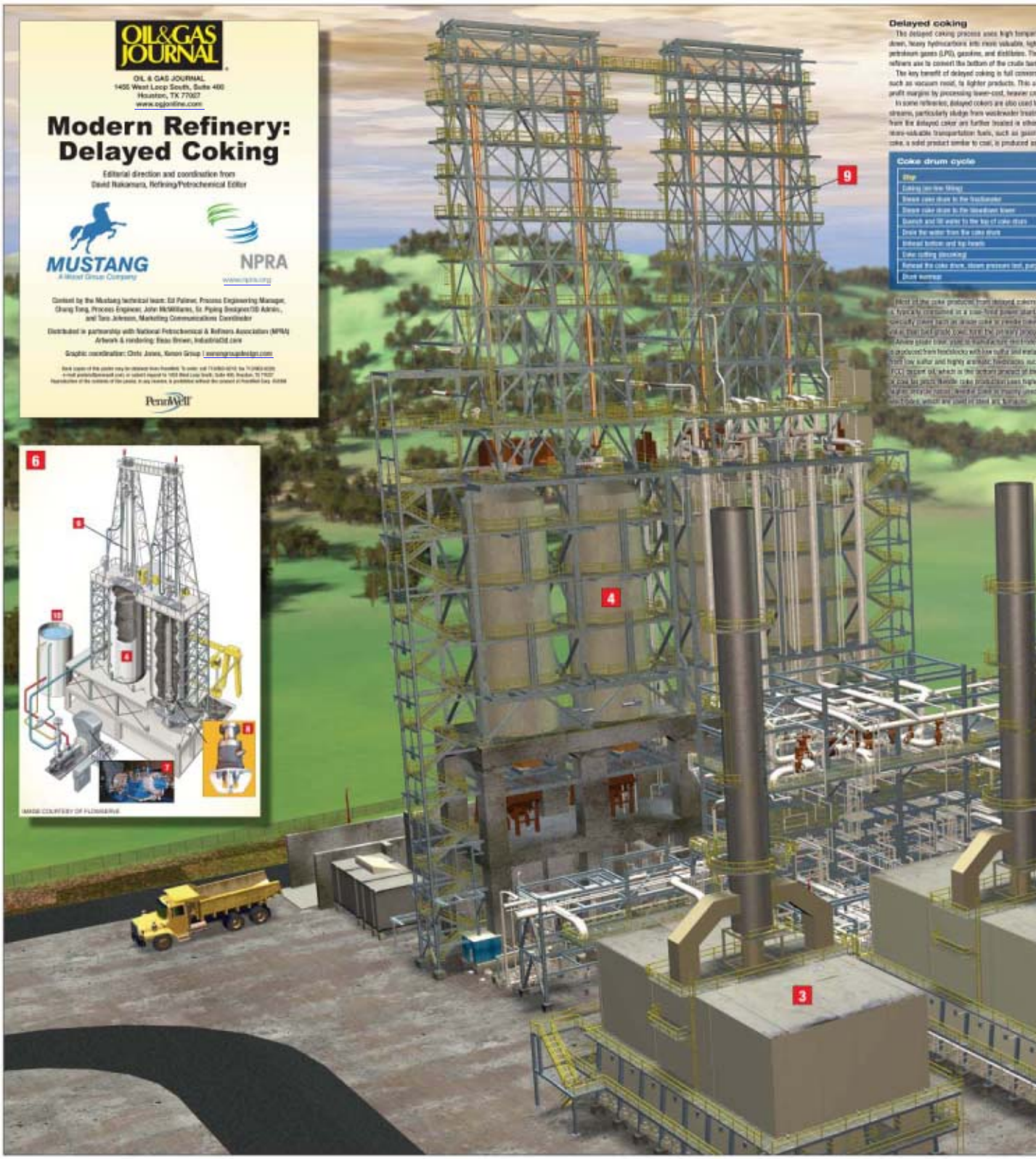
Adam Sieminski, Deutsche Bank's chief energy economist in New York, said, "Price elasticity of demand is finally showing up in the data." He said, "The real price of gasoline in the US is approaching the peak last seen in March 1980. Along with higher natural gas prices, rising electricity bills, and soaring expenditures for food, gasoline use in the US is starting to feel the pressure of pinched consumer spending."

Jakob said, "The fundamentals are still miles away from providing a clear justification for the current price level." He noted oil imports into the US "were suffering from fog delays" during the reported period and that 2.4 million bbl of the 3.1 million bbl crude draw occurred in the isolated Petroleum Administration for Defense District (PADD) 5, including the West Coast, Alaska, and Hawaii, "which in normal days would be discounted."

Jakob said, "The argument used to be that oil prices will rise until a top is defined by demand destruction. The [EIA] statistics are now showing US demand for the 4-week average down 1.1 million b/d from last year. Emerging countries running on state subsidies can still have some growth, but it will not translate in much oil demand growth on a worldwide basis. Given some of the fall in US oil demand is coming more from the industrial sector (fuel and 'other' oils), the demand for the main clean products (middle distillates, kerosine, gasoline) is still down 400,000 b/d for the 4-week yearly comparison."

Furthermore, Jakob said, "The dollar might be weak, but buying oil for the dollar trade is getting so amplified that even on a dollar-adjusted basis, oil is [at a] record high, which is of no relief to the nondollar consumer. WTI has gained 21% in 1 month and newcomers on the long side [of the crude futures market] need to believe that further gains are possible. Paradoxically, it is the fact that there is no compelling fundamental story that is making a further rise possible, as then $105/bbl is just a number that could as well be $120/bbl."

(Online Mar. 10, 2008; author's e-mail: samf@ogjonline.com)



Process description. Heavy oil feeds such as vacuum resid or atmospheric reduced crude are preheated in heat exchangers 1 with coker gas oils and then fed to the bottom section of the coker fractionator 2. Fresh feed combines with recycle, which is net liquid from the fractionator wash section above the feed inlet, and is routed to the coker heaters 3 with the coker charge pumps.

In the coker heater, the combined feed is heated to 920° F. or more to allow the coking reaction to occur in the coke drums. High-pressure steam, steam condensate, or boiler feed water is injected into heater coils at various locations to increase the velocity through the tubes and therefore minimize the amount of coke depositing on the heater tubes.

Effluent from the coker heater accumulates in insulated vessels called coke drums 4. The drums allow sufficient time (delayed) to thermally crack the feed into lighter gases, naphtha, distillates, gas oil, and coke. The coking cycle can be as short as 10 hr in a fuel-grade coker operation, which is built to maximize throughput, or more than 24 hr (see attached table).

A lower coke drum operating pressure and less recycle will result in more liquid and less coke produced. A modern delayed coker that maximizes liquid yields typically has a coker drum top operating pressure of about 15 psig and a recycle-to-feed ratio of 5% or less. Needle coker production, however, usually demands a high pressure (about 100 psig) and a high recycle-to-feed ratio (about 1) to achieve the desired needle coke properties.

A vapor stream of about 809° F. from the coke drum is routed to a fractionator 2, where it is separated into light gases, unstabilized gasoline, distillate, heavy coker gas oil, and a recycle stream. The coker fractionator off gas is compressed in a wet-gas compressor, which increases the pressure of the gas up to 200 psi. This stream then goes to a gas plant 5 along with the unstabilized gasoline, where it is further separated into dry gas, LPG, and stabilized gasoline.

The coker gas plant is similar to an FCC unit's gas plant and usually consists of an absorber/stripper/debutanizer. Dryer coker dry gas from the gas plant is sometimes sent to remove hydrogen sulfide before it feeds the refinery's fuel gas system.

The total coker LPG is treated with amine and caustic to remove hydrogen sulfide and mercaptan sulfur to make it suitable for use or as feedstock in other process units such as alkylation. The gasoline, distillate, and heavy gas oil from the delayed coker are typically hydrotreated before further processing in other refinery units.

Drum cycle. Coke drums are typically installed in pairs, with one coker heater for every two coke drums. The feed stream switches between these two drums. While one drum is filling with heater effluent, the other one is stripped with steam, quenched with water, drained, decoked, and warmed up for the next cycle.

The table summarizes the steps and approximately how much time each step takes in a typical coke drum cycle for fuel-grade coke operation.

The full coke drum is first purged with steam, which first flows to the fractionator and then the blowdown drum, to strip hydrocarbons from the coke. After the coke drum is steamed out, water is gradually introduced into the coke drum to cool the drum and coke.

Steam produced due to vaporizing the quench water is sent to the blowdown drum for condensation and to recover water and heavy hydrocarbons. The quench water flow rate then increases until the coke drum is filled with water. This water is subsequently drained from the coke drum and the top and bottom heads of the drum are opened.

Because of safety concerns, automatic unheading devices are commonly used. The coke in the drum is cut and removed with high-pressure water. The empty drum is then closed, and purged and pressure tested with steam. Vapors from the coke drum in operation are used to heat the off-line, empty coke drum.

Hydrocarbons condensed during the drum-heating step are drained to the blowdown drum or fractionator. When the drum is heated sufficiently, it is ready to receive effluent from the coker heater and start the coking cycle.

Decoking system. A decoking system 5 typically consists of:

- A cutting water (jet) pump 1
- Coke-cutting equipment, which includes a cutting tool 2, drill stem 3, drilling water hose, decoking control valve, and enclosed operator shelter.
- Decoking water tank 4.

High-pressure water cuts the coke out of the drum. The cutting water pump, which is a multi-stage centrifugal pump, takes suction from the decoking water tank and delivers the high pressure water through a hose to the rotary joint. The rotary joint uses an hydraulic or electric motor to rotate the drill stem.

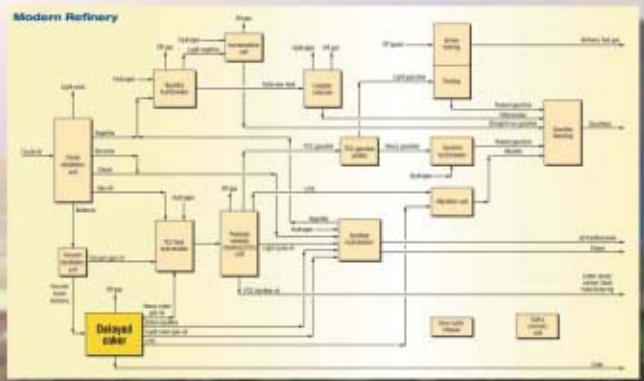
The discharge pressure of the cutting water pump varies according to the size of coke drum and type of coke produced. For large-diameter coke drums, the discharge pressure can be more than 4,000 psig.

A cutting tool, equipped with either downward-oriented, pilot hole cutting nozzles or side-oriented cutting nozzles, is attached to the bottom of the drill stem. First, a pilot hole is bored through the coke that has built up in the drum with the downward-oriented nozzles. The cutting tool is then pulled up to the top and switched to side-oriented cutting nozzles. The cutting tool then slowly moves through the length of the coke drum to cut out the coke.

Coke handling. Coke and cutting water from the coke drums fall into an adjacent large concrete pit or pad. Water drained from the pit or pad is collected in a nearby settling basin, which separates small coke particles (fines) from the water.

Water from the settling basin is pumped back to the decoking water tank for reuse. This decoking water tank also serves as storage for water that is used to quench the hot coke drum.

Coke in the pit or pad remains there long enough for the water to drain. A crane or front-end loader moves the dewatered coke to a crusher. Then a conveyor belt typically transfers the coke to storage, railcar, ship, or other transport method. In some units, the coke is cut directly into railcars or to a crusher and then sluiced as a water slurry to dewatering and storage facilities.



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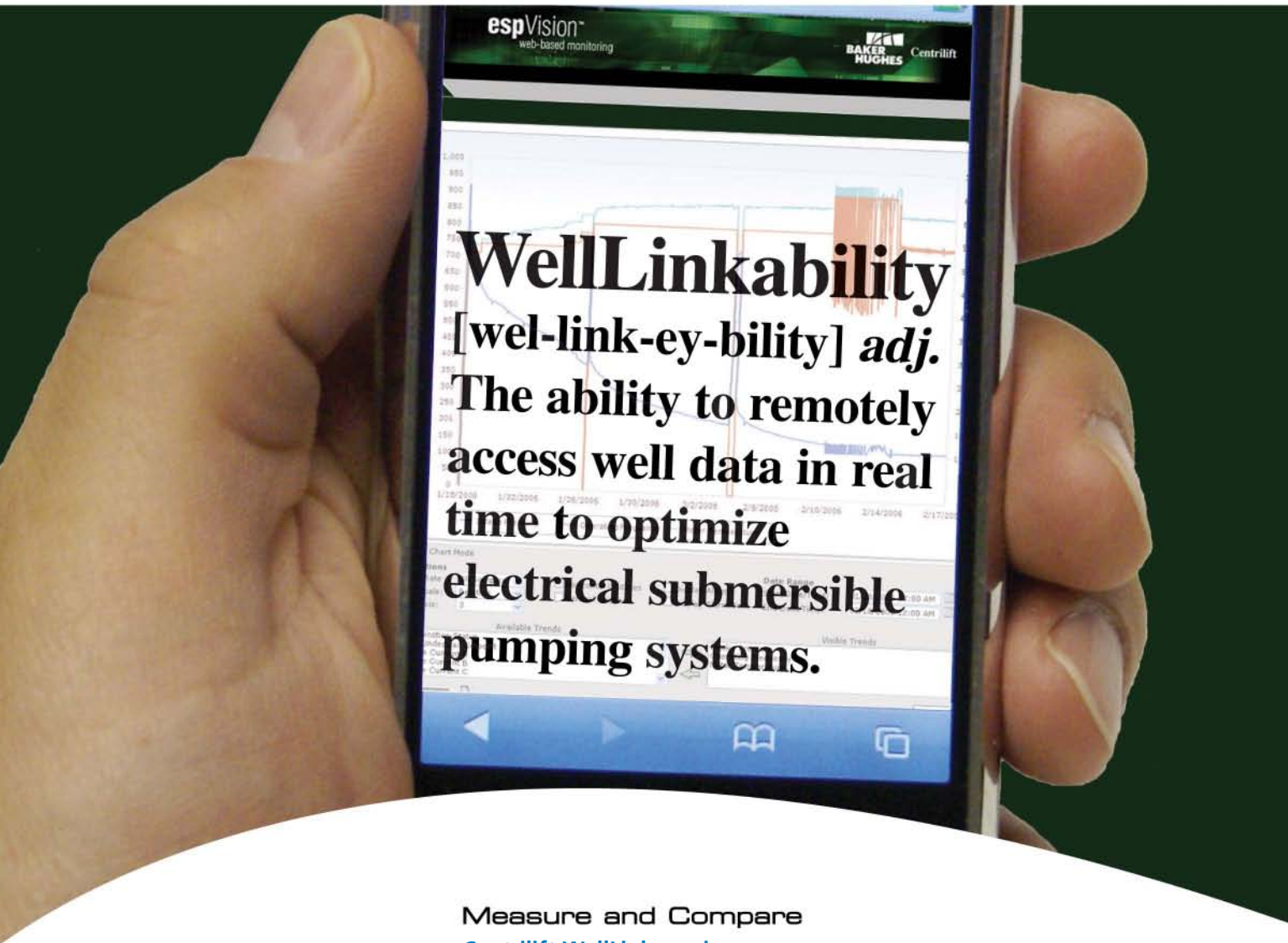

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