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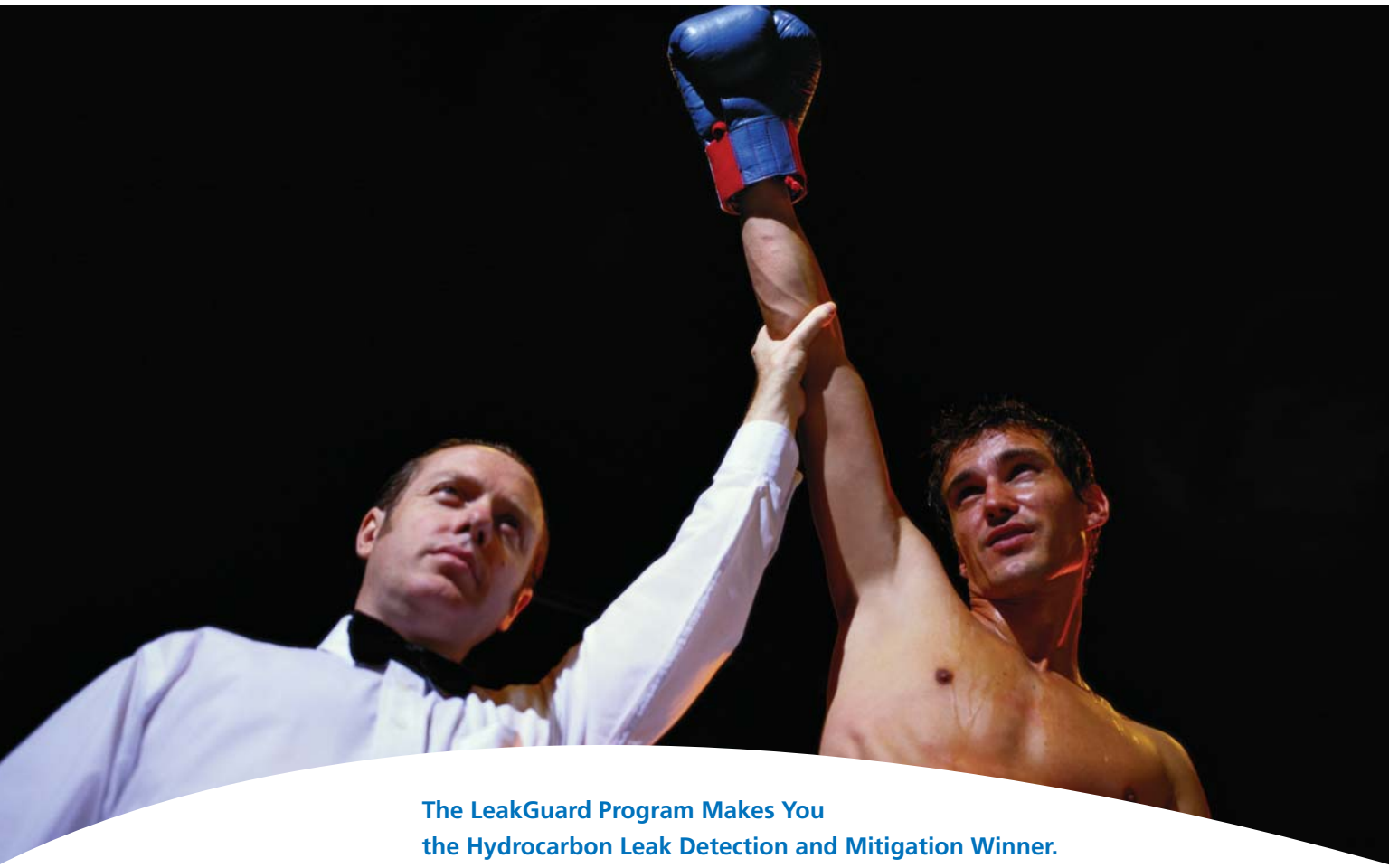

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Refining Report

Renewables not adaptable to large-scale installations
Iowa Forest City prospect may be large Paleozoic trap
Pattern approach finds rotating steering system faults
Company name change requires diligent execution

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Mar. 16, 2009
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Cover

Petro-Canada is planning to add a 25,000-b/d coker to its 130,000-b/d Montreal refinery. Many refiners in the US and Canada are adding bottom-of-the-barrel upgrading units to handle greater volumes of heavy crude. Refiners in the US are also planning for future regulations that tighten specifications for gasoline and other transportation fuels. The first article in this week's special report, p. 52, discusses the different routes refiners can use to comply with lower regulations for benzene in gasoline. The second article, p. 56, discusses a possible change in Russia's tax regime and how it could affect refiners there. Photo courtesy of Petro-Canada.

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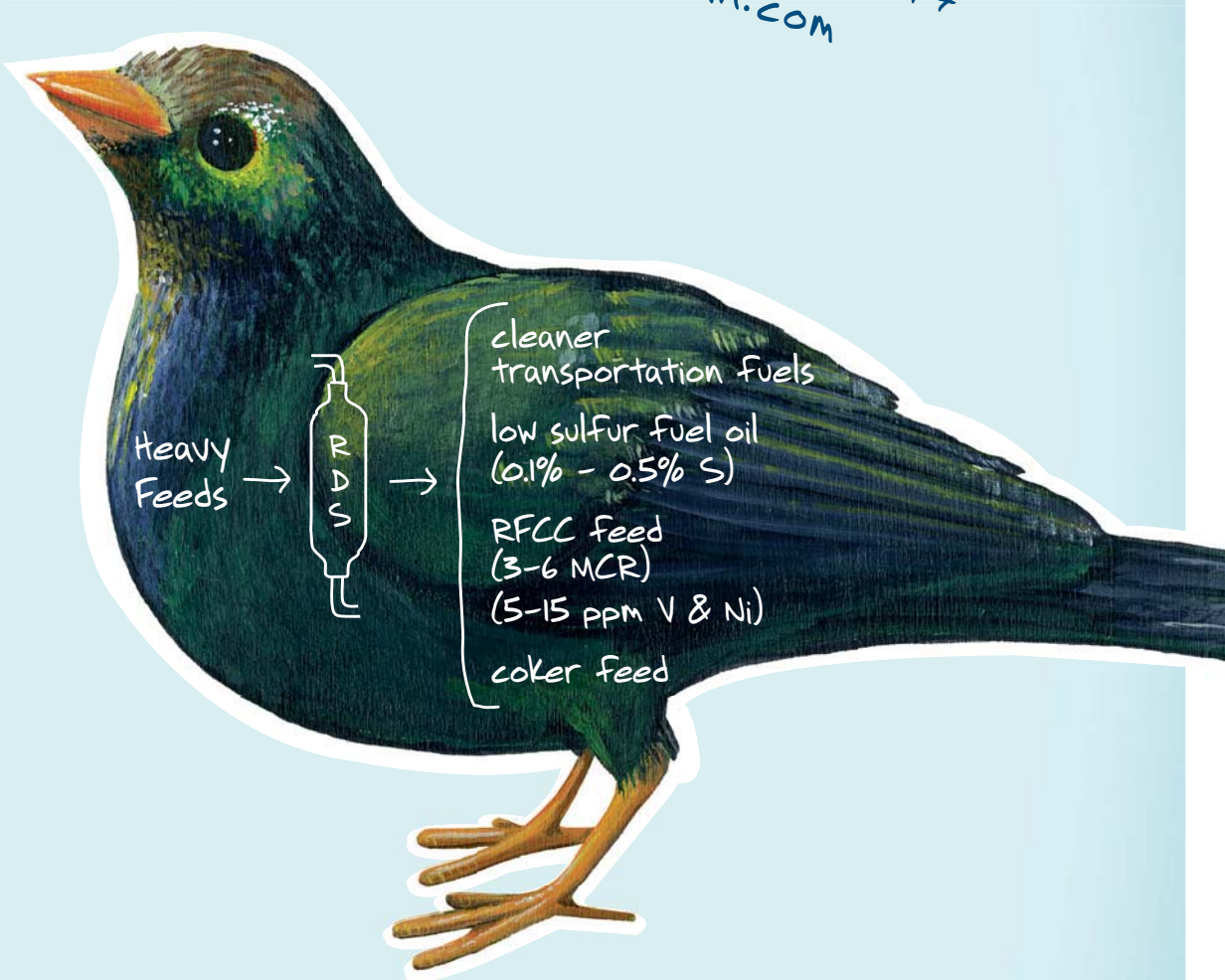

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General Interest — *Quick Takes*

GPA09: Gas recovery coming sooner, not later

Rapidly declining US natural gas rig counts and prices are setting the stage for a recovery in both sooner rather than later. That was the message of Gregory A. Dodd, vice-president for natural gas marketing and supply at Devon Energy Corp. in remarks made Mar. 10 to the 88th Annual Convention of the Gas Processors Association in San Antonio.

Dodd sees signs of this eventuality in the rapid pace that gas rigs are being laid down or otherwise pulled away from US gas plays, especially shale areas. He also said many wells are being completed but not yet tied into gathering and transmission infrastructure.

The coming recovery is evident in the accelerating rate of production decline, the increased use of natural gas in electric power generation as falling prices make it more of the fuel of choice, and the inevitable US economic recovery. Devon, said Dodd, is "getting ready for a turnaround" by, in part, increasing its 2009 capital budget over 2008.

Natural gas, Dodd said, is "not the fuel of the future but the fuel of today." Companies need to be prepared for recovery by reducing debt and reorganizing management structures to speed decision making.

They also need to shorten response times for rig mobilization once recovery begins and be actively influencing policy making, especially at the federal level. Currently, said Dodd, the story of natural gas is not getting told in Washington, DC.

LNG will play a critical role, he said, in meeting demand in the recovery, as it will take US production companies 6 months from the time rigs are called back to work and increased production from that new work.

M&A activity rises among UK-based oil, gas firms

Mergers and acquisitions among UK-listed oil and gas companies soared by more than 70% in the last year, according to law firm Freshfields Bruckhaus Deringer LLP. The rise could indicate larger players' desire to acquire smaller operators, now struggling to access capital.

Oil prices dropping more than 60% since the peak of $147/bbl in July 2008 diminished the value of oil and gas firms, and opened cheaper deals for those who are cash rich enough to weather the downturn.

FBD said the level of M&A activity in the UK rose despite the slowdown in pace of global M&A deals. The value of these transactions involving London Stock Exchange-listed companies leapt by 183% to £2.1 billion in 2008. In volume terms they rose to 52 deals, representing a rise of 73%.

"Somewhat against the grain of what we have seen in UK and global M&A as a whole, activity levels within the oil and gas sector involving London-listed companies in particular have been decidedly busier and look set to become even more intense throughout 2009," said Simon Marchant, a corporate partner at FBD and head of the firm's energy and natural resources group.

In 2008, the industry's global M&A deals increased by more than 51% on the previous year. However, they fell by 18% in value terms to £146 billion.

Last August, Jarpeno Ltd., the investment vehicle of India's Oil & Natural Gas Corp., bought Imperial Energy Corp. PLC for $2.6 billion—the largest deal in the UK.

China 'stocking up' on world oil, analysts say

China is taking advantage of the worldwide recession to stock up on foreign oil, last month offering some $43 billion in loans to foreign oil companies in Brazil, Venezuela, and Russia to secure future oil supplies.

The flurry of deals comes despite the global recession and a worldwide decline in oil demand, according to a report by Radio Free Asia, which said that China views those conditions as "an opportunity" rather than a reason to cut back on its investment plans.

Philip Andrews-Speed, an energy expert at Scotland's University of Dundee, said China is still not putting its trust in the market, but that its latest overseas deals suggest a new approach.

"The balance between the government and the companies has changed, so the government now is in the lead, providing these loans in return for oil," Andrews-Speed said. "It's the same set of objectives but with a different set of cards in the hand."

Andrews-Speed sees China's new strategy as more beneficial for oil development because the state-owned oil companies of Russia, Brazil, and Venezuela all face funding problems in a declining market.

"These are state companies that don't have enough money to develop new reserves as fast as they want to. Thus the Chinese loans will allow them to move ahead faster and produce additional oil earlier than we would have expected," he said.

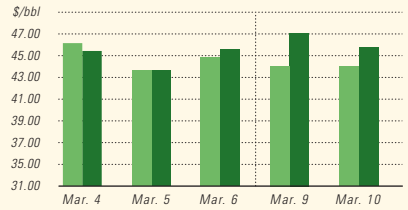
Experts told RFA that China's oil loans are a sign of both opportunism and confidence that its economy will recover from the worldwide recession soon.

In January, China's oil imports fell 8% to their lowest level in 14 months, the General Administration of Customs reported. But the government appears to be investing for the longer term.

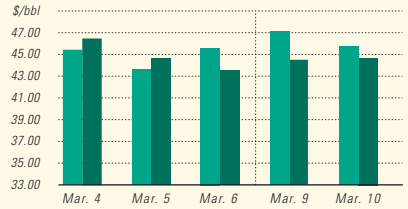
"Putting aside the current economic crisis, we're looking for China's oil imports to double in only a very few years," said Andrews-Speed. "So, if you don't trust the market, you'll be doing more of these deals, and now is a very good time to be doing these deals." ✦

Industry Scoreboard

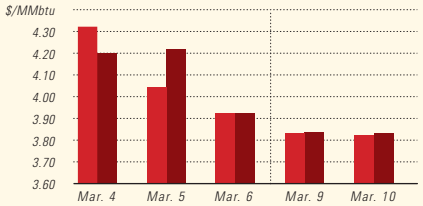
IPE BRENT / NYMEX LIGHT SWEET CRUDE



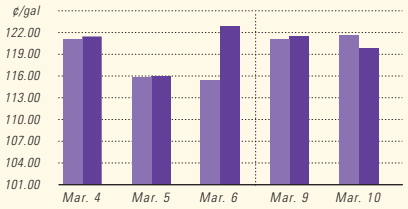
WTI CUSHING / BRENT SPOT



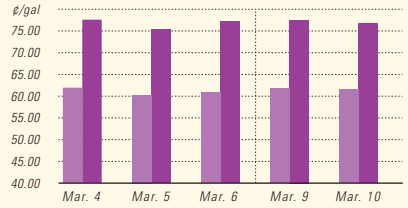
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



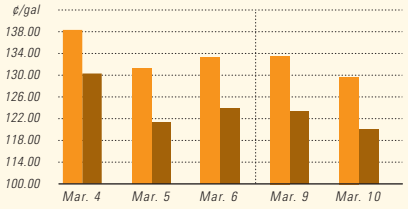
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



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

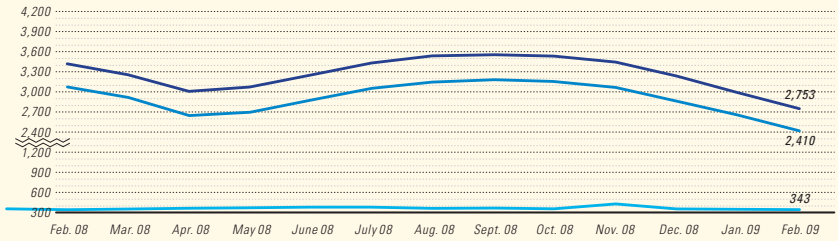
US INDUSTRY SCOREBOARD — 3/16

Latest week 2/27	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	9,032	8,840	2.2	8,909	8,828	0.9
Distillate	4,057	4,248	–4.5	4,084	4,209	–3.0
Jet fuel	1,306	1,538	–15.1	1,342	1,546	–13.2
Residual	494	561	–11.9	604	672	–10.1
Other products	4,652	4,619	0.7	4,637	4,736	–2.1
TOTAL DEMAND	19,541	19,806	–1.3	19,577	19,991	–2.1
Supply, 1,000 b/d						
Crude production	5,331	5,112	4.3	5,167	5,103	1.3
NGL production[2]	2,173	2,201	–1.3	2,173	2,164	0.5
Crude imports	9,061	9,634	–5.9	9,563	9,810	–2.5
Product imports	3,049	3,033	0.5	3,200	3,253	–1.7
Other supply[3]	1,355	1,431	–5.3	1,504	1,012	48.7
TOTAL SUPPLY	20,969	21,411	–2.1	21,607	21,341	1.2
Refining, 1,000 b/d						
Crude runs to stills	14,253	14,161	0.7	14,253	14,715	–3.1
Input to crude stills	14,631	14,955	–2.2	14,631	15,018	–2.6
% utilization	83.0	85.0	—	83.0	85.4	—

Latest week 2/27	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	350,590	351,347	–757	305,449	45,141	14.8
Motor gasoline	215,510	215,342	168	234,276	–18,766	–8.0
Distillate	143,296	141,634	1,662	117,625	25,671	21.8
Jet fuel-kerosine	41,692	40,474	1,218	39,342	2,350	6.0
Residual	36,636	36,397	239	36,508	128	0.4
Stock cover (days)[4]			Change, %		Change, %	
Crude	24.8	24.9	–0.4	20.9	18.7	
Motor gasoline	23.9	24.0	–0.4	25.8	–7.4	
Distillate	35.3	34.0	3.8	26.7	32.2	
Propane	25.0	25.7	–2.7	18.4	35.9	
Futures prices[5] 3/6			Change		Change	%
Light sweet crude ($/bbl)	43.26	42.18	1.08	100.84	–57.58	–57.1
Natural gas, $/MMbtu	4.16	4.13	0.03	9.23	–5.07	–54.9

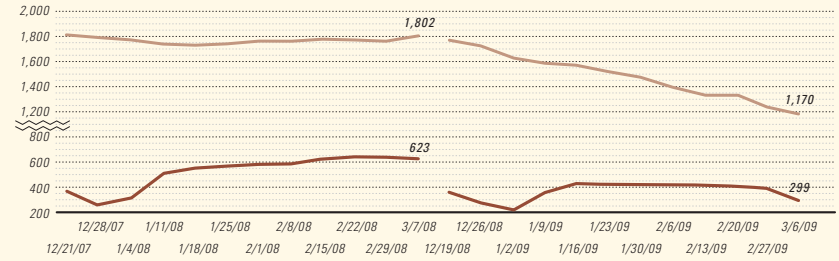
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

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

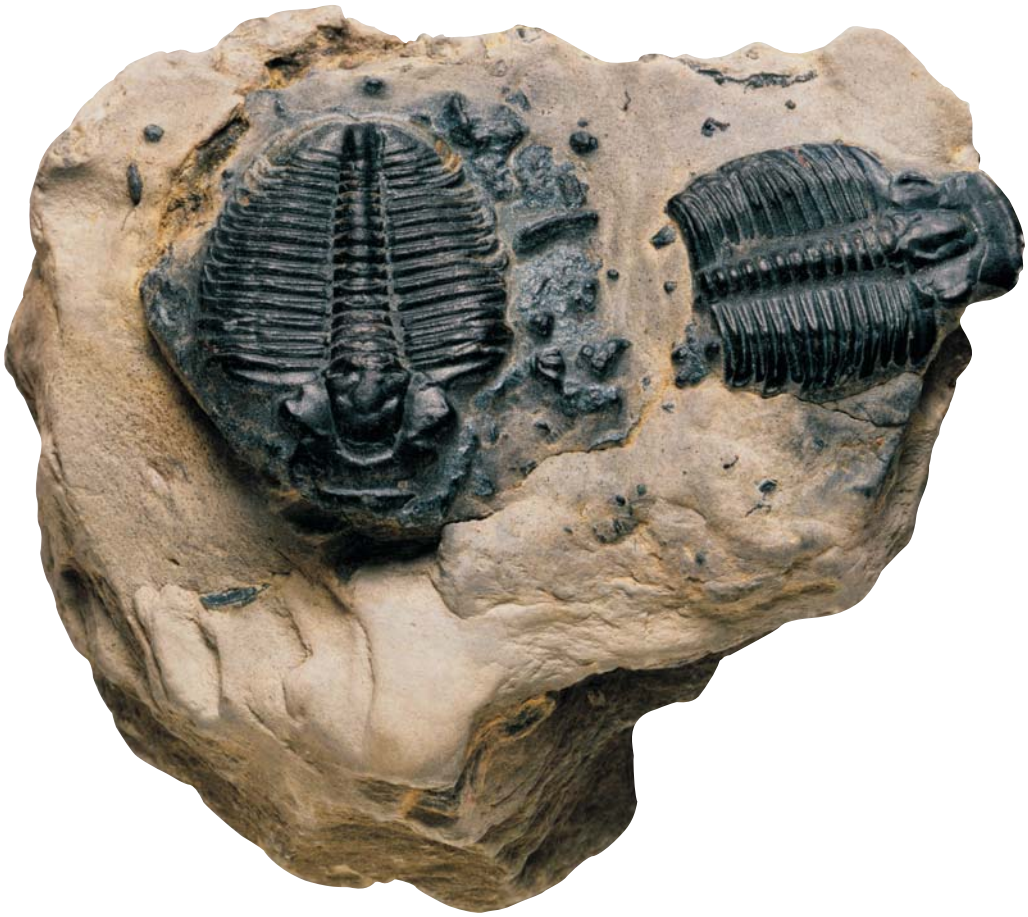


Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count



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Chesapeake shuts in gas, may idle more rigs

Chesapeake Energy Corp., Oklahoma City, shut-in 7% of its operated natural gas and oil production due to low Midcontinent wellhead prices and is considering a further 10% reduction in drilling in 2009 if prices stay low the next few months.

The volumes shut in at least through March are 200 MMcfd of gas and 6,000 b/d of oil.

Chesapeake, however, said it "believes conditions are developing that will support higher prices for natural gas and oil later this year and in 2010."

Chesapeake said it was taking the action to protect shareholder and royalty owner values with Midcontinent gas prices at most major interstate delivery points at $2.70/MMbtu, a price at which most gas production is unprofitable.

Chesapeake said, "We believe low wellhead prices combined with constrained capital availability will likely cause US drilling activity to decline well beyond the 40% drop already seen since August 2008. As a result, US natural gas production will begin to dramatically decline before the end of 2009 and consequently natural gas markets will regain better supply-demand balance by the end of 2009, if not sooner."

The company said its attractive hedges and cash availability provide it with the operational and financial flexibility to shut in production in periods of unusually low prices, such as the current market.

A 10% reduction in rigs, if implemented, would be in addition to a drop to 110 rigs from the 158 it operated in August 2008.

Petrobank slows Bakken work in Saskatchewan

Petrobank Energy & Resources Ltd., Calgary, said it is the largest Bakken producer in Canada.

The company built the production of its Canadian business unit to an average of 22,274 boe/d in the 2008 fourth quarter compared with 17,775 boe/d for all of 2008, mainly on strong Bakken results. The unit's production was estimated at 22,000 boe/d in February 2009.

Operating in the Williston basin generally east and northeast of Weyburn, Sask., Petrobank is running two rigs in the Bakken. It reduced its activity as commodity prices declined from an average of eight rigs in 2008 and as many as 10 rigs.

The company drilled 161 net wells in 2008 with a 99.4% success rate and compressed the time from spud to on production to 35 days. It plans to drill 40 wells in 2009 at current prices and as many as 120 if prices improve.

The company's recent efforts to further improve Bakken production have focused on increasing the intensity of fracs by several means.

It is increasing the number of staged fracs from 8 to 11 in its 1,400-m laterals for a 38% increase in frac intensity per square mile. It is doubling the number of wells per square mile with shorter 600 to 700-m laterals and 8 fracs in each leg for a 200% increase in frac intensity.

It is also doubling the number of locations per square mile, with each well having two 600 to 700-m laterals from a single vertical well bore and each leg receiving 8 staged fracs, representing a 400% increase in frac intensity.

Facilities at Viewfield, Creelman, and Freestone, Sask., have been connected to the main Midale gas processing plant with 100 km of new pipeline to capture gas and gas liquids produced with the Bakken's light oil. Together they are conserving more than 6.5 MMcfd plus NGL. Two more gathering facilities are to be built in 2010 as drilling spreads north.

Petrobank grew its land base in 2008 to 270 gross (236 net) square miles.

Since acquiring Peerless Energy Inc. in January 2008, Petrobank has developed an innovative way to reenter old producing Peerless trilateral wells and perform multistage fracs in the two outside horizontal legs. Results exceeded expectations.

Bakken player focuses on cutting costs

With rig activity down more than 40% from the peak in late 2008, Encore Acquisition Co., Fort Worth, is focused on reducing costs, high-grading acreage, and continuing a highly successful refrac program.

The company, which has drilled 24 wells in several areas of its 307,900 acres in the Bakken play, estimates 3.75 billion bbl of oil in place on its holdings. Initial potential rates averaged 411 b/d.

Low recovery of 1.9% of the oil in place per well based on 300,000 bbl/well presents opportunities for downspacing, improved drilling and completion techniques, and possibly even enhanced recovery once oil prices recovery, the company said Mar. 3.

Encore saw its costs per 640-acre Bakken single-lateral well climb to $5.2 million in 2008 from $4.5 million in 2007. It has a goal of reducing the average to $4 million this year. It is already seeing 8-10% cost savings compared with 2008 wells and needs another 14% reduction to reach the $4 million goal.

Casing costs, which doubled in 2008, are starting to decline. Stimulation costs have dropped 40% since mid-2008, and other costs are 15% lower.

Encore wants to cut $1 million from the cost of 1,280-acre Bakken wells that averaged $6.5 million last year.

The company has drilled 12 operated Middle Bakken wells that averaged 380 boe/d in the first 7 days on production and 7 Sanish wells that averaged 487 boe/d. Gas-oil ratio is assumed to be 1,000 scf/st-tk bbl.

Refracs, initiated 9-18 months after the initial completion, are returning 80,000 bbl of incremental reserves at a cost of $500,000. Multiple refracs may be possible at many wells.

Encore, producing 3,000 boe/d from the play, has a $73 million budget for 2009 that includes $12 million for land acquisition. It has an interest in 530 identified locations in five areas. Economics are marginal at $50/bbl and $5/Mcf at $5 million/well and 250,000-300,000 bbl recovery.

Bakken and Sanish appear to be in communication in some areas where they are separated by less than 20 ft but may be separate along the Nesson anticline where they are 50-75 ft apart, Encore said.

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New Guinea Energy to fast-track PNG oil appraisal

New Guinea Energy Ltd., Sydney, intends to fast-track the drilling of its Panakawa oil prospect on the PPL267 onshore permit in the Papua New Guinea forelands.

The company has just completed a seismic survey in the wholly owned permit over an area containing an oil seep discovered in 2006.

The seismic data has delineated a fault-closed structure with 16.5 sq km of potential areal closure that the company's reservoir engineers suggest could contain around 187 million bbl of oil in the Cretaceous Toro sandstone reservoir.

The oil found flowing naturally to surface in 2006 at an estimated rate of 5 b/d had an API gravity of 35° rather than the traditional 55° oil found in the PNG highlands. The company has spent $7 million (Aus.) over the last 3 years evaluating the region, and it plans to begin a drilling program in late 2009.

The Panakawa prospect is located just 1 km from the Panakawa logging and veneer timber plant wharf on the navigable Fly River which is used to export products direct to international markets via ships and barges. New Guinea Energy will be able to deliver the rig and equipment directly from barges to the drill site without the use of helicopters—a boon for logistics of the operation.

Target depth of the reservoirs is a relatively shallow 2,500 m. ✦

Drilling & Production — *Quick Takes*

Coastal Energy starts Songkhla oil production

Coastal Energy Co. has begun production from a mobile offshore production unit (MOPU) in Songkhla field in the Gulf of Thailand following delays caused by poor weather in January.

The field is producing 11,000 b/d from the Songkhla A-01 and A-03 wells. Coastal Energy used a MOPU different from the originally contracted unit, which had been damaged by the weather. Production from the Songkhla A-07 exploration well is scheduled for mid-March and will be tied in.

Randy Bartley, president and chief executive officer of Coastal Energy said, "The Songkhla wells' production rates are exceeding our original estimates. Our combined onshore and offshore production is now [about] 12,800 boe/d. We currently plan to build our liquidity position and commence another phase of drilling later in 2009. However, we have no related capital expenditures committed at this time."

Last December Coastal Energy successfully completed two wells on Block G5/43, which ensured an average oil production of 9,000 b/d from Songkhla field (OGJ Online, Dec. 31, 2008).

Coastal Energy, the sole operator of the block, said it has identified numerous undrilled prospects along the northwest margin of the Songkhla basin.

Total starts production from Nigeria's Akpo field

Total Upstream Nigeria Ltd. (Tupni) has brought on stream deepwater Akpo gas condensate field in Nigeria a month ahead of schedule. It expects to reach plateau levels this summer.

Akpo's production will be ramped up to 175,000 b/d of condensate and 320 MMscfd of gas from 44 wells (22 producers, 20 water injectors, and 2 gas injectors), 22 of which have already been drilled. Output is being delivered through a 100,000-tonne dry weight floating production, storage, and offloading vessel. The FPSO has a capacity of 185,000 b/d and can store up to 2 million bbl of stabilized liquid hydrocarbons.

The gas, which will go to the Amenam hub, will be used in the domestic market and at the Nigeria LNG plant on Bonny Island. Gas and condensate is delivered to a single-point mooring oil terminal 2 km away. The subsea infrastructures transporting the hydrocarbon effluents consist of 110 km of high-pressure, high-temperature subsea flowlines connected by steel catenary risers to the FPSO.

Akpo is a strategically important field underpinning Total's growth strategy as it would harness gas that would otherwise be flared. It "has been designed as a hybrid development capable of handling up to 530 MMscfd of high-pressure gas, out of which 185 MMscfd will be reinjected into the reservoir to maximize hydrocarbon recovery, and 320 MMscfd will be exported by pipeline," said Total.

Akpo, on OML 130, has estimated proved and probable reserves of 620 millions bbl of condensate and more than 1 tcf of gas. Condensate is 50°. The field, discovered in 2000, is 200 km off Nigeria in 1,200-1,400 m of water.

Pemex awards drilling, rig contracts

Mexico's Petroleos Mexicanos, aiming to boost production at aging fields, has awarded a $687 million oil well drilling contract to a consortium led by Schlumberger.

The group, which includes Dowell Schlumberger de Mexico, OFS Servicios, and Drillers Technology de Mexico, will begin drilling 500 wells in the Chicontepec field in April. The contract runs through June 2012.

Pemex hopes to boost output from Chicontepec to 600,000 b/d from 30,000 b/d, with spending plans for the area pegged at more than $2.3 billion this year.

Meanwhile, Diamond Offshore Drilling Inc. said it will start two rig contracts with Pemex in 2009. In late July, the 300-ft Ocean Summit jack up rig will leave the US Gulf of Mexico to start a 476-day contract in Mexico, while Diamond also extended a contract for the Ocean Nugget.

The existing contract, due to expire this month, will last from April through June 2011 following the extension agreement. ✦

Processing — *Quick Takes*

China approves new Guangdong refinery project

China's National Development and Reform Commission has approved China National Petroleum Corp.'s plans to construct a 10-million-tonne/year refinery at Jieyang in southern Guangdong province.

The approval is the latest effort by the government to boost Chi-

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na's refining capacity in the wake of severe shortages over the past several years throughout the country, but especially in its southern regions.

"The refinery will help CNPC better tap the rising demand for petrochemical products in the Pearl River Delta region," said Cai Enming, an executive with China Petroleum and Chemical Association.

Although China's other two main oil companies, Sinopec and CNOOC, already have refineries in Guangdong, the facility marks a new departure for CNPC as most of its existing refineries are located in China's northeastern and northwestern regions.

Cai underlined the need for CNPC to operate a refinery closer to the market it serves, saying that, "The cost would be too high for CNPC to transport its products from these [northern] refineries to Guangdong."

Chinese media reported that the project would likely refine heavy oil imported from Venezuela.

The reports follow an announcement by CNPC on Feb. 13 that it has started a new research program that aims to lighten heavy crude oil, enabling it to build several refineries able to process such Venezuelan oil (OGJ Online, Feb. 20, 2009).

Pertamina renews Balikpapan refinery upgrade

Indonesia's state-owned PT Pertamina, renewing interest in an earlier plan, has signed a memorandum of understanding with Dubai-based Star Petro Energy (ETA Group) and Japan's Itochu Corp. to upgrade the country's 260,000 b/d refinery at Balikpapan in East Kalimantan.

"By signing the memorandum of commitment, Pertamina and those companies will hold further talks on upgrading Balikpapan refinery," company spokesman Anang Noor said of the signing, which took place at the World Islamic Economic Forum in Jakarta.

"Cooperating with world-class companies is important in our efforts to improve ourselves as soon as possible in order to increase the performance of our refineries," said Karen Agustiawan, Pertamina president director.

She expressed hope that negotiations with ETA Group and Itochu would be concluded soon so that the project could be started on time.

State Enterprise Minister Sofyan Djalil, who said that negotiations with the two firms are continuing, estimated the venture as worth up to $1.7 billion. "It is still a tentative figure," he said, adding, "We still have to explore the actual price."

Sofyan said cooperation with the two firms should result in the improved performance of the refinery in Balikpapan, especially its processing of residual materials.

So far 30% of the total volume of oil processed by the refinery becomes residue which was sold very cheaply, Sofyan said, expressing hope that the refinery upgrade would enable 100% higher priced products.

Pertamina has previously said it wanted to boost capacity at the Balikpapan refinery, which has two crude distillation units with respective capacities of 200,000 b/d and 60,000 b/d.

Pertamina said it wanted to increase total capacity to 280,000 b/d, switch from sweet crude to cheaper sour crude, and add a 50,000 b/d cracking unit to process heavy residue into gasoline and petrochemical products. ✦

Transportation — *Quick Takes*

Alaska outlines intrastate gas pipeline plan

An intrastate natural gas pipeline that extends from Alaska's North Slope (ANS) to the Cook Inlet area could cost $4 billion and be in service as early as 2015, according to state-appointed project manager Harry Noah. The line would provide gas to meet Alaskan space heating and industrial demand.

The 800-mile, 24-in. OD pipeline would use two compressor stations and deliver about 500 MMcfd. Alaska sees the line as a complement to an eventual trans-Alaska gas pipeline delivering supplies to the Lower 48.

Two proposals for a natural gas pipeline from ANS into Canada have advanced to the detailed planning and project development stage, the US Federal Energy Regulatory Commission told Congress on Feb. 20. "At this point in project development, both Denali and TC Alaska are now fully working towards obtaining quality information to conduct their respective open seasons to obtain shippers for their pipeline," FERC said in its seventh report to federal lawmakers on the project (OGJ, Mar. 2, 2009, p. 27).

Noah named a number of tasks to be completed on the in-state line by June 2011, including guaranteeing a gas supply, obtaining commitments from purchaser, establishing tariffs, obtaining permits, and turning the project over to a builder-operator. He also said the project would build on work completed by Enstar and the Alaska Natural Gas Development Authority.

Oman Shipping commissions product tanker

Oman's state-owned Oman Shipping Co., as part of a larger plan aimed at boosting its refined and oil transport capabilities, has commissioned the LR2 Haima product tanker built by Japan's Mitsui Engineering & Shipbuilding.

The 245-m long, 42-m wide vessel, which boasts navigational equipment enabling it to operate in a variety of climatic conditions, can transport as much as 110,000 tonnes of oil products and will become the 18th ship in the OSC fleet.

The LR2 Haima is the second ship of its kind to be taken by Oman, following December's delivery of the LR2 Liwa. The vessel represents the latest move by OSC to step up its ability to carry oil and products.

In mid-December, OSC and Emirates for Trade Agencies (ETA) signed in Dubai an agreement to establish a 50-50 joint venture to own three 300,000-tonne crude oil tankers.

The Omani-Emirates agreement followed an announcement by OSC in September that it planned to raise $4 billion by the end of 2008, aiming to add 15-20 product tankers to its fleet, in addition to the order for 10 vessels it announced in February.

The 10 vessels are due for delivery between November 2011 and April 2012. ✦

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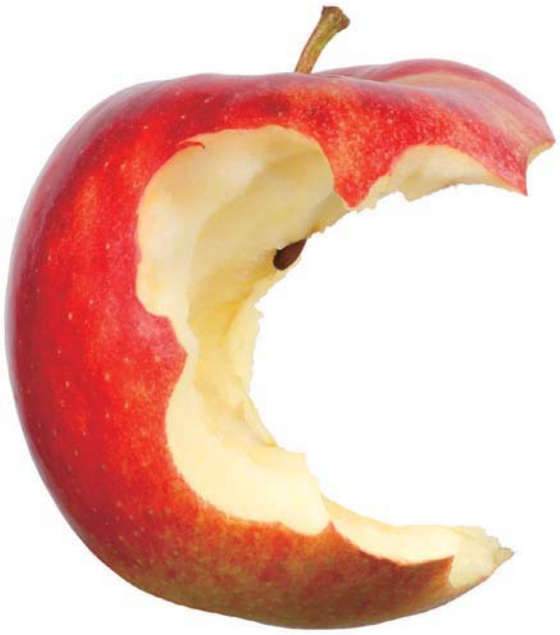

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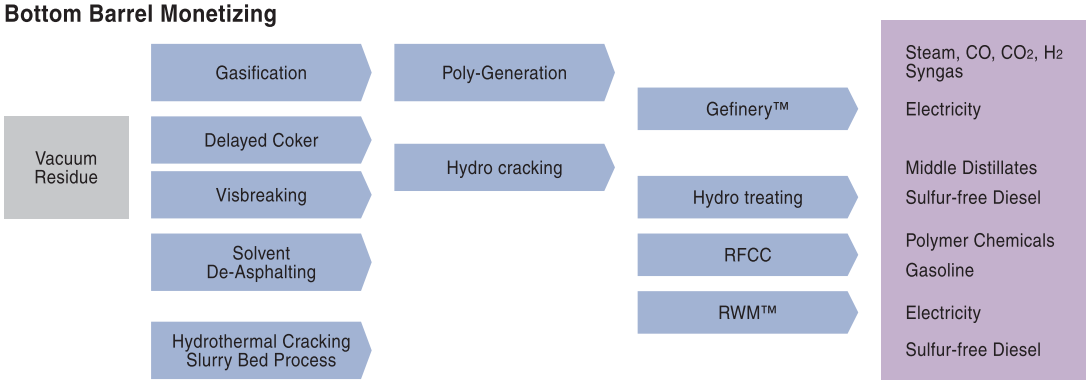

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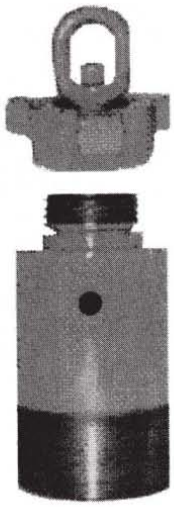

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Purvin & Gertz Annual International LPG Seminar, The Woodlands, Tex., (281) 367-9797, website: www.purvingertz.com. 16-19.

Gas Asia, Kuala Lumpur, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 17-18.

SPE/IADC Drilling Conference & Exhibition, Amsterdam, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website; www.spe.org. 17-19.

Latin American Meeting on Energy Economics, Santiago, 56 2 3541411, 56 2 5521608 (fax), e-mail: info@elaee.org, website: www.elaee.org. 22-24.

NPRA Annual Meeting, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 22-24.

ACS Spring National Meeting & Exposition, Salt Lake City, (202) 872-4600, e-mail: service@acs.org, website: www.acs.org. 22-26.

NACE Corrosion Conference & Expo, Atlanta, (281) 228-6200, (281) 228-6300 (fax), website: www.nace.org/c2009. 22-26.

SPE Americas E&P Environmental and Safety Conference, San Antonio, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website; www.spe.org. 23-25.

API Spring Petroleum Measurement Standards Meeting, Dallas, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 23-26.

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.

SPE Western Regional Meeting, San Jose, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website; www.spe.org. 24-26.

Offshore Mediterranean Conference & Exhibition (OMC), Ravenna, +39 0544 219418, +39 0544 39347 (fax), e-mail: conference@omc.it, website: www.omc2009.it. 25-27.

NPRA International Petrochemical Conference, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 29-31.

Petroleum Geology Conference, London, +44 (0)20 7434 9944, +44 (0)20 7494 0579 (fax), e-mail: georgina.worrall@geolsoc.org.uk, web-

site: www.geolsoc.org.uk. Mar. 30-Apr. 2.

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. Mar. 31-Apr. 1.

Offshore Asia/Multiphase Pumping & Technologies Conference & Exhibition, Bangkok, 918) 831-9160, (918) 831-9161 (fax), e-mail: attendingOA@pennwell.com, website: www.offshoreasiaevent.com. Mar. 31-Apr. 2.

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SPE Production and Operations Symposium, Oklahoma City, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 4-8.

SPE Digital Energy Conference, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 7-8.

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Rocky Mountain Unconventional Resources Conference & Exhibition, Denver, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.RMURconference.com. 14-16.

GPA Mid-continent Annual Meeting, Oklahoma City, (918) 493-3872, (918) 493-3875 (fax), website: www.gasprocessors.com. 16.

Middle East Petroleum & Gas Conference, Dubai, 65 6338 0064, 65 6338 4090 (fax), e-mail: info@cconnection.org, website: www.cconnection.org. 19-21.

ERTC Coking & Gasification Conference, Budapest, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 20-22.

Hannover Messe Pipeline Technology Conference, Hannover, +49 511 89 31240, +49 511 89 32626 (fax), website: www.hannovermesse.de. 20-24.

IADC Drilling HSE Middle East Conference & Exhibition, Abu Dhabi, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 21-22.

API Pipeline Conference, Fort Worth, Tex., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 21-22.

Pipeline Transport Conference & Exhibition, Moscow, +43 1 230 85 35 33, website: www.expopipeline.com. 21-23.

Base Oils and Lubricants in Russia & CIS Conference, Moscow, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 22-23.

Instrumentation Systems Automation Show & Conference, (ISA), Calgary, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 22-23.

CPS/SEG International Geophysical Conference & Exposition, Beijing, (918) 497-5500, (918) 497-5557 (fax), e-mail: semery@seg.org, website: www.seg.org. 24-27.

AIChE Spring National Meeting, Tampa, (203) 702-7660, (203) 775-5177 (fax), website: www.aiche.org. 26-30.

API Spring Refining and Equipment Standards Meeting, Denver, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 27-29.

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ENTELEC Conference & Expo, Houston, (972) 929-3169, (972) 915-6040 (fax), e-mail: blaine@entelec.org, website: www.entelec.org. Apr. 29-May 1.

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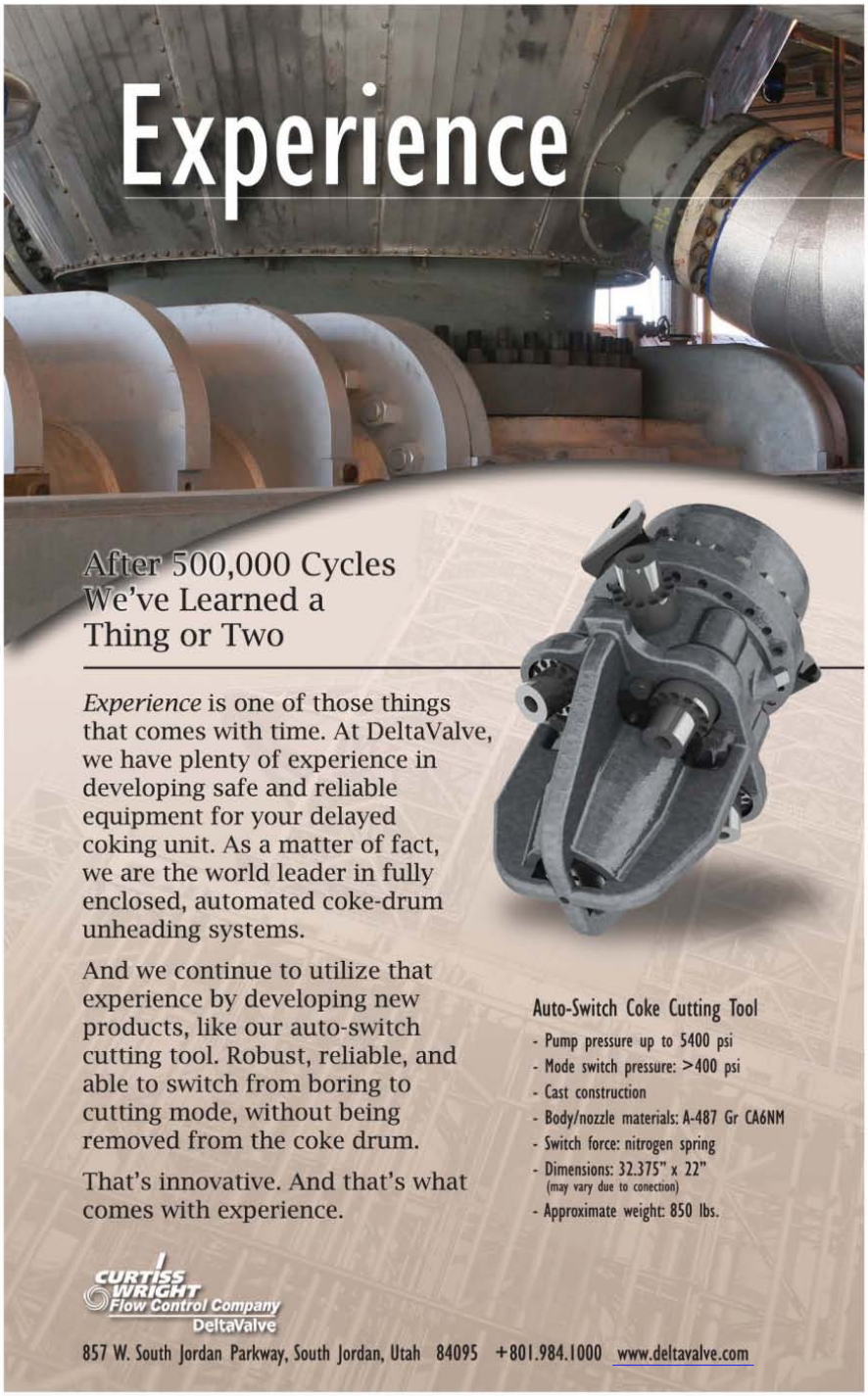
EAGE International Petroleum Conference & Exhibition, Shiraz, +31 88 995 5055, +31 30 6343524 (fax), e-mail: eage@eage.org, website: www.eage.org. 4-6.

Offshore Technology Conference (OTC), Houston, (972) 952-9494, (972) 952-9435 (fax), e-mail: service@otcnet.org, website: www.otcnet.org. 4-7.



GPA Permian Basin Annual Meeting, Austin, (918) 493-3872, (918) 493-3875 (fax), website: www.gasprocessors.com. 5.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

JUNE

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Society of Professional Well Log Analysts Annual Symposium (SPWLA), The Woodlands, Tex., (713) 947-8727, (713) 947-7181 (fax),

Calendar

website: www.spwla.org. 21-24.

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

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

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

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

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

JULY

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

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

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

AUGUST

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

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

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

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

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

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

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

SEPTEMBER

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

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

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

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

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

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

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

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

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

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

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

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

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

OCTOBER

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

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

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

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

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

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

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

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

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

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

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

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

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

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

NOVEMBER

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

IPAA Annual Meeting, New Orleans, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 4-6.

Capture and Geological Storage of CO_2 Symposium, Paris, +33 1 47 52 67 21, +33 1 47 52 70 96 (fax), e-mail: patricia.fulgoni@ifp.fr, website: www.CO_2symposium.com. 5-6.

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

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

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

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

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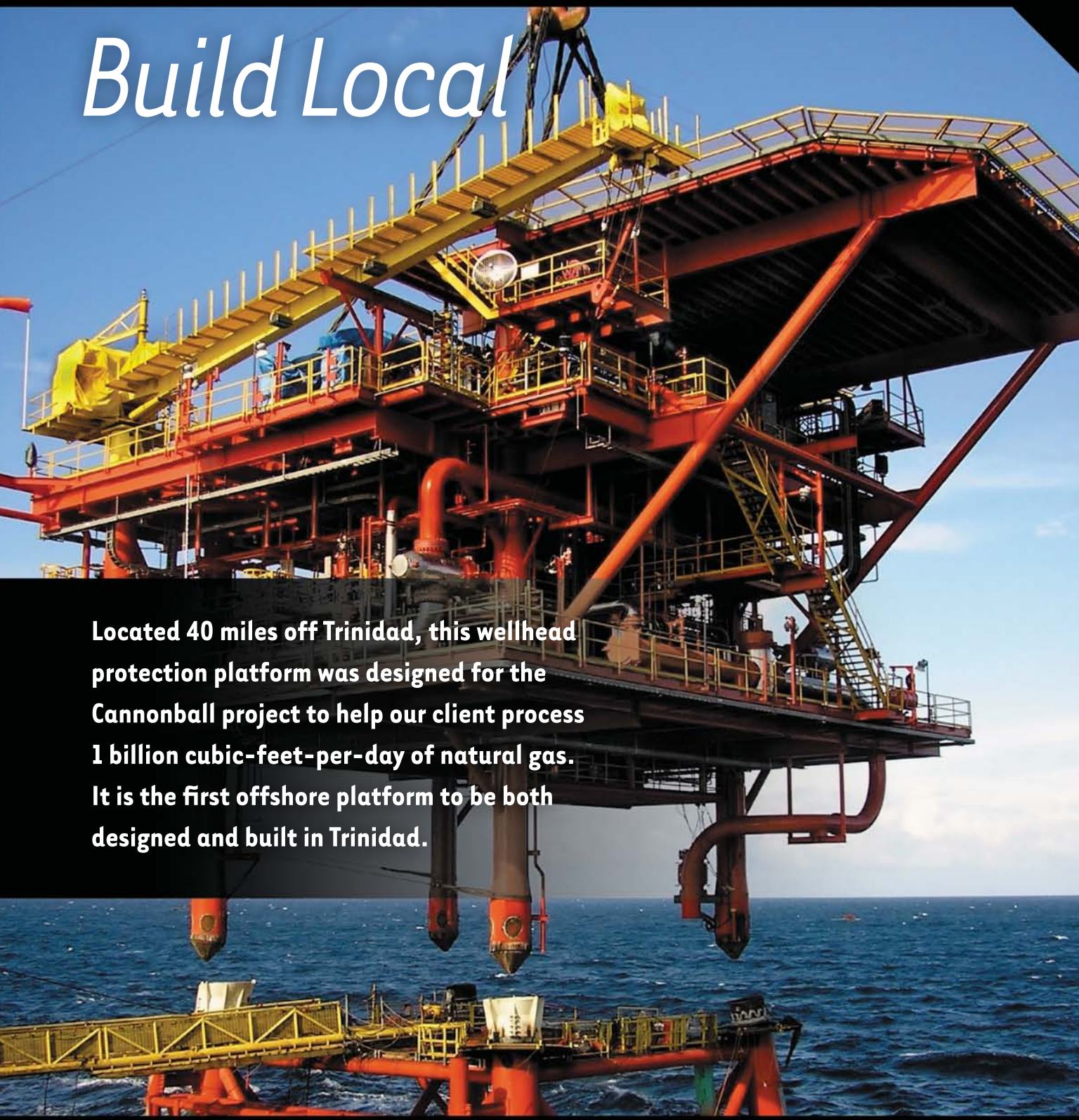

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Oil and aviation safety

Bob Tippee
Editor

If you've never worked with radar, you can't fully appreciate the contribution oil companies in the Gulf of Mexico are making to the safety of air transportation….

…Unless, of course, you encounter an Oil & Gas Journal editor who spent 4 years in the US Air Force several decades ago as a "weapons controller."

A weapons controller is—or was, if they no longer have them—like an air traffic controller with an important difference.

Air traffic controllers use intermittent positional information provided by radar about airborne objects to tell pilots where and how fast to fly in order to keep aircraft safely distant from one another.

Weapons controllers use the information to tell pilots how to get close enough to other aircraft to blast them out of the sky.

Either species of controller can tell you a couple of things you need to know about radar if you're to know what Gulf of Mexico producers are doing for air safety.

Rotating rectangles

Anyone who has visited an airport has seen a radar antenna. It's a curved rectangle that rotates atop a tower.

Most radars that track aircraft are—or were 30-some years ago—pulse systems. The antenna emits a radio pulse and listens for reflection signals from objects out in the wild blue yonder. Emission of the pulse and detection of the return signal have to occur in the same sweep of the antenna.

Since the good old days, of course, improvements in computers, airborne transponders, and who knows what else have enhanced the abilities of pulse radars and ancillary systems to track aircraft.

As long as radar antennae rotate close to the ground, however, important limitations apply. Basically, maximum range becomes a trade-off with the antenna rotation rate and, therefore, sampling frequency. And an antenna positioned a few tens of feet from the ground inevitably "paints," as they used to say, nearby buildings, utility poles, hills, birds, and whatnot, creating a presentation mess known as "ground clutter."

While this explanation is very basic and probably dated in places, it should illuminate the gains to be had from elevating radar antennae—or something better—to altitudes well above ground level—perhaps into space.

That's what the Gulf of Mexico oil and gas industry is helping to accomplish.

A partnership of 44 companies, the Helicopter Association International (HAI), and Federal Aviation Administration is implementing for gulf chopper transport a system destined for use by all commercial aviation called Automatic Dependent Surveillance Broadcast, or ADS-B.

Instead of ground-based radars, ADS-B uses signals from Global Positioning System satellites to monitor air traffic.

In the gulf, that's a lot of aircraft.

According to Ann Carroll, HAI vice-president of legislative affairs, 650 helicopters serving oil and gas installations make as many as 7,500 trips/day in the 500-mile-by-250-mile aerial region off Texas, Louisiana, and Mississippi. They carry an estimated 2.6 million passengers/year.

Until now, pilots of those aircraft haven't received the communications, weather reporting, and surveillance services that FAA provides other domestic air traffic.

When the necessary equipment is installed offshore and aboard aircraft, ADS-B will provide positional and other information—such as heading, altitude, speed, aircraft category, call sign, and distance—simultaneously to all pilots in the gulf and to controllers in Houston. Prime among the many consequent advantages will be improved safety.

To help make this possible, gulf operators are providing space on platforms and other installations for communications, weather, and other equipment and helping pay for the work. Carroll says the value of in-kind services offered by companies in the gulf to support the new system will exceed $100 million over 20 years.

Equipment related to the new aviation system becomes operational as it's installed. The partnership's first offshore communications site to start up was on BP's deepwater Atlantis platform last Dec. 18.

Improving safety

Carroll expects ADS-B transformation of Gulf of Mexico airspace to be complete in December. The oil and gas industry then will have contributed to a crucial piece of what FAA calls the Next-Generation Air Transportation System, implementation of which received approval in 2005 and is expected to take 20 years.

The space-based perspective and other improvements over terrestrial radar systems will, without doubt, enormously boost the safety and capacity of US air transport.

If aviation officials ever need to get airplanes within fighting distance of one another the old-fashioned way, though, they know whom to call. ✦

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Editorial

Fix the misunderstanding

In a fight over energy policy that is fast becoming fateful, the US oil and gas industry has more than a political problem. It has an intellectual problem. Americans don't think well about energy. The deficiency is manifest in President Barack Obama's federal budget for the 2009-10 fiscal year—a proposal with menacing portents.

In the political arena, the industry has no choice: It must oppose the budget—with its new taxes, repeal of capital-formation tools essential to small producers, and other horrors. Industry associations and lobbyists are responding in Washington, DC. A few company chiefs are speaking out. But a political response isn't enough.

Thorough misunderstanding

The industry reels from a thorough misunderstanding in the US about nearly everything having to do with energy, from dimensions of the need to relative costs and the role of markets. The misunderstanding drives politics. It explains how ideas rejected for lack of merit, such as punishing taxation of the industry responsible for 60% of US energy supply, keep squirming back onto the political agenda. And it won't be fixed in Washington, DC. Too many politicians profit from treating the oil and gas business as a demonic force.

The repair must occur in the minds of Americans where Americans live and work. It can occur only if industry leaders—not actors in television ads—speak directly and honestly to people about energy and human welfare and do so without the soft-pedaling and fear of controversy that emasculate too much industry communication.

The problem is urgent. It's also bipartisan. It developed because Americans quit thinking about energy during a long period of comfort that began with the lifting of oil price controls 30 years ago. While prices were low and the economy strong, Americans didn't worry about energy. In fact, their insouciance mated with a loophole in vehicle fuel-efficiency standards to breed uniquely American symbols of energy profligacy: the sport utility vehicle and gargantuan pickup truck.

When, inevitably, the market tightened and prices rose, political leaders exploited the new discontent by touting fantasies instead of facts. The result has been a steady degradation in American thinking about energy, which can be traced through recent political history.

A place to start is the 2003 State of the Union address in which former President George W. Bush held up "energy independence" as a national goal. He wasn't the first to trumpet the futile slogan, of course. But he gave it the stature of his office, forfeiting a chance to bring realism to energy policy-making.

In 2005, Congress passed and Bush signed a comprehensive energy bill that reestablished a governmental role in fuel choice. The law enshrined the discredited misapprehension that energy is too important to leave to markets. Early the next year, Bush stooped to extremist rhetoric when he declared in his state-of-the-union address that the US was "addicted to oil."

Thus inspired, Congress in 2007 passed a bill toughening fuel-efficiency standards and, dangerously, expanding to possibly unachievable levels already-costly mandates for renewable fuel additives. Framing that law, the Energy Independence and Security Act, is the view that conservation and renewable energy represent the beginning and end of energy policy. While both goals are righteous, they can't be pursued economically at the exclusion of oil and gas. Yet that's the course implicit in the get-out-of-town budget of a president who last month bewailed "the tyranny of oil." As Obama unveiled his hostile fiscal agenda, moreover, his interior secretary was restricting producer access to federal land every way he could find.

Mountain of cost

This scenario can't get much worse for the industry, energy consumers, and taxpayers. Yet most Americans remain oblivious to the mountain of cost into which their sputtering economy and overextended government soon will crash.

The industry can no longer afford to treat chronic ignorance as just another frustration. Its leaders need to spend more time than they do now behind podiums and microphones outside Houston and Washington, DC, while at least some Americans who don't live in producing states think they have something relevant to say. ✦

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GENERAL INTEREST

Renewables not adaptable to large-scale installations

Harry W. Parker
Lake Jackson, Tex.

Proponents of renewable energies frequently say those energy forms will become economic when accomplished on a very large scale. This article will discuss the favorable economies of large-scale operations and describe how these economies do not apply to most renewable energy resources.

In addition, proponents of renewable energy claim that experience will reduce renewable energy costs until renewable forms are competitive with fossil and nuclear energy. This "learning curve" observation, which began in World War II for aircraft manufacture, quantifies the reduction in labor effort required to accomplish repetitive manufacturing tasks, and it has been extended to other circumstances. Its application to renewable energy is limited.

A previous OGJ publication discussed how manufacturing costs and energy costs move together in a 1.0 correlation on a log-log graph.[1] OGJ refinery fuel and refinery inflation index data for over 70 years are utilized on a log plot to obtain the 1.0 correlation. This observation suggests that the source costs of renewable energy resources will increase in parallel with energy costs in general, and thus they cannot gain a cost advantage.

COMMENT

Large scale economies

The economies of large-scale operations range from large petroleum refineries and petrochemical complexes to personal shopping at Wal-Mart. This observation, published over 60 years ago, has been quantified in industrial processes as the "six-tenths rule" relating capital cost and capacity as follows:[2]

$$\text{Cost}\$_2 = \text{Cost}\$_1\ (\text{capacity}_2\ /\ \text{capacity}_1)^{0.6}$$

The value of the exponent varies with the processes involved, and values have been widely published. One example of these exponents is given in Table 1. The average value of the exponents in Table 1 is 0.65, differing little from the six-tenths rule. So if the capacity of a facility is increased by a factor of 3 the six-tenths rule says the required investment cost will be increased by a factor of only 1.9.

The underlying logic of the six-tenths rule can be illustrated by considering a low-pressure cylindrical tank or reaction vessel. Its cost is proportional to the area of material required for its construction, and its actual function in a process is proportional to its volume. For this reason at a constant length-to-diameter ratio, costs can be related to capacities via simple geometry to result in the following equation:

$$\text{Cost}\ \$_2 = \text{Cost}\ \$_1\ (\text{Capacity}_2/\text{Capacity}_1)^{(0.667)}$$

The above exponent of 0.667, two-thirds, is an approximate verification of the six-tenths rule, and it is calculated only with considerations of geometry.

Labor requirements are proportional to the 0.2-0.25 power of plant capacity, according to a reference cited by F.C. Jelen.[3] This greatly reduces the labor requirement for larger plants, again making it more difficult for smaller facilities to compete with large facilities.

Extrapolating the rule

As with all extrapolations, extrapolation of the six-tenths rule must be done with great caution. When extrapolated to larger sizes, several constraints may apply:

- The capability to fabricate, transport, and install larger process equipment items limits the size of processing units. The realistic expedient is multiunit processing units and multitrain processing facilities. This practice elimi-

nates much of the economies of scale indicated by the six-tenths rule.

- Difficulty in scaling up solids processing facilities, so multiple units are used. An example is the Lurgi gasifiers for coal used in the South Dakota coal gasification facility. Oil shale retorts have the same constraints. This constraint is also demonstrated by construction of many duplicate wind turbines in a row, rather than just one exceptionally large one.
- Availability of raw materials and the shipping charges associated with them. This constraint applies to many biomass processes as well as the processing of oil and gas at their initial production sites.
- Impact on the product market from a new, large-scale facility. The result may be closure of smaller facilities producing the same product.

These constraints limit the practical size of a processing facility, and that size limit is termed a "world-scale" facility. The size of the ideal "world-scale" facility may increase as new demands and technologies develop.

Extrapolation also fails when the six-tenths rule is extrapolated to smaller processing facilities. In the case for smaller sized facilities, the number of things—valves, instruments, and controls—remains constant, so little or nothing is really gained by attempting to make a smaller facility, hoping that it will be somewhat less costly.

These "large-size" and "small-size" constraints on the six-tenths rule are illustrated in Fig. 1. The constraints are a part of the real world today. Persons considering a new larger or smaller facility must decide where they are positioned on the curve in Fig. 1. Intentionally, there are no numerical values on the X and Y scales of the figure because values differ for each process and facility. This circumstance will be applied to alternative energies in this article.

Exponents for investment cost vs. capacity

Acetylene	0.73
Aluminum (from alumina)	0.76
Ammonia (from methane)	0.72
Butadiene	0.65
Butyl alcohol	0.55
Carbon black	0.53
Chlorine	0.62
Ethanol, synthetic	0.60
Ethylene	0.72
Hydrogen	0.64
Methanol	0.83
Nitric acid 50-60%	0.66
Oxygen	0.72
Power plants: coal and nuclear	0.67
Styrene	0.68
Sulfuric acid	0.68
Urea (small sized)	0.67
Urea (large sized)	0.20
Average	**0.646**

Source: O.T. Zimmerman, I. Lavine, Cost Eng., Vol. 6., July 1961, pp.16-18, and Vol. 12, October 1967

The learning curve

The learning curve is another empirical observation that can be cited to justify hoped-for reductions in costs for renewable energy sources. It was observed and quantified for aircraft production during WWII. H.J. Behrens has discussed its mathematical details.[4] Simply stated, every time commercial production of an item is doubled, the effort required for production of the next unit is an empirical fraction of the effort for the final unit of the previous "doubling." W.B. Hirschmann generalized this observation as 80% for human paced production and 90% for machine-paced production (Fig. 2).[5]

This learning curve concept applies to commercial production. During research and development, estimated per-unit costs frequently increase due to making more-detailed designs and associated difficulties. This circumstance has been termed the negative learning curve and may apply to present non-commercial alternative energy sources.[6]

Note that the number of units required to "double" production continues to double, also, so the cost reduction of the learning curve is much diminished after production of huge numbers of units as Fig. 2 illustrates.

Solar energy

Solar energy has the potential of supplying US electric power needs with modest levels of land usage, but its investment cost and intermittent availability have prevented large scale commercial usage for supplying the electricity marketed by utilities.

Solar collectors of all types are rated on the area that intercepts the sunlight. For this reason they do not have the noted economies of larger-scale operations.

Some large-scale economies can be achieved in the conversion facilities that utilize the energy collected by solar collectors. So buying solar collectors is somewhat analogous to buying carpet by the square yard or meter except that a photovoltaic solar cell is a sophisticated, semiconductor device—a flat, very large junction formed between P-type and N-type semiconductor materials.

Small solar cells can be installed on roofs of both commercial and residential buildings with little penalty for small-scale operations except the cost of the "interface" that connects them to the utility grid or to a residence. These installations are costly, so they remain dependent on support by regulations, subsidies, and the environmental concerns of individuals.

Solar-thermal power generation facilities substitute mirrors for semiconductor-based solar cells. They acquire the cost of continual re-aiming the mirrors at a receiver on a "steam" boiler, and are burdened with the thermodynamic inefficiencies inherent with all "heat engines." There are economies of large-scale operation to the extent that large mirror "fields" are practical.

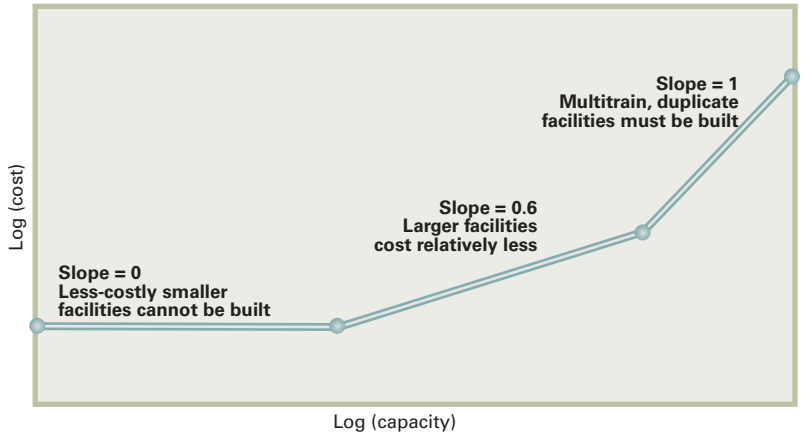
The mechanical and optical problems associated with solar-thermal power generation are solvable with existing technologies, but the resulting high costs have prohibited widespread commercial applications.

Other constraints on solar energy include a low intensity relative to industrial furnaces—1/500 according to one reference.[7] In addition, sunlight is intermittent—when it is needed most for heating buildings and light, the sun has set.

Intermittency limits the fraction of

SIMPLIFIED COST VS. CAPACITY ILLUSTRATION

Fig. 1



time that the investment made in solar collectors can be used for a financial return on the investment.

The inherent high cost of the electricity generated from solar energy, however, should not deter architects and home-builders from including passive solar energy management in their buildings, where economic.

Wind energy

The problem of intermittency and electric power storage must be considered for another renewable energy source—wind.

Wind energy has the potential of supplying a large portion of US electric power requirements with a minimal amount of land usage, just as with solar energy, but it meets with the same constraints of being intermittent and variable. It cannot gain the full six-tenths rule economies of large-scale operation, as demonstrated by the long rows of duplicate wind turbines being installed. This multiplicity of units does gain reduced costs via the learning curve for the replication and installation of near duplicate units.

A typical large wind turbine farm consists of several hundred thin towers 35 stories high topped with 65 tons of mechanical and electrical equipment for production of 1.5 Mw of electricity each at the design wind speed. The blade span is longer than a football field, and the blade tips travel at about 200 mph. This rotating equipment must be maintained on each tower.[8]

Simple design concepts for wind turbines consider the fact that power production is proportional to blade length squared and that the potential power available is proportional to the wind speed cubed, so a 12 mph wind contains 73% more energy than a 10 mph wind.

Variations in wind speed become the challenge in the selection and design of wind turbines. They often are designed for a selected wind speed that is frequently reached, with feathering of the blades when that wind speed is exceeded in order to maintain a constant power output consistent with the mechanical and electrical design of the wind turbine.

So selecting the design point wind speed is crucial, but good data are not always available. In addition there is no assurance that a selected wind speed will remain optimal during the expected 20-30-year life span of the turbine.

The wind is already kinetic energy, so it not constrained by the thermodynamics of "heat engines." But it is constrained by the need for the "exhausted wind" to move away from the rotor, limiting the theoretical efficiency to about 60%. Due to mechanical losses, the overall efficiency is closer to 35%.[9]

Since wind is abundant, this relatively low efficiency is not crucial, but it does require additional investments for a particular output power capacity.

A more important concern is the variable and intermittent nature of the wind, which enables the turbine to produce only a fraction of its possible "nameplate" power in a particular year. The actual number of kilowatt-hours sold during the year will be only a fraction of the nameplate rating of the turbine. One reference gives this factor as one-third.[10] Therefore, when investments are given for wind power in terms of installed megawatts, the dollar value should be multiplied by three before comparing it to nuclear or fossil energy investments per megawatt installed.

If wind energy becomes a major fraction of the electric power generated, another major cost is incurred—maintenance of reserve generating facilities, even "rotating reserves," for when the wind stops blowing at the wind farm. Texas almost experienced a "brownout" in late April 2008 when a "no wind" event occurred in conjunction with other grid concerns.[11 12]

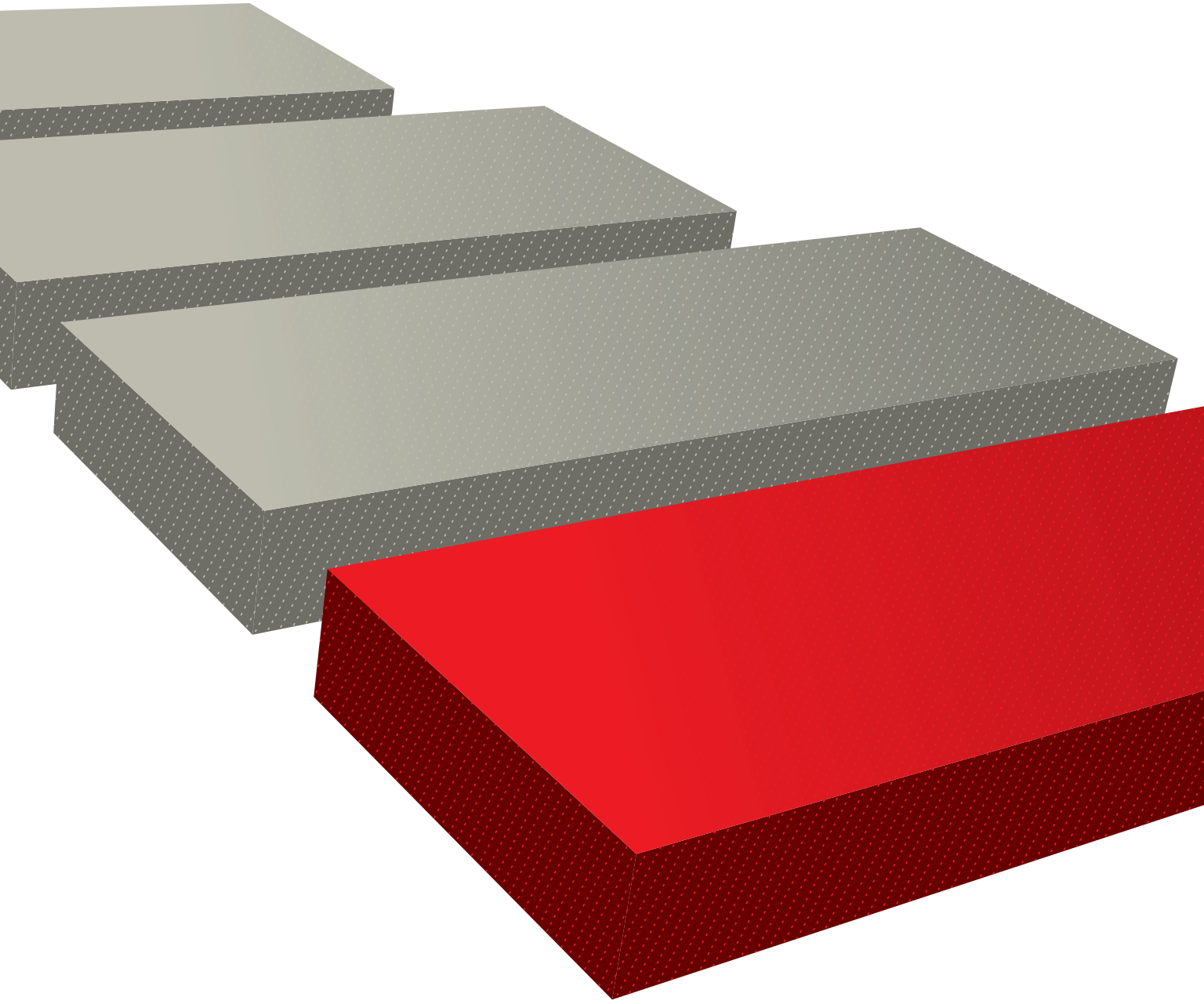
Ocean waves and tides

The ocean represents four fifths of the surface of the earth, and humankind has always been impressed with the kinetic energy contained in the moving water of the waves and tides.

Still, the mechanical technology has not been demonstrated to routinely convert this immense available energy source into economic electric power. There has been very limited success with tides, which are cyclic, depending on the relative position of the moon.

There has not been commercial success with waves, however. Waves are a reciprocating motion that vary greatly in height and so require considerable mechanical apparatus to convert them to steady rotary motion needed for electric power production.

A recent newspaper review briefly



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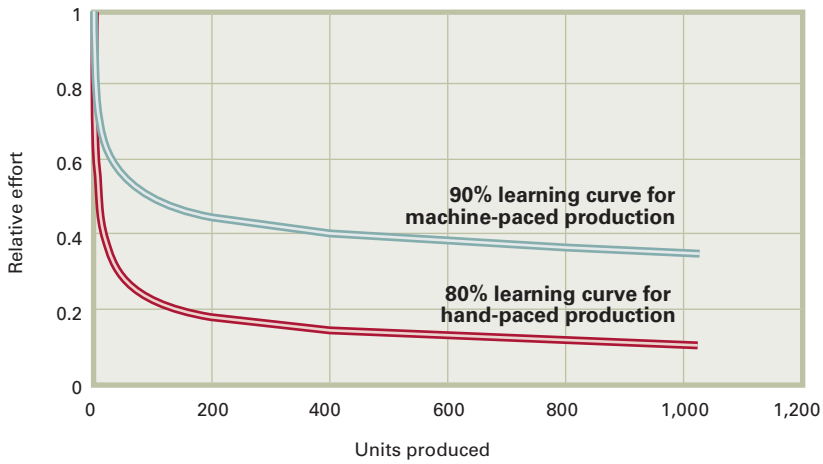
LEARNING CURVE ILLUSTRATION

Fig. 2



cited efforts with waves and tides for energy and listed their mechanical and environmental problems.[13] A cost of 40¢/kw-hr was cited in one case, and many of the projects projected their major demonstrated results into the future. Neither wind nor waves have the economics of very large-scale operations available to them because they are both local and cyclic.

Storing electric power

Wind and solar power both require economic and efficient large-scale storage and transmission of electricity. In favorable locations, limited power storage is accomplished by "pumped storage" at hydroelectric facilities. Water is just pumped back up to the dam when there is excess available power, so it will be available to generate addition power when it is needed. If the efficiency of both the pump and turbine are 90%, the resulting power storage is 81% efficient. This option for power storage is not generally available, however.

Small-scale electrical storage techniques such as batteries and capacitors are not economically adapted to large-scale power storage. Electrolysis of water to hydrogen and oxygen with wind or solar power has not been demonstrated on an effective scale despite past efforts, although there are current efforts in this regard.[14]

Larger electric power grids are a partial solution, and that option may include high-voltage direct current as a power transmission method. Still there is a strong need for large-scale storage of electric power from both wind and solar, which may prove physically impossible.

Compressed air was recently illustrated as a means of storing power, with a commercial installation in Alabama cited.[12] Natural gas-fired turbines are well adapted to power storage because the air compressor on the gas turbine requires about 60% of the expanders' horsepower output, leaving only 40% for net electric power generation. Substitution of stored compressed air for turbine compressed air ideally releases this 60% of the turbine power for generation of additional electricity. When electrical demand is decreased, air can be compressed and stored for future use.

There are solvable mechanical problems associated with these arrangements and several options for their implementation, including direct compression of air by wind turbines. The major concern is economical storage of large volumes of compressed air. Several options for storage are available such as salt domes, depleted mines, or mined caverns. Optimal economic design of such storage units is not a simple task.

Nuclear explosives can very directly produce air storage caverns with known technology. The author has five patents for retorting oil shale shattered with nuclear explosives to form a deep vertical cylinder of broken shale known as a nuclear chimney. One example patent is referenced.[15] These inventions could be readily modified to store compressed air simultaneously with retorting oil shale and even producing hot combustion gases for the expansion turbines. Because there are several nations developing nuclear weapons in defiance of world pressures, US restraint in not using nuclear explosives for peaceful purposes perhaps should be reconsidered.

Enhanced geothermal

Geothermal energy circumvents the problems of intermittence associated with renewable wind and solar energy. Where available, it provides electric power conveniently, so Italy, Iceland, and the western US have considerable geothermal power production facilities. This limited-availability resource has already been largely developed. Conventional geothermal energy depends on the coincidence of permeable hot rock and hot water, not a frequent occurrence.

Enhanced geothermal systems (EGS) depend only on the availability of hot rock at some economically drillable depth. Cold water is injected via an injection well into the hot rock whereupon production wells produce hot water for power production. The water circulation process is aided by making numerous hydraulic fractures in the hot rock. The technique was briefly demonstrated at the Fenton Hills site in New Mexico around 1990. Commercial power was not produced at that time.

However, the Fenton Hills personnel, among others, have continued their interest in EGS, and information regarding increased interest in EGS is available on the internet (Potter Drilling or Altaenergy).

EGS should be considered on par

with other renewable energy resources. Much effort is required for EGS's commercial implementation. It offers the advantages of being continually available and of making a small footprint on the land and adjacent environment. Some problems exist such as corrosion and silica solubility in very hot water. Petroleum production and drilling technologies easily support development of EGS.

EGS is constrained by the energy content of hot rock. A 50 Mw-equivalent power plant, for example, would daily have to remove the thermal energy from as much as 850,000 cu ft of hot rock in one set of assumptions. The thermal conductivity of rock is rather low, so extensive and controlled hydraulic fracturing would be necessary, not an easy task.

A more challenging and interesting task would be to drill into the magma region near a volcano. Drilling should be done with water as the drilling fluid under very high pressure. The result would be local cooling as the water flashes through the drillbit jets, resulting in high-pressure steam for geothermal power production. One well, gradually drilled to increased depths, could continually produce large volumes of steam for geothermal power.

Biomass

Biomass residues can be used as boiler fuel, and the forest products industries use their residues as boiler fuel for their own internal consumption, but the byproduct may have other value, including returning it to the land.

Both gathering and transporting biomass residue constrains the size and associated economies of scale of electric power generation facilities. Recently announced facilities produce only 50 Mw of electricity.

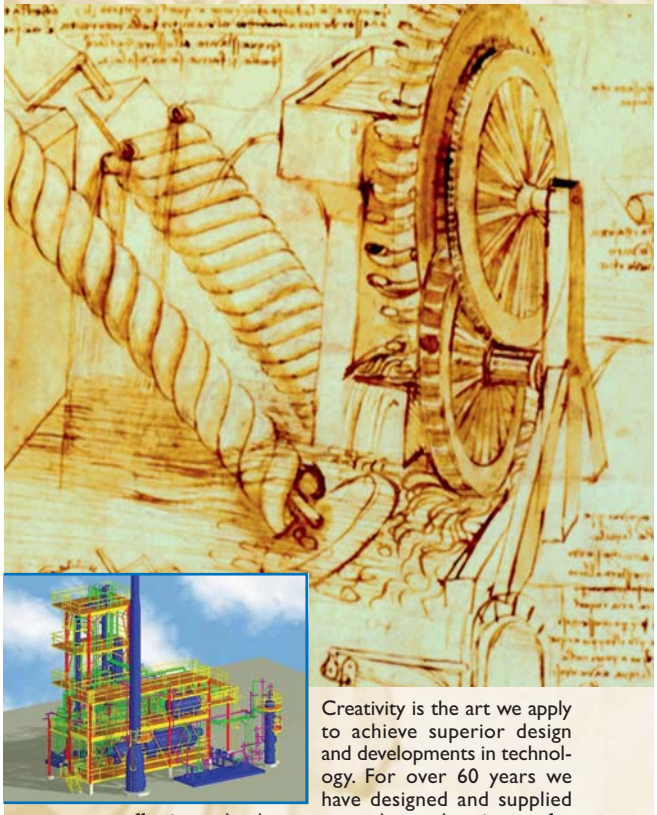
Liquid fuels from biomass—fermentation ethanol and biodiesel—are supported by federal regulations and subsidizes, and agri-industries and farm groups lobby for them in Congress. However, these biomass transportation fuels should not even be considered for favorable federal and state support as long has they are developed with the use of fossil fuels.

The net energy from fermentation ethanol that exceeds the fossil energy inputs is a matter of considerable debate. One author averaged several studies of net energy from fermentation ethanol production and found it to be a negative 2%.[18]

Other carbon sources

Petroleum is the dominate source of liquid transportation fuels. In addition, compressed natural gas is receiving increased attention as a transportation

Italian design
A masterpiece



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fuel. There are several other sources of organic carbon for transportation fuels such as coal, tar sands, oil shale, and black shales.[19]

Furthermore, even marginal petroleum reservoirs, deep offshore reservoirs, and sophisticated enhanced oil recovery techniques may yield oil and gas at costs below that of many of the energy alternatives discussed in this article.

No energy independence

This article has noted many difficulties with our nation's becoming "energy independent" using particular domestic options other than nuclear—which is beyond the scope of this article (France, however, has shown that nuclear energy remains an excellent choice for electric power production).[20]

It is impossible for the US to be "energy independent" using only domestic fuels.[21] Newspaper columnist, John Stossel, has made similar observations.[22]

Renewable energy resources are very much constrained by the impossibility of their ability to be scaled up to power huge facilities such as refineries and (currently coal-fired) power plants.

The "learning curve" is limited in reducing the cost of renewable energy due to repetitive activities. Investment costs frequently increase when energy costs increase.

Renewable and alternative energy resources will not become competitive with fossil and nuclear energy without continued major government subsidies—a drain on US taxpayers and on the national economy. ✦

References

References are available from the author at HarryWParker@comcast.net.

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Harry W. Parker (HarryWParker@comcast.net) is professor emeritus of chemical engineering, Texas Tech University. He has been involved in energy-related research at many levels, including in positions with Phillips Petroleum Co. and Washington, DC, research organizations. He was associate and full professor in the Texas Tech University Department of Chemical Engineering from 1970 until his retirement. In November 2008 Parker was awarded the Technology Innovation Award by the Brazosport section of the American Chemical Society. He holds degrees from Texas Tech University and Northwestern University.

Fourth-quarter results slide on weaker oil, gas prices

Marilyn Radler
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Statistics Editor

Collectively, a sampling of US and Canadian operators posted dismal results for the fourth quarter of 2008.

In a group of 48 US-based producers and refiners, 26 recorded a net loss for the quarter. The group's full-year results show that 18 incurred a net loss for 2008.

In the sample of eight companies based in Canada, two reported a quarterly loss. As a group, their combined earnings declined 49% from a year earlier.

Oil and gas prices plunged during the quarter, although operating costs remained high. Some refiners experienced a sharp downturn in earnings as gasoline prices plummeted on weak demand and swelling inventories.

Boosting the fourth-quarter results of some of the operators were net gains on the mark-to-market of hedges and derivatives contracts. Meanwhile, others were hard hit by impairment charges.

A sample of service and supply firms fared much better as a whole for the fourth quarter and the full year. The 21 companies in this group reported a combined 3% increase in 2008 net income compared with 2007, although their combined earnings for the fourth quarter were down from a year earlier. Revenues, however, were up sharply from a year earlier for both the quarter and the year.

Prices, margins

In the final 2008 quarter, the front-month futures contract for West Texas Intermediate on the New York Mercantile Exchange averaged $59.06/bbl.

This compares with $118.22/bbl in third-quarter 2008, and $ 90.50/bbl in the final 2007 quarter.

Gas prices also fell in the 2008 fourth quarter, with the front-month NYMEX contract averaging $6.398/MMbtu, down from $7.392/MMbtu in fourth-quarter 2007.

High product prices suppressed demand during the second half of last year. The average pump price for all formulas of unleaded gasoline in the US reached as high as $4.165/gal in the first week of July 2008, and then dropped to $1.71/gal in the final week of last year. Refinery utilization in the US sank to below 85% in December.

Cash operating margins for refiners on the US Gulf Coast averaged $5.45/bbl in the 2008 fourth quarter. This compares to an average of $8.83/bbl a year earlier, according to Muse, Stancil, & Co.

Integrated companies

The integrated firms in the sample of US-based operators reported weaker results for the recent quarter compared with a year earlier. But for the entire year, revenues and earnings for these companies were generally improved from 2007, benefiting from record oil and gas prices in third-quarter 2008.

These companies' fourth-quarter earnings were mostly lower due to weaker oil prices and higher operating expenses.

But ConocoPhillips posted a $31.764 billion loss for the fourth quarter due to charges, including a $7.4 billion write-down on the company's investment in Lukoil. ConocoPhillips also recorded a $25.4 billion impairment of all its E&P segment goodwill, the difference between the purchase price of assets and their net worth.

ExxonMobil reported that its $7.82 billion earnings for the fourth quarter were down as higher downstream margins were partly offset by weaker crude oil prices, higher operating expenses, lower chemical volumes, and the lingering impacts of Gulf Coast hurricanes in the final 2008 quarter.

For the 2008 fourth quarter, ExxonMobil's revenues were down 28%, and earnings were down 33% from a year earlier. For the year 2008, the company's revenues climbed 18% from 2007, while net income increased 11% to a record $45.22 billion.

Chevron Corp. recorded a 26% decline in fourth-quarter 2008 revenues but a slight gain in net income for the quarter. Income from the company's upstream operations declined to $3.15 billion from $4.84 billion a year earlier. Meanwhile, Chevron's refining, marketing, and transportation income soared to $2.08 billion from $204 million in the fourth quarter of 2007.

"Fourth-quarter earnings for our downstream business improved as the lower cost of crude oil feedstocks used in the refining process helped boost margins on the sale of gasoline and other refined products," said Chairman and CEO Dave O'Reilly. "Lower quarterly profits for our upstream operations reflected a sharp decline in crude oil prices from a year ago," O'Reilly said.

Independent operators

Many of the independent oil and gas producers in the sample of US-

US OIL AND GAS FIRMS' FOURTH QUARTER 2008 REVENUES, EARNINGS

	Revenues		Net income		Revenues		Net income	
	4th quarter				Full year			
	2008	2007	2008	2007	2008	2007	2008	2007
	Million $							
Anadarko Petroleum Corp.	2,997.0	2,760.0	786.0	265.0	15,723.0	15,892.0	3,261.0	3,781.0
Apache Corp.	1,936.9	3,019.4	(2,945.6)	1,072.5	12,389.8	9,999.8	712.0	2,812.4
Apache Offshore Investment Partnership	1.1	2.1	0.4	1.3	8.0	7.8	5.3	4.8
Basic Earth Science Systems Inc.*	2.2	2.1	(0.8)	0.5	8.3	5.6	0.8	1.2
Berry Petroleum Co.	160.3	148.4	(12.0)	32.3	801.5	583.5	133.5	129.9
Bill Barrett Corp.	146.8	108.9	6.9	2.5	617.9	390.3	107.6	26.8
Cabot Oil & Gas Corp.	232.5	193.9	43.7	42.0	945.8	732.2	211.3	167.4
Cheniere Energy Inc.	0.7	0.6	(106.8)	(52.6)	27.5	83.3	(356.5)	(181.8)
Chesapeake Energy Corp.	2,982.0	2,088.0	(861.0)	303.0	11,629.0	7,800.0	723.0	1,451.0
Chevron Corp.	45,203.0	61,410.0	4,895.0	4,875.0	273,005.0	220,904.0	23,931.0	18,688.0
Cimarex Energy Co.	298.8	438.7	(1,048.7)	130.0	1,970.3	1,430.5	(901.7)	346.5
CNX Gas Corp.	206.1	119.7	57.5	29.9	789.4	479.5	239.1	135.7
Comstock Resources Inc.	100.2	95.5	(96.4)	21.7	591.0	332.0	252.0	68.9
ConocoPhillips	44,504.0	52,685.0	(31,764.0)	4,371.0	246,182.0	194,495.0	(16,998.0)	11,891.0
Continental Resouces Inc.	135.8	159.0	0.4	60.9	960.5	582.2	320.9	28.6
Delta Petroleum Corp.	53.5	54.0	(459.6)	(28.5)	281.3	197.0	(452.0)	(147.2)
Denbury Resources Inc.	223.9	323.1	43.8	106.0	1,365.7	973.1	388.4	253.1
Devon Energy Corp.	2,710.0	3,197.0	(6,816.0)	1,316.0	15,211.0	11,362.0	(2,148.0)	3,606.0
Dorchester Minerals LP	15.2	18.3	9.6	12.4	89.9	65.4	66.8	43.0
El Paso Corp.	1,343.0	1,262.0	(1,678.0)	160.0	5,363.0	4,648.0	(823.0)	436.0
Encore Acquisition Co.	167.7	239.7	229.0	19.4	1,135.4	754.9	430.8	17.2
EOG Resources Inc.	1,633.7	1,286.0	461.5	361.2	7,127.1	4,239.3	2,436.9	1,089.9
Exco Resources Inc.	272.4	270.2	(1,161.4)	(37.0)	1,490.3	894.6	(1,733.5)	49.7
ExxonMobil Corp.	80,495.0	111,965.0	7,820.0	11,660.0	477,359.0	404,552.0	45,220.0	40,610.0
Forest Oil Corp.	281.3	333.6	(1,382.6)	27.6	1,647.2	1,083.9	(1,026.3)	169.3
Frontier Oil Corp.	1,348.1	1,319.6	(97.4)	43.4	6,498.8	5,188.7	80.2	499.1
Helix Energy Solutions Group Inc.	540.9	500.2	(859.3)	121.3	2,148.3	1,767.4	(630.8)	320.5
Hess Corp.	7,383.0	9,456.0	(74.0)	510.0	41,094.0	31,924.0	2,360.0	1,832.0
HKN Inc.	0.6	6.3	(27.0)	0.5	19.5	24.3	(26.7)	3.2
Holly Corp.	923.9	1,440.2	50.6	49.8	5,878.5	4,806.8	(120.6)	334.1
Marathon Oil Corp.	14,345.0	18,185.0	(41.0)	668.0	78,569.0	65,207.0	3,528.0	3,956.0
Murphy Oil Corp.	4,479.5	5,608.6	127.4	206.1	27,512.5	18,439.1	1,740.0	766.5
Newfield Exploration Co.	338.0	398.0	(789.0)	313.0	2,225.0	1,783.0	(373.0)	450.0
Noble Energy Inc.	573.0	921.0	305.0	300.0	3,901.0	3,272.0	1,350.0	944.0
Occidental Petroleum Corp.	4,021.0	5,517.0	443.0	1,452.0	24,480.0	20,013.0	6,857.0	5,400.0
Parallel Petroleum Corp.	26.3	36.1	(158.6)	(8.3)	182.8	116.2	(131.9)	(4.7)
Pioneer Natural Resources Co.	472.6	530.9	(65.5)	204.7	2,338.3	1,830.6	220.1	372.7
Plains Exploration & Production Co.	328.2	493.6	(1,568.7)	80.0	2,403.5	1,272.8	(709.1)	158.8
Southwestern Energy Co.	500.1	402.8	104.2	71.6	2,311.6	1,255.1	567.9	221.2
Stone Energy Corp.	166.1	201.6	(1,316.4)	64.9	812.3	765.4	(1,137.2)	181.4
Sunoco Inc.	9,103.0	13,136.0	204.0	(9.0)	54,146.0	44,728.0	776.0	891.0
Tesoro Petroleum Corp.	4,326.0	6,533.0	97.0	(40.0)	28,316.0	21,948.0	278.0	566.0
Valero Energy Corp.	18,569.0	28,671.0	(3,278.0)	567.0	119,114.0	95,327.0	(1,131.0)	5,234.0
W&T Offshore Inc.	108.3	339.5	(851.4)	49.4	1,215.6	1,113.7	(558.8)	144.3
Warren Resources Inc.	16.5	20.2	(284.6)	4.0	109.2	61.6	(241.6)	11.4
Whiting Petroleum Corp.	213.8	251.1	(3.0)	45.8	1,222.1	818.7	252.1	130.6
Williams Cos. Inc.	2,202.0	2,489.0	130.0	225.0	12,352.0	10,486.0	1,418.0	990.0
XTO Energy Inc.	1,961.0	1,594.0	351.0	464.0	7,695.0	5,513.0	1,912.0	1,691.0
Total	**258,049.0**	**340,230.9**	**(41,580.8)**	**30,135.3**	**1,501,263.9**	**1,220,149.3**	**70,280.0**	**110,571.5**

*Third quarter.

SERVICE-SUPPLY COMPANIES' FOURTH QUARTER 2008 REVENUES, EARNINGS

	Revenues		Net income		Revenues		Net income	
	4th quarter				Full year			
	2008	2007	2008	2007	2008	2007	2008	2007
	Million $							
Baker Hughes Inc.	3,186.0	2,740.0	432.0	401.0	11,864.0	10,428.0	1,635.0	1,514.0
Cameron International Corp.	1,524.3	1,344.1	149.1	125.9	5,848.9	4,666.4	593.7	500.9
Diamond Offshore Drilling Inc.	903.2	666.7	293.5	164.9	3,555.8	2,601.3	1,311.0	846.5
Dril-Quip Inc.	132.8	135.5	32.2	25.0	446.4	503.8	86.9	107.9
Fluor Corp.	6,071.5	4,712.5	190.1	259.5	22,325.9	16,691.0	720.5	533.3
Foster Wheeler Ltd.	1,639.2	1,465.5	99.9	78.1	6,899.0	5,142.9	526.6	393.9
Gulfmark Offshore Inc.	121.9	91.5	59.3	12.7	413.2	309.2	183.8	99.0
Halliburton Co.	4,910.0	4,179.0	468.0	690.0	18,318.0	15,388.0	1,538.0	3,499.0
Hornbeck Offshore Services Inc.	121.0	101.1	35.1	25.8	433.6	357.4	117.1	94.8
Nabors Industries Ltd.	1,245.8	1,317.0	(84.0)	222.2	5,303.8	4,940.7	551.2	930.7
Noble Corp.	1,276.0	842.8	418.6	347.4	3,812.3	3,006.5	1,561.0	1,206.0
Oceaneering International Inc.	525.7	481.6	51.0	45.5	1,978.3	1,744.3	199.4	180.4
Parker Drilling Co.	212.6	486.8	7.0	2.9	831.2	661.1	25.6	104.1
Patterson-UTI Energy Inc.	520.5	569.8	85.1	79.5	2,210.7	2,116.5	347.1	438.6
Pioneer Drilling Co.	170.7	104.6*	(117.9)	(4.5)*	612.1	316.3	(62.7)	(39.6)
Pride International Inc.	621.6	482.4	234.7	135.0	2,327.9	1,965.9	852.1	784.3
Rowan Cos. Inc.	623.6	613.0	138.5	94.3	2,219.0	2,115.9	427.7	483.8
Schlumberger Ltd.	6,868.0	6,248.0	1,150.0	1,383.0	27,162.9	23,276.5	5,434.8	5,176.5
Smith International Inc.	3,056.4	2,297.2	199.2	167.0	10,774.0	8,768.4	767.3	647.1
Transocean Inc.	3,270.0	2,077.0	800.0	1,056.0	12,706.0	6,407.0	4,202.0	3,131.0
Weatherford International Inc.	2,634.6	2,191.8	348.1	331.0	9,600.6	7,832.1	1,353.9	1,070.6
Total	**39,635.4**	**33,147.9**	**4,989.5**	**5,642.2**	**149,643.6**	**119,239.2**	**22,372.0**	**21,702.8**

*Third quarter.

CANADIAN OIL AND GAS FIRMS' FOURTH QUARTER 2008 REVENUES, EARNINGS

	Revenues		Net income		Revenues		Net income	
	4th quarter				Full year			
	2008	2007	2008	2007	2008	2007	2008	2007
	Million $ (Can.)							
Enbridge Inc.	3,923.5	3,198.5	265.2	240.4	16,131.3	11,919.4	1,327.7	707.1
EnCana Corp.	7,783.4	7,191.0	1,318.2	1,324.4	36,798.3	26,560.8	7,275.5	4,845.8
Husky Energy Inc.	5,754.0	5,826.2	284.0	1,314.6	30,234.0	18,994.0	4,594.9	3,933.9
Imperial Oil Ltd.	5,942.0	6,740.0	660.0	886.0	31,579.0	25,443.0	3,878.0	3,188.0
Nexen Inc.	1,696.0	1,846.0	(181.0)	194.0	8,237.0	6,604.0	1,715.0	1,086.0
Pennwest Energy Trust	968.0	644.0	404.0	127.0	4,651.0	2,462.0	1,221.0	175.0
Suncor Energy Inc.	7,196.0	5,185.0	(215.0)	1,042.0	30,089.0	18,565.0	2,137.0	2,983.0
TransCanada Corp.	2,332.0	2,189.0	277.0	377.0	8,619.0	8,828.0	1,440.0	1,223.0
Total	**35,594.9**	**32,819.7**	**2,812.4**	**5,505.3**	**166,338.7**	**119,376.2**	**23,589.1**	**18,141.9**

based companies incurred losses in the 2008 fourth quarter.

Apache Corp. reported a $2.9 billion loss for the recent quarter and a 75% drop in its 2008 net income to $712 million, which includes a $3.6 billion noncash, after-tax reduction in the carrying value of its oil and gas properties stemming from significantly lower commodity prices at yearend 2008.

Plains Exploration & Production Co. incurred a similar noncash impairment charge on its oil and gas properties, which resulted in losses for the recent quarter and for 2008.

Exco Resources Inc. recorded a net loss in the recent quarter and for the year. The company said these results were impacted by a $2.8 billion pretax ($1.7 billion after-tax) ceiling-test write-down, partially offset by $484 million pretax ($290 million after-tax) mark-to-market gain on derivatives, and a $540 million income tax valuation allowance.

Anadarko Petroleum Corp. is among the E&P companies that posted positive net income for both the full year and for the fourth quarter of 2008. Anadarko reported fourth-quarter 2008 net income of $786 million. Of this, $750 million after tax was due to gains on derivatives and divestitures minus impairments and other adjustments.

Refiners

The refiners in the sample of US companies posted varied results for the fourth quarter and for the year. Holly Corp. and Tesoro Petroleum each recorded positive net income for the final 2008 quarter, but Valero Energy Corp. reported a loss for the 3-month period. Full-year results revealed a loss for Holly and Valero and $278 million in earnings for Tesoro.

Tesoro reported that earnings climbed to $97 million in fourth-quarter 2008 from a $40 million loss a year earlier, even though revenues declined 34%. The San Antonio-based refiner's expenses for the recent quarter were down 37% from a year earlier, due partly to the write-off of a $91 million receivable for which collection was deemed unlikely.

Tesoro Petroleum reported that its fourth quarter segment operating

income of $204 million was $196 million higher than in the fourth quarter of 2007, primarily due to higher gross margins, especially in the Hawaii and California regions, and improved results from its retail segment. The increase in segment operating income was partially offset by lower throughput rates.

Tesoro's gross refining margin increased to $12.47/bbl from $8.28/bbl in the fourth quarter of 2007. Margin realization improved as a result of efforts to increase crude flexibility and distillate production, the company said.

Valero's $3.278 billion loss in the fourth quarter brought the company's loss for the year to $1.131 billion. Excluding a $4.1 billion noncash loss from the impairment of goodwill would put Valero's fourth-quarter 2008 net income at $732 million and full-year 2008 net income at $2.9 billion.

Holly Corp. reported that the principal factor contributing to its increase in fourth-quarter 2008 net income was an increase in refined product margins, partially offset by a decrease in sulfur credit sales of $15 million. Overall refinery gross margins were $12.01/bbl for the quarter, a 22% increase from the fourth quarter of 2007.

Canadian firms

Most of the companies in a sample of eight producers and pipeline companies based in Canada posted positive net income for the fourth quarter and for 2008. Four of these firms posted a slide in earnings from fourth-quarter 2007, while two incurred a loss for the recent quarter.

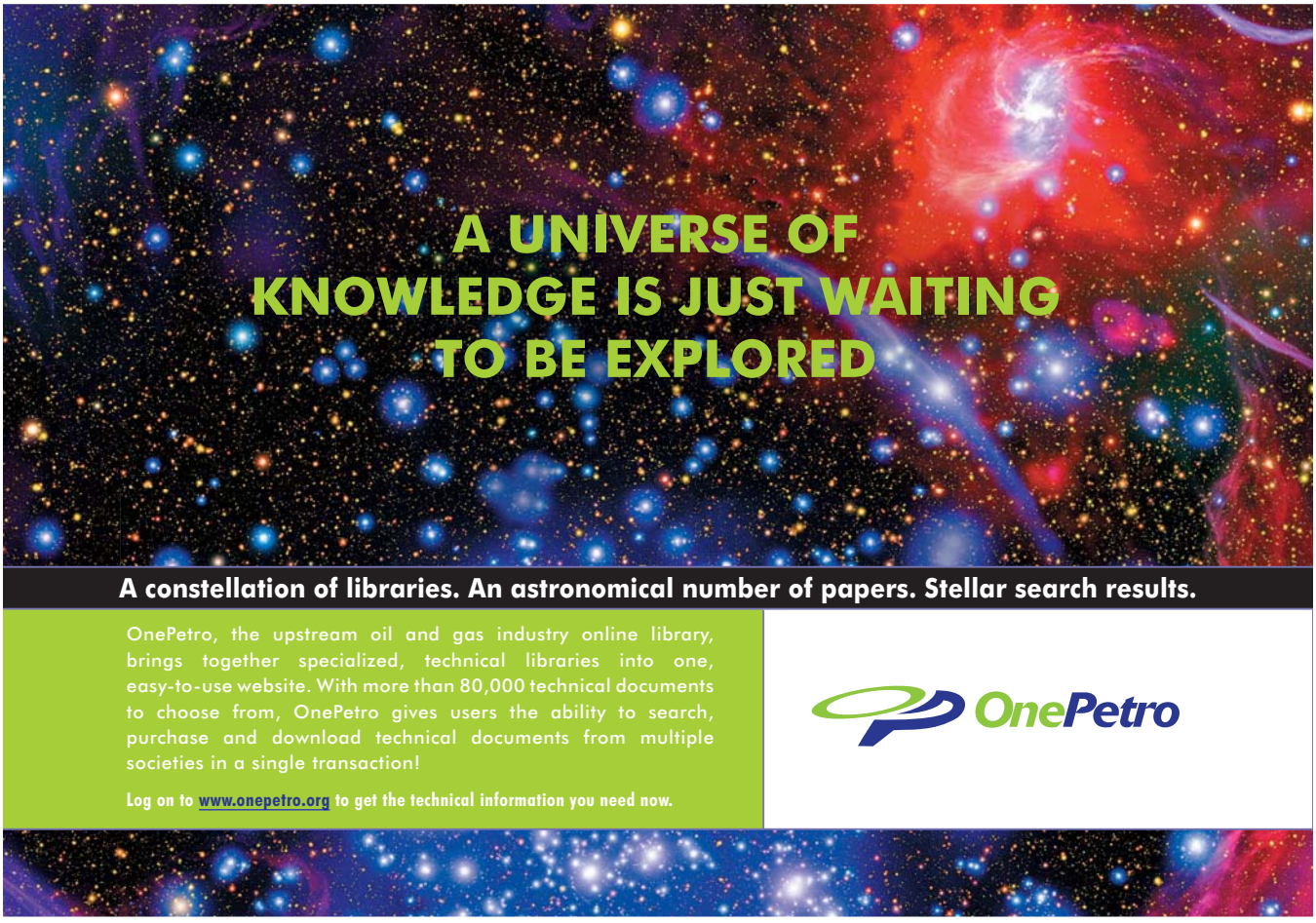
Although its revenues in the quarter climbed 39%, Suncor Energy Inc. reported a $215 million (Can.) fourth-quarter 2008 loss vs. $1 billion (Can.) in earnings a year earlier. The company said the decline was due primarily to major decreases in commodity prices in the 2008 fourth quarter.

"This negatively impacted both our sales revenues and the value of our inventories. In addition, we had higher operating expenses in our oil sands business. These impacts were partially offset by mark-to-market gains on our crude oil hedges," the company said.

Service, supply companies

The collective net income for a sample of service, supply, and engineering firms was down 12% for the final 2008 quarter despite a 20% jump in revenues from a year earlier. Higher expenses and taxes weighed on some of the firms' results.

Baker Hughes Inc. announced that its net income for fourth-quarter 2008



was $432 million compared with $401 million a year earlier. Net income for the year 2008 was $1.64 billion, up from $1.51 billion in 2007.

Chad C. Deaton, Baker Hughes chairman, president, and chief executive officer, said the company's fourth-quarter results were particularly strong in the Western Hemisphere despite the global economic slowdown and eroding commodity prices.

"In North America, service-intensive horizontal drilling remained strong, and our completion and production business posted solid results. Revenue increases in Brazil and Colombia led a strong quarter in Latin America. In the Europe-Africa-Russia-Caspian region, weakening of local currencies against the US dollar, a declining Russian market, as well as weather and project-related delays in the North Sea and Nigeria impacted our results. Sequentially, Middle East-Asia Pacific region revenue increases were led by strong results from Saudi Arabia, Indonesia, and Egypt," Deaton said. ✦

Think-tank advocates emergency gasoline stockpile

Sam Fletcher
Senior Writer

A Rice University think-tank said the US government should require the oil industry to maintain "average minimum gasoline inventories" to prevent emergency supply shortages and price spikes that occurred after hurricanes hit the Gulf Coast in 2005 and 2008.

That is arguably the most unusual of seven proposals for US gasoline policy included in a series of focused policy recommendations for President Barack Obama's administration issued at the end of January by the Baker Institute for Public Policy on the Rice campus in Houston.

The proposal provides no details of the mandated inventory program other than it would be "similar to what is currently done in Europe." However, it said, "A minimum gasoline inventory level for industry makes more sense than federal government-held stocks because of the physical specifications for gasoline, which has a shorter shelf life than crude oil. Thus, gasoline inventories would need to be cycled over time, but this can be done easily by industry so long as there are prespecified sustained minimum levels."

The proposal does not stipulate the minimum amount of inventory necessary to respond to an unexpected emergency, nor does it say whether the inventory should be centrally located or spread among refiners, jobbers, and retail outlets.

It's not clear whether stockpiles of extra gasoline would be limited to the Gulf Coast where Hurricanes Katrina, Rita, Gustav, and Ike came ashore. It doesn't suggest how far inland extra inventories of gasoline would be required to fuel evacuations from the coast, nor does it note whether similar inventories would be required in parts of California prone to wildfires and earthquakes or along the Mississippi and other rivers where flooding sometimes occurs.

It also doesn't address the problem of accessing those inventories if the electrical power is off, roads are blocked by debris or water, and civilian employees decide to evacuate their families instead of reporting to work as military and government emergency teams are required to do.

Possibly dual inventories of reformulated and conventional gasolines would be required, depending on the time of year and location of the emergency. Institute officials did not respond to multiple requests by OGJ for additional details of the proposal.

A federal requirement to maintain a certain level of inventory means additional expense for the industry, the report acknowledges. But, it said, "This cost would be offset allowing a small price markup that guarantees a rate of return, much as regulatory agencies permit in the power generation and natural gas industries."

Other proposals

The study recommends that the Obama administration take additional steps in formulating a national gasoline policy:

- Raise the US corporate average fuel efficiency (CAFÉ) standards to 50 mpg.
- Negotiate an international CAFÉ standard among major oil-consuming countries as part of a global climate agreement.
- Phase in a higher federal gasoline tax to maintain conservation gains.
- Establish a special diplomatic energy envoy to China.
- Increase federal spending on new energy technologies, energy efficiency, and alternative energy.
- Avoid "overly complex" policies to restrict carbon in the transportation sector, such as a national low carbon fuel standard.

High and rapidly fluctuating gasoline prices are a problem for low-income and middle-class US residents and by transport-dependent businesses, the study said. Last summer when retail US gasoline prices averaged $4.11/gal at the pump, families earning less than $15,000/year were spending as much

as 15% of their household income on gasoline—"double the proportion just 7 years earlier," said Baker Institute officials.

With domestic oil production in general decline since 1970, the US is more dependent on foreign oil than ever. It imported 13.5 million b/d or 65% of total consumption in 2007, up from 35% of US consumption in 1973. "US oil demand is up by almost 20% over demand in 1973," institute officials reported.

They said the US alone accounted for 45% of the increase in global oil trade in 1990-2005. This allowed the Organization of Petroleum Exporting Countries to "increase its share of the global market from 38% in 1990 to 43% in 2005—a market share not seen since 1980" at the peak of the last major oil boom, they said.

"To the extent that the US—or some group of large oil-consuming countries—takes actions to reduce oil demand, it can lower the market price and reduce the monopoly power of key oil-producing countries, some of whom may have hostile intentions towards the US and its allies," said the Baker Institute report.

Yet when the 1979-80 oil boom went bust in 1981, with oil prices plummeting by 1986 to the lowest levels in decades, the first source of oil eliminated was not OPEC production with its advantages of large reserves and low lifting costs, but the marginal high-cost, low-production stripper wells in the US.

Once shut in, most of those stripper wells could not be returned to production and therefore were lost forever. More oil then had to be imported to make up for that loss.

Hard line on energy cuts

The study takes a hard line on reducing energy use apparently in spite of possible consequences.

"The new 35 mpg fuel efficiency standard will shave 2.3 million b/d from US oil demand by 2020," it said. "We must not undo this regulation because Detroit has fallen on hard times. Pushing for a more ambitious target of 50 mpg could save as much as 7 million b/d of oil over what would be consumed if we did nothing," it said.

However, organized labor is still a strong element of the Democratic Party, and ignoring "hard times" among auto workers may conflict with Obama's campaign promises to stop the layoffs and put more people back to work.

The report noted many governments in Europe and Asia have kept gasoline demand flat and funded social programs via "hefty consumer taxes" on oil and petroleum products. A similar policy would give the US government more money to repair aging roads and bridges while making it more expensive for motorists to use those facilities.

The additional tax income also would fund rebates to lower-income households to offset the regressive effects of the tax. Perhaps rebates will act as subsidies so the poor can buy as much gasoline as the middle class.

The Baker Institute suggests "a gradual phase-in of a higher gasoline tax" so consumers will have time to adjust to the additional cost at the pump. OPEC members have long complained of consumer nations that heavily tax fuels while blaming the cartel for high oil prices.

Abdalla Salem El-Badri, OPEC's secretary general, recently said, "Raising taxes can be to the detriment of both oil producers and consumers. From the consumer's perspective, higher taxes translate into higher prices at the pump. This impacts individuals and does little to instill consumer confidence in the current economic climate. For producers, higher taxes create further uncertainty for long-term planning in an already distorted price environment and volatile market."

Moreover, would a Congress that was talking a few months ago about temporarily lifting the federal tax on gasoline when pump prices were $4/gal be willing to risk reelection by hiking those same taxes?

While the US would like to reduce oil imports and improve its trade balance, oil is the primary source of income for several producing countries, generating revenue to finance public and social programs.

Saudi Arabia and Venezuela have said they need higher oil prices—around $75/bbl—to maintain their economies. And most of the OPEC and non-OPEC countries are producing at full capacity, so they can't bring more crude on stream.

However, OPEC has again proven in recent months that it can reduce crude production faster than the US can reduce crude consumption, halting a sharp drop in oil prices.

More research spending

The Baker Institute also suggested: "More aggressive research and development spending—particularly in electricity storage and transmission—could facilitate a switch to hybrid plug-in electric automobiles that tap renewable energy as a fuel source to compete with conventional gasoline."

It also would require more power plants burning fossil fuels to meet the enhanced demand for electricity.

"The existence of viable alternative energy technologies creates an incentive for oil producers to avoid price shocks and supply disruptions for fear that the new technologies would be more rapidly adopted, permanently displacing oil use," said the study. However, it does not explain how fear of losing market to alternative fuels will help the industry avoid supply disruptions caused by hurricanes that break pipelines and flood refineries or against attacks by rebels in Nigeria and Iraq that disrupt oil exports.

The Baker Institute report complained that the US lacks domestic refining capacity to meet rising summer demand, making the US market more dependent on gasoline imports and increasing the risk of summer price spikes. No new grassroots refinery has been built in the US in some decades because it has proven almost impossible for the industry to get past antipollution laws, resistance

from conservationists, and the prevalent "not in my backyard" syndrome.

Because the rise and fall of China's economy affects energy supplies and prices, the institute said a senior US diplomat "with energy experience" should be named to a new post as energy diplomacy liaison in Beijing. That liaison "could report to the vice-president, who could take a diplomatic lead on a high-level US-China dialogue much the way [former US Vice-President] Al Gore and Victor Chernomyrdin [then Russian prime minister] discussed US-Russian energy cooperation in the 1990s, paving the way for US-Russian joint investment in major energy projects," said institute officials. ✦

EIA outlook lowers oil, gas demand forecast

Nick Snow
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In its latest Short-Term Energy Outlook (STEO), the US Energy Information Administration has lowered its projections for oil and natural gas demand in 2009-10 as the global economic contraction continues to depress energy demand.

EIA now expects US real gross domestic product to decline 2.8% in 2009, leading to a reduction in energy consumption for all major fuels. EIA forecasts that an economic rebound will begin in 2010, with 1.9% year-over-year growth in US real GDP.

Average annual world oil consumption is projected to decline almost 1.4 million b/d in 2009, with consumption in Organization for Economic Co-operation and Development countries falling 1.6 million b/d. This expected decline is 200,000 b/d larger than in last month's STEO, reflecting lower expectations of global economic activity this year.

EIA assumes that worldwide GDP growth will decline 0.8% this year, followed by growth of 2.6% in 2010, compared with last month's assumption of a 0.1% decline this year and 3% growth next year.

Gas demand, production

The US economic downturn is also the principal cause for the expected decline in domestic gas consumption, EIA said, particularly in industrial usage, where gas demand is projected to fall 6% in 2009.

EIA sees US gas consumption declining 1.3% this year, and then rebounding a bit in 2010. However, it forecasts that gas consumption by the electric power industry will grow 0.4% in 2009.

Consequently, EIA's latest monthly forecast indicated that total US marketed gas production is expected to remain flat in 2009 and then fall by 0.8% in 2010. "Baker Hughes reports 916 natural gas rigs working in the United States as of Mar. 6, a decline of 43% from August 2008. Consequently, the robust growth in gas production in the Lower 48 states (excluding the Gulf of Mexico) over the last few years is expected to end as production reaches about 53 bcfd in early 2009, then declines during the second half," EIA said.

The extent of the second-half production decline "is highly uncertain and subject to fluctuations in demand and prices over the period," it added. "However, annual average production is still projected to be lower next year because of the decline in new wells drilled this year."

Oil, gas price forecasts

EIA forecasts that the global economic slowdown will cut the price of West Texas Intermediate crude by more than half from last year's $100/bbl average. It expects WTI to average $42/bbl in 2009, and $53/bbl in 2010. These price forecasts are slightly lower than in the previous STEO.

Federal Reserve Bank of Dallas, in its latest Houston Economic Update, said the West Texas Intermediate crude price has fluctuated at $34-48/bbl since early January. The Israel-Hamas and Russia-Ukraine conflicts, plus cold weather and production cuts by Organization of Petroleum Exporting Countries members, worked to boost prices but were trumped by the weak economy and the massive buildup in US crude inventories, which "pushed their levels far outside historical ranges," the Dallas Fed economists reported.

In contrast, very cold weather in Chicago and key East Coast markets held gas prices in place for much of the winter, said the Dallas Fed, "but as weather has moderated and winter ends, prices have fallen…to near $4/Mcf, the lowest level in over 6 years. Rising domestic production, Canadian imports, and very weak industrial demand combined to pull [gas] prices down in the absence of frigid temperatures," it continued.

EIA said the Henry Hub natural gas spot price is forecast to decline to about $4.70/Mcf this year, from an average of $9.13/Mcf in 2008 but then increase in 2010 to an average of almost $5.90/Mcf.

Downstream trends

The Dallas Fed reported that oil refiners' margins have slowly improved the past few weeks from very poor levels in December "and the last few weeks have been quite good. Operating rates, however, were relatively weak throughout the period."

It expects US liquid fuels demand to drop another 420,200 b/d to an average 19 million b/d this year after plunging nearly 1.3 million b/d to an average 19.4 million b/d in 2008. By 2010, it anticipates a 210,400 b/d increase to an average 19.2 million b/d in the wake of the expected economic recovery.

EIA replaced its petroleum products classification this month with a new liquid fuels category that includes natural gas liquids, biofuels, and liquids derived from other hydrocarbon sources such as coal and gas.

EIA reported in its latest STEO that retail gasoline prices, slowly increasing over the last 2 months, are projected to average $1.96/gal in 2009 and $2.18/gal next year.

"The monthly average price [of regular grade retail gasoline] is expected to peak slightly over $2/gal this year, although it remains possible that weekly prices could rise significantly higher at some point this spring or summer," EIA said. "Because of lower motor gasoline consumption, refining margins for gasoline are expected to remain depressed for much of 2009 but are expected to increase slightly in 2010 as consumption begins to recover."

EIA projects an average on-highway diesel fuel retail price of $2.19/gal for 2009 and $2.51/gal for 2010. "The expected continuing decline in diesel fuel consumption in the United States this year as well as the growing weakness in distillate fuel usage outside the United States are projected to result in a narrowing of refining margins for distillate throughout the forecast period. Because of the global weakness in industrial output, it is possible that we will see diesel prices fall below gasoline prices this summer," it added.

Texas, Houston hit hard

The domestic rig count has followed oil and gas prices down, according to the Dallas Fed report. Citing figures compiled by Baker Hughes Inc., it said the number of rigs making hole peaked during September 2008 at 2,031 before dropping to 1,720 at yearend and 1,170 on Mar. 6. "Texas has been a major part of the slide, accounting for 58% of the fall in the US rig count since yearend," it said.

"Production of goods consumed in the drilling process is falling along with the rig count, but demand for durable goods (pump, drill pipe, bits) can be down as much as 90% as parts are cannibalized from rigs not in service. Layoffs are widespread," it added.

Houston, the nation's foremost oil and gas center, is especially feeling the pain, said the Dallas Fed economists in their report. "Houston's growth advantage over the rest of the nation during the past 5 years—oil and natural gas—has not only evaporated in the face of a global commodity bust but has turned into a definite liability. The coming year will see significant job losses in Houston, led by the energy sector," the analysts said. ✦

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AMERICAN PETROLEUM INSTITUTE

Deutsche Bank analyzes oil production costs

Marilyn Radler
Senior Editor-Economics

A recent Deutsche Bank analysis finds that in the short term, oil prices likely would have to fall to $20/bbl and below for nonmembers of the Organization of Petroleum Exporting Countries to shut in a large amount of production.

However, with investment now falling, the downside risks to supply forecasts are increasing. This suggests that upside price risks, once demand recovers, are considerable.

Deutsche Bank used research partner Wood Mackenzie's country-by-country database to gain a better understanding of the potential impact of the current global economic turmoil on oil supply in both the short and medium term.

To assess the volume of current production that may be vulnerable to falling oil prices, the analysis started with a review of the cash costs (operating expenses plus royalties) of extracting oil within the world's main producing regions and reviewed the risks to current production in mature basins.

With the costs of developing new fields substantially higher and new investment decisions sharply reduced, the analysts also looked at what oil price would be required for projects to deliver an economic return in today's growth markets of Angola, Brazil, the US Gulf of Mexico, and Nigeria's deep waters.

Deutsche Bank analysts Lucas Herrmann, Elaine Dunphy, and Adam Sieminski said four simple observations can be made. First, cash operating costs are very low. On average the cash cost of extracting a barrel of oil in the mature and higher-cost, non-OPEC markets of Russia, UK, Norway, and Alaska is about $15/bbl—greatly below the current oil price. Only in the Canadian oil sands do average cash costs of about $28/bbl approach the prevailing $35-40/bbl price of West Texas Intermediate.

Second, the analysis found that lower oil prices would shut in much oil production. Looking at the marginal cash cost curves within these mature regions, a modest 700,000 b/d of production would be cash negative with an oil price of $30/bbl, including 400,000 b/d of oil sands production. However, at a $20/bbl WTI oil price this rises towards a more substantial 3.5 million b/d shut in.

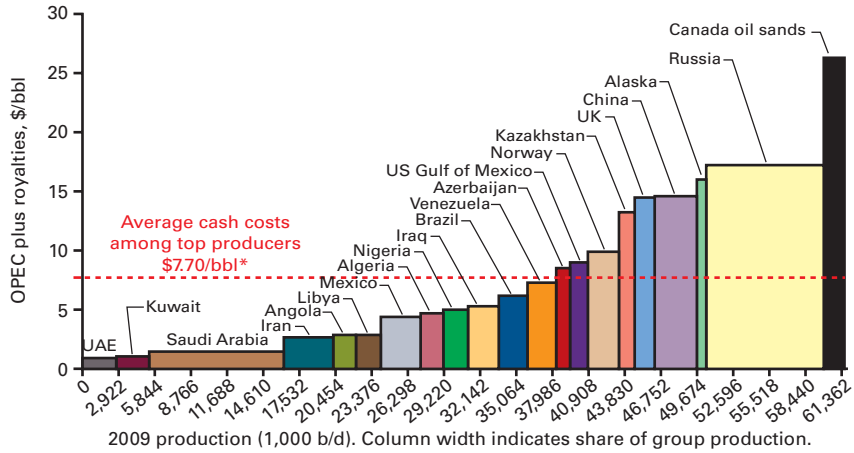
The third observation is that decline rates could curtail supply quickly. Past oil-price collapses have been associated with a sharp increase in the decline rates observed in mature basins.

Using past production curves as a proxy, Deutsche Bank estimates that as much as 1.5 million b/d of supply could be lost to accelerated decline over the next 2 years within the US onshore, Alaska, Canada, UK, Norway, and Russia.

Deutsche Bank believes that few supply estimates allow for these decline rates. Non-OPEC decline rates have averaged 7% over the 2000-2008 period, led by mature regions, according to the analysis. The decline rate over the period was about 21% in the UK and about 18% for the US offshore, the report shows.

Finally, the analysts see that new supply projects are being postponed. Within the growth regions, the rise in costs and taxes in recent years suggests that the average oil price necessary to achieve a 15% rate of return is now $68/bbl in Angola, $62/bbl in the US Gulf of Mexico, $60/bbl in deep-water Nigeria and in Brazil, although this depends heavily on the scale of the develop-

Production costs in major oil producing regions



*Average is $12.50/bbl excluding OPEC countries.
Source: Deutsche Bank

Production at risk in mature provinces*

	Oil prices below $20/bbl	Oil prices below $30/bbl	Oil prices below $40/bbl
	1,000 b/d		
UK	471	132	70
Norway	228	47	20
Canada oil sands	1,610	460	—
Alaska	18	15	—
Russian export	1,033	—	—

*Excludes US Lower 48.
Source: Deutsche Bank

ment considered.

"Whilst this is in line with our estimate of the companies' long-run planning price, against the current economic backdrop, it comes as little surprise that 2008 saw fewer final investment decisions taken than in any year since 1989 despite the surge in the oil price," the analysts said. ✦

EPA proposes CO_2, greenhouse gas reporting rule

Paula Dittrick
Senior Staff Writer

The US Environmental Protection Agency has proposed the first comprehensive national system for reporting emissions of carbon dioxide and other greenhouse gases produced by major sources.

The other gases covered by the proposed rule are methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride, and other fluorinated gases, including nitrogen trifluoride and hydrofluorinated ethers.

EPA Administrator Lisa P. Jackson said the reporting would provide comprehensive and accurate data about the production of GHG emissions. The proposal covers about 13,000 plants, accounting for 85-90% of GHG emissions in the US, she said.

The rule is being developed under the authority of the Clean Air Act. The proposed rule will be open for public comment for 60 days after publication in the Federal Register. Public hearings are scheduled for Apr. 6-7 in Arlington, Va., and Apr. 16 in Sacramento, Calif.

The new reporting requirements would apply to suppliers of fossil fuels and industrial chemicals, manufacturers of motor vehicles and engines, and large direct emitters of GHG emissions equal to or greater than a threshold of 25,000 tonnes/year.

WATCHING GOVERNMENT

Nick Snow, Washington Editor

Blog at www.ogjonline.com

Energy and water

The US Congress is finally ready to talk about the relationship between energy and water. The discussion is starting none-too-soon, as Congress considers ways to curb greenhouse gases, experts told the Senate Energy and Natural Resources Committee on Mar. 10.

"Using today's technologies, efforts to capture carbon from existing coal and natural gas plants or from new fossil [fuel] plants would cause increases in water consumption, a big concern for some regions, and may increase the cost of electricity, a concern for all," said Carl O. Bauer, director of the US Department of Energy's National Energy Technology Laboratory.

Carbon capture and sequestration would increase both water and electricity costs, Bauer said. "A doubling of the price of electricity would raise the cost of water 25-40% because moving water over large distances requires substantial amounts of electricity," he said.

The witnesses appeared before the committee to discuss S. 531, which Chairman Jeff Bingaman (D-NM) and ranking minority member Lisa Murkowski (R-Alas.) introduced on Mar. 6. The bill would authorize six studies that would analyze the impacts energy and water policies have on each other.

An emerging nexus

"Whether it involves electricity generation or fuel production, the choice of fuel stock can dramatically influence the amount of water needed as part of the process of producing that energy," Bingaman said in his opening statement, adding, "That nexus is starting to emerge in permitting decisions across the country."

Bingaman said, "Similarly, acquiring, treating, and delivering water consumes a large amount of energy. Improving water use efficiencies may yield multiple benefits in the form of reduced water demand during times of shortage, and reduced energy consumption with attendant cost-savings that result from reduced energy production."

Emerging energy-water issues seemingly have their biggest impact on electricity generation. But they also affect oil and gas. Although they weren't mentioned at the hearing, hydraulic fracturing and produced water are immediate examples.

Transportation fuels

Michael E. Webber, associate director of the Center for International Energy and Environmental Policy at the University of Texas at Austin, said, "The move toward more water-intensive energy is especially relevant for transportation fuels such as unconventional fossil fuels (oil shale, coal-to-liquids, gas-to-liquids, tar sands), electricity and biofuels. All can require significantly more water to produce than gasoline."

Problems also emerge because some energy processes that have less climate impact use more water. "We should encourage biofuels development only when it's not water-intensive," said Peter H. Glieck, president of the Pacific Institute in Oakland, Calif.

"Let's promote additional research and development on ways traditional energy sources can use water more efficiently. We're going to continue using fossil fuels for a long time," Glieck said.

Murkowski noted, "Several people say water is 'the next oil' in terms of competition. I believe we're moving in that direction, and it could be a real fight." ✦

WATCHING THE WORLD

Eric Watkins, Oil Diplomacy Editor

Blog at www.ogjonline.com

Strike oil, get financing

The global financial crisis is hurting eastern Africa's efforts to find oil and gas as prospectors cut back on investment and activities, according to one energy official from the region.

"The current global financial meltdown and reduction in oil prices have adversely affected the exploration finance base of many companies," said Kenya's energy minister, Kiraitu Murungi.

"Many of the companies exploring for oil and gas in the region have put on hold, scaled down, or rescheduled their work," Murungi told a conference on oil and gas exploration in his country's Port of Mombasa.

Murungi said new applications for exploration licenses in Kenya have fallen to nearly none from a record 14 licenses issued last year as firms encouraged by record-breaking crude prices aggressively pursued oil in frontier zones such as eastern Africa.

Tullow's $2 billion

Still, some people are getting funds for exploration and development in the region despite the current global financial crisis. Consider the $2 billion loan that Tullow Oil secured last week even as the Kenyan minister was speaking.

Tullow said that $2 billion in loans was offered by BNP Paribas, Bank of Scotland PLC, Barclays Bank PLC, Calyon, ING Bank NV, Lloyds TSB Bank PLC, Natixis SA, NIBC Bank NV, and Societe Generale.

Also backing Tullow's $2 billion loan package was Standard Bank PLC, Standard Chartered Bank, Sumitomo Mitsui Banking Corp., Royal Bank of Scotland PLC, and IFC, a member of World Bank Group.

"These new debt arrangements represent a major milestone in the development of Tullow's financial capability," said Tullow Chief Financial Officer Ian Springett. "To put in place debt arrangements of this scale, particularly in the current credit environment, is a tremendous achievement," he said.

It is indeed a tremendous achievement, and Springett underlined the reasons for it, saying, "This demonstrates the quality of Tullow's assets as well as the strength of our banking relationships."

Ugandan exports coming

More to the point, Springett noted how the $2 billion loan will positively affect the company's plans. "Combined with our equity placing in January, we are strongly positioned to pursue our current investment plans and longer-term growth strategy," he said.

Hardly had the ink dried on the loan documents than Tullow announced plans to expand its early oil production scheme in Uganda and could be producing 10,000-20,000 b/d there within a few years.

According to Tullow Chief Operating Officer Paul McDade, oil from the early production scheme is intended for consumption in Uganda's domestic market, with first production of as much as 2,000 b/d expected at yearend or by early 2010.

However, Kenyan energy officials should take note of one more very important fact: The expansion of Uganda's domestic oil production plan won't delay a 100,000-150,000 b/d export plan involving the eventual construction of a 1,300-km pipeline to the Indian Ocean through—guess where?—Kenya's Port of Mombasa. ✦

API, NPRA studying proposal

The American Petroleum Institute and the National Petrochemical & Refiners Association both said they were analyzing the 1,400-page draft rule.

"API has spent more than 10 years in creating the API Compendium for measuring and estimating emissions, so we are not surprised by the complexity," API said.

The API Compendium has been endorsed by the US Department of Energy, EPA, the International Petroleum Industry Environmental Conservation Association, as well as other groups.

"Any final rule should be a unified system for state and regional governments that is practical for companies to implement," API said.

NPRA said it would like to see some basic principles included in a GHG reporting rule.

"Those would include reporting at the facility level, reporting on an annual basis, every effort to develop one standard for state and federal reporting, and rejecting the notion of a third-party verification requirement," NPRA said.

CERA comments

Cambridge Energy Research Associates issued a statement saying the rule could prove to be far reaching.

Robert LaCount, director of CERA's climate change and clean energy research, said the rule "draws on a long and complex list of reporting protocols to establish a federal standard that will now apply across all of a company's facilities regardless of their location."

LaCount also noted that the rule shifts reporting from mostly voluntary programs to a mandatory system "at breakneck speed."

The first annual report would be submitted to EPA in 2011 for the calendar year 2010, except for vehicle and engine manufacturers, which would begin reporting for model year 2011.

EPA estimates that the expected cost to comply with the reporting requirements to the private sector would be $160 million for the first year. In subsequent years, the estimated costs for the private sector would be $127 million/year. ✦

Iowa Forest City prospect may be large Paleozoic trap

George H. Miller
Consulting Geologist
Brady, Tex.

A 1930s type oil field prospect exists in the Forest City basin in southwestern Iowa.

This isolated graben-type filled depression of carbonates is in the shallow Paleozoic Silurian-Devonian Hunton petroleum trend whose northern two oil traps are represented by Falls City and Barada oil fields in Richardson County, southeast Nebraska. There, initial oil production was 50 to 900 b/d of oil from 2,400 ft (Fig. 1).

The 1930s type oil field prospect area is an extension of a proven oil field trend line that was developed by drilling thousands of wells into Paleozoic sediments from giant Oklahoma City field to Barada field, a distance of 200 miles or more (Fig. 2).

On the other hand, one deep well 100 miles north of the oil prospect has established the genetic petroleum system set forth by recent erudite academic authors.

Detrital sediments penetrated by one well, Amoco Eischeid-1, in 6-83n-35w, Carroll County, Iowa, drilled to 17,851 ft in 1986, established the Proterozoic Nonesuch shale as an enormous oil source zone for deep clastic enigmatic "reservoir" rocks and younger.

The genetic relation of the Nonesuch shale Proterozoic oil source zone and basin clastics is set forth on the left side of Fig. 3.

Petroleum system—Proterozoic

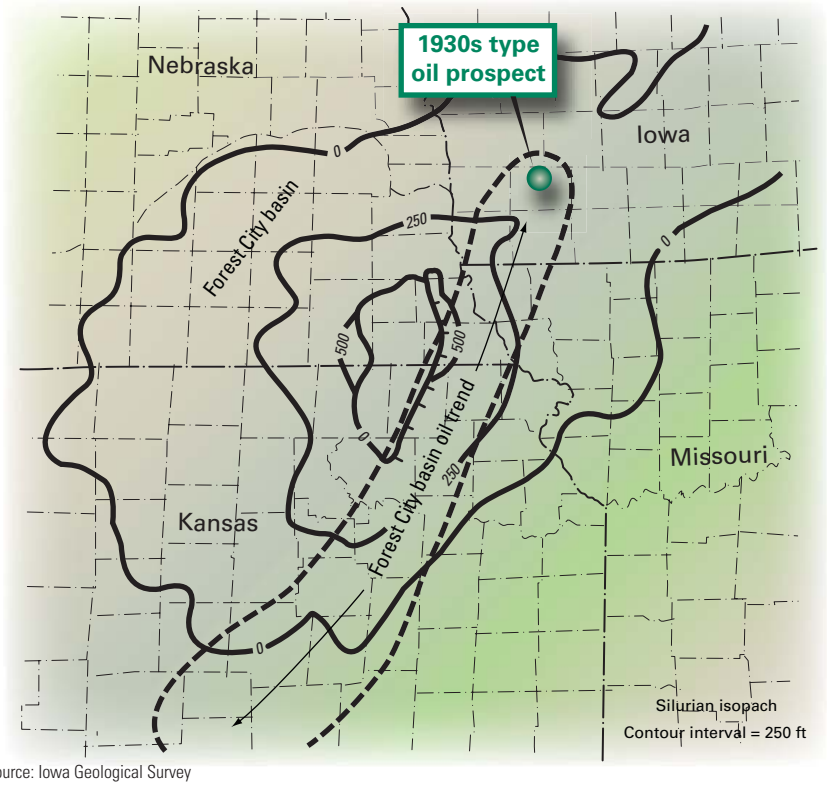
The potential petroleum system consisted of 12,178 ft of clastic sediments in a Proterozoic depression above Unit C, the Nonesuch shale oil source zone as depicted on the north side of the horst, MGA.

The 600 ft thick Nonesuch shale source bed equivalent was logged at 15,000 ft below surface in the Eischeid well. Its age was logged at 1,000-1,100+ Ma.[1]

The Eischeid well logged the Devonian at 1,200 ft. An unconformity was

EXTENT OF FOREST CITY BASIN OIL TREND

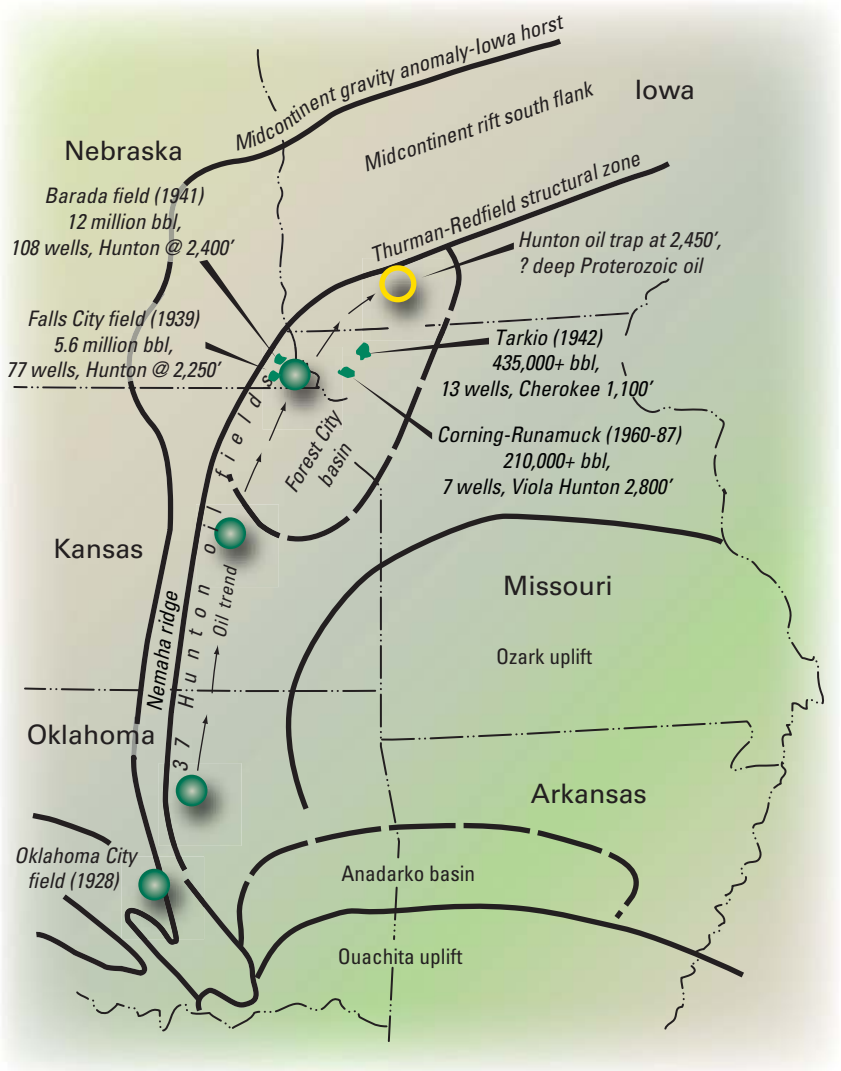
Fig. 1



Source: Iowa Geological Survey

MAJOR MIDCONTINENT STRUCTURAL FEATURES

Fig. 2



logged at 400 Ma. Devonian was lying on Ordovician 1,630 ft. No Silurian sediments were logged on the north flank of the horst in the graben.

Petroleum play—Paleozoic

On the right side of Fig. 3, the Silurian zone missing in the Eischeid well was logged at 2,470 ft below kelly bushing in the Bruno Miller-1, in 24-72n-39w, Montgomery County, Iowa, in 1988. TD below KB was 3,610 ft, 10 ft into arkosic Cambrian sandstone.

Devonian is lying on Ordovician in 24-72n-39w.

Hunton oil trap

The Midcontinent geophysical anomaly (MGA) consists of a horst in the middle, a basin to the north, and a basin to the south (Fig. 4).

The MGA is 1,000 miles long and 100 miles wide. The Nonesuch Lake has been postulated to have been on the same order of magnitude, a huge oil source environment that developed over geologic time.

The Bruno Miller-1 well was drilled on the south side of the horst in the Paleozoic sedimentary basin, graben, major depression, Forest City basin.

Note that porous Silurian carbonates are present on the south flank of the MGA, Iowa horst (right side of Fig. 3, and Figs. 4 and 5), 5½ miles south of 24-72n-39w, in 18-71n-38w[A], and they are truncated in 24-72n-39w.

Oklahoma City oil field

Oklahoma City field is a giant because of its location near the south end of the buried mobile basement feature—the Nemaha ridge—and its intersection with the northeast rim of the Anadarko basin.

The prominence of the uplift provided the environment for the development of very large flanking stratigraphic traps in the Siluro-Devonian Hunton limestone.[2]

Oil trend discoveries

The Hunton oil trend line begins with Oklahoma City field (Fig. 2).

A Silurian oil trap question to be answered is whether the 200-mile proved oil trend of Hunton oil traps, which follow the Nemaha ridge, where truncated at the even larger buried mobile feature the Midcontinent rift, a 40+ mile extension, provide the environment for the development of very large flanking traps in the Hunton, and thus the potential for a major Hunton truncated oil trap in Iowa?

1. *Play evaluation (shallow-Paleozoic).*

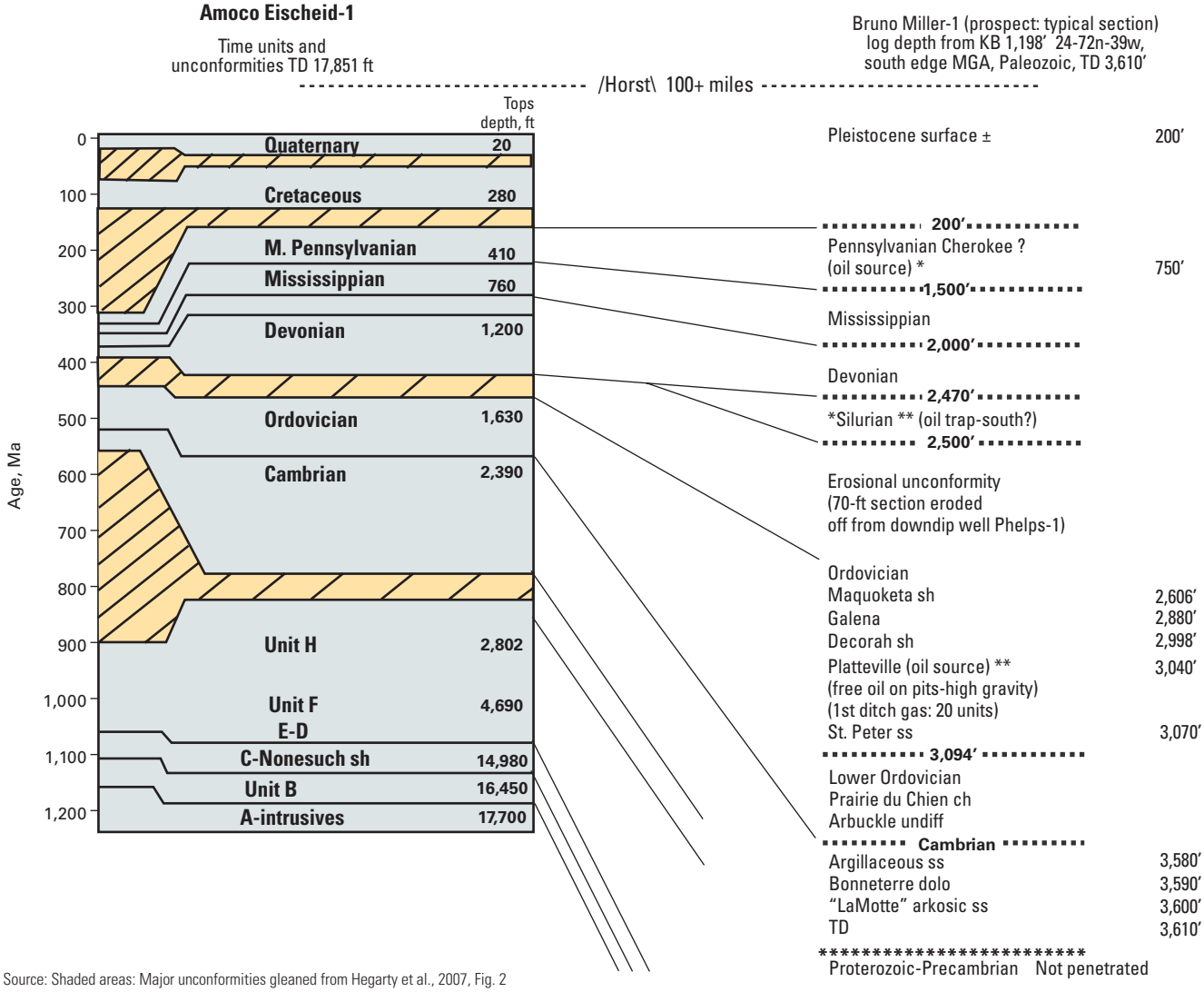
The Hunton stratigraphic unit exists from Oklahoma City field in the Anadarko basin to Falls City and Barada fields in the Forest City basin. The 200-mile underlying, controlling, structural, tectonic, petroleum accumulation "buried mobile feature" was the Nemaha ridge. Extension of the trend line intersects the Silurian zone with the MGA.

2. *Genetic evaluation (deep-Proterozoic).*

Underpinning a reliable petroleum system model for the Midcontinent rift system, Hegarty et al.[1] set forth the criteria for the huge deep Nonesuch shale as an oil source bed, which is often quoted as having a remarkable low

Iowa geological correlations

Fig. 3



Source: Shaded areas: Major unconformities gleaned from Hegarty et al., 2007, Fig. 2

temperature history with oil dripping from the shale zone in a copper mine to the north.

The Iowa Geological Survey[3] echoed the petroleum source rock and the obscure potential detrital overlying Proterozoic petroleum system.

But there is not one word in regard to the known Hunton oil traps within the 0 to 500-ft contours of Fig. 1 and the Silurian truncation with intersection of the Midcontinent rift and associated tectonic events in either article; Paleozoic play evaluation was not intertwined with the Proterozoic petroleum system study, although they intertwined at depth in 24-72n-39w.

Stratigraphy

Stratigraphic control for Fig. 5 comes from three induction "E" logs.

A' and A" surface geographical location overlie the deep-seated mobile feature as depicted in Fig. 5, the south flank of the Iowa horst and contiguous graben. The Thurman-Redfield structural zone was a linear series of domes, basins, and anticlines in Paleozoic rocks atop the south flank of the Midcontinent rift.

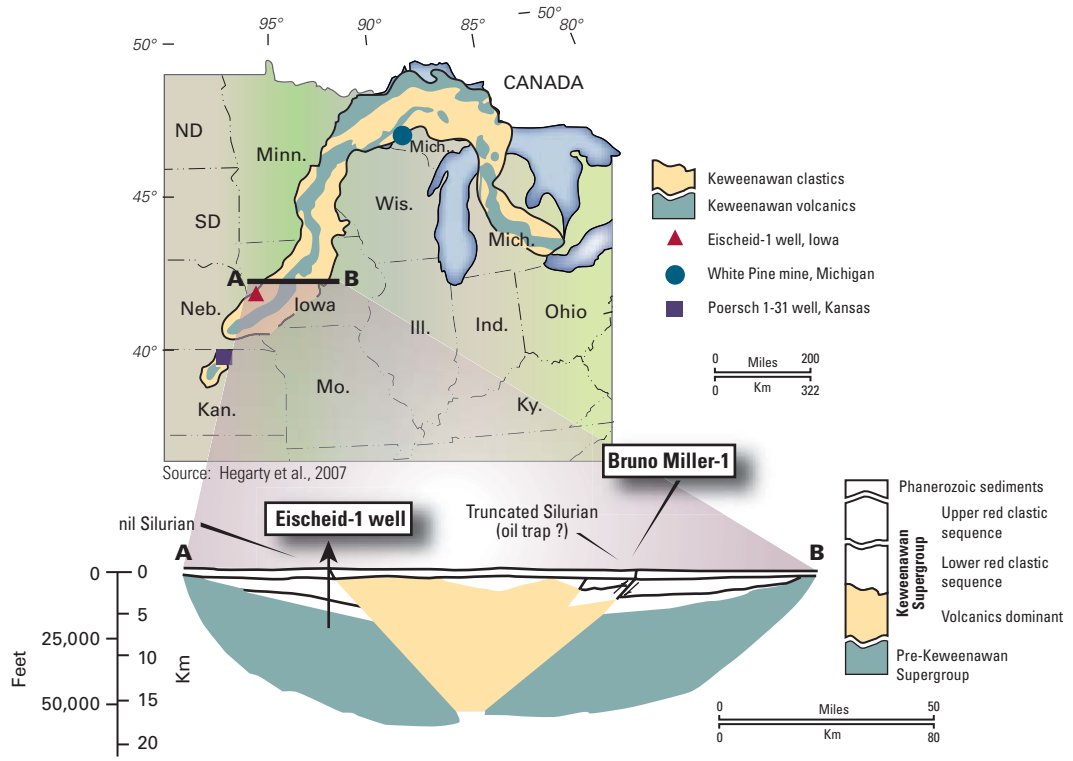
Western Seismograph 1984 regional gravity and magnetic surveys have all left their signatures for these features at the location of the Bruno Miller-1 (4-3-88) and the Ozona Brown-1 (5-19-08) in 24-72n-39w.

Zero time line was the top of Silurian porosity zone as depicted in [A] Teague Phelps-1 (8-12-84), which was 209 ft structurally low to truncated Silurian in [A'], a potential oil column of 200 ft, 40 ft of Silurian porosity, gross 80 ft eroded off the truncated Silurian [A] zone which is truncated at [A'] and [A"].

The Ordovician Maquoketa was below porous Silurian in Phelps-1 [A]. At

GEOLOGICAL SETTING OF THE MIDCONTINENT RIFT SYSTEM

Fig. 4



Source: Modified from Palacas et al., 1990

updip truncation of Silurian, A'-A", less than 5½ miles north, Devonian argillaceous carbonates (cap rock) are lying on older Maquoketa members, i.e., a potential stratigraphic oil trap to the south (Fig. 5).

The addition of 184 ft of Maquoketa sediments below the erosional unconformity within the 1 mile distance between A' and A" suggests that the exact location of forced folds, which were formed by fault blocks simply pushing up the overlying sediments and then erosion and nearby detrital accumulation, may be depicted in 24-72n-39w.

Note that the tectonic activity and subsequent increase in deposition stopped at the base of the Devonian, zero time line. Thus, there may be a major Silurian truncated oil trap to the south (Figs. 3-5).

Method of discovery

The source of Hunton oil trap exploration as depicted in Fig. 5 was as tangible as it can get.

A mineral core hole driller extracted three core hole logs from a file-cabinet identified by well numbers only. Two logs described very porous cores saturated with high gravity oil. The depth was more than 2,400 ft. A third handwritten (field copy) log described thick asphalt at 1,900 ft where the core hole was "lost."

During the 1980s, a core hole driller drilled core holes with three Longyear-type rigs exploring for lead and zinc in Iowa, Kansas, Oklahoma, Tennessee, and Kentucky. He reported to the author and others, "The two cores in Iowa had more high gravity oil recovered than all the others combined."

In Cumberland County, Ky., some core holes produced 500 b/d of oil from 1,500 ft below surface from eroded Ordovician Knox hills.

Possible analogs

Fig. 5 is a stratigraphic cross-section that depicts the stratigraphic Hunton (updip) truncation that flanks the south Midcontinent rift system as set forth for this type petroleum deposit zone of the Paleozoic that fits the model exactly of criteria set forth by giant Oklahoma City field for the Hunton.

Oklahoma City field is 12 miles long and 4½ miles wide. The Iowa Silurian Hunton prospect is 4+ miles north-south. No well has been drilled for 10 miles east or west of the potential Silurian oil trap within the limits graphically defined in Fig. 5 and within the 0 to 500-ft Silurian contours of Fig. 1 and on strike with the MGA.

The Silurian prospect is for an independent oil company looking for an oil trap with 20 million bbl of oil potential, more or less, at a shallow depth, in a large oil producing sedimentary-structural depression that is an extension of a 200-mile oil trend.

The deeper underlying Proterozoic petroleum system is also exactly defined by Fig. 5. The thermal history of the Nonesuch shale obtained from the Amoco Eischeid well drilled in 1986 penetrated 15,000 ft of Proterozoic clastics that may be suitable for hydrocarbon exploration.

Western Seismograph indicated that these same basin type sediments are below the 24-72n-39w area, on the MGA south flank, and above a deep-seated mobile feature; they are also on the hydrocarbon production trend line in this government section.

Hegarty et al.[1] wrote, "Two outstanding attributes of the Midcontinent rift system led geologists to the widely held

model that the Phanerozoic was tectonically quiescent," which may be academic cant. Above the erosional unconformity, base Devonian through Pennsylvanian sedimentation correlation was flat.

Immediately below the unconformity and base of Maquoketa Group within less than a mile is an additional 184 ft of sediments that may indicate contiguous force folds and faulting from Nonesuch shale through Upper Ordovician, not Phanerozoic and younger tectonic quiescent, but possible deep source beds with migration paths, solution trends, of oil for a defined Forest City basin Silurian Hunton oil trap. The same area lies at the end of an established oil trend line for the deep "enigmatic" Midcontinent rift petroleum system.

Robinson field was the first and largest oil field discovered in Illinois. Erudite geologists of the Standard oil companies informed the wildcatter Mike L. Benedum, that his trend line had been tested and found to have no merit.[4]

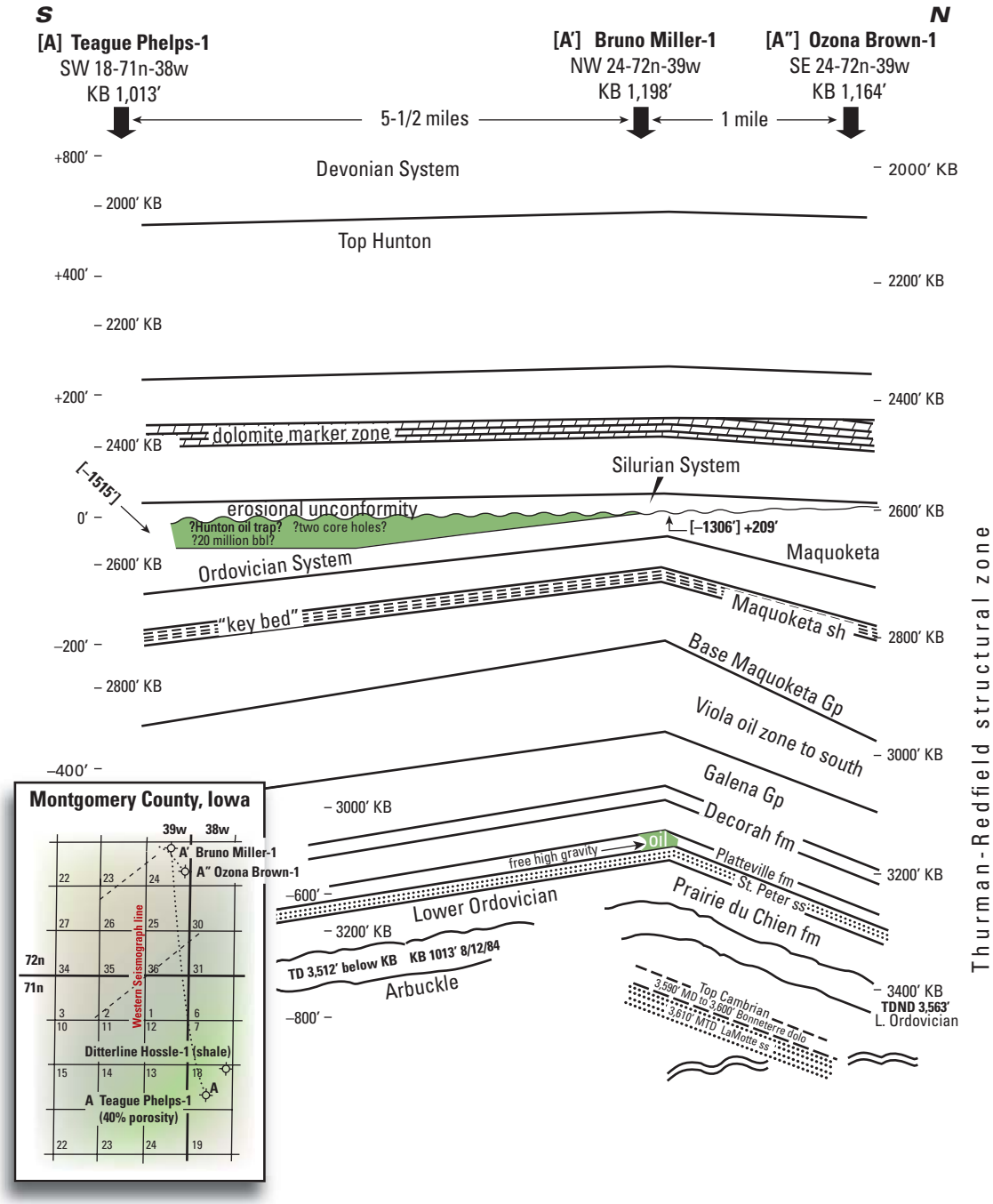
More than 100 number 1 wells in a few months proved that the correct trend line in Illinois was all that was needed for the first Illinois giant oil discovery.

Similarly, perhaps it will take shallow Paleozoic trend wells to discover and develop the Silurian oil trap extension of the Forest City basin oil trap(s) for the first oil field(s) in Iowa? Or will the deep elusive Phanerozoic petroleum system at the termination of a Paleozoic oil trend produce a huge oil discovery for the first oil field in Iowa? Or maybe they both share the same deep oil source?

Two updip Silurian truncated wells have been drilled. The downdip well

STRATIGRAPHIC CROSS SECTION, MONTGOMERY COUNTY, IOWA

Fig. 5



with Silurian porosity has been drilled. The geographical area in between is yet to be tested with a single well drilled for Hunton trapped oil. ✦

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The author

George H. Miller (ggh@cebridge.net) is a consulting petroleum geologist in Brady, Tex. He has more than 50 years of oil and gas industry experience and has been consulting since 1962. He started with Plymouth Oil, a Benedum-Trees company, as an analog seismograph plotter and later as geologist for North Louisiana, Arkansas, and East Texas. He has also worked the Cincinnati arch. He has an MS in geology from Texas A&M University.

Australia

Texalta Petroleum Ltd., Calgary, plans to shoot seismic on Exploration Permits 103 and 104 in the frontier Georgina basin in Australia's Northern Territory under a renegotiated farmout.

Texalta renegotiated terms of its late 2007 farmout with Officer Basin Energy Pty. Ltd., a subsidiary of Rodinia Oil Corp. Officer Basin Energy plans to assign its rights to Australia Energy Corp., newly incorporated with the same management as Rodinia Oil.

The work commitment is for 100 line-km of seismic on Permit 103 and 50 line-km on Permit 104.

Morocco

San Leon Energy PLC plans to negotiate with Morocco's ONHYM to convert its Zag reconnaissance license into an exploration license.

San Leon said a high-resolution aeromagnetic survey integrated with surface and subsurface data indicated large structures, including a 60-km anticline with hydrocarbon potential.

RWE-Dea took a farmout on the license just north of San Leon's Zag license. San Leon operates Zag with 50% interest, Longreach Oil & Gas has 30%, and Island Oil & Gas PLC has 20%.

Alaska

Oooguruk field off Alaska's North Slope reached giant status when operator Pioneer Natural Resources Co., Dallas, hiked the field's net resource potential last month.

Pioneer hiked Oooguruk's resource potential to 120-150 million boe net to its 70% interest from the previous estimate of 70-90 million boe. Eni Petroleum Inc. holds 30% interest.

Production, 3,000 b/d at the end of 2008, was expected to rise gradually to 10,000-14,000 b/d in 2011 and average 5,000 b/d in 2009. Pioneer is reevaluating the 2009 estimate after the initial production rate at the most recent development well was about 7,000 b/d.

Oooguruk is being developed from a gravel island in Harrison Bay 5 miles northwest of Oliktok Point.

Utah

No appreciable drilling success came from Delta Petroleum Corp.'s first three exploratory wells in the Utah Hingeline play other than to establish that oil appears to have migrated through the region, the company said.

The company impaired 90% of its acreage cost basis and believes it has condemned only six of the 21 intially identified structural features.

Delta, with 65% interest in the acreage, will likely seek further joint venture participation in Utah as it focuses a majority of its capital expenditures on lower risk projects.

Washington

High mud weights were required to control gas flows in several sandstone intervals in Delta Petroleum Corp.'s Gray 31-23 exploratory well in the Columbia River basin of Washington.

The gas column in the Kittitas County well appears to be much higher in the stratigraphic section compared with other wells in the basin, the company said. Delta expects to reach total depth by early April.

The well "has encountered numerous sandstones that contain several hundred net feet of porous and permeable sands based on wireline logs and core analysis. Porosities range from 12% to 17% with an average of 14% and permeabilities are very good and range from 27 md to 107 md," Delta said.

"Volumetric calculations based solely on logs and cores indicate the potential for significant gas volumes, and completion results will provide the necessary information to generate reserve estimates," Delta added.

The Denver company has begun permitting efforts for a second well but plans no further capital commitments it finishes the Gray well.

Pattern recognition-based approach finds rotating steering system faults

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J. Lehr
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Celle, Germany

J.W. Hines
University of Tennessee
Knoxville

A pattern recognition-based anomaly detection system for bottomhole assemblies can determine whether the tools in the BHA are operating in a nominal or degraded mode.

The developed system has demonstrated that it can detect faults in a rotating steering system tool and can provide about 16 hr of warning before tool failure. Furthermore, in a demonstration, the system detected about 94% of the faults present in a collection of runs known to contain steering system faults.

As the costs of rig downtime continue to increase, it is becoming increasingly important to mitigate or prevent downhole failures. In its present state, the described system enables faster root-cause analysis at maintenance facilities and in the field. In the near future, plans include distribution of the system to workshops and rigs so that they can make more accurate operations and maintenance decisions, such as the prevention of rerunning faulted tools.

These applications provide monetary savings for both service providers and rig operators.

Need for system

Modern drilling equipment operates in increasingly severe environments, with downhole temperatures exceeding 200° C. and high-impact vibration events being common. Additionally, rig operators are asking tools to perform mission profiles that previously were impossible, thereby increasing the stress on the downhole tools. All the while, customers have started to demand in contracts a high reliability to help them prevent costly downhole failures and ensure profitability.

The current periodic maintenance practices have proven insufficient or cost intensive to meet these new challenges.

Because of this, industry is shifting toward simple condition-based maintenance approaches, which use design guidelines and rough operational thresholds to assess individual tool health. While this approach has value, there is a large amount of tool performance and environmental data collected during operations that companies have yet to incorporate effectively into the health assessment process.

This article presents a new, empirical model-based approach for detecting faults before failure in components of BHA tools. One can describe this approach briefly as using real-world examples of good runs to establish a statistical definition of unfaulted tool operation. To determine whether another tool operates normally, a statistical test determines if the tool operates in a nominal mode, in which the statistics are similar to unfaulted behavior, or degraded mode, in which the statis-

FAULT DETECTION

Run No.	No. of alarms	Detected?
1	274	Yes
2	186	Yes
3	11	No
4	313	Yes
5	44	Yes
6	241	Yes
7	259	Yes
8	1,703	Yes
9	322	Yes
10	0	No
11	105	Yes
12	673	Yes
13	643	Yes
14	421	Yes
15	142	Yes
16	51	Yes
17	178	Yes
18	606	Yes
19	80	Yes
20	356	Yes
21	82	Yes
22	592	Yes
23	188	Yes
24	83	Yes
25	79	Yes
26	140	Yes
27	680	Yes
28	675	Yes
29	138	Yes
30	76	Yes
31	1,822	Yes
32	126	Yes
33	1,921	Yes

tics differ from unfaulted behavior.

In this way, one can assess tool health based on its actual performance, as compared with its expected performance for quantized environmental factors such as:

- Elevated static loads such as bending.
- Dynamic loads such as lateral vibration.
- The combination of static and dynamic loads.

Operational data collected from a rotating steering system tool demonstrates this approach. The developed system will allow service providers to make more agile maintenance decisions and provide operators the means to incorporate reliability into the well planning and operations processes, enabling monetary savings for both parties.

Anomaly detection

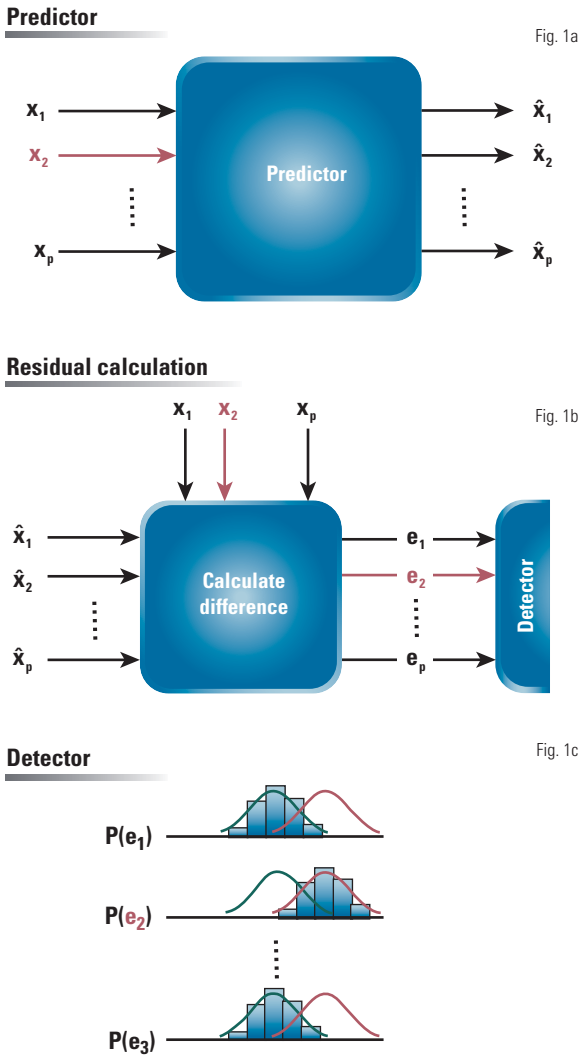
The goal in fault or anomaly detection is to detect subtle changes in process parameters beyond those normally expected. The petroleum industry has restricted the field of anomaly detection to the problem of monitoring mud flow for well control.[1-6]

These particular applications have the objective of detecting anomalies in mud flow to help operators prevent various problems, such as the occurrences of kicks, loss of circulation, and degradation of pump efficiency. These problems could lead potentially to costly rig downtime.

The historical development of the previously described kick-detection systems has two features that are of interest in development of anomaly detection systems that closely mirror those of other industries, such as the nuclear[7-9] and computing industries.[10 11]

PATTERN RECOGNITION PROCESS

Fig. 1



First, most implement a three-step process for anomaly detection:

1. Estimate signal values.
2. Calculate the residuals between the observed and estimates.
3. Pass the residuals to a detector to determine if the residuals indicate anomalous behavior.

Second, there is an increasing gravitation toward empirical models, as compared with physical models because empirical models often are more accurate and malleable for real-world applications.

The work discussed in this article uses the previously described three-step anomaly detection process (predict, calculate residuals, and detect) and purely data-driven algorithms to predict and detect tasks. This work also is, to the authors' knowledge, the first implementation of an anomaly detection system for BHA tools.

The system described in the next section demonstrates its application for detecting anomalies in a rotating steering system (RSS) using real-world data.

Method

As described in the previous section, the anomaly detection process has three major steps. The following hypothetical example provides more details on the process.

As depicted in Fig. 1, suppose that we have trained a predictor to estimate p signals based on their healthy correlations and we have trained a detector to recognize the distributions of the estimate residuals for healthy observations. For this example, let us suppose that a fault in the system has caused the second signal (denoted by x_2) to deviate from its healthy behavior.

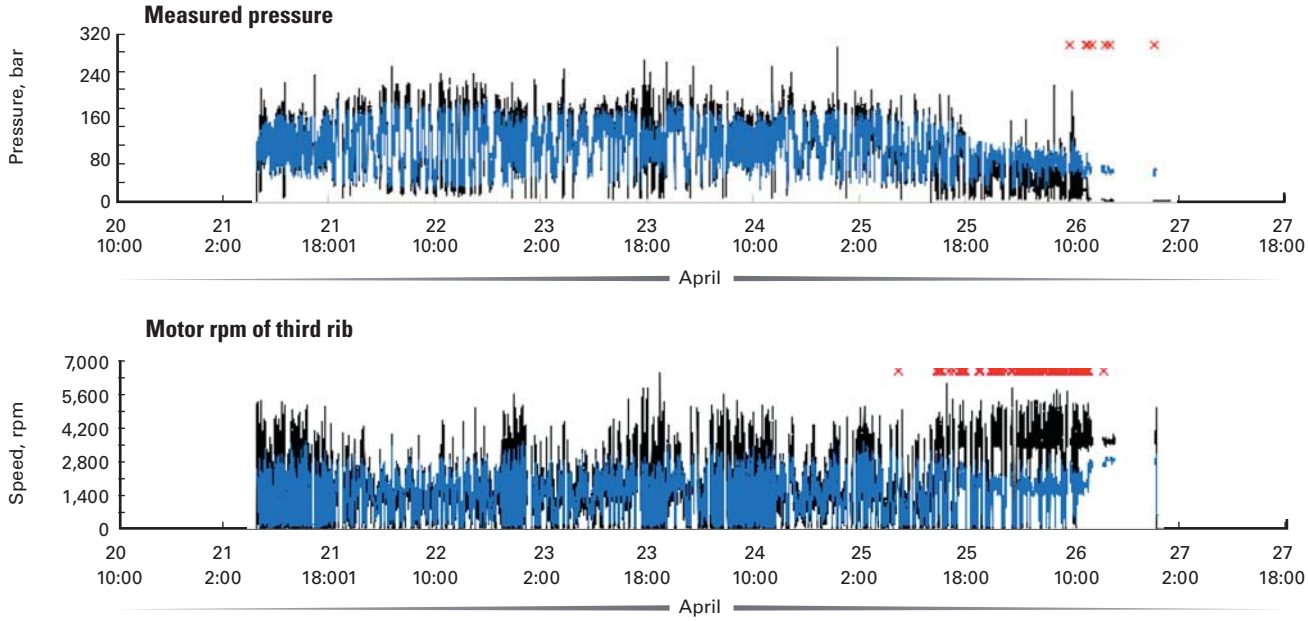
The first step in the process passes the p observed signals to the predictor that produces estimates of the signals based on their healthy correlations (Fig. 1a). Because training of the predictor used unfaulted data, the estimates will lie near to the expected values if no fault occurred in the system.

Next, we quantify the difference between the observations and estimates by calculating the residuals (Fig. 1b). Since the second signal deviates from its healthy behavior, we can expect the second residual (e_2) to have a different distribution than that of its healthy counterparts.

Once we have calculated the residu-

Fault detection

Fig. 2



als, we pass them to the detector, where we use a statistical test to detect slight deviations (Fig. 1c). The detector compares the observed probability distribution of the estimated residuals (denoted by gray rectangles) to a nominal (black dashed line) and degraded modes (red dashed line), only one of which is presented in Fig. 1c.

In the figure, we can see that the distributions of the residuals for the first and p^{th} signal lie close to the nominal mode. In these cases, the detector would conclude that healthy distributions more likely had generated the residuals; therefore, the detector would deem these signals as healthy.

This is not the case for the second residual. Notice that the observed distribution lies near the degraded mode. In this case, the detector would deem that the second signal does not represent healthy behavior, and it would raise an alarm.

This work uses the nonparametric fuzzy inference system (NFIS)[12] to predict the signal values and the sequential probability ratio test (SPRT)[13] to differentiate between nominal and degraded modes. A detailed description of these algorithms is beyond the scope of this article, but a reader can obtain addition information from References 12 and 13.

Operations

To demonstrate the previously described system, a study used it to detect faults in the hydraulic units of a rotating steering system (RSS). The study selected the RSS based on its high failure costs to rig operations and critical influence on overall BHA reliability.[14 15] In the system studied, three hydraulic units exert pressure on the borehole wall to steer the BHA in the desired direction.

The system first trained a NFIS predictor and SPRT detector on three signals collected from three hydraulic ribs: pressure, electrical motor current, and motor rpm. To complete the training, the system algorithmically chose exemplar observations of the selected signals from the memory dump data collected from more than 100 good runs.

In the next step, the system calibrated the detector by calculating the mean and variance of the predictor residuals for all good data. It also calculated the values of the mean shifts from the data by setting M_i to be $3\sigma_i$, where σ_i is the standard deviation of the ith nominal distribution.

It is important to note that the system performed this entire training procedure automatically. In fact, the automation is to the extent that the system updates the predictors and detectors daily, continuously integrating additional data as they become available.

The trained system then detected faults in a memory dump collected from real-world operations that contained a known. In this case, the fault is mud intrusion, where mud enters the hydraulics of the ribs and eventually leads to complete unit failure.

Fig. 2 shows the detected measured pressure and the motor rpm. In the figure, the observed values are black, the NFIS estimates are blue, and the alarms are red Xs.

The figure indicates that the hydraulic unit failed on Apr. 26 at 10:00, in that the unit no longer can build the required pressure. At that point, one can see that the system has generated numerous alarms.

Next, examining the rpm signal reveals a pronounced change in the level of the rpm as compared with the NFIS estimates. More specifically, for the

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observed pressure, the NFIS estimates a lower rpm, which agrees with nominal system behavior. Notice, however, that the rpm is not low but slightly higher than its estimates.

From the alarms, one can see that on Apr. 25 at 18:00, the rpm begins abnormal behavior. At this point, mud begins to enter the hydraulic system, resulting in a more viscous fluid. As a result, the motor must work harder to build pressure in the unit, which produces the observed change in correlations that the anomaly detection system senses.

In this case, one can see that the unit can build pressure for about 16 hr before the unit fails.

Now that this example has demonstrated the system performance for an individual run, it is important to take a step back and evaluate its performance during many runs that are representative of different operating conditions and failure modes.

To do this, the system evaluated 33 runs with validated RSS faults (see table). The system bases its decision on the number and extent of the alarms.

The results show that the system detected faults in 31 of the 33 runs for a detection sensitivity of about 94%. These results indicate that the developed approach is robust enough to detect reliably and accurately anomalies in the RSS. ✦

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Extraction route economical for benzene reduction, even for smaller US refiners

James Jones
Donald Bird
Turner, Mason & Co.
Dallas

A recent study quantified the economic incentive for extraction vs. saturation to lower the amount of benzene in a typical US refinery gasoline product. Benzene saturation and extraction are two viable and proven routes available to refiners for complying with the pending benzene limits for US gasoline.

The study, conducted by Turner, Mason & Co., Dallas, found that, although the extraction route has many complexities compared with saturation, it is economical for many refiners, even smaller ones.

Creative solutions such as regional extraction facilities can overcome real and perceived hurdles allowing smaller refineries the opportunity to participate in the potential economic reward from producing chemical benzene.

Benzene processes

By January 2011, US regulations will require that most US refiners lower the benzene content of their gasoline to 0.62 vol %. The primary source of benzene in gasoline is from the reformer and, to a lesser extent, the FCC, and any naturally occurring benzene found in crude oil.

The FCC is a minor contributor to gasoline benzene, but it is difficult to remove benzene from FCC naphtha. Benzene from crude oil is generally directed to the light naphtha cut and represents a small volume of the gasoline pool for most refiners. Much of this benzene is already saturated in refinery isomerization units.

Refiners typically concentrate on removing benzene from the reformate stream. They have several strategies available to control the benzene content of reformate.

They can practice aggressive fractionation of the reformer feed to eliminate benzene precursors, but this may be an unreliable route to future compliance because about 1% benzene is produced in the reformer from feed that contains zero precursors.

Saturation of benzene to cyclohexane appears to be a favored route that provides a measure of control to the refiner unavailable from the precursor-removal approach. This is accomplished in common isomerization units and specialized versions of this process con-

figured to handle higher concentrations of benzene typically found in light reformate. Many California refineries have successfully used this technology to produce low-benzene CARB gasoline since its introduction in the 1990s.

A third route is extraction of benzene from reformate for sale as a chemical. This proven technology is typically used in larger refineries or facilities owned by companies that participate in petrochemical markets in addition to producing fuels. We feel that refineries already extracting benzene will have the least difficulty complying with the looming 0.62 vol %/year benzene limit.

Saturation of benzene to cyclohexane is favored by most refiners not already extracting benzene. This technology provides a reliable method for controlling total benzene from reformate. Furthermore, it is a simple process with relatively low capital and operating cost.

Hydrogenation of benzene to cyclohexane requires about 4,500 std. cu ft of hydrogen and results in a volumetric gain of 20%/each barrel of contained benzene. The consumption of additional hydrogen could be an important factor for refineries with limited hydrogen supply.

Benzene and cyclohexane have about the same Reid vapor pressure; therefore, the effect on gasoline volatility is essentially neutral. The lower octane of cyclohexane relative to that of benzene, however, degrades the average octane of the gasoline pool.

Another route to compliance is to extract the benzene as a product with one of several extraction processes.

Benzene has always demanded a higher market price than its associated blending value in motor fuel; otherwise it would not have been produced. Extraction will, therefore, also be economically superior to saturation processes that further reduce the blending value of benzene, assuming a flood of new benzene does not disrupt current price relationships.

We believe, however, that real and perceived obstacles will discourage many refiners from choosing the extraction route. These obstacles include:

- Increased regulatory burden of storing and handling benzene.
- Economies of scale in the case of smaller refiners.
- Relative access to chemicals markets.
- A reluctance to enter new markets.
- The additional overhead cost associated with a new business line.

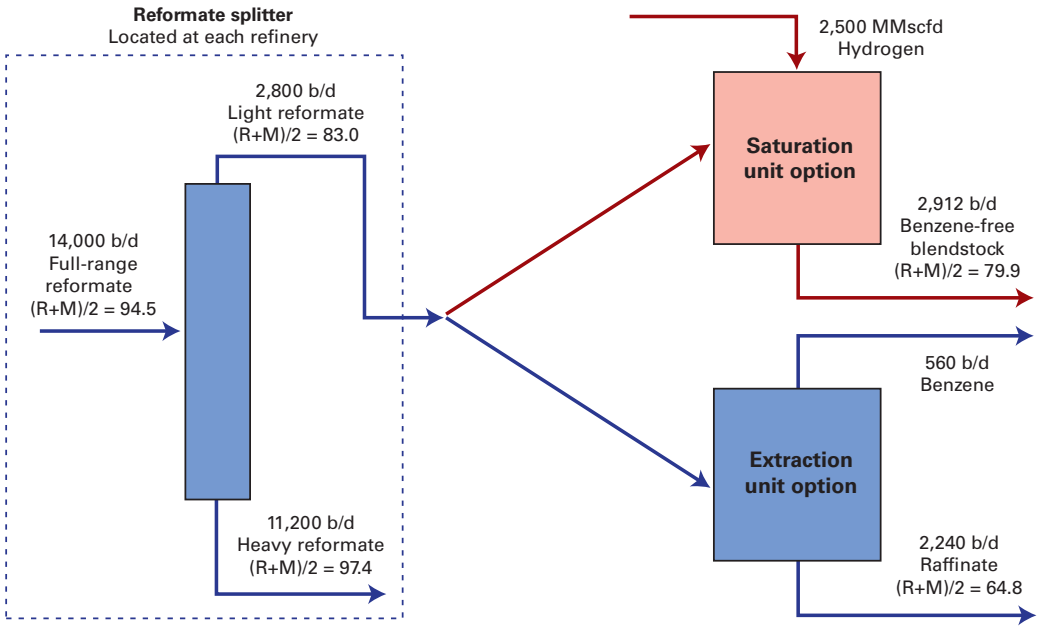
Extraction vs. saturation

The starting point for our study was a typical 14,000-b/d refinery reformate stream that was split into light and heavy reformate cuts. We assumed the light reformate contained 20% of the benzene.

Table 1 shows the major study assumptions. The resulting 2,800 b/d of light reformate was then processed in a saturation unit and alternatively in an extraction unit for comparison of these two

Extraction vs. Saturation

Fig. 1



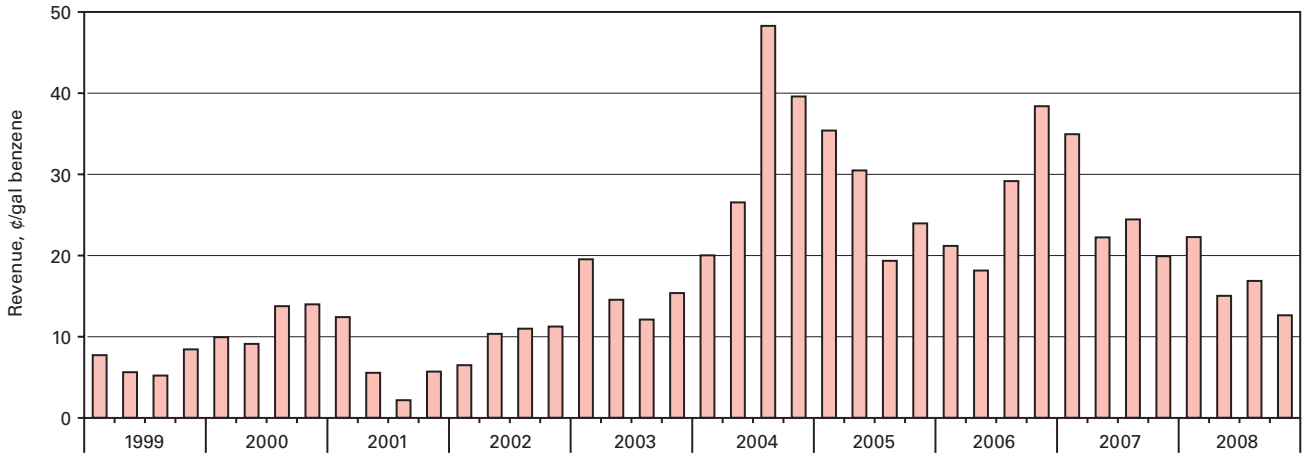
Study assumptions

Table 1

Reformate volume, b/d		14,000
Light reformate yield, vol %		20
Heavy reformate yield, vol %		80
Benzene in light reformate, vol %		20
Cyclohexane yield from benzene, vol %		120
Hydrogen consumption, Mcf/bbl of benzene		4,502
Saturation unit operating cost, $/bbl		0.25
Extraction unit operating cost, $/bbl		0.50
Stream properties	(R+M)/2	Rvp
Reformate	94.5	4.0
Light reformate	83.0	6.0
Heavy reformate	97.4	1.0
Regular gasoline	87.0	10.0
Premium gasoline	93.0	10.0
Benzene	105.5	3.2
Cyclohexane	80.1	3.3
Saturated light reformate	78.0	6.0
Light raffinate	77.4	6.7

NET OPERATING REVENUE*

Fig. 2



*Excluding net capital charges.

options (Fig. 1).

Because the benzene-rich light reformate stream is separated from the benzene-free heavy reformate in both cases, we chose to exclude the operating and capital cost of reformate splitting from our analysis. The loss of gasoline pool octane was restored by adding premium motor fuel to the gasoline pool in each case.

The cost of purchased hydrogen was charged to the saturation unit case. We assumed net operating costs of 25¢/bbl for the saturation case and 50¢/bbl for the extraction case. The saturation case's economics also benefited from an increased volume of motor fuel from the volume gain of converting benzene to cyclohexane.

No depreciation or capital charge was included in the comparison because our intent was to determine the financial incentive for any incremental capital cost associated with the extraction route.

With historic prices, the extraction and sale of benzene would have maximized the value of the light reformate stream relative to the saturation route. Results from our 10-year back cast (Fig. 2) demonstrate this point.

Additional net operating revenue/gallon of benzene recovered by extraction, compared to saturation, would have ranged from as little as 2¢/gal to as much as 48¢/gal during the past 10 years, under application of average quarterly prices. More importantly, there would have been no financially negative operating quarters (exclusive of any capital charges) during this period relative to the saturation route.

Back cast prices may not indicate future price relationships between benzene and motor fuels once permitted benzene levels are reduced. In fact, if every refinery implemented the extraction route, the resulting 32,000-b/d increase in benzene production would overwhelm current demand. We doubt this will occur, however, because so many refiners appear poised to take the saturation route.

Small refineries

As standalone entities, smaller refineries appear to be better served with the saturation option. For individual refineries, saturation's lower capital cost is appealing. For small reformate streams similar to the volume in our study, it is doubtful the incremental benefit from extraction would provide an attractive return on the incremental investment needed for an individual refinery extraction unit.

Regulatory issues also multiply when dealing with streams that contain benzene greater than 20 vol %. Finally, marketing of a chemical product, such as benzene, may well be outside the expertise and business model of many gasoline-oriented refiners. Many refiners may therefore be inclined to choose the saturation approach.

Given the historic margins associated with recovering benzene, however, it appears refiners will continue to have some economic incentive to produce this chemical. Overcoming the aforementioned hurdles, therefore, becomes the primary task for those refiners not already producing benzene.

Larger refineries will have an easier time clearing these hurdles and can generally "go it alone," if they choose. Smaller facilities will have much greater difficulty and creative solutions will be required for these refiners to participate in any future economic benefit from producing benzene.

One solution could be a joint venture of two or more refineries in which only one refinery processes all of the light reformate from multiple facilities. Partnering with another refiner that already operates an extraction unit would be an ideal solution for smaller plants.

This is especially the case if the existing extraction unit can be cost-effectively expanded. When this is not the case, a single, joint-venture facility could be constructed adjacent to one or more participating refineries.

A regional extraction unit is also

suitable for a service-oriented third party to own and operate. This approach is similar to the many "across the fence" hydrogen plants located throughout the refining industry.

Such an entity could easily be structured as a master limited partnership, which could facilitate financing not readily available to individual refining companies in the current credit crunch. Furthermore, MLPs can typically accept lower returns on capital employed than their refining counterparts.

A centralized extraction facility can benefit its refinery "customers" in several ways in addition to allowing participation in margins associated with benzene recovery and sale.

Such a facility can:

- Minimize overall capital spending by concentrating investment into a single, large extraction unit instead of multiple smaller saturation units.
- Minimize capital spending at the refinery.
- Avoid the extra hydrogen consumption associated with saturation (with the possibility of an increase in hydrogen supply from the reformer because precursor control would no longer be an issue).
- Increase the octane of the refinery gasoline pool, which may offset the octane loss associated with producing ultralow-sulfur gasoline.
- Allow the refinery staff to focus on what it does best, which is fuels production.
- Allow for centralized marketing of a much larger benzene product stream.

Table 2 shows that there are many refining centers in the US where a regional extraction facility would be a nice fit. Several of these refining centers also have reasonable access to ethylene producers willing to purchase the light raffinate by-product.

In locations where selling raffinate as a cracking stock is impractical, this material can still be blended into motor fuel with the use of higher-octane components such as ethanol. We believe a common extraction facility will likely be more attractive than individual saturation units, provided satisfactory agreements can be achieved among the participating refineries and, if present, the third-party operator. ✦

SIGNIFICANT US REFINING CENTERS

Table 2

	Number of refineries	Crude oil Capacity, b/d	Reformer Capacity, b/d
Beaumont	4	1,110,952	274,039
New Orleans	7	1,461,500	255,100
Corpus Christi	4	737,050	210,890
Texas City	3	748,250	149,200
Chicago	3	783,400	135,680
Houston	4	814,900	130,500
Oklahoma	5	486,000	106,979

Source: 2008 OGJ Refinery Survey

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Change in Russian export duties unlikely to affect margins

Falling crude prices could upset the symmetry between duties on crude and products in Russia, potentially changing the incentives and actions of refiners there, according to a recent Refinery Evaluation Model Insight from Wood Mackenzie.

For a long time, Russia used an oil export duty to provide an incentive for domestic refiners to run crude, upgrade facilities, make products, and protect employment. This strategy enjoyed much success in the past, with Russia setting the duty level accordingly to encourage these behaviors.

Wood Mackenzie's report, entitled "How will lower oil prices affect Russian refiners?", examines the role of the export duty regime and implications of changes in crude price, duty, and transportation tariffs on four sample refineries—two on the coast, and two inland. The study considered how investment and behaviors would change with lower oil prices and a refining industry suffering from increasing uncertainty and falling margins.

Changes in Russia's duty regime aim to encourage refiners to modernize existing capacity by increasing the incentive to produce light products for export while penalizing exports of feedstocks and fuel oil. Wood Mackenzie's calculations, however, show that in the current low-crude-price environment, tax change benefits are unlikely to be sufficient to prevent run cuts from inland refiners due to the extent that transportation and fixed operating costs have affected margins.

This would affect European and other products markets if supplies from Russia did decline, prospectively reducing fuel oil and vacuum gas oil feedstocks and, to a lesser but potentially significant extent, reducing gas oil and diesel product deliveries.

According to the report, Western and Central European refiners would welcome any prospective reductions in Russian refinery utilization. Resulting reductions in fuel-oil exports would support straight-run fuel oil prices and assist European hydroskimming margins.

A lower supply of vacuum gas oil and straight-run fuel oil could also lead to increased feedstock costs for high-complexity refiners in Europe; this, however, may at least be partially offset by stronger crack spreads for gas oil and diesel, a result of reduced imports from Russia. Overall, this should support simple refining margins in Europe, likely to be under pressure due to lower product demand in the Atlantic Basin, the report said.

Another positive factor for European refiners would be any increased potential availability of Urals crude. Many refiners in Central Europe on the Druzhba pipeline have faced higher prices recently because the "Druzhba discount" has decreased.

Some Russian producers could find themselves in a position to negotiate higher crude prices. Overall, however, Wood Mackenzie is forecasting lower Russian production in 2010 than did the firm earlier this year. The point at which Transneft crude export capacity is exploited fully would mean any further exports by rail, with correspondingly lower netbacks, would potentially reduce domestic crude prices further.

Wood Mackenzie argues that domestic refiners reducing crude runs and logistics restricting crude exports is unlikely to be sustainable. If crude and products prices remain low, then it is possible that the government could be encouraged to reduce product export duties relative to crude duties to support crude runs and utilization, particularly inland.

Location plays a key role. Distance, and therefore costs, factor in. And any changes in rates for crude export via pipeline or rail will affect different refiners in different ways, reflecting

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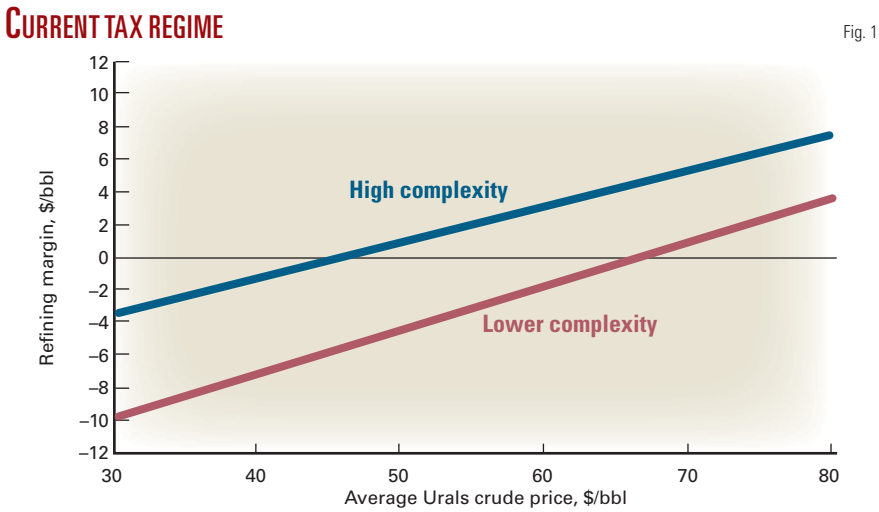


Source: Wood Mackenzie

differences in location and feedstock export logistics.

Russian product prices

Russian domestic product prices, particularly for gas oil, diesel, and high-sulfur fuel oil, have largely followed export price parity. Exports have become a key element of refiners' strategy, with export duty a significant component of final price.

Historically, the export duty on products like fuel oil was set lower than the export duty on crude, resulting in an incentive for refiners to run crude and to maintain employment rather than to simply export raw crude.

Crude is exported mainly through the Transneft pipeline network, a 48,000-km system that handles more than 90% of total crude destined for both domestic and foreign markets. A relatively small proportion of crude goes by rail, often for segregation of premium quality.

Products are moved either by the Transneft pipeline network or by rail. Fuel oil is exported predominantly by rail; about 7 million tons/year are transported on inland waterways during the summer.

Wood Mackenzie estimates that product pipeline tariffs are roughly half the cost of rail freight. The variation in both rail and pipeline tariffs with crude and product prices is relatively low. As oil prices fall, therefore, there is a point at which the incentive to refine crude oil no longer offsets the incremental cost of transporting products to export markets compared to transporting and exporting crude. Refineries farthest from export points suffer the most because these sites generally incur higher transportation costs to move products to export markets.

With product prices reaching highs in July 2008, Wood Mackenzie estimated that product transportation costs accounted for 11% of the gross product worth (GPW) for a low-complexity inland refiner. By the beginning of December 2008, this had risen to 29%. In contrast, a low-complexity coastal refinery saw transportation costs rise to about 8% from 4% of GPW during the same period.

It has taken some time for the effects of the loss of the export duty incentive to have an effect. Reductions in domestic oil product prices have lagged the fall in international prices.

Until recently, Russian export duties were based on 2-month lagged oil prices; therefore, given the precipitous decline in crude oil prices during the fall of 2008, crude exports sometimes yielded negative returns. Consequently domestic crude prices fell further, bolstering refining margins.

Overall, the Russian market is now becoming much more fully exposed to the effect of sustained lower crude oil prices on refining profitability, according to the report.

Implications

For comparison, Wood Mackenzie modeled four refineries to calculate refining margins given different market situations. Included were a high-complexity refinery and a lower-complexity refinery close to ports and a higher-complexity and lower-complexity refinery inland. The high-complexity refinery located inland is in the Moscow area, the lower-complexity inland refinery is in the Volga-Urals region.

Wood Mackenzie obtained the yields from its Refinery Evaluation Model. The analysis assumed that all of the fuel oil and most of the gas oil production was exported, with an adjustment made to account for local sales of gasoline and naphtha.

More-complex refineries produce a greater proportion of higher-value, lighter products and have a higher GPW than less-complex refineries. For higher and lower-complexity coastal refineries, transportation costs rose, unsurprisingly, in identical fashion, to 8% from 4% during July to early December 2008, according to the report. In contrast, for a complex inland refinery, transportation costs rose to more than 17% from 7%.

Although downstream transport costs for refiners closest to export markets have doubled, these costs remain a significantly smaller proportion than those for inland refineries. Rates for inland refineries have risen by 2.5-3 times starting from a much higher base, resulting in a much more severe effect on profitability.

For refineries even farther inland than the two examples modeled, the effect is more acute. For a complex refinery in West Siberia, product transportation costs accounted for 11% of GPW in July and had risen to more than 32% in early December, according to the report.

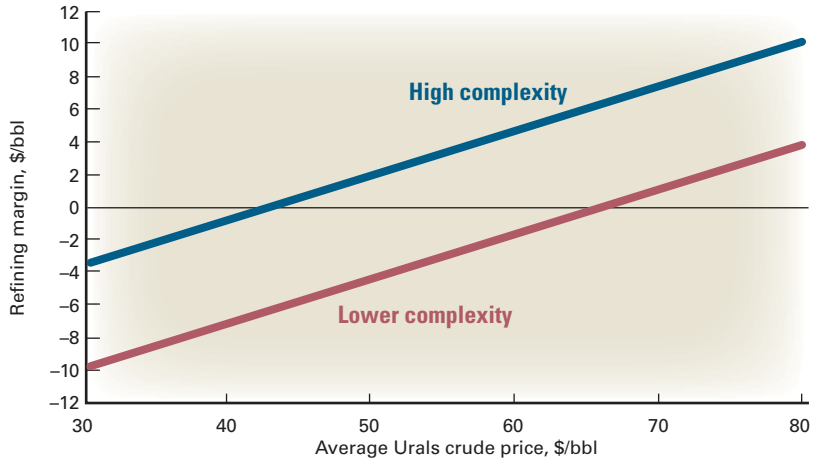
This effect increases when crude

and products prices fall. On a net-cash margin basis, Wood Mackenzie's modeling shows that both inland refineries produced negative refining margins at the beginning of December and would likely consider cutting utilization.

Both the higher and lower-complexity coastal refiners had positive margins in early December, according to Wood Mackenzie's model, but have seen margins fall considerably. Conversely, a complex refinery in Rotterdam would have generated a higher margin during the same time, which shows that Russian refineries were at a distinct disadvantage due to the increased proportion of logistical costs.

POTENTIAL NEW TAX REGIME

Fig. 2



Source: Wood Mackenzie

Current export duty regime

Fig. 1 shows relative break-even points for the inland refineries modeled. Wood Mackenzie calculated product prices using crack spreads from early December applied to varying crude prices. Export duty costs were adjusted according to the crude price using the current tax formulas for crude and products.

Given the current product export-duty regime, the more-complex inland refinery breaks even when the average CIF Urals price in northwestern Europe and Mediterranean is about $46/bbl; the less-complex inland refinery breaks even at about $67/bbl. This shows that the lower-complexity inland refinery operates at a significant loss and is likely to cut runs and the more-complex refinery would be under economic pressure to reduce output.

The break-even points, however, for coastal refineries are significantly lower, $40/bbl for the simpler of the two and $30/bbl for the more complex refiner. Most Russian refining capacity lies inland and is lower complexity; therefore, there are likely to be many inland refiners that have, or are considering, cutting runs in the current market environment.

The average Wood Mackenzie complexity index for refining capacity in Russia is 4.3, significantly lower than the European average of 6.5, as calculated by Wood Mackenzie's Refinery Evaluation Model.

These calculations used current oil products export duty calculations. The formulas set the export duty for light products at about 70% of the crude export duty fee and the export duty for "dark" products (vacuum gas oil and fuel oil) at about 40% of the crude export duty fee.

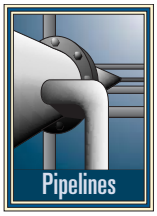
The difference between the duty rates on different products historically supported simple and less-complex refiners delivering higher yields of dark products. It is possible that this differential could be removed and the export duty for all products subsequently become 54% of the crude export duty fee, according to the report.

New export-duty regime

The potential new regime, which includes a change to dues calculated monthly, would encourage refiners to invest in deeper refining of domestic crude and also to modernize refineries and produce higher-quality products. For the simplest refineries producing a high fuel-oil yield, the change would result in a higher tax burden, but for the refineries modeled the changes would be positive for refining margins. Higher-complexity refineries would benefit the most.

Fig. 2 shows the relative break-even points for each refinery type under the revised tax regime with all other costs unchanged.

In this scenario, break-even for the more-complex inland refinery is reduced $4/bbl to $42/bbl, with break-even for the less complex inland operator only $1/bbl less, at $66/bbl. Using early December 2008 crude and products prices, Wood Mackenzie calculated that the refining margin at more complex refineries would be about $1/bbl higher under the new regime, with the less-complex refineries achieving a margin just $0.20/bbl higher under the same circumstances. ✦



Company name change requires diligent execution

Ken Palmer
Bill Byrd
RCP Inc.
Houston

Changing a pipeline company's name following a merger or acquisition requires a comprehensive, unified approach. Failure to properly organize and execute the name-change process can lead to unnecessary delays, regulatory complications, and the additional costs associated with both. This article describes one such process, demonstrating the benefits accrued from using a systemic approach.

Background

Several generations of acquisition, divestiture, and other company transitions may be included in a pipeline's genealogy. Completing a simple name change of a company's assets can quickly evolve into a complicated maze of uncertainties related to who owns what, who operates what, and how everything is regulated by various government agencies.

In the case examined for this article, Company A, Company B, and Company C merged with parent Company F several years earlier, placing most of A's holdings under Company D and all of B's holdings under Company E. Company C retained its name.

Based on presentation to the International Pipeline Conference, Calgary, Sept. 29-Oct. 3, 2008.

Company A initially operated the pipeline facilities; then its employees made the transition to become employees of Company F. This period of transition left behind remnants of the past companies' names—including a hybrid of the two names—in assets, manuals, permits, registrations, etc.

This project sought to change the name of the remnant assets of Company A to a newly formed company, Company G. "Name change" applied to a legal name change for a specific company's assets and to regulated operational activities. Indentifying associated assets of sister Companies C, D, and E facilitated the process.

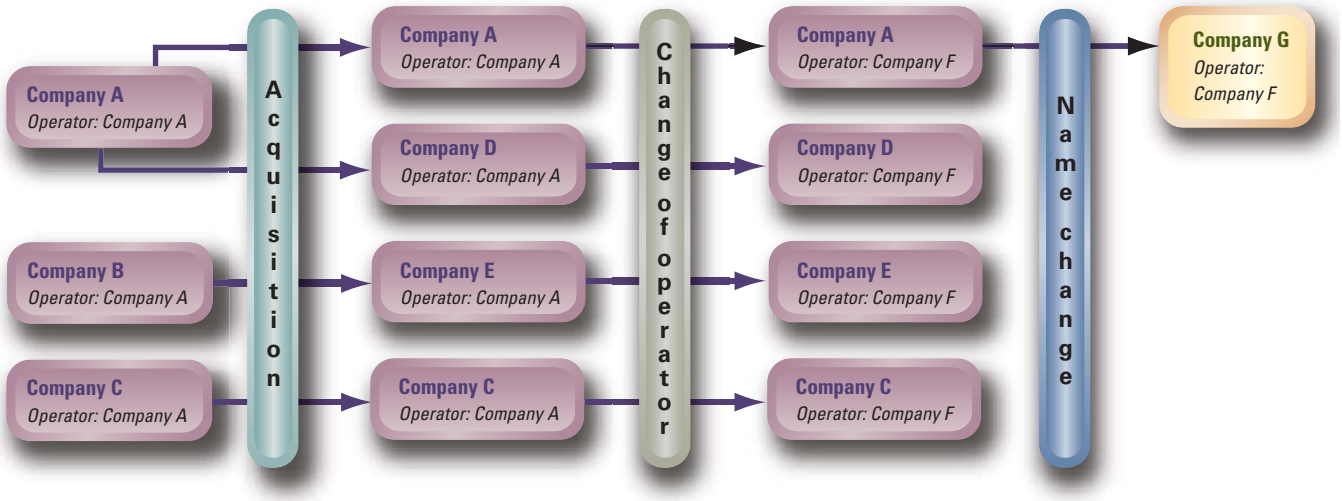
Company F, which was the new operator of the assets of Companies C, D, E, and G also had to be identified in applicable permits, registrations, and internal documents. Some permits and plans required correction of the owner and operator involved due to the multiple transitions. Fig. 1 shows the acquisition, change of operators, and name change. Fig. 2 shows the steps taken to complete the name-change project.

Company personnel in the example outlined by this article included specialists, team leaders, field team leaders, and operators, all of whom provided information important to the process's success.

Having identified the players in the

Acquisition flow chart

Fig. 1



Sample abridged stoplight information spreadsheet

Table 1

Stoplight status	Agency	Regulatory description	Agency notification required, type	Deadline	Execution: consultant final	Execution: client approval	Proposed procedure for name change	Comments
Complete	Department of Transportation, Office of Pipeline Safety (OPS)	Federal operator ID No.	Yes, registration	Jan. 1, 2008	Complete	Complete	Client will be responsible for making the operator name change to the Federal Operator ID No.	Refer to Report Appendix 1 for asset information.
Complete	Louisiana Department of Natural Resources (LDNR), Office of Conservation (OOC), Engineering Division	Annual registration (Form OR-1)	Yes, registration	Mar. 15, 2008	Complete	Complete	Consultant will complete and file the Organization Report (OR-1) for operator codes. Form requires client's signature.	Refer to Report Appendix 1 for asset information.
Complete	Pipeline and Hazardous Materials Safety Administration, OPS	Pipeline operator qualification program (OQ)	Yes, edits to OQ manual	Jan. 1, 2008	Complete	Complete	Joe Doe to make any required name changes. Remove old version of program from field offices.	Standard name change to an existing document, no agency notification required.
Complete	Louisiana Department of Environmental Quality, Application Verification Group, Office of Environmental Service	Facility air permits	Yes, permit, filing (Form NOC-1, etc.) closure forms	Within 45 days after name change	Complete	Complete	See Report Table 1 for list of air permits and procedures for name change. Consultant to prepare and submit forms since Air and Water permit changes require simultaneous filing.	File Form NOC-1, etc.
Complete	LDNR, OOC, Injection and Mining Division	Well storage permit – Permit to inject, Well No. A-4	Yes, amendment to Permit to drill for minerals, Well No. A-4	As soon as possible after name change	Complete	Complete	Consultant to complete and submit Form MD-10-R-AO to LDNR for this well. Form requires client's signature (see Report Appendix E).	Company A listed as owner-operator.
Complete	LDNR, Office of Coastal Resources Management	Louisiana coastal use permits	Yes, filing, permit transfer	None indicated	Complete	Complete	Consultant will prepare and submit the CUP transfer request form for each permit. A list of permits is provided in Table 4 (Report Appendix D. The form requires client's signature.	Permit expires 5 years from issuance date. Permits searched from May 1, 2002 and will continue to be searched until name-change date.

acquisition, Company A's remaining assets now had to be determined. Prepared inventories facilitated the correct cross-referencing of owner-operator for permits, registrations, plans, etc. But a complete inventory of these items may not be readily obtained as part of an acquisition because of an incomplete transfer of documents. Cross-referencing permits with the files of the appropriate agency can provide a better understanding of the company's history.

Assets

About 815 miles of pipeline from 10 hazardous liquid and gas systems transferred as remnants from Company A to Company G. Pipe diameters were mainly 6-8 in., although sections of larger diameter pipe were also included in the inventory.

The asset study also identified 19 separate facilities, including gas separation-processing-dehydration, barge loading, underground gas storage, and pump, compressor, and booster stations. Operators had taken four of the identi-

fied facilities permanently out of service and permanently leased another to an outside company. Several other companies also held 33 of the meter stations.

Methodology

A spreadsheet called the stoplight information spreadsheet (SIS) assisted in identifying and tracking acquired information. This included a comprehensive list of all potential applicable regulatory requirements, agencies, and regulated changes and a stoplight color code to track project progress. SIS identified about 200 potential regulatory requirements for this company name-change process involving as many as six federal and 16 state agencies. SIS also identified 14 company employees, contractors, and vendors to manage selected tasks in the name-change process.

Three categories of contacts provided data over the course of the name-change project:

- Company personnel.
- Regulatory agencies.
- Company contractors.

A list provided by the client initially identified key company personnel. A list of permit information provided by the client initially identified applicable regulatory agencies, permits, and plans. Interviews with company personnel identified company contractors. Communicating with contractors helped determine what tasks they performed and how they could best be informed of any name change procedures related to their tasks. Each of these lists expanded as additional information was gathered.

Table 1 provides an abridged sample of the SIS spreadsheet.

Inventorying

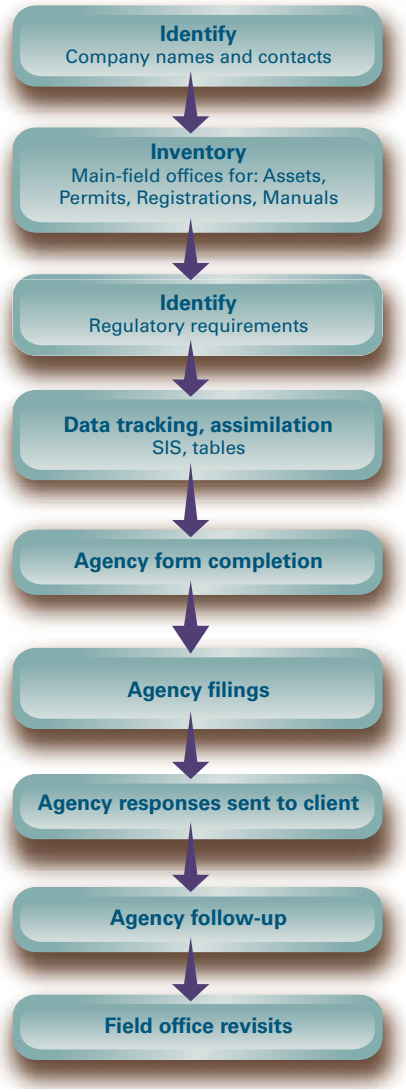
Inventory of acquired assets was a necessary early step in the name-change project. Participants found the list of assets on hand to be out of date and correct information not easily attainable. Visiting the client's main office, field offices, and key operational facilities and interviewing employees eventually yielded accurate inventory information.

Field-site visits proved invaluable in identifying operations and facilities abandoned due to process change and natural gas availability. Such assets as wells and septic tanks, as well as field vehicles such as trailers, boats, and ATVs, were included in the inventory's scope. Some vehicle registration information was lost during Hurricane Katrina, requiring duplicate titles be requested from the motor vehicles office before filing the name change forms.

Identification of additional company names during the inventory process made attributing ownership and operator names to certain assets confusing. The perator was not certain of same-asset ownership, especially information pertaining to acquisition and divestiture to sister companies. Names of past companies and hybrid names existed in manuals, permits, registrations, etc., all of which had to be identified and corrected.

Name-change flow chart

Fig. 1



Agency forms

Agency form completion followed the inventory process as the second most important task to be addressed during the name change. The client was assisted in completing operator-name change regulatory agency forms for air and water permits, coastal use-Army Corps of Engineers permits, operator identification numbers, injection-drill permits, vehicle registrations, and drip points registrations.

Identifying and confirming responsible company officials who would provide signatures before form completion expedited the form-signing process. The consultant paid form fees and was reimbursed by the client, avoiding delays and any bottlenecking of documents.

Internal documents

The client or its vendors completed name changes to agency forms electronically filed by the client, and to client documents such as manuals and plans. In some cases it was more efficient for the client to electronically file the changes themselves through their secured web site including annual reporting to the US Department

of Transportation's Office of Pipeline Safety. In other cases, changes to manuals and plans were completed by the client or their vendor, including owner-operator name changes to integrity management plans and spill prevention, control, and countermeasure (SPCC) plans.

KEY NAME-CHANGE PROJECTS STATISTICS

Table 2

Category	Value
Pipeline length, Company G	815 miles
Facilities requiring name change	11
Companies involved	7
Federal, state operator codes	6 discontinued, 3 new
Regulatory agencies, divisions affected	25
Client officials required for signatures	6
Client personal contacted	42
Agency fees	$15,000
Project duration	12 months
Consultant fees	$120,000
Client costs for internal changes; signs, vendors, etc.	$130,000
Total projects costs	$265,000

Report preparation

Hard copies of the name-change report given to the client for distribution to its legal department and other appropriate departments provided guidance and acted as a tracking tool before and during the formal name change process. The name-change report included a record of the asset inventory and any letters to the agencies with completed forms. Color coding name-change requirements by sister company helped identify specific name-change requirements, since seven company names were involved.

Revisiting the field offices after completing the name-change process helps ensure all documents affected by the change have been updated.

Discussion

RCP used several procedures smoothly to move the remaining assets of Company A to Company G and avoid processing delays once the go ahead for the name change was given. A turnkey approach included obtaining a signature list for documents requiring signatures and paying form fees directly to expedite the process. Extensive interviews with experienced field personnel accessed accurate company background information.

Discussion with well-informed individuals, including land people, and use of geographic information systems helped resolve any unclear items. Reporting potential regulatory violations to the client before submitting name change documentation to the various agencies avoided processing delays.

The parent company was not always certain of asset ownership, and different opinions were discovered within the company. In addition, monies allocated to field offices for name change purposes were sometimes diverted to other projects, escalating the actual costs of the name change project. Several facilities determined to be permanently out of service were still included in active permits, resulting in additional liability and extra expense from permitting fees and sampling fees.

The client lacked a comprehensive and accurately identified inventory of permits, registrations, and plans due to an incomplete transfer of information. In-house copies of permits often retained the names of former owners and operators. Some permits may only be renewed every 5 years and a name change may have occurred within this period and therefore would not be readily apparent on copies of in-house permits. These circumstances were corrected through contact with regulatory agencies when copies of all in-house permits were cross-referenced and verified to determine the accuracy of existing permit status, owner, and operator.

Table 2 shows some of this name-change project's key statistics. Any efficiency savings stemming from having used an integrated approach to the project exceeding the $120,000 included for consultant costs can been seen as a net gain. ✦

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In January, Golar LNG delivered the Golar Spirit to Petrobras for its first offshore LNG terminal off Pecem. (Photograph from Golar LNG; copyright Petrobras)

Petrobras gains floating regas vessel for first LNG terminal

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

Petrobras In January took delivery of the world's first floating storage and regasification vessel, the Golar Spirit, following commissioning tests on the vessel's regasification trains. The contract was completed by Golar LNG Ltd. following award in April 2007.

Called an "FSRU," the vessel is going into service at Petrobras's LNG terminal, at Pecem, Ceará state. Each of its three regas units can send out up to 130 MMcfd, with two units normally working while the third remains on standby, according to Blake Blackwell, vice-president of business development for Golar LNG.

Conversion

The 127,000-cu m Golar Spirit was converted from a traditional LNG carrier in about 6 months at the Keppel Shipyard, Singapore. Kawasaki Heavy Industries Ltd. originally built the vessel at its Sakaide, Japan, yard. Commissioned in 1981, it was the first LNG carrier built in Japan.

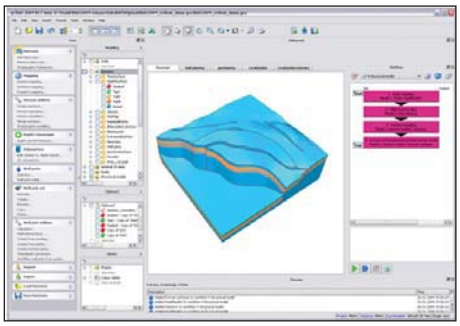
Its conversion in 2007 involved addition of the three vaporizers, designed by Moss Maritime; three booster pumps, five in-line pumps, and more turbo generation capacity, all manufactured by Shinko Industries Ltd., Hiroshima; and automation, manufactured by Kongsberg. The 289-m vessel contains five Moss Rosenberg spherical aluminum storage tanks.

"FSRUs are site and project specific," Blackwell told OGJ. In this case, Petrobras has elected to place the LNG unloading arms and high-pressure gas arms (yellow in the photograph's foreground) on the pier.

An LNG carrier berths on the side away from the FSRU (lower part of photograph) and unloads its cargo with the unloading arms onto the FSRU, which then regasifies the LNG and moves the natural gas ashore via the HP gas arms, said Blackwell. By locating the HP arms and LNG loading arms on the pier, Petrobras can move an FSRU among demand centers.

Later this year, Petrobras will use the Golar Spirit to commission a second offshore LNG terminal, in Guanabara Bay, Rio de Janeiro. In the meantime, Blackwell said a second LNG carrier, the Golar Winter, is undergoing conversion at the Keppel yard. ✦

Equipment/Software/Literature



Reservoir modeling software redesigned

Newly released RMS2009 is a redesigned version of reservoir modeling solution IRAP RMS.

RMS2009 provides users with a new and modernized user interface that resembles familiar, everyday software applications. The new user interface has further increased the usability of IRAP RMS and, as a result, reduced the learning curve for new users of the software. In addition, with new technologies and increased functionality, RMS2009 enables users:

- To quickly and easily update facies and petrophysical models based upon new data or interpretations, in contrast to methods that would involve rerunning all or part of the model. This is accomplished without breaking history matching as only local adjustments are made.
- To access superquality structural modeling tools for simple and complex structures, reducing the time required to build models (especially larger ones) and resulting in what the company says are higher quality grids for reservoir modeling and simulation. Hundreds of faults can be modeled in minutes with all geometries permitted; yet, the work flow is simple and easy to learn, the firm notes.
- To benefit from improvements to real time geosteering and monitoring in IRAP RMS that allows users to import real time data, compare the model with the well being drilled, and potentially make better decisions while drilling.
- To have increased data importing functionality with a standardized import dialog, which provides an array of import format options. This helps make the task of importing data simpler and faster.

Source: **Roxar ASA**, Gamle Forusvei 17, Box 112, 4065 Stavanger, Norway.

Firm certified for nondestructive testing in GOM

Tri Drill Inc., Broussard, La., a provider of inspection services throughout the Gulf of Mexico Coast, recently earned certification from Oslo-based Det Norske Veritas to perform nondestructive testing on offshore drilling rigs and drilling components.

After a DNV audit in October 2008, Tri Drill's NDT Level II and III inspectors proved to be in compliance. Tri Drill performs NDT inspections on drill pipe, tubing, bottomhole assembly tools, heavy-lift components, and handling equipment. Tri Drill also is certified according to Columbus, Ohio-based American Society for Nondestructive Testing guidelines.

Source: **Tri Drill Inc.,** 1001 Briar Patch Rd., Broussard, LA 70518.

Services/Suppliers

Baker Hughes Inc.,

Houston, has appointed Martin S. Craighead senior vice-president and COO effective Apr. 30. Craighead, currently president of Baker Hughes's drilling and evaluation group, has more than 27 years of experience. Previously, he was president of INTEQ and, prior to that, president of Baker Atlas. Craighead joined the company in 1986 and has served Western Atlas and Baker Atlas in a number of operational positions. Before joining Baker Hughes, he worked as a research engineer at BJ Services. Craighead has a BS in petroleum and natural gas engineering from Pennsylvania State University and an MBA from Vanderbilt University.

In addition, David H. Barr, Baker Hughes group president, completion and production, will retire from the company on Apr. 30 after 36 years in the industry, most of it at Baker Hughes. Baker Hughes provides reservoir consulting, drilling, formation evaluation, completion, and production products and services to the worldwide oil and gas industry.

Mustang Engineering,

Hughes

Houston, has appointed J.L. (Jim) Hughes as manager of its pipeline engineering and services office in Fort Worth. He has more than 23 years of experience in onshore and offshore facilities design, with pipeline experience including all aspects of transmission and distribution pipeline engineering, design, routing, and all field activities and construction.

Meanwhile, John W. Dalton Sr., executive vice-president of Mustang, has been elected the 2009 chairman of the executive committee for the Construction Industry Institute. CII is a consortium of more than 100 leading global owners, contractors, suppliers, and academia who have joined together to create industry best practices and measurably improve the delivery of capital facilities. Dalton has operations oversight for Mustang's global engineering, project services, IT, and construction operations and for the midstream and process and industrial business units. He is a graduate of the University of Houston. Mustang, part of international energy services company John Wood Group PLC, is an independent services provider to the global oil, gas, chemical, and manufacturing industries. Mustang specializes in design, engineering, procurement, project management, and construction management and offers these services through its six business units: upstream oil and gas, midstream, pipeline, automation and control, refining and petrochemicals, and process and industrial.

Dalton

Wood Group is an international energy services company with three businesses—engineering and production facilities, well support, and gas turbine services—providing a range of engineering, production support, maintenance management, and industrial gas turbine overhaul and repair services to the oil and gas and power generation industries worldwide.

Imports of crude and products

	Districts 1–4		District 5		Total US		
	2-27 2009	2-20 2009	2-27 2009	2-20 2009	2-27 2009	2-20 2009	*2-29 2008
	1,000 b/d						
Total motor gasoline	1,051	750	119	55	1,170	805	800
Mo. gas. blending comp.	987	648	112	0	1,099	648	460
Distillate	294	282	0	0	294	282	186
Residual	436	306	0	0	436	306	302
Jet fuel–kerosine	59	60	0	0	59	60	87
Propane–propylene	471	157	74	57	545	214	121
Other	(19)	471	(89)	22	(108)	493	1,186
Total products	**3,279**	**2,674**	**216**	**134**	**3,495**	**2,808**	**3,142**
Total crude	**7,833**	**7,619**	**1,195**	**1,150**	**9,028**	**8,769**	**9,437**
Total imports	**11,112**	**10,293**	**1,411**	**1,284**	**12,523**	**11,577**	**12,579**

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

Purvin & Gertz LNG netbacks—Mar. 6, 2009

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	11.05	7.79	10.29	7.70	8.31	10.21
Everett	3.91	2.16	3.59	2.28	2.59	4.19
Isle of Grain	3.74	1.91	3.14	1.83	2.34	3.16
Lake Charles	1.99	0.52	1.81	0.64	0.76	2.50
Sodegaura	4.62	7.68	4.88	7.42	5.66	4.13
Zeebrugge	7.25	4.64	6.22	4.52	5.38	6.28

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	14,125	55,452	34,574	10,125	51,695	12,644	1,847
PADD 2	84,231	55,346	23,170	8,237	35,650	1,200	12,516
PADD 3	179,619	69,946	40,409	13,104	38,632	17,379	22,304
PADD 4	15,213	6,788	2,372	534	3,537	265	[1]1,087
PADD 5	57,402	27,978	23,771	9,692	13,782	5,148	—
Feb. 27, 2009	**350,590**	**215,510**	**124,296**	**41,692**	**143,296**	**36,636**	**37,754**
Feb. 20, 2009	**351,347**	**215,342**	**122,250**	**40,474**	**141,634**	**36,397**	**39,395**
Feb. 29, 2008[2]	**305,449**	**234,276**	**116,493**	**39,342**	**117,625**	**36,508**	**28,873**

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

Refinery report—Feb. 27, 2009

District	Refinery operations		Refinery output				
	Gross inputs	Crude oil inputs	Total motor gasoline	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual	Propane–propylene
	1,000 b/d						
PADD 1	1,095	1,102	2,262	71	329	94	42
PADD 2	3,080	3,068	2,300	223	880	53	207
PADD 3	7,166	7,059	2,643	675	2,184	246	642
PADD 4	550	546	313	26	155	9	[1]142
PADD 5	2,759	2,570	1,485	454	540	89	—
Feb. 27, 2009	**14,650**	**14,345**	**9,003**	**1,449**	**4,088**	**491**	**1,033**
Feb. 20, 2009	**14,340**	**13,936**	**8,937**	**1,364**	**4,213**	**608**	**1,020**
Feb. 29, 2008[2]	**14,979**	**14,868**	**9,042**	**1,392**	**4,005**	**630**	**1,127**
	17,621 Operable capacity		**83.1% 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

	*3-6-09	*3-7-08	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	51.08	112.15	–61.07	–54.5
Brent crude	43.99	102.97	–58.98	–57.3
Crack spread	7.09	9.17	–2.08	–22.7
FUTURES MARKET PRICES				
One month				
Product value	53.37	115.19	–61.82	–53.7
Light sweet crude	43.26	103.42	–60.16	–58.2
Crack spread	10.10	11.77	–1.66	–14.1
Six month				
Product value	55.17	113.31	–58.13	–51.3
Light sweet crude	48.95	100.63	–51.68	–51.4
Crack spread	6.22	12.68	–6.46	–50.9

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

OGJ GASOLINE PRICES

	Price ex tax 3-4-09	Pump price* 3-4-09	Pump price 3-5-08
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	147.3	193.8	326.1
Baltimore	149.9	191.8	315.6
Boston	148.0	189.9	312.3
Buffalo	134.9	195.8	334.6
Miami	140.9	192.5	339.3
Newark	151.9	184.5	298.2
New York	121.0	181.9	314.1
Norfolk	146.4	184.8	312.1
Philadelphia	148.2	198.9	320.0
Pittsburgh	158.1	208.8	318.1
Wash., DC	169.5	207.9	321.4
PAD I avg	146.9	193.7	319.2
Chicago	145.9	210.3	341.9
Cleveland	144.3	190.7	305.3
Des Moines	144.3	184.7	308.7
Detroit	132.6	192.0	307.7
Indianapolis	129.6	189.0	312.7
Kansas City	144.7	180.7	304.0
Louisville	146.1	187.0	325.4
Memphis	139.9	179.7	307.7
Milwaukee	137.0	188.3	305.5
Minn.-St. Paul	140.3	184.3	301.4
Oklahoma City	135.2	170.6	303.9
Omaha	139.4	184.7	311.9
St. Louis	140.7	176.7	290.4
Tulsa	137.3	172.7	300.3
Wichita	134.6	178.0	299.6
PAD II avg	139.4	184.6	308.4
Albuquerque	148.9	185.3	307.9
Birmingham	144.0	183.3	316.7
Dallas-Fort Worth	141.9	180.3	310.6
Houston	137.9	176.3	310.0
Little Rock	147.6	187.8	313.2
New Orleans	145.4	183.8	310.1
San Antonio	143.9	182.3	304.1
PAD III avg	144.2	182.7	310.4
Cheyenne	141.9	174.3	292.3
Denver	145.1	185.5	307.2
Salt Lake City	140.4	183.3	309.8
PAD IV avg	142.5	181.1	303.1
Los Angeles	147.4	214.5	342.9
Phoenix	162.3	199.7	300.5
Portland	180.3	223.7	337.5
San Diego	162.3	229.4	354.3
San Francisco	167.3	234.4	367.8
Seattle	167.4	223.3	346.8
PAD V avg	164.5	220.8	341.6
Week's avg.	**146.0**	**191.6**	**315.9**
Feb. avg.	**144.0**	**189.6**	**303.1**
Jan. avg.	**131.5**	**177.1**	**304.5**
2009 to date	**138.7**	**184.3**	—
2008 to date	**261.5**	**305.1**	—

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

REFINED PRODUCT PRICES

	2-27-09 ¢/gal		2-27-09 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	126.70	New York Harbor	127.13
Gulf Coast	126.95	Gulf Coast	121.77
Los Angeles	147.53	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	118.13	ARA	124.81
Singapore	130.60	Singapore	117.14
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	126.20	New York Harbor	92.93
Gulf Coast	125.03	Gulf Coast	99.33
Los Angeles	153.53	Los Angeles	113.07
		ARA	85.49
		Singapore	93.16

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

BAKER HUGHES RIG COUNT

	3-6-09	3-7-08
Alabama	2	3
Alaska	11	9
Arkansas	47	39
California	24	35
Land	23	34
Offshore	1	1
Colorado	63	115
Florida	0	0
Illinois	1	0
Indiana	2	2
Kansas	19	9
Kentucky	11	11
Louisiana	140	155
N. Land	71	56
S. Inland waters	5	18
S. Land	19	28
Offshore	45	53
Maryland	0	0
Michigan	0	1
Mississippi	12	11
Montana	3	11
Nebraska	0	1
New Mexico	42	71
New York	3	3
North Dakota	55	59
Ohio	7	13
Oklahoma	115	201
Pennsylvania	27	20
South Dakota	0	2
Texas	480	884
Offshore	4	7
Inland waters	0	4
Dist. 1	8	24
Dist. 2	18	34
Dist. 3	42	55
Dist. 4	43	95
Dist. 5	110	182
Dist. 6	89	122
Dist. 7B	12	37
Dist. 7C	18	49
Dist. 8	54	129
Dist. 8A	18	19
Dist. 9	21	42
Dist. 10	43	85
Utah	23	41
West Virginia	22	24
Wyoming	47	71
Others—NV-5; TN-4; VA-3; WA-2	14	11
Total US	**1,170**	**1,802**
Total Canada	**299**	**623**
Grand total	**1,469**	**2,425**
US Oil rigs	241	337
US Gas rigs	916	1,456
Total US offshore	51	61
Total US cum. avg. YTD	**1,623**	**1,762**

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	3-6-09 Percent footage*	Rig count	3-7-08 Percent footage*
0-2,500	44	—	83	3.6
2,501-5,000	63	55.5	108	53.7
5,001-7,500	163	21.4	189	21.6
7,501-10,000	248	2.4	451	2.8
10,001-12,500	233	3.8	424	4.9
12,501-15,000	228	—	319	0.3
15,001-17,500	130	—	95	—
17,501-20,000	72	—	79	—
20,001-over	38	—	39	—
Total	**1,219**	**6.9**	**1,787**	**7.6**
INLAND	14		35	
LAND	1,158		1,696	
OFFSHORE	47		56	

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

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

OGJ PRODUCTION REPORT

	[1]3-6-09	[2]3-7-08
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	22	22
Alaska	733	710
California	660	661
Colorado	63	67
Florida	7	6
Illinois	25	24
Kansas	105	105
Louisiana	1,410	1,275
Michigan	15	16
Mississippi	60	58
Montana	92	86
New Mexico	163	161
North Dakota	194	140
Oklahoma	176	171
Texas	1,360	1,333
Utah	58	56
Wyoming	148	144
All others	69	70
Total	**5,360**	**5,105**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

	3-6-09 $/bbl*
Alaska-North Slope 27°	35.34
South Louisiana Sweet	47.50
California-Kern River 13°	39.40
Lost Hills 30°	50.20
Wyoming Sweet	31.52
East Texas Sweet	41.50
West Texas Sour 34°	34.25
West Texas Intermediate	42.00
Oklahoma Sweet	42.00
Texas Upper Gulf Coast	35.00
Michigan Sour	34.00
Kansas Common	41.00
North Dakota Sweet	36.75

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

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

WORLD CRUDE PRICES

$/bbl[1]	2-27-09
United Kingdom-Brent 38°	41.97
Russia-Urals 32°	41.34
Saudi Light 34°	37.16
Dubai Fateh 32°	41.47
Algeria Saharan 44°	43.67
Nigeria-Bonny Light 37°	45.41
Indonesia-Minas 34°	42.90
Venezuela-Tia Juana Light 31°	39.95
Mexico-Isthmus 33°	39.84
OPEC basket	41.53
Total OPEC[2]	40.06
Total non-OPEC[2]	40.43
Total world[2]	40.22
US imports[3]	38.60

[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]

	2-27-09	2-20-09	2-27-08	Change, %
	bcf			
Producing region	708	723	545	**29.9**
Consuming region east	793	876	786	**0.9**
Consuming region west	292	296	191	**52.9**
Total US	**1,793**	**1,895**	**1,522**	**17.8**
	Dec. 08	**Dec. 07**	**Change, %**	
Total US[2]	**2,840**	**2,879**	**–1.4**	

[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. 2009 Land	Feb. 2009 Off.	Feb. 2009 Total	Feb. 08 Total
WESTERN HEMISPHERE				
Argentina	63	1	64	85
Bolivia	2	—	2	2
Brazil	30	30	60	46
Canada	412	1	413	620
Chile	3	—	3	1
Colombia	29	—	29	42
Ecuador	10	—	10	7
Mexico	98	34	132	94
Peru	3	1	4	6
Trinidad	—	1	1	5
United States	1,264	57	1,320	1,765
Venezuela	56	13	69	83
Other	—	—	—	2
Subtotal	**1,970**	**137**	**2,107**	**2,758**
ASIA-PACIFIC				
Australia	12	9	21	24
Brunei	1	3	4	3
China-offshore	—	24	24	22
India	52	24	76	85
Indonesia	55	13	68	67
Japan	2	—	2	1
Malaysia	—	18	18	10
Myanmar	1	1	2	8
New Zealand	4	1	5	6
Papua New Guinea	—	—	—	3
Philippines	3	—	3	—
Taiwan	—	—	—	—
Thailand	3	9	12	9
Vietnam	—	7	7	6
Other	—	—	—	4
Subtotal	**133**	**109**	**242**	**248**
AFRICA				
Algeria	23	—	23	22
Angola	—	5	5	6
Congo	1	1	2	2
Gabon	—	1	1	2
Kenya	—	—	—	—
Libya	15	1	16	14
Nigeria	2	5	7	6
South Africa	—	—	—	—
Tunisia	1	1	2	4
Other	2	1	3	2
Subtotal	**44**	**15**	**59**	**58**
MIDDLE EAST				
Abu Dhabi	7	3	10	11
Dubai	1	—	1	1
Egypt	44	8	52	51
Iran	—	—	—	—
Iraq	—	—	—	—
Jordan	2	—	2	—
Kuwait	10	—	10	11
Oman	53	—	53	53
Pakistan	21	—	21	19
Qatar	1	8	9	11
Saudi Arabia	60	12	72	79
Sudan	—	—	—	—
Syria	21	—	21	21
Yemen	12	—	12	14
Other	1	—	1	1
Subtotal	**233**	**31**	**264**	**272**
EUROPE				
Croatia	—	1	1	1
Denmark	—	3	3	2
France	—	—	—	—
Germany	10	—	10	7
Hungary	1	—	1	3
Italy	3	—	3	5
Netherlands	—	2	2	3
Norway	—	25	25	11
Poland	—	—	—	2
Romania	8	—	8	20
Turkey	5	—	5	5
UK	—	20	20	16
Other	3	—	3	6
Subtotal	**30**	**51**	**81**	**81**
Total	**2,410**	**343**	**2,753**	**3,417**

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	215	2.46
Caribbean	Houston	Resid.	380	70	0.90
Caribbean	Houston	Resid.	500	73	0.94
N. Europe	New York	Dist.	200	158	2.91
N. Europe	Houston	Crude	400	82	2.22
W. Africa	Houston	Crude	910	74	2.27
Persian Gulf	Houston	Crude	1,900	36	2.09
W. Africa	N. Europe	Crude	910	71	1.60
Persian Gulf	N. Europe	Crude	1,900	36	1.51
Persian Gulf	Japan	Crude	1,750	48	1.61

*Feb. 2009 average.
Source: Drewry Shipping Consultants Ltd. Data available in OGJ Online Research Center.

Waterborne energy inc. US LNG imports

Country	Jan. 2009	Dec. 2008	Jan. 2008	Change from a year ago, %
	MMcf			
Algeria	—	—	—	—
Egypt	6,060	5,820	2,960	104.7
Equatorial Guinea	—	—	—	—
Nigeria	—	—	—	—
Norway	2,980	2,980	—	—
Qatar	—	—	—	—
Trinidad and Tobago	25,400	22,590	22,570	12.5
Total	**34,440**	**31,390**	**25,530**	**34.9**

Source: Waterborne Energy Inc.
Data available in OGJ Online Research Center.
Data not available at press time.

Propane prices

	Jan. 2009	Feb. 2009	Jan. 2008	Feb. 2008
	¢/gal			
Mont Belvieu	72.71	65.88	150.58	142.52
Conway	80.11	70.46	146.37	148.92
Northwest Europe	83.62	100.73	171.87	159.06

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. 2009						
Product revenues	52.64	50.79	51.16	61.80	51.89	51.03
Feedstock costs	–44.87	–45.38	–42.23	–36.75	–42.84	–44.70
Gross margin	7.77	5.41	8.93	25.05	9.05	6.33
Fixed costs	–2.12	–2.45	–2.39	–2.78	–2.39	–1.86
Variable costs	–1.50	–1.10	–1.36	–2.28	–1.85	–0.71
Cash operating margin	**4.15**	**1.86**	**5.18**	**19.99**	**4.81**	**3.76**
Jan. 2009	6.67	3.12	8.52	19.59	6.51	4.68
YTD avg.	5.41	2.49	6.85	19.79	5.66	4.22
2008 avg.	9.09	3.05	11.53	13.28	6.35	3.81
2007 avg.	12.60	6.65	18.66	20.89	5.75	2.26
2006 avg.	12.54	6.38	14.97	23.69	5.88	1.06

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. 2009	Chicago*	Houston	Los Angeles	New York
	¢/gal			
Retail price	195.52	166.14	198.48	187.47
Taxes	49.65	38.40	52.11	46.36
Wholesale price	136.01	124.98	140.99	131.68
Spot price	123.65	117.30	145.29	115.89
Retail margin	9.87	2.76	5.38	9.43
Wholesale margin	12.36	7.68	-4.30	15.79
Gross marketing margin	**22.23**	**10.44**	**1.08**	**25.22**
Dec. 2008	27.34	26.19	15.58	46.32
YTD avg.	22.23	10.44	1.08	25.22
2008 avg.	33.11	32.15	27.22	41.81
2007 avg.	26.96	23.12	19.05	31.10
2006 avg.	19.74	20.34	18.03	27.90

*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. 2009			
Product revenues	38.31	58.65	67.91
Feedstock costs	–14.75	–37.44	–61.05
Gross margin	23.56	21.21	6.86
Fixed costs	–5.38	–6.36	–7.19
Variable costs	–3.28	–3.81	–5.01
Cash operating margin	**14.90**	**11.04**	**–5.34**
Jan. 2009	13.51	6.29	–5.73
YTD avg.	14.21	8.67	–5.54
2008 avg.	20.99	22.72	–6.11
2007 avg.	14.41	14.14	–7.42
2006 avg.	19.53	22.44	1.34

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. 2009	Gulf Coast	Mid-continent
	$/Mcf	
Gross revenue		
Gas	4.38	2.92
Liquids	0.69	1.85
Gas purchase cost	4.88	3.92
Operating costs	0.07	0.15
Cash operating margin	**0.12**	**0.70**
Jan. 2009	0.07	0.63
YTD avg.	0.10	0.67
2008 avg.	0.45	1.61
2007 avg.	0.44	1.47
2006 avg.	0.26	0.97
Breakeven producer payment, % of liquids	78%	60%

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

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Strange thinking steers assault on oil, gas, economy

Just when it seems utterances from Washington, DC, can't get any loonier, someone in the Obama administration says what he thinks.

The first budget proposal by President Barack Obama is a frontal assault on the US oil and gas industry (OGJ Online, Feb. 26, 2009).

It calls for new taxes on oil and gas companies and on production from the Gulf of Mexico and for repeal of tax preferences crucial to independent producers, such as percentage depletion and expensing of intangible drilling costs.

In fact, the budget items specifically addressing oil and gas revive disastrous ideas proposed but rejected in a vengeful Congress when gasoline prices were extraordinarily high.

If enacted, they will curtail drilling and chase some companies out of the country while subsidizing renewable energy forms.

The budget also proposes to raise hundreds of billions of dollars from a cap-and-trade system for cutting emissions of greenhouse gases. That move amounts to a tax extracted through sharply higher energy costs.

A logical response to these missiles aimed at the oil and gas industry and US economy has been to ask: What are these people thinking?

Now we know.

"We don't believe it makes sense to significantly subsidize the production and use of sources of energy (like oil and gas) that are dramatically going to add to our climate change (problem)," said Interior Sec. Timothy Geithner in testimony to the Senate Finance Committed, according to Reuters. "We don't think that's good economic policy, and we think changing those incentives is good for the country."

In fact, tax preferences for oil and gas, not all of which represent subsidies, aren't as large as Geithner implies. They're not nearly as large on a per-btu basis as subsidies in effect for the high-cost, low-volume fuels this administration prefers.

If the incentive changes occur, especially in conjunction with an aggressive cap-and-trade scheme, the US will produce less cheap energy than it does now and not nearly enough politically favored, costly energy to compensate. Oil imports will surge. Energy costs will leap.

That the treasury secretary sees those outcomes as improvements to economic policy is frightening.

(Online Mar. 6, 2009; author's e-mail: bobt@ogjonline.com)

The Editor's Perspective

by Bob Tippee, Editor

Market Journal

by Sam Fletcher, Senior Writer

Cycle sinking 'deeper, longer'

This down-cycle for oil and gas will be "deeper and longer than most expect, with oil consumption falling for 3 years—the longest period since the early 1980s," warned analysts at Friedman, Billings, Ramsey & Co. Inc. (FBR) in Arlington, Va.

In a separate report, Adam Sieminski, chief energy economist, Deutsche Bank, Washington, DC, said, "We believe the potential for global oil demand to be even lower than the most bearish of current forecasts. We expect this will prompt the Organization of Petroleum Exporting Countries into further [production cuts] at some point in 2009. However, we are reassured by the ongoing flattening in the crude oil curve, which we expect will help lift oil prices into the second quarter."

FBR analysts said, "The steep drop in oil prices and limited access to capital will further reduce exploration and production [spending]. Deflation will take years, not quarters, to set in; thus, we expect a U-shaped cycle, not a V-shaped recovery as some expect." They expect the worst spending downturn since the early 1980s, but not as severe. Consumption declines should be similar to the 1980s' declines in duration, but not as deep. In 1979-84, oil and gas consumption decreased 6.5%, with capital spending falling 59% from 1981 to 1987. FBR is expecting consumption to decrease 2.7% from 2008 to through 2011 and foresees a 33% drop in capital expenditures over the same period.

Natural gas blues

In Houston, analysts at Raymond James & Associates Inc. reiterated, "Gas is going to be ugly, and NGL production levels aren't winning any pageants either. Due to declining refinery utilization and weak industrial-consumer demand for NGL feedstocks, NGL margins have remained depressed, and average NGL production levels are down 600 MMcfd on a year-over-year basis since the beginning of withdrawal season."

Raymond James analysts expect improved processing margins during the second half of this year could increase production, "thereby narrowing the year-over-year gas supply level from current levels of 600 MMcfd to 300 MMcfd looser."

FBR analysts said, "The US natural gas market can produce more with fewer resources due to the new methods of horizontal drilling, multistage completions, and shale formations." As a result, they expect a downward shift in long-term spending necessary to maintain production. "Non-shale capex will be lower for longer," they said. "Furthermore, operators with international or domestic deepwater oil opportunities should further shift their investments toward those projects. We expect US operators to spend only 80% of their cash flow in 2009, 67% in 2010, and 80-85% long term, as projects are not economical at a long-term gas price of $4.50/Mcf."

FBR analysts noted, "Improved technology and methodology are making a large quantity of low-cost shale gas economical. Lower demand and excess capacity are also lowering service costs. This should lower the weighted-average marginal cost of production 20% in 2009 to below $3. Even with more than a 60% reduction in gas capex, the natural gas market will not be balanced in our opinion. There could need to be another 25-30% drop in gas capex in 2010 to balance the market. The 2008 capex level is unlikely to be seen for many years."

Too many rigs

According to FBR analysts, "There has been a structural shift in natural gas production, and the casual relationship of 'three times as many rigs needed to maintain production' should be dispelled. The dramatic increase in lower-cost shale gas and more productive completion methods should reduce the long-term call on conventional drilling rigs."

FBR said 1,000 US land rigs need to be retired. "We expect the natural gas rig count to average 882 rigs in 2009 and 782 in 2010 as capex is cut to balance the natural gas market. In 2011, we expect the US land rig count to average 1,220. With more than 2,500 rigs marketed at the peak of the 2008 cycle, including 750 new builds and not including 100 under construction new builds, we believe 1,000 rigs need be stacked for land rig margins to rise above cash costs. Utilization for 2009 and 2010 should be around 40% and 74% long term after 1,000 rigs are stacked," they said.

"Over the last several months, the market has declined at an increasingly rapid pace for both jack ups and deepwater [rigs]. Tender activity has dried up considerably," said FBR analysts. "We expect deepwater day rates to fall on average by 42% from peak rates while we expect jack up day rates to fall on average by 53% from peak rates."

(Online Mar. 9, 2009; author's e-mail: samf@ogjonline.com)

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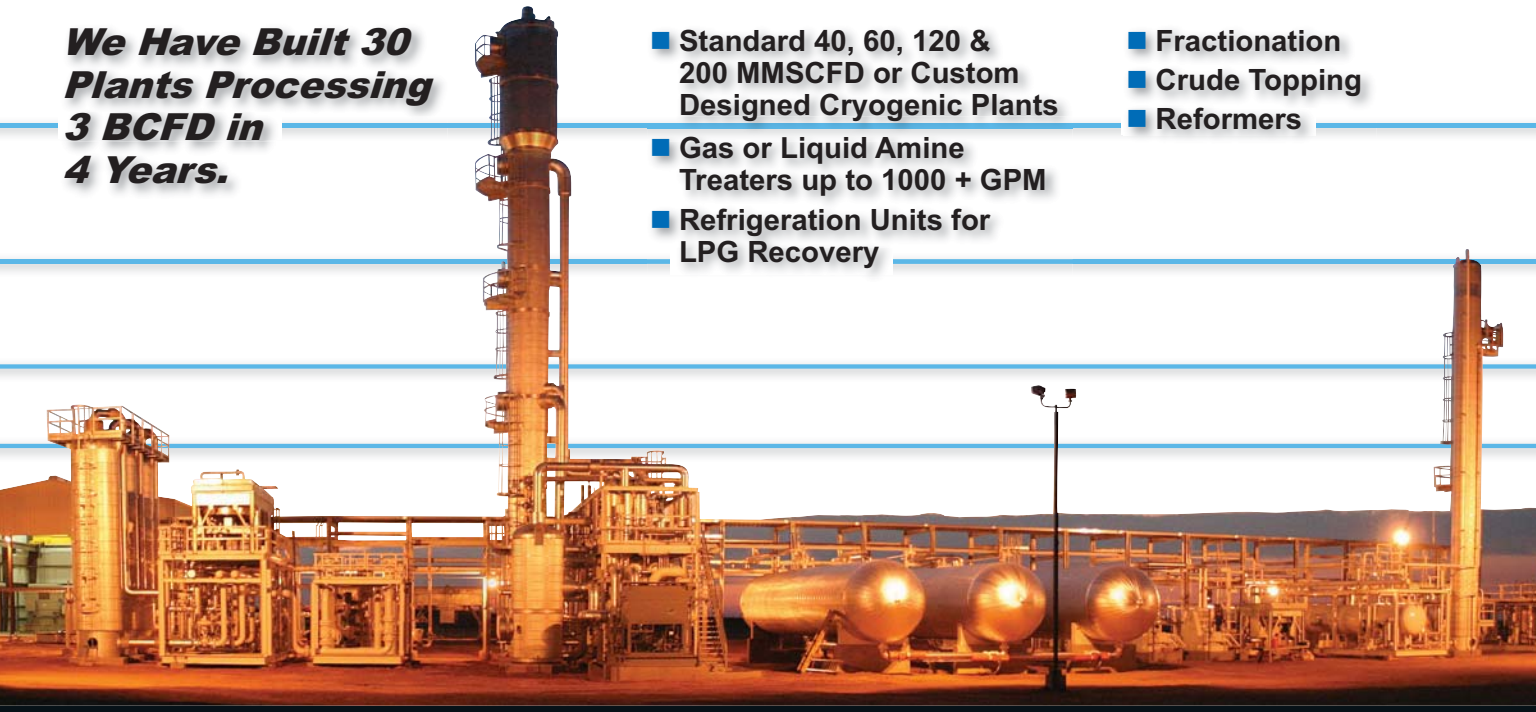

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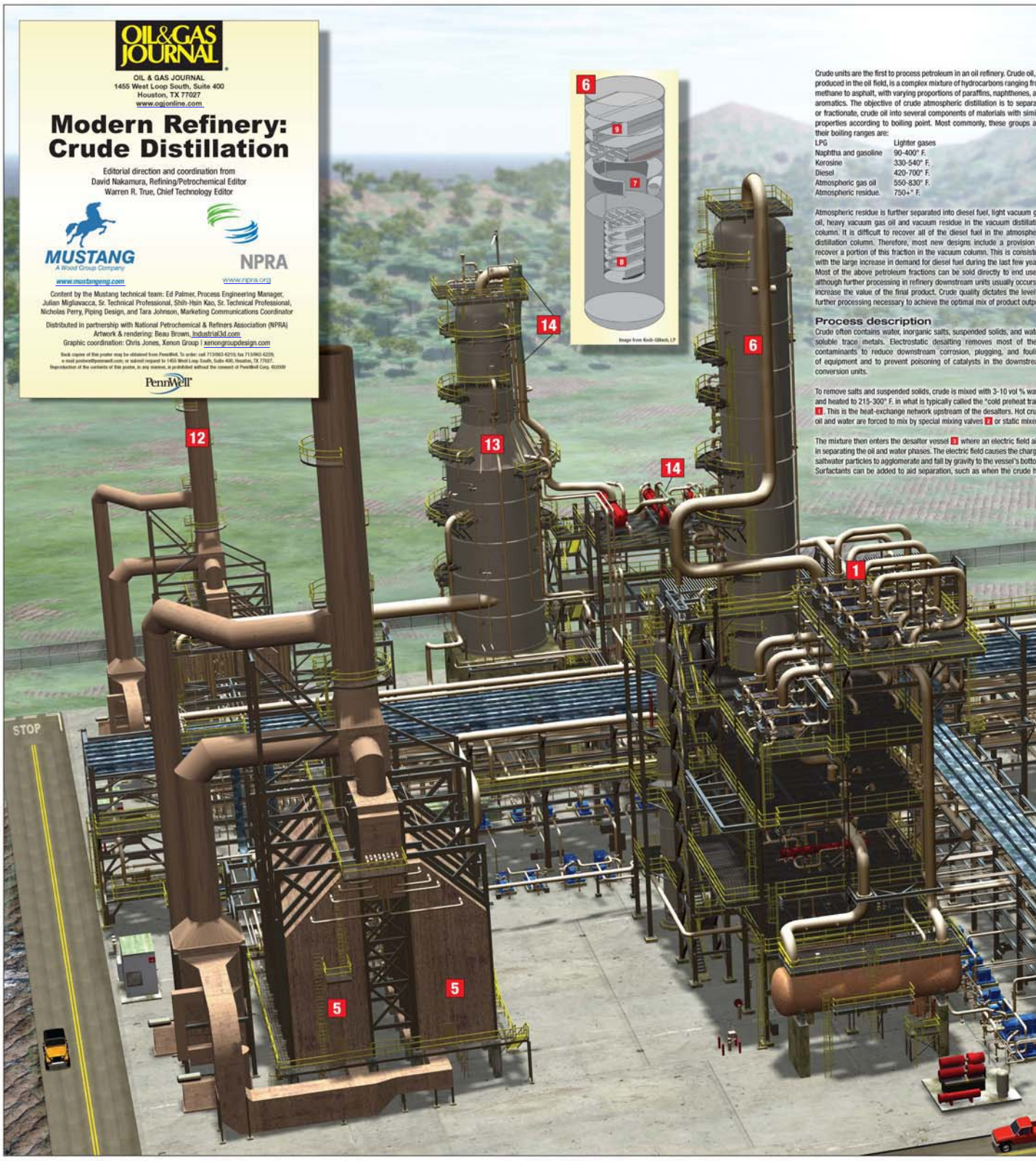

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a large amount of suspended solids or certain chemical compounds that encourage emulsion formation. Chemical surfactants (demulsifiers) aid salts and other impurities to dissolve into the water or attach to the water to make their removal easier.

Collected water (brine) contains 95-99% of the crude's salt content and flows to the waste water-treatment plant. Depending on crude type and the required degree of desalting, two stages of desalting may be necessary and may utilize multiple types of electric fields.

Desalted crude enters another heat-exchanger network, typically called the "hot preheat train" 6. Both hot and cold preheat trains use waste heat from multiple product and "pumparound" streams (defined to the right) that need cooling as part of the process.

Preheated crude enters the crude furnace 3, where it is further heated to about 650-700° F. before entering the crude tower 4.

Partially vaporized crude is fed into the feed region of the crude tower, known as the "flash zone" 7, where vapor and liquid separate. The vapor leaving the flash zone includes all the components that comprise the products, while the liquid contains the atmospheric residue with a small amount of components in the atmospheric gas-oil product range. Some of these components are removed from the residue by steam stripping at the bottom of the column 8.

The crude column contains horizontal trays 9 for separating and collecting the various hydrocarbons that comprise the end product liquids. Liquid flows down the tower across each tray, while vapor rises in the tower through perforations (valves, holes, bubble caps) in each tray. These perforations permit the vapors to bubble through the liquid, causing heat and mass transfer.

At each tray, a small amount of higher-boiling components in the vapor condense, while a small amount of lower-boiling components in the liquid vaporize. This process (distillation) causes the light components to concentrate in the vapor and heavy components to concentrate in the liquid. The liquid drains from each tray via "downcomers" to the tray below, where the process is repeated over enough trays to meet product-purity requirements.

The crude tower bottoms product is known by several names including "topped crude," "atmospheric resid," "atmospheric reduced crude" (ARC), and "atmospheric tower bottoms" (ATB). At successively higher points in the tower, major products such as gas oil, diesel, kerosine, naphtha, and uncondensed gases are withdrawn.

Some products are sent to side strippers to reduce the content of the lightest components in each product. In addition, for more effective heat integration, liquid is withdrawn at strategic locations, cooled by exchange with cold crude and returned to the column a few trays above the draw location. These arrangements in which some of the column liquid is withdrawn, cooled, and pumped back to the column are called "pumparounds." These provide much of the duty needed to heat the crude oil from storage temperature to the crude column's feed temperature.

Usually the kerosine, diesel, and gas-oil components from the crude tower are cooled and sent to other refinery units for upgrading to marketable products. The naphtha or gasoline range cut is produced from the tower as a vapor and condensed via exchange with cold crude and by air and/or water overhead condensers.

Some of this condensed liquid returns to the tower top tray as reflux; the remainder (overhead liquid product) flows to a naphtha stabilizer 10. The stabilizer removes nearly all the butanes and lighter materials to lower the naphtha vapor pressure so that it can be stored in atmospheric tanks.

Overhead liquid from the naphtha stabilizer consists mainly of methane, ethane, propane and butanes, which flow to the refinery gas plant. The naphtha stabilizer may have a vapor product, which is sent to the sour fuel-gas system. Common practice is to send the stabilized naphtha to a naphtha splitter 11 to create a light naphtha stream low in heptanes and a heavy naphtha stream low in hexanes. Light naphtha can be sent to an isomerization unit, and the heavy naphtha is typically desulfurized and used as catalytic reformer feed.

Topped crude leaving the bottom of the atmospheric tower contains a large amount of valuable components. Because the distillation temperature required to recover these components at atmospheric pressure is higher than that where thermal decomposition occurs, further heating and distillation are conducted under vacuum conditions.

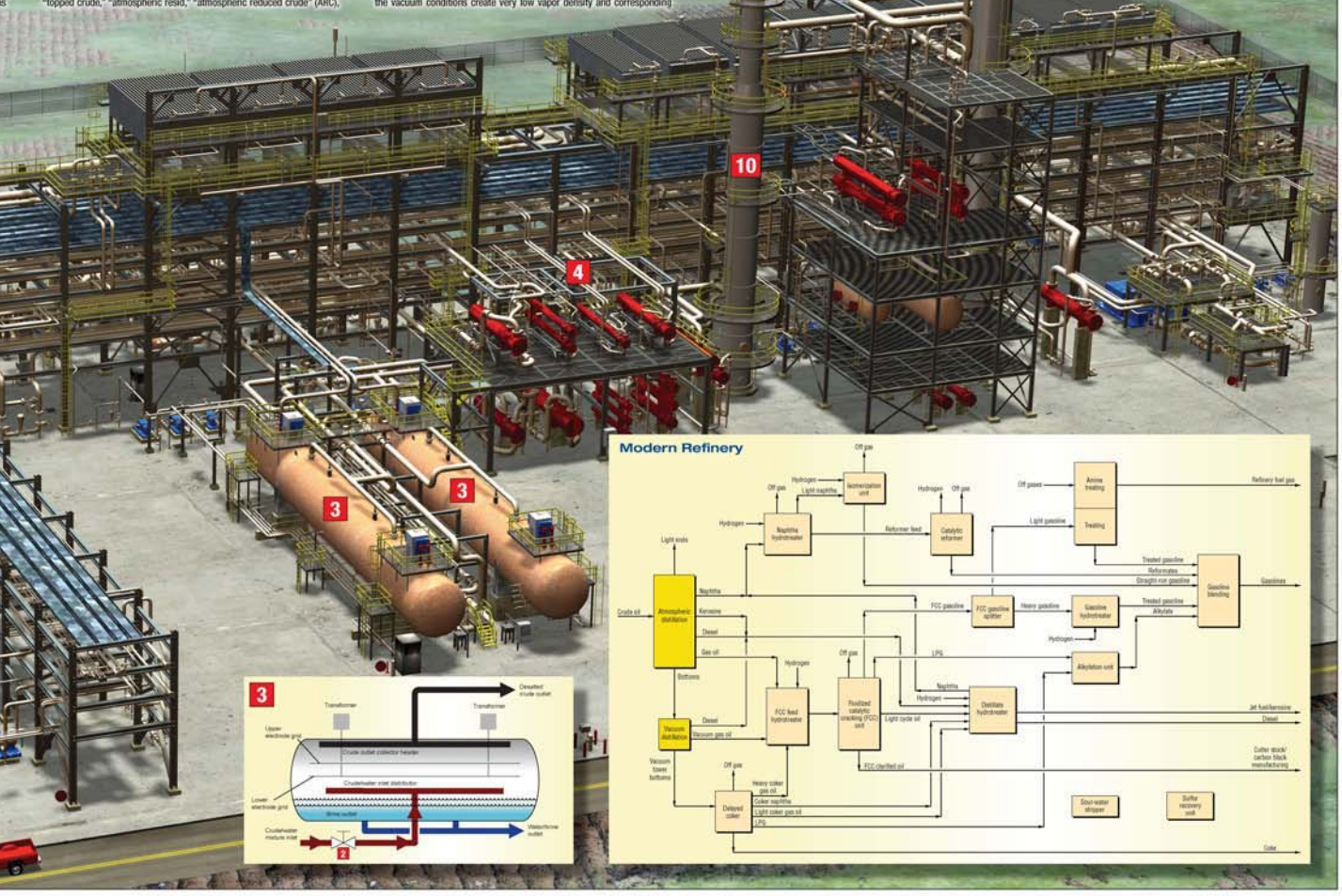
Topped crude is heated in the vacuum furnace 12 to about 750° F. Because the vacuum conditions create very low vapor density and corresponding high vapor volume flows, the vacuum tower 13 has a distinctively large diameter to provide sufficient cross sectional area for the vapor traffic.

Similar to the crude tower, the vacuum tower uses pumparounds to condense liquid products while recovering valuable heat to the crude oil charge. Packing in the vacuum tower serves a similar purpose as trays in the crude column but at a much lower pressure drop.

The vacuum tower does not have a traditional overhead condenser and does not typically use side strippers. A vacuum is maintained with steam jet ejectors 14 followed by water-cooled steam condensers. In some cases a liquid-ring vacuum pump is used for the third stage of the vacuum system to reduce steam use and waste water generation.

Because the heavy crude fraction contains metal complexes (asphaltenes and porphyrines) that are catalyst poisons for downstream processes, circulating "wash oil" above the flash zone minimizes entrainment of heavy fraction droplets up the column. Although a single cut of vacuum gas oil (VGO) is used in some cases, drawing light vacuum gas oil (LVGO) and heavy vacuum gas oil (HVGO) separately allows for increased heat recovery to the crude oil because the HVGO draw temperature is 200-250° F. higher than the draw temperature of a single VGO cut. It is common to draw separate LVGO and HVGO products from the vacuum tower and immediately combine these streams when they leave the unit.

Both LVGO and HVGO typically feed the fluid catalytic cracking (FCC) unit, hydrocracking unit, or both. As noted previously, most new designs include provisions to yield a diesel product above the LVGO draw. The vacuum tower bottoms (VTB) can be blended into residual fuels or used as feed to a delayed coker, visbreaker, vacuum resid hydroprocessing, or asphalt unit.



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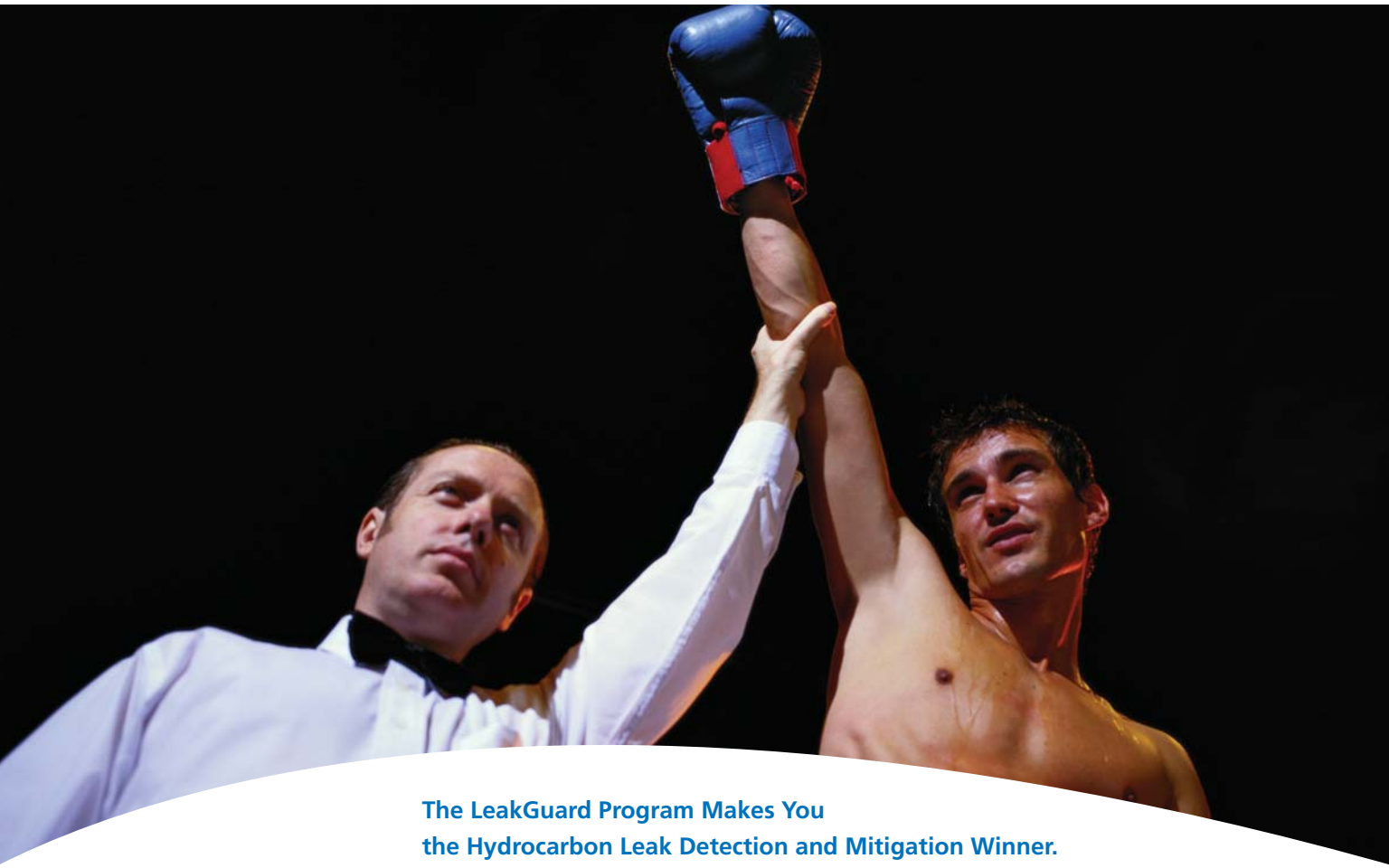

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