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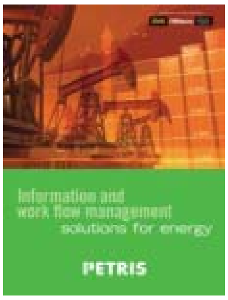

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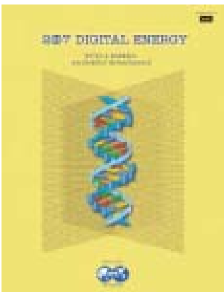

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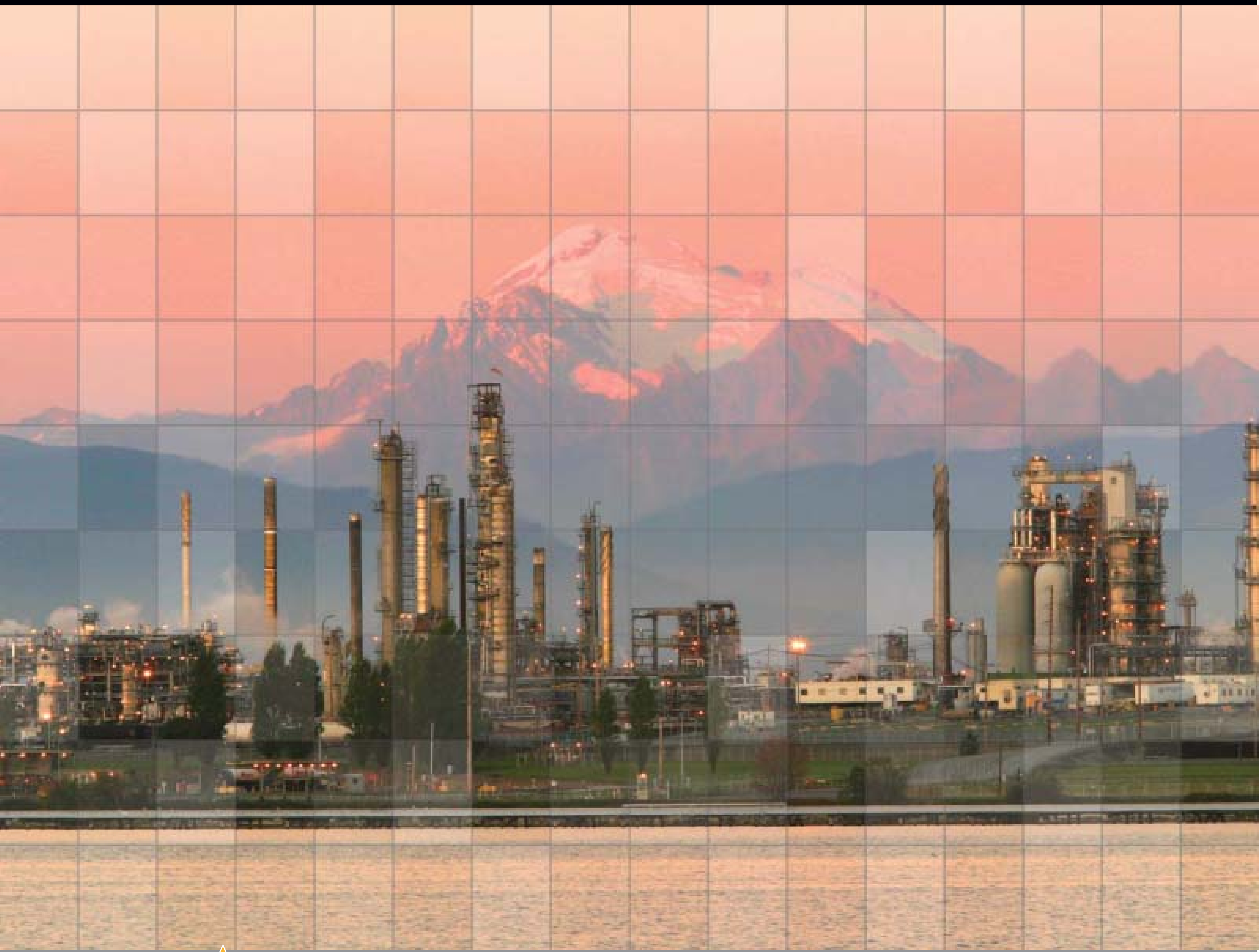

Refining Report

US ethanol forecast presents refiner, marketer opportunities
Find maximum depth for commercial deepwater production
Mexilhao development includes largest fixed platform off Brazil
Testing explores tubular technology for transport pipelines

OIL&GAS JOURNAL

Mar. 19, 2007
Volume 105.11

Refining Report

Regular Features

Cover

Boutique fuels, such as those produced in Tesoro Corp.'s 115,000 b/d Anacortes, Wash., refinery and for use in California and other areas of the US West Coast, represent added complexity for refiners worldwide. The first article in this week's special report, p. 18, outlines opportunities for refiners and ethanol blenders while the nation's ethanol production capacity and imports are expected to exceed blenders' ability to blend ethanol into gasoline. The second article, p. 44, discusses the shifting global refined product specifications and how they are forcing increased investments in refining capacity. The third article, p. 49, covers the expected supply of clean diesel and naphtha from gas-to-liquids plants and how it will affect the global marketplace. The photo above shows Tesoro's 58,000 b/cd Mandan, ND, refinery. Photos from Tesoro.

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General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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Mar. 19, 2007

International news for oil and gas professionals
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General Interest — Quick Takes

US, Brazil take steps toward ethanol partnership

During a recent visit to Brazil, US President George W. Bush announced a new energy partnership with Brazil to promote wider production of ethanol throughout the region as an alternative to oil.

The agreement was crafted to expand research, share technology, stimulate investment, and develop common international standards for biofuels. The US and Brazil, which together make 70% of the world's ethanol, will team up to encourage other nations to produce and consume alternative fuels, starting in Central America and the Caribbean.

Bush and Brazilian President Luiz Inácio Lula da Silva said increasing alternative fuel use will lead to more jobs, a cleaner environment, and greater independence from the whims of the oil market. In Brazil, nearly eight in 10 new cars already run on fuel made from sugar cane.

Under a memorandum of understanding signed by US Sec. of State Condoleezza Rice and Brazil Foreign Minister Celso Amorim, the two nations pledged closer cooperation on researching alternative energy production, promoting alternative fuels in the region and developing industry-wide standards and codes that could lay the groundwork for a global biofuels market.

The agreement entails cooperation in research and development of next-generation biofuel technology, such as ethanol production from cellulose.

In January Bush called on Congress to require the use of 35 billion gal/year of ethanol and other alternative fuels such as biodiesel by 2017. To help meet the goal, the president also is pushing research to make ethanol from material such as wood chips and switchgrass.

WoodMac expects increasing non-OPEC oil supply

Last year's fourth-quarter momentum for oil supply from outside the Organization of Petroleum Exporting Countries is expected to be maintained during 2007, said Edinburgh consultant Wood Mackenzie Ltd.

WoodMac's forecast came in a report entitled "Outlook for Supply in 2007: Non-OPEC Increases to Continue," in which analysts present a global project-by-project oil supply picture for 2007.

Total non-OPEC oil and natural gas liquids production, including Angola, is forecast to average 50.2 million b/d in 2007, up 1.5 million b/d from 2006, WoodMac said. Although Angola recently joined OPEC, WoodMac included Angola in the non-OPEC countries for the purposes of comparison with 2006.

Patrick Gibson, WoodMac principal oil supply analyst, said, "Our analysis shows that there will be significant increases in the [Former Soviet Union] states, North America, and Africa. The main areas that will experience decline are the North Sea and the Asia-Pacific region."

Gibson said WoodMac identified seven projects, led by BP PLC's Azeri Chirag Guneshli development in Azerbaijan, that will add an average of over 100,000 b/d each. Six of those projects already are on stream.

"With the top 25 projects adding an aggregate 2.1 million b/d of capacity, there is a broad base to the production growth expected," Gibson said. "The bulk of the additional supply in 2007 will consist of light and medium-grade crudes."

The forecast is based upon a risked approach that takes into account average levels of supply losses, Gibson said. Unexpected geopolitical events and technical failures could affect the forecast.

Ann-Louise Hittle, WoodMac head of oil market analysis, said there is little room in the market for OPEC member states to increase production.

"The non-OPEC supply serves to keep the pressure on OPEC to defend prices," Hittle said. "This points towards more OPEC 10 production restraint during 2007, which serves to increase the group's spare productive capacity. During 2007 this could be a source of downward price pressure, although the tension over Iran's nuclear enrichment program is an offsetting factor."

Iraq faces decisions about oil future, study says

Iraq's decisions about the future organization of its oil sector will have major implications for future oil market trends and global oil prices, said a Rice University Baker Institute study on national oil companies.

In a case study entitled "Iraq's Oil Sector: Past, Present, and Future," Baker Institute researcher Amy Myers Jaffe said the manner of Iraq's participation in oil markets will be a major factor of the next decade and beyond.

If Iraq reconstitutes its NOC under strategies similar to the manner it participated in international oil trade during the 1960-70s, it could become a leader working with other members of the Organization of Petroleum Exporting Countries to restrain future investment in oil resources and to limit output to achieve high oil prices, Jaffe said.

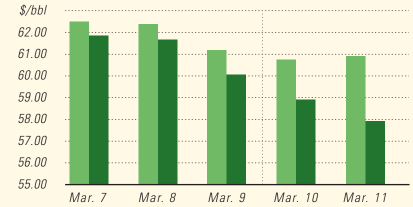
"If on the other hand, Iraq were to restructure its industry to allow foreign direct investment or to privatize its oil sector, fostering increased competition among domestic operations inside the country's oil sector, the consequences are likely to lead to more competitive structures for global oil markets in general and thereby lower energy prices over time," she said.

Iraq's oil sector needs several billion dollars worth of investment just to restore oil production and more than an estimated $20 billion to raise output to 5 million b/d, she said.

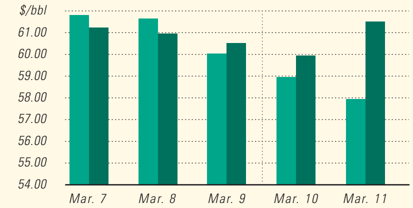
"The question of how to raise such sums has to be addressed,"

Industry Scoreboard

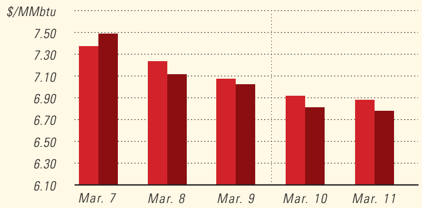
IPE BRENT / NYMEX LIGHT SWEET CRUDE



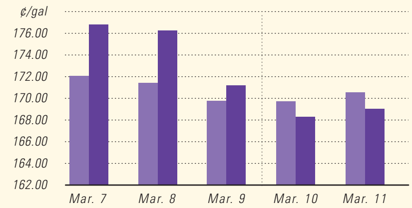
WTI CUSHING / BRENT SPOT



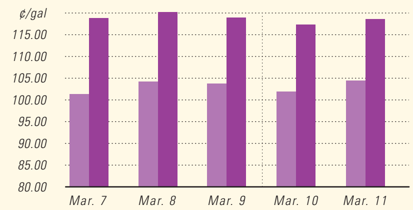
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



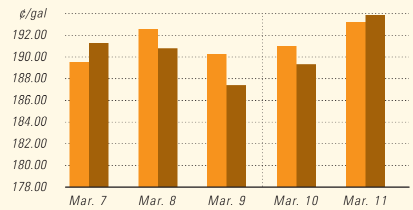
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



[1]Nonoxygenated regular unleaded

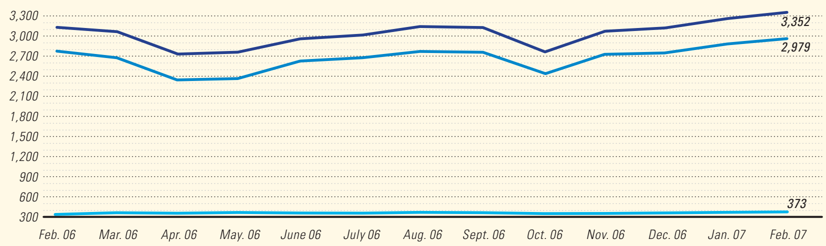
US INDUSTRY SCOREBOARD — 3/19

Latest week 3/9	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	9,196	8,930	3.0	9,096	8,897	2.2
Distillate	4,516	4,371	3.3	4,426	4,320	2.5
Jet fuel	1,661	1,548	7.3	1,644	1,545	6.4
Residual	883	791	11.6	708	821	–13.8
Other products	5,242	4,797	9.3	5,002	4,790	4.4
TOTAL DEMAND	21,499	20,438	5.2	20,876	20,374	2.5
Supply, 1,000 b/d						
Crude production	5,319	5,038	5.6	5,314	5,037	5.5
NGL production	2,420	1,680	44.0	2,408	1,683	43.1
Crude imports	9,837	9,865	–0.3	9,633	9,806	–1.8
Product imports	3,010	3,306	–9.0	3,082	3,449	–10.7
Other supply[2]	916	1,316	–30.4	971	1,182	–17.9
TOTAL SUPPLY	21,501	21,205	1.4	21,408	21,157	1.2
Refining, 1,000 b/d						
Crude runs to stills	14,368	14,580	–1.4	14,623	14,658	–0.2
Input to crude stills	14,785	14,968	–1.2	15,048	14,995	0.4
% utilization	85.3	86.2	—	86.8	86.4	—

Latest week 3/9	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	323,692	317,434	6,258	338,166	–14,474	–4.3
Motor gasoline	203,941	204,442	–501	217,162	–13,221	–6.1
Distillate	123,510	127,783	–4,273	127,267	–3,757	–3.0
Jet fuel	39,433	40,994	–1,561	43,219	–3,786	–8.8
Residual	38,509	29,708	–1,199	39,328	–819	–2.1
Stock cover (days)[3] **3/2**			**Change, %**		**Change, %**	
Crude	22.1	22.4	–1.3	23.2	–4.7	
Motor gasoline	23.7	24.1	–1.7	24.9	–4.8	
Distillate	26.4	26.5	–0.4	30.6	–13.7	
Propane	16.6	17.1	–2.9	23.5	–29.4	
Futures prices[4] **3/9**			**Change**		**Change**	**Change, %**
Light sweet crude, $/bbl	61.05	61.72	–0.67	60.89	0.16	0.3
Natural gas, $/MMbtu	7.28	7.38	–0.10	6.62	0.66	10.0

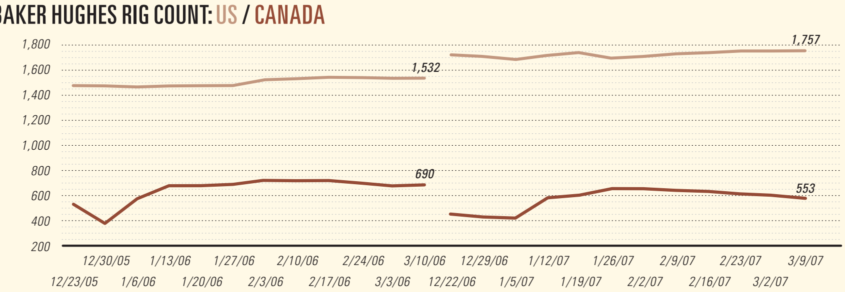
[1]Based on revised figures. [2]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [3]Stocks divided by average daily product supplied for the prior 4 weeks. [4]Weekly average of daily closing futures prices.
Sources: Energy Information Administration, American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

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



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

Jaffe said. "If it is decided that higher levels of production are desired, it is inevitable that the potential role of outside investors and lenders will loom large."

Jaffe concluded, "Improved national oil company management will have to serve as a basis for any program to expand production. Issues related to the role of the existing oil company subsidiaries such as South Oil Co. and North Oil Co. will have to be tackled head on."

ExxonMobil to start up 20 projects through 2009

ExxonMobil Corp. plans to start up more than 20 new global projects through 2009, said the company's chairman and chief executive officer Rex Tillerson. At peak production, these projects are expected to add 1 million boe/d to the supermajor's volumes.

The project inventory at yearend 2006 is expected to develop 24 billion boe net to ExxonMobil, Tillerson told analysts at the New York Stock Exchange on Mar. 7.

His 100-page presentation included maps showing 7 major project start-ups for 2006, 14 for 2007, 32 for 2008-09, and 63 for 2010 and beyond.

An ExxonMobil list naming the 20-plus projects to which Tillerson specifically referred was unavailable at presstime. Last year, OGJ listed ExxonMobil as operator of 27 major projects in an article on upstream megaprojects (OGJ, June 12, 2006, p. 41).

"Market and geopolitical forces continue to shape the environment in which we operate," said Tillerson. "We continue to prudently invest more in technology than our competitors. In 2006 we spent more than $700 million and have invested more than $3 billion since 2002." ✦

Exploration & Development — *Quick Takes*

Talisman makes gas find in British Columbia

Talisman Energy Inc. and Husky Oil Operations Ltd. have drilled a successful natural gas exploration well in the foothills area of northeastern British Columbia. The companies are equal partners in the discovery.

The well, designated Talisman Husky Federal d-28-H/94-B-7, tested at restricted rates of 21-25 MMcfd of gross raw gas. Its flowing wellhead pressure was 2,300 psi.

Production from the well is expected to start by November. It was drilled along a new exploration fairway, about 100 km north of Talisman's Monkman area. Talisman holds rights to about 10,000 gross hectares in the region.

Talisman said it has identified two 100% opportunities on the structure, which it expects to drill during this year and in 2008.

Louisiana well tab $60 million to 30,000 ft

Meridian Resource Corp., Houston, and others are gearing up to drill an ultradeep wildcat near New Orleans for which the dry hole cost is an estimated $60 million.

The well is projected to 30,000 ft to test a Jurassic Cotton Valley four-way closure in the Biloxi Marshlands area. It is to spud in early second quarter 2008 on the Deep Archtop Prospect in St. Bernard Parish. Meridian generated the prospect and began marketing it in January.

The prospect, imaged by 3D seismic surveys, has more than 14,400 acres of closure and potential recovery of as much as 5 tcf of gas.

"The shallow marshlands water location provides the potential for significant savings in drilling the test well and post development infrastructure," the company said.

Meridian said it will spend the coming year in predrill work, followed by 300-plus days to drill the well.

Offshore projects of similar size typically cost much more and require longer periods of time to construct the necessary pipelines and production facilities, the company noted. Meridian owns production facilities and pipelines in the immediate area.

Meridian intends to retain and pay its share of 20% working interest to casing point in this well. It did not disclose the other participants.

Well off Peru flows oil, gas at hefty rates

A well in Corvina field off northwestern Peru has flowed at rates of 40 MMcfd of gas and 3,150 b/d of crude oil from separate intervals, exceeding expectations, said BPZ Energy Inc., Houston.

BPZ ran four drillstem tests at the CX11-21XD well that covered a total of 413 ft in the Miocene Lower and Upper Zorritos formations.

DST-4 over 130 ft of pay in the top of Upper Zorritos flowed 40 MMcfd with 1,500 psia wellhead pressure. The nearly pure methane is ideal for the proposed 160-MW, 40 MMcfd power plant at Nueva Esperanza.

DST-3 of 45 ft in the middle of Upper Zorritos made 3,150 b/d of 22° gravity sweet crude, no water, with 1,000 psia wellhead pressure. BPZ may later test other intervals that appear to contain crude oil.

DST-2 on 138 ft of lowermost Upper Zorritos was inclusive due to mechanical problems and may be retested later as the company feels the zone may still contain commercial hydrocarbons.

DST-1 over 100 ft of Lower Zorritos produced gas and so much formation water that the zone is deemed noncommercial in this part of the field. BPZ is optimistic that this formerly untested formation contains commercial gas as evidenced on logs from three other Corvina field wells.

The well is strikingly similar to the 8X-2 well that the former Tenneco drilled decades ago in Albacora field, which BPZ plans to redevelop soon. The 8X-2 well tested 4,365 b/d of oil and 21 MMcfd of gas with 893 b/d of condensate.

BPZ plans to rework the shut-in CX-11-16X well that previously tested 16.6 MMcfd and then drill a second new well in Corvina field to prove up more gas reserves and appraise the oil discovery.

Toreador finds more gas off Turkey

Toreador Resources Corp. and partners have made two additional gas discoveries in the South Akcakoca subbasin in the Black Sea off Turkey.

The Atwood Oceanics Inc. Southern Cross semisubmersible drilled the Guluc-1 exploration well on a separate structure on the same geological trend as the recently announced Akcakoca and Akcakoca East discoveries (OGJ Online, Feb. 8, 2007).

Guluc-1 encountered gas-bearing sands in six zones between 1,226 m and 1,453 m TVD in the same Eocene-age Kusuri formation as in the other wells in the South Akcakoca subbasin. The well tested 17 MMcfd of gas from 37 m of perforations across all six zones on a 48⁄64-in. choke with flowing pressure of 1,180 psi.

The Alapli-1 exploration well, drilled using the Prometheus jack up, is on a separate structure to the northeast of Akkaya field currently under development. Alapli-1 encountered gas-bearing sands in three zones between 1,068 m and 1,242 m TVD. The two lower zones, with 12 m of net pay, tested 6.8 MMcfd of gas on a 32⁄64-in. choke with a flowing pressure of 1,064 psi. The upper zone at 1,239 to 1,242 m TVD will be tested soon.

The Atwood Southern Cross rig, having completed its initial three-well program in the South Akcakoca subbasin, will now be released to work for another operator off Bulgaria. And the Prometheus jack up will drill a well for one of the partners in another permit area before coming back to the South Akcakoca subbasin to set the Ayazli tripod and topsides in late April.

The topsides for the Akkaya production tripod already have been set and secured. ✦

Drilling & Production — *Quick Takes*

Statoil to continue production from Norne field

The Norwegian Petroleum Safety Authority has granted Statoil ASA consent to employ Transocean Offshore's Polar Pioneer semisubmersible drilling rig to continue oil production in Norne oil and gas field in the Norwegian Sea.

PSA said the Polar Pioneer would help Statoil, which operates the field, to drill an additional production well, complete two subsea wells on Block 6608/10, and sidetrack an injector well to improve pressure support on Svale.

Norne, which lies in 380 m of water, is part of Production License 128. Statoil said last year that it plans to improve recovery from Norne and reach a plateau of 1 million boe/d by 2015. It installed a subsea template to increase production by 10 million b/d of oil.

The other Norne licensees are Eni Norge AS, Norsk Hydro Produksjon AS, and Petoro AS.

BPTT expects Mango-Cashima fields output in fall

BP Trinidad & Tobago LLC is moving to bring online 800 MMcfd of natural gas from its Mango and Cashima fields off eastern Trinidad and Tobago this year.

"This production level will give BPTT the capacity to sustain its gas production at the level of 400,000 boe/d of oil," BPTT Chairman and Chief Executive Robert Riley said. He said the production would go towards meeting the company's commitments to Atlantic LNG and the National Gas Co. of Trinidad and Tobago LLC.

Reserves in Mango and Cashima are estimated at 2 tcf.

The first gas output from Mango is expected by September and from Cashima by October. The Constellation and Monitor contract rigs will drill six developmental wells in Mango and Cashima respectively. Gas from Cashima would be sent to a new hub at BPTT's Amherstia field.

BPTT has had a single processing hub, but Riley said that had to change. "Centering gas production around a single processing hub has always had its risks," he said. "With Amherstia joining the Cassia B as an additional 1 bcfd hub, we will now have much greater flexibility to manage any operational hiccups that may develop in the future."

The platforms would have a combined processing capacity of 1.5 bscfd of gas.

Callon plans to produce Entrada by 2009

Callon Petroleum Co., Natchez, Miss., plans to take a development partner and has set a goal of starting production from Entrada field in the Gulf of Mexico by 2009.

The planned $190 million purchase of BP Exploration & Production Co.'s 80% interest, to close within 45 days, is the largest transaction in Callon's history, said Fred Callon, chairman and chief executive officer (OGJ Online, Mar. 9, 2007).

Callon has been a partner in the field, a 2003 discovery in 4,690 ft of water on Garden Banks Block 782. The company has a good technical and operational understanding of the field, which has compelling economics, Callon said.

Callon, which at closing will own a 100% working interest and become operator, is well along in negotiations with ConocoPhillips, operator of the Magnolia tension leg platform on adjacent Block 783, to produce Entrada through the Magnolia facilities.

Callon's initial development plan is to drill and equip two wells as subsea tiebacks to Magnolia and make provision for similar link-ups of future wells. Expected capability is 15,000 b/d/well of oil and 50 MMcfd/well of gas, subject to capacity on Magnolia. Callon expects to have some level of firm capacity at Magnolia and anticipates some rate limitation initially.

The first two wells should begin producing in 2009.

Callon is seeking a deepwater rig to drill the wells in 2008. Despite rig market tightness, a rig could become available from another operator whose plans changed or from a potential Entrada partner that has a rig under contract, Callon said.

Total additional development cost is $200 million, bringing Entrada's fully developed cost to $15.60/bbl, Callon said.

The company also intends to explore other potential it sees on the five blocks being acquired, he said. ✦

Processing — *Quick Takes*

Japan to receive bulk of Brazil's ethanol exports

The Japan Bank for International Cooperation (JBIC) has signed a memorandum of understanding to provide Brazil's state-run Petroleo Brasileiro SA (Petrobras) with $8 billion to help it export ethanol to Japan.

As a result of the aid, annual shipments to Japan by Petrobras are expected to rocket to 3 billion l., with the Asian country taking nearly 90% of Brazil's available exports. In 2006, Brazil exported

3.4 billion l. of ethanol, of which less than 7%, or 225.4 million l., went to Japan.

The JBIC assistance will help Petrobras expand output and sales to Japan, with financing to cover ethanol plants, storage tanks, pipelines, and ports, according to a Mar. 4 report in Brazil's largest newspaper, Folha de S. Paulo, which quoted Petrobras executive Paulo Roberto Costa. Projects to be evaluated include the production and sale of ethanol and biodiesel, electric power plants using sugar cane bagasse as raw material, and carbon credit opportunities.

On Feb. 26, it was announced that Japan's Marubeni Corp. and Dutch grain trader Agrenco Group in 2008 plan jointly to start producing biodiesel from Brazilian soybean oil (OGJ Online, Feb. 26, 2007).

And on Feb. 27 Petrobras announced an MOU with Japan's Mitsui & Co. and Brazilian Construces e Comercio Camargo Correa SA to study the construction of pipelines for exporting ethanol (OGJ Online, Feb 28, 2007).

IOC's Gujarat refinery due delayed coker

Indian Oil Corp. Ltd. (IOC) plans to add a 3.7 million tonne/year delayed coker at its 185,100 b/cd refinery in Gujarat, India, as part of a residue-upgrading project.

IOC has selected Foster Wheeler USA Corp. to provide a license and basic engineering package for the coker. Terms of the contract were not disclosed.

The coker will be based on Foster Wheeler's selective yield delayed coking (Sydec) technology, which is a thermal process that converts heavy-residue feed into transportation fuels. The Sydec process achieves maximum clean-liquid yields and minimum fuel-coke yields from high-sulfur residues, Foster Wheeler said.

Hydrocracker to be installed at Holly refinery

Process Dynamics Inc. has been awarded a contract to provide licensing, a process design package, and reactor internals for a grassroots gas-oil mild hydrocracker at Holly Corp.'s 26,000 b/cd refinery in Woods Cross, Utah.

The unit can process as much as 15,000 b/d of mixed feed and will use Process Dynamic's IsoTherming hydrocracking technology.

Mustang Engineers & Constructors Inc. assisted in the development of the process design package.

The unit is scheduled for startup in 2008.

Guangxi refinery due polypropylene plant

PetroChina has let a contract to Aker Kvaerner ASA and a subsidiary of China National Petroleum Corp. for basic engineering design and supply of certain equipment for a 200,000 tonne/year polypropylene plant to be installed at the Guangxi Petrochemical Co. complex in China.

The contract value was not disclosed.

The plant, which will use Dow Chemical Co.'s UNIPOL polypropylene technology, is expected to start operations in 2008. ✦

Transportation — *Quick Takes*

Dolphin gets QP gas; prepares for UAE imports

Dolphin Energy Ltd., Abu Dhabi, has received its first supplies of natural gas through a pipeline from Qatar and is testing its import facilities ahead of the project's planned commercial launch this summer.

"Gas is being received from Qatar Petroleum (QP) for Dolphin's export pipeline connecting Qatar with the UAE," Dolphin said without detailing the quantity of gas received.

The $3.5 billion pipeline initially is planned to carry 2 bcfd, but the pipeline has a design capacity of 3.5 bcfd to accommodate expected later demand. Qatar plans to export 200 MMcfd to Oman starting in 2008 (OGJ, Feb. 19, 2007, p. 48).

Two weeks after completion of testing, the Taweelah import and distribution terminal in Abu Dhabi will begin supplying up to 400 MMcfd to Dubai under a preliminary supply agreement with QP.

Once Dolphin's own gas begins arriving from Qatar in midsummer for UAE customers, the arrangement for the early gas deliveries with QP will end. Full commercial operations will start in midsummer, when Dolphin will send as much as 3.5 bcfd of gas to the UAE.

Abu Dhabi government-run Mubadala Development Co. owns 51% of Dolphin, while the remaining 49% is shared 50:50 by Total SA and Occidental Petroleum Corp.

MacKenzie Valley line cost estimates updated

Mackenzie Valley Pipeline sponsors have updated the cost estimates for the Mackenzie natural gas transportation project to $16.2 billion (Can.) and delayed the expected completion date by 3 years, operator Imperial Oil Ltd. said.

The changes were outlined in updated information Imperial filed with Canada's National Energy Board and Joint Review Panel, the Calgary-based firm said Mar. 12.

Project costs are now estimated at $7.8 billion for the Mackenzie Valley mainline and $3.5 billion for the gas gathering system. In addition, the estimated cost of anchor fields development is $4.9 billion.

The 1,200-km pipeline, previously pegged at $6.5 billion, would link Beaufort Sea fields to the Alberta border. Project timing is uncertain, but production start-up is expected no sooner than 2014, Imperial said. Previously, the anticipated construction completion was 2011(OGJ Online, Feb. 23, 2007).

The Mackenzie gas project would include development of 6 tcf of gas in three onshore fields in the Mackenzie Delta and construction of a gas and natural gas liquids gathering system, gas pipeline, and related facilities.

The Mackenzie Valley gas pipeline would have 1.2 bcfd of throughput capacity, and would be expandable to accommodate gas from other fields. ✦

Letters

'Flimsy' energy policy

Congratulations you for "hitting the nail squarely on the head" by pointing out the hypocrisy of the federal government and their flimsy energy policy (Editor's Perspective, OGJ Online, Feb. 23, 2007). We need to cut our dependency on foreign energy sources back to less than we were in 1973. The marketplace should be the dictator of the viability of renewable energy more than government tax abatements and tariffs.

I am a farmer, and this year I will benefit greatly from the governmental policies on ethanol and biofuels that are enhancing the prices I will receive for my grains and oilseeds.

Dependence on foreign energy and the politics thereof that fuel the speculation in the marketplace drive up the cost of energy for all of us. My expenses for my farming operation that are derived from energy usage, i.e. diesel, gasoline, electricity, fertilizer, chemicals, tires, shipping, raised my total operational expenses 10% last year. The profit margin from better commodity prices is surely to be taken away by the gouging manipulation of foreign oil and government manipulation.

Again, I say, you made a very good statement.

James Hinton
Floydada, Tex.

Calendar

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

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2007

NPRA Annual Meeting, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org , http://www.npra.org.. 18-20.

SPE/ICoTA Coiled Tubing and Well Intervention Conference and Exhibition, The Woodlands, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 20-21.

ARTC Refining & Petrochemical Annual Meeting, Bangkok, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 20-22.

Offshore West Africa Conference & Exhibition, Abuja, (918) 831-9160, (918) 831-9161 (fax), e-mail:

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owaconference@pennwell.com, website: www.offshorewestafrica.com. 20-22.

Georgian International Oil, Gas, Energy and Infrastructure Conference & Showcase, Tbilisi, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 22-23.

NPRA International Petrochemical Conference, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 25-27.

American Chemical Society National Meeting & Exposition, Chicago, (202) 872-4600, (202) 872-4615 (fax), e-mail: natlmtgs@acs.org, website: www.acs.org. 25-29.

Turkish Oil & Gas Exhibition and Conference, Ankara, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 27-29.

Offshore Mediterranean Conference, Ravenna, +39 0544 219418, +39 0544 39347 (fax), e-mail: conference@omc.it, website: www.omc.it. 28-30.

SPE Production and Operations Symposium, Oklahoma City, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. Mar. 31-Apr. 3.

APRIL

SPE Hydrocarbon Economics and Evaluation Symposium, Dallas, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 1-3.

AAPG Annual Convention and Exhibition, Long Beach (918) 584-2555, (918) 560-2694 (fax), e-mail: postmaster@aapg.org, website: www.aapg.org. 1-4.

PIRA Natural Gas and LNG Markets Conference, Houston, 212-686-6808, 212-686-6628 (Fax), e-mail: sales@pira.com, website: www.pira.com. 2-3.

China International Oil & Gas Conference, Beijing, +44 (0) 207 596 5233, +44 (0) 207 596 5106 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com. 3-4.

IADC/SPE Managed Pressure Drilling & Underbalanced Operations Conference, Galveston, Tex., (713) 292-1945, (713) 292-1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 3-4.

IADC Environmental Conference & Exhibition, Amsterdam, (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 3-4.

Instrumentation Systems Automation Show & Conference, Calgary, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 11-12.

SPE Digital Energy Conference and Exhibition, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 11-12.

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Middle East Petroleum & Gas Conference, Dubai, 65 62220230, 65 62220121 (fax), e-mail: info@cconnection.org, website: www.cconnection.org. 15-17.

SPE Latin American & Caribbean Petroleum Engineering Conference, Buenos Aires, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 15-18.

Society of Petrophysicists and Well Log Analysts (SPWLA) Middle East Regional Symposium, Abu Dhabi, (713) 947-8727, (713) 947-7181 (fax), e-mail: info@spwla.org, website: www.spwla.org. 15-19.

International Pipeline Conference & Exhibition, Moscow, +43 1 402 89 54 12, +43 1 402 89 54 54 (fax), e-mail: pipeline@msi-fairs.com, website: www.msi-fairs.com. 16-17.

Russia & CIS Refining & Petrochemicals Equipment Conference & Exhibition, Moscow, +44 (0) 20 7357 8394, e-mail: Conference@EuroPetro.com, website: www.europetro.com. 16-17.

API Spring Refining and Equipment Standards Meeting, Seattle, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 16-18.

ERTC Coking and Gasification Conference, Paris, 44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 16-18.

SPE Rocky Mountain Oil & Gas Technology Symposium, Denver, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 16-18.

Pipeline Technology Conference & Exhibition, Hannover, +49 511 89 31240, +49 511 89 32626 (fax), e-mail: info@messe.de, website: www.hannovermesse.de. 16-20.

API/NPRA Spring Operating Practices Symposium, Seattle, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 17.

TAML MultiLateral Knowledge-Sharing Conference, Singapore, +44 (0) 1483 598000, e-mail: info@taml.net, website: www.taml.net. 17.

IADC Drilling HSE Middle East Conference & Exhibition, Bahrain, (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 17-18.

API Annual Pipeline Conference, Albuquerque, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 17-18.

ETF Expandable Technology Forum Technical Conference, Singapore, +44 (0) 1483 598000, +44 (0) 1483 598010 (fax), e-mail: sally.marriage@otmnet.com, website: www.expandableforum.com. 18-19.

Russia & CIS Bottom of the Barrel Technology Conference & Exhibition, Moscow, +44 (0) 20 7357 8394, e-mail: Conference@EuroPetro.com, website: www.europetro.com. 18-19.

GPA Midcontinent Annual Meeting, Oklahoma City, (918) 493-3872, (918) 493-3875 (fax), website: www.gasprocessors.com. 19.

American Institute of Chemical Engineers Spring National Meeting, Houston, (212) 591-8100, (212) 591-8888 (fax), website: www.aiche.org. 22-26.

EnviroArabia Environmental Progress in Oil & Petrochemical Conference, Bahrain, +973 17 729819, +973 17 729819 (fax), e-mail: bseng@batelco.com.bh, website: www.mohandis.org. 23-25.

Sea + sun = energy source?

David N. Nakamura
Refining/Petrochemical Editor

Often on this page, OGJ editors have discussed promising new technologies—such as windmills, harnessing ocean waves, and various types of biofuels—that might someday replace oil and natural gas as power sources. One not-so-new technology that hasn't been discussed, but that is just as intriguing, is ocean thermal energy conversion (OTEC).

The OTEC technology uses differences in seawater temperatures at various depths to generate electricity, desalinate water, and even condition air. The Earth's ocean acts as an enormous collector of solar energy.

According to the National Renewable Energy Laboratory's OTEC web site, "On an average day, 60 million sq km of tropical seas absorb an amount of solar radiation equal in heat content to about 250 billion bbl of oil." And although the economics of OTEC do not compete currently with conventional power generation technologies, the vast potential of this amount of energy is very compelling.

It makes sense that the hotter the surface water temperature, the greater the potential of the OTEC technology. The technology is therefore most promising for tropical island communities that have to depend on diesel-generated electricity. The fact that the technology produces desalinated water is an added benefit. And the chilled water can be used for mariculture ponds in which cold-water ocean species, such as lobster and salmon, can be raised.

OTEC history

As previously mentioned, this technology is not a new idea. In fact, it was first proposed in 1881 by a French physicist named Jacques Arsene d'Arsonval.

One of his students, Georges Claude, was the first to build an OTEC plant in 1930 in Matanzas Bay, Cuba. Using a low-pressure turbine, the plant produced 22 kw of electricity.

Claude constructed another plant off the coast of Brazil in 1935. Both of his plants, however, were destroyed by the sea. Neither plant ever produced net positive electricity.

In 1974, with oil prices rising after the Arab oil embargo, the US government got involved with OTEC research. It established the National Energy Laboratory of Hawaii Authority (NELHA) at Keahole Point on the Kona coast. In 1979, the facility started up a 50-kw OTEC demonstration plant. The plant produced 52 kw of gross power and 15 kw of net power.

In 1981, Japan produced 31.5 kw of net power during a demonstration of a shore-based plant. Then in 1993, NELHA produced 50 kw of net electricity in an open-cycle OTEC plant. Finally, in 1999, NELHA tested a 250-kw pilot OTEC plant.

OTEC technology

The OTEC technology has three different designs—closed cycle, open cycle, and hybrid—and it can be located on land, on a sea shelf, aboard a floating vessel, or theoretically in a submerged plant.

The closed-cycle system pumps cold water from depths of up to 1 km into a heat exchanger that condenses a vapor, such as ammonia or propylene. The heat-transfer fluid is then pumped through a second heat exchanger, where it is vaporized with the warmer surface seawater. The expanding vapor turns a turbine, which generates electricity.

In an open-cycle system, warm seawater is boiled in a low-pressure container. The steam expands in a low-pressure turbine to generate electricity. The steam, now nearly pure water, is condensed with the cold deep-sea water.

The hybrid system combines features of the closed and open-cycle systems. Steam is still generated at low pressure, but in this system it is used to vaporize the fluid, which is in a closed loop.

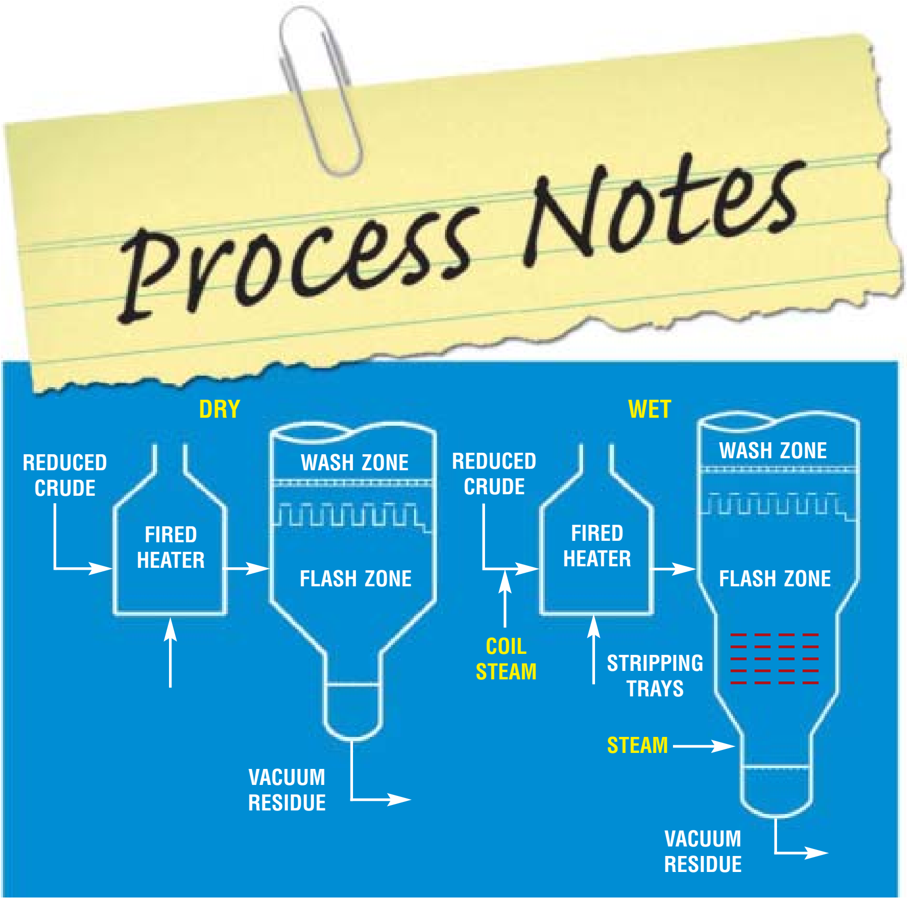
Future work

A company called Sea Solar Power Inc. in Pennsylvania is currently developing plants based on OTEC technology. The company has two models in development: a 10-Mw, land-based plant and a 100-Mw floating plantship.

The company reports that the land-based plant is specifically designed for small tropical islands and that the plantship is suited for continental applications. The company has recognized that conventional heat exchangers and turbomachinery are inefficient for OTEC plants and is designing those units to be most efficient for their specific application.

Sea Solar Power says the land-based plant should cost \$45-50 million, for which the company already has financing. The first plantship should cost about \$250 million.

Indeed, it will be interesting to see if OTEC can take advantage of further technological advancements to someday compete with conventional oil-based electricity generation. ✦



Cold Eyes Must Be Clear Eyes Too

Today many refinery engineers charged with responsibility for managing both revamps and grass root projects have signed on to a protocol that spells out what questions to have an outside reviewer ask in the early design phases of a project. This makes sense. Getting a second opinion is as important for plant design as it is for major surgery. One caveat, however. While the reviewer should not have any commercial connection with the project, the person should have intimate knowledge and expertise in the engineering involved.

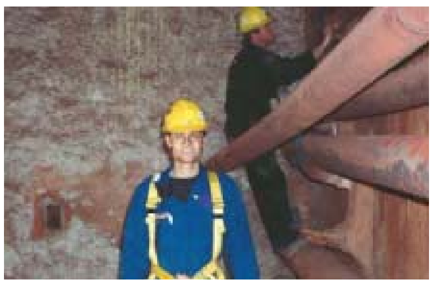
Dry or wet? Is there really any choice?

Nowhere in the whole project plan is this more important than in process design. The fate of an entire project depends on its process design, because although it is responsible for only 8-12% of engineering cost it can influence 60% or more of downstream project cost. A good process design is one that controls scope growth, an inevitable consequence of insufficient or inexpert process work carried out in early project stages. Competent design eliminates the need for value engineering, scope rationalization or other measures that just run up billable hours. It results in a unit with no more or less of the right equipment needed to produce required yields of products of correct specifications. It does so using no more energy than is required. And it will result in a unit that works right from startup and continues running stably and reliably with no unscheduled shutdowns.

Unfortunately, today it is often assumed that to guarantee such process reliability, it is necessary only to develop a process flow sheet model or review the design basis simulation. This is wrong. For the review to be worthwhile the reviewer must have experience with the process being revamped or designed and understand the specific equipment involved. For example, the reviewer may need to know whether a dry or wet vacuum unit is appropriate for the type of crude being processed. This experience does not come from a process model.

What is clear is this: No one is more expert than the project manager himself* in evaluating both the skills and limitations of his process contractor, but when he wants to augment his own knowledge and verify his decisions he is best advised to choose cold eyes that are clear eyes too.

*In the interest of brevity we use only masculine pronouns but feminine are also implied. No offense meant.



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Editorial

Ethanol's global politics

Live by politics, die by politics. No one escapes the rule. But some live by politics better than others do.

As a vehicle fuel, ethanol lives by politics. Relatively little of the material would enter US gasoline streams if not for state and federal tax credits and a volumetric mandate. But a subsidized, growing market for ethanol enriches corn growers and distillers and thus finds political favor among agricultural interests. For others, ethanol can be made to seem like a way for the US to grow its way out of dependency on foreign oil.

US President George W. Bush took ethanol politics abroad this month in his swing through Latin America. Amid much local hoopla, he signed a memorandum of understanding with Brazilian President Luiz Inacio Lula da Silva on cooperation in research on renewable energy. Brazil has been using ethanol as a vehicle fuel since the mid-1980s and now basks in the glory of showing the world how it's done.

The triumph

So how, exactly, did Brazil achieve this marvelous triumph? With decrees by the military government that ruled the country until 1985—that's how. Stung by the oil price increases of the 1970s and wanting to boost agriculture, the generals-in-chief paid farmers to grow sugar cane, the source of Brazilian ethanol, and capped retail prices of the fuel. It's really quite simple—for countries ruled by soldiers little concerned about economics and consumer choice.

But all that's history. Brazil has its fleet of tax-favored vehicles that burn ethanol, which is still subsidized, and its network for distributing and dispensing the fuel. And nearly everyone has forgotten how, after oil prices fell in the latter 1980s and civilians replaced the military in the government, it looked like a big mistake. Yes, Brazil and the US have much to teach one another about ethanol.

For example, there's that nagging rule about living and dying by politics. Brazil sees in the US an export market much bigger than exists now for its ethanol. It also sees a problem: a 54¢/gal US tariff that shields US ethanol producers from competition. It's a political market, after all. In Brazil, Bush made clear that the tariff wasn't something he wanted to discuss with Lula. This diplomatic equivalent of an invitation to dance without touching represents the "die by" aspect of politics.

In US farm country, the hollow overture still stirred up worry.

"Transferring the United States' addiction to foreign oil to foreign biofuels doesn't make sense," declared National Farmers Union Pres. Tom Buis in a press statement. Buis complained about press reports that the Bush-Lula agreement might enable Brazil to ship sugar cane to processors in the Caribbean that are exempt from the tariff. "The current tariff," he said, "ensures US taxpayer dollars do not subsidize foreign-produced ethanol."

What a distressing prospect! It's only patriotic to prefer that taxpayer dollars subsidize US-produced ethanol made from corn, which even before distillation receives various subsidies that the Congressional Research Service estimates have averaged $5.5 billion/year since 2000. That plus the $2.5 billion or so that the federal ethanol blender's credit will cost the treasury this year might not sound like much against the whole federal budget. But it's $8 billion that taxpayers are spending to make politically favored constituencies rich.

Consumers' contribution

Food and fuel consumers also are contributing to agricultural prosperity. Growing demand for ethanol is raising the price of corn and foods that contain it. And refiners making summertime gasoline must reject more normal butane and pentane than they have in the past from blendstock to accommodate ethanol's volatility. An extra supply squeeze just before driving season will tend to raise gasoline prices. Consumers won't recognize the increment, which is impossible to measure, just as they probably don't notice the 3% mileage penalty that comes with 10% ethanol blends. Overall, though, they're spending more to drive than they were before ethanol's expansion in the fuel market.

For all this, consumers can thank politics, which if they grow or distill corn might make them rich. If not, well, sorry. ✦

US ethanol forecast identifies refiner, marketer opportunities

Logan Caldwell
Houston BioFuel Consultants LLC
Houston

This spring, US ethanol production capacity and imports are expected to exceed blenders' current ability to blend ethanol into gasoline. During the next 2 years, new plants and expansions of existing plants will come on stream, creating by the end of 2008 an 8-10 billion gal/year (1.17 million b/d) ethanol production capacity. Only in 2009 will production capability finally match demand.

In the meantime, refiners and gasoline blenders will have an opportunity to develop ethanol supplies for both current and additional blending requirements on a very attractive economic basis.

This forecast by Houston BioFuels Consultants LLC (HBC) paints a picture of the US ethanol industry and market during the next 2 years. Figures are given both in gallons, which the ethanol industry currently is using, and in barrels, employed by the oil and refining industry.

Since May 2006, when ethanol replaced methyl tertiary butyl ether in the US gasoline pool, ethanol demand in the US has been steady, averaging 5.9 billion gal/year (385,000 b/d) through November 2006. This is considerably more than the amount mandated by the 2005 Energy Policy Act (EPACT) for 2006 (4 billion gal/year) and 2007 (4.7 billion gal/year.)

Then the 2006-07 winter oxygenate program and unseasonably strong gasoline demand increased ethanol demand to 6.2 billion gal/year or 404,000 b/d, which is 2.2 billion gal/year more than EPACT's 2006 requirement.

Weekly variations have been within a narrow band of plus or minus 400 million gal/year (26,000 b/d) and are mainly the result of deviations in demand for Environmental Protection Agency-specified reformulated gasoline (RFG)—which comprises about one third of US gasoline demand but contains two thirds of ethanol demand (Fig. 1).

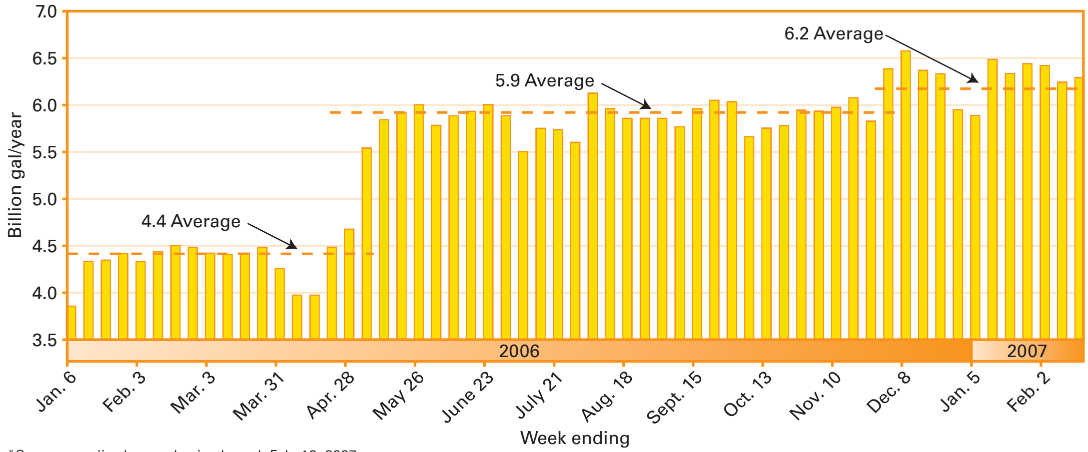
Weeks around major holiday weekends—Memorial Day, Fourth of July, Labor Day, and Thanksgiving—that always show volatile demand because of short reporting weeks and holiday demand represent a major component of the variation seen in the weekly ethanol demand estimated by HBC.

Viewing ethanol demand on a monthly basis eliminates much of this variation and provides a convenient method for comparing HBC's ethanol demand estimates with the ethanol production, imports, and inventory reported in the Energy Information Administration's EIA 819 Monthly Oxygenate Report, published 2 months in arrears. Agreement between the two is quite close, with known exports being one reason the EIA report tended to be higher in 2005 when there wasn't such a call on ethanol production in the US (Fig. 2).

Supplies of ethanol from imports and inventory draws have provided the volume to fill the gap between US ethanol production, estimated at nearly 5.6 billion gal/year (365,000 b/d) at yearend 2006, and demand. By comparison, at the end of 2005 and 2004, ethanol production capacity in the US was 4.8 billion gal/year (313,000 b/d) and 4.3 billion gal/year (280,000 b/d), respectively, already significantly above the mandated amount of 4 billion gal/year for 2006.

US WEEKLY ETHANOL DEMAND*

Fig. 1



*On an annualized usage basis, through Feb. 16, 2007.
Source: Houston BioFuels Consultants LLC estimates

By the end of first-quarter 2007, an additional 600 million gal/year (39,000 b/d) of ethanol production capacity is expected to be on stream from a dozen or more new ethanol plants. This is nearly the same capacity that was added in all of 2006 by 13 new plants; capacity expansions—about 200 million gal/year (13,000 b/d)—provided the balance of the 2006 increase.

HBC forecasts imports of 500 million gal/year (33,000 b/d) during the next 2 years, which is somewhat less than the 700 million gal/year (46,000 b/d) imported in 2006. Imports likely will continue because Brazil currently has no other market comparable to the US and blenders want to maintain an alternate supply chain.

"The main driver for increased ethanol usage during the [2-year] forecast period will be favorable blending economics giving gasoline blenders incentive to blend more ethanol."

Throughout the remainder of the 2-year forecast period, new plants and expansions of existing plants already well under way—and for all intents and purposes "locked-in"—will come on stream so that by the end of 2008 there will be at least 8 billion gal/year (522,000 b/d) of ethanol production capacity in the US and perhaps as much as 10 billion gal/year (652,000 b/d) (Fig. 3).

The low end of this range will occur if sponsors of the legitimate ethanol projects that are ready to proceed recognize the oversupply and tight margin situation (high corn prices but low ethanol prices), defer projects, and bide time until prospects for margins improve.

The high end of this range will result if, instead, the many independent ethanol project developers and their financiers believe their projects can withstand the market conditions during an indefinite period following initial operation.

At the moment, ethanol project developers speak confidently of their projects' ability to weather the storm. Are they engaged in a game of waiting for other developers to blink, or are they going to proceed regardless? That is the uncertainty differentiating HBC's high and low forecast production capacities.

In either case, production capacity would exceed HBC's demand forecast.

If developers restrain production capacity as we expect, an oversupply will still occur, but ethanol prices will fall just low enough to continually induce more blenders to use ethanol. In the unrestrained production capacity case, ethanol prices are likely to fall below what is needed as incentive for blenders. In this latter scenario, a battle could result among producers to lower prices enough to reduce capacity utilization so that supply and demand balance—as ultimately they must.

Demand increase forecast

The HBC-forecast increase in ethanol demand from today's 5.9 billion gal/year (385,000 b/d) level is predicated on discretionary blending taking place—that is, additional blending beyond the amounts mandated by EPACT. Ethanol producers will offer economic inducements sufficient to overcome the blenders' capital and switching costs, so they will blend more ethanol than required by EPACT.

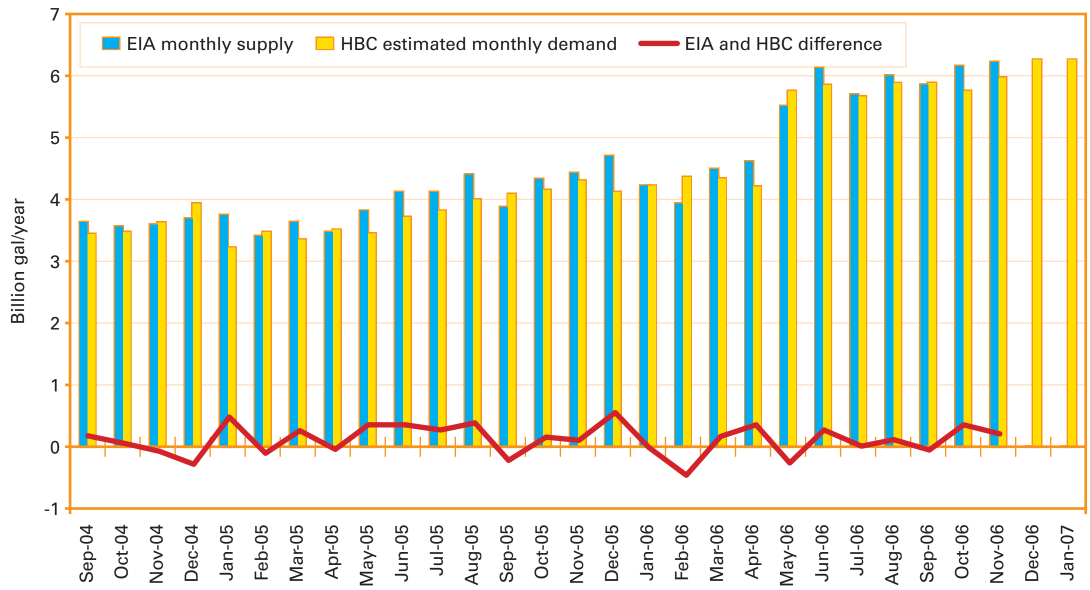
The forecast includes an additional 300 million gal/year (20,000 b/d) of demand in California, starting in the second half of 2008. HBC believes changes in the state's predictive model regulating California gasoline quality and possibly a state mandate for greater use of renewable fuel will bring about this increase.

Demand will increase in lumps because of varying lead times to install needed facilities at terminals to enable ethanol blending.

With current usage far exceeding the federal renewable fuels standard requirements and with future mandates unlikely to significantly contribute to ethanol demand until 2009 and onward—when the mandate will be

EIA US MONTHLY SUPPLY ESTIMATES VS. DEMAND*

Fig. 2



*HBC figures.
Source: Energy Information Administration, Houston Biofuels Consultants LLC

6.1 billion gal/year—the main driver for increased ethanol usage during the forecast period will be favorable blending economics giving gasoline blenders incentive to blend more ethanol.

Most current discretionary ethanol blending is in the Midwest, and this is where most of the additional ethanol blending is expected to occur during the forecast period because the proximity to ethanol production will result in the lowest ethanol cost in the country relative to gasoline. Hence Midwest blenders will have the most economic incentive to blend more ethanol than is mandated.

HBC estimates that about 30% of the terminals in the Midwest can begin blending ethanol at relatively low cost within 4 months of deciding to do so. Other Midwest terminals will require more time and capital to install ethanol blending facilities, 18 months in some cases, but by the end of 2008, an additional 1.7 billion gal/year (111,000 b/d) of discretionary ethanol blending is expected to take place in the Midwest, most of which will be 10% ethanol.

Discretionary blending will increase in other areas of the US, as well, but to a lesser extent and on a less systematic basis. One example of this would be the Atlanta area, which has had facilities to blend ethanol at its terminals since 2005. More examples would be Florida and other main population centers in the Southeast. However, should these coastal areas convert to ethanol blends, we expect that imports from Brazil or the Caribbean Basin Initiative (CBI) countries would increase and provide much of the supply. Overall US ethanol demand would increase but would not significantly impact the forecast increase in discretionary blending in the Midwest or help provide demand to meet the US ethanol production capacity.

To a certain extent, it is in the ethanol producers' best interest to encourage additional discretionary blending in the Midwest states to reduce the threat of foreign ethanol taking market share. This is but one area where ethanol producers and marketers interests may begin to diverge.

The HBC forecast shows production capacity exceeding demand by about 240 million gal/year (16,000 b/d) —4% of capacity—starting in second-quarter 2007 and persisting until at least yearend 2008. This excess capacity will be the main driver pushing ethanol prices down to the point that discretionary blenders will take the steps needed to increase ethanol blending.

Events in the ethanol market, Washington, DC, state legislatures, and the oil markets will have a major impact on what happens in 2009 and beyond, but for the next 2 years, the large increase in ethanol production capacity will be the key driver in the US ethanol market, and the laws of supply and demand will prevail.

Opportunities

The ethanol industry has evolved such that ethanol marketing companies currently are the intermediaries between ethanol producers and blenders, supplying rail cars and other logistics and scheduling as well as coordinating plant output with blenders.

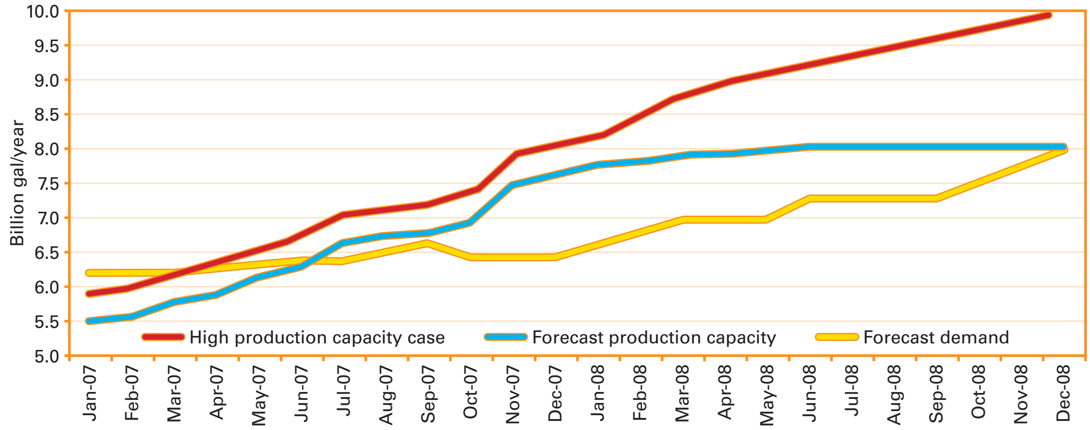
Ethanol producers are predominantly from agribusiness rather than the oil industry. This arrangement has worked well until now, with companies and terminals interested in using ethanol relatively easy to locate, as most of the country's ethanol demand has been generated by federal RFG requirements or state governmental mandates such as California's.

The marketing companies typically represent dozens or more ethanol plants whose individual production is relatively small compared with the needs of any one blender. They locate the supply and arrange logistics for reliable delivery of the ethanol to the blending or regional transloading terminals.

Starting in the spring and continuing through at least yearend 2008, the situation will be reversed: Ethanol supply

FORECAST US ETHANOL PRODUCTION* VS. DEMAND

Fig. 3



*For total supply, add imports forecast at 500 million gal/year.
Source: Houston BioFuels Consultants LLC

will be well-defined and easy to locate, but the additional demand is going to be more difficult to pin down because it will be in the form of discretionary blending. Refiners and gasoline blenders have an opportunity to develop the ethanol supplies for both current and additional blending requirements on a very attractive economic basis.

Overproduction effects

With the large increase in new ethanol production capacity, refiners will recognize the oversupply situation in the ethanol market. In an oversupply situation, refiners are forced by market conditions to sell products on the basis of something over the variable cost of production rather than on the basis of value-added supplied to the customer.

Oversupply will tie ethanol prices to the variable cost of production. Ethanol producers will operate so long as their net-back prices cover variable costs. At prices any lower, they will be better off shutting down. Some ethanol plants during this overcapacity period might be shuttered, at least temporarily.

Cooperatives that own ethanol plants and supply corn might maintain ethanol production and forgo some of the corn value-added even if ethanol prices are below variable cost.

Refiners can relate to this, remembering when high-cost refineries (e.g. in Europe and Asia) continued to operate during periods of global overcapacity because they were government-owned or because government policy dictated that they stay online.

As in any other manufacturing industry, there is a cost curve for all the ethanol plants, with some in better cost positions than others. The large wet mills are some of the lowest-cost producers because netting out byproduct sales provides a greater credit than distiller grain solubles do for dry mills.

Cost considerations

Refiners and gasoline blenders in the Midwest should be in position to gain the most advantage from the oversupply. Blenders in the coastal markets may also have the opportunity to source economically advantaged gasoline blendstocks from the oversupplied ethanol industry—even with corn at $4/bushel. At $4/bushel of corn and $8.50/Mcf of natural gas, the variable cost for a dry mill, with no freight costs, is about $1.60/gal.

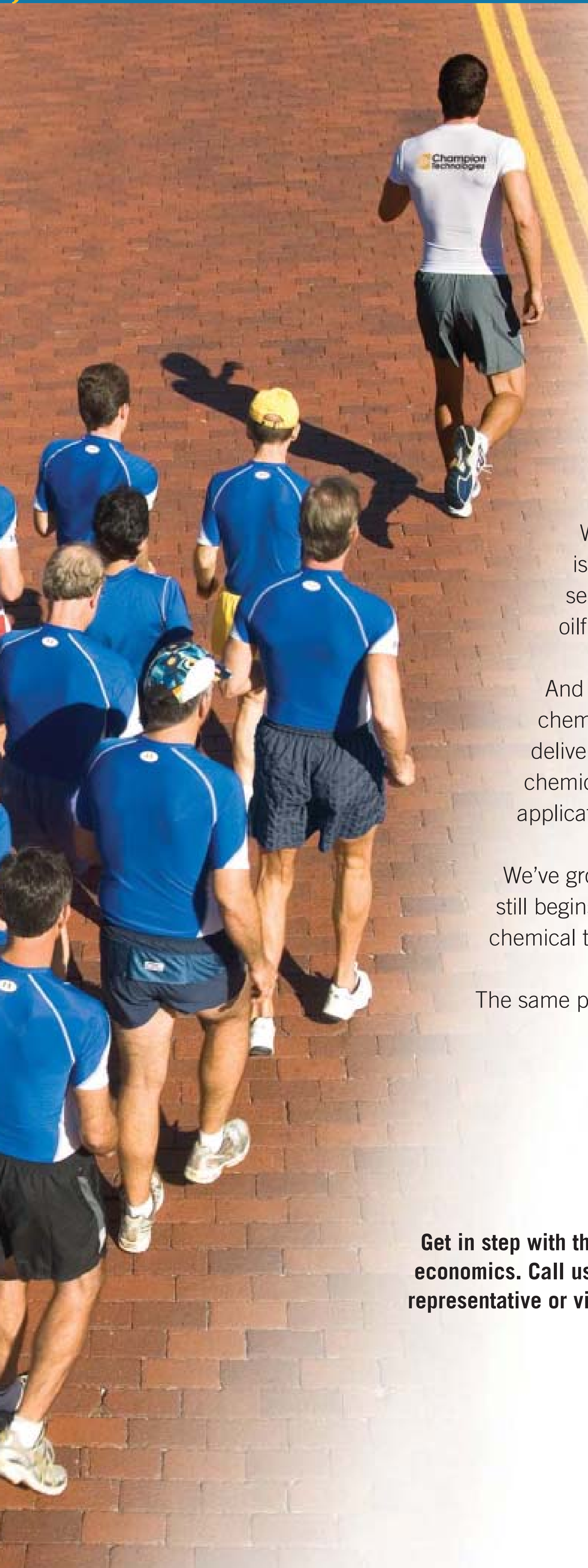
If the total cost of logistics from the ethanol plant to the blending terminal is 25¢/gal or less, the delivered cost to the blender—less the excise tax credit of 51¢/gal—would be $1.34/gal or less. Incentives grow to the extent that corn prices, natural gas, or other costs are lower. Readers can compare this with their gasoline price forecasts.

The capital cost of modifying a facility and the average ethanol throughput per terminal can give an indication of the price incentive blenders will need before investing. The average terminal ethanol throughput in the Midwest, assuming all gasoline is E10, is about 10 million gal/year (650 b/d). For a simple, 3-year payback, a rough proxy for a 25% discounted cash-flow after-tax return on capital—about 3.3¢/gal—would be needed for a $1 million investment. Double that—or 6.7¢/gal—would be needed for a $2 million investment.

The foregoing should only be used as a rough indication of the incentives that will be required, as each blender will have its own cost for facilities modifications, potential ethanol throughput, view on forecast crude oil and gasoline prices, risk-adjusted return hurdle rate, and other metrics for gauging the potential attractiveness of ethanol blending.

All potential additional discretionary blenders must be convinced that ethanol prices will stay low enough long enough for them to recover their capital and switching costs and still profit by switching to ethanol blending. Because of the prevalence of exchanges for areas such as Florida and the Southeast, where no ethanol is currently being blended, more than one blender may need to be independently convinced of the economics before discretionary blending becomes a viable option.

Another implication of this forecast is that refiners contemplating investments in ethanol production may wish to consider several options. Oversupply will invariably mean low return on investments for ethanol plants until demand catches up to production capacity. It will mean that some current ethanol



plant owners will decide to exit.

Ethanol production assets should be available at prices better than today's, reflecting lower valuations because of the low-margin environment (lower free cash flows).

Another opportunity and alternative to investing directly is toll processing. Refiners should find some ethanol producers receptive to toll processing arrangements that will provide producers with reliable outlet channels for their production and enable them to increase capacity utilization rates. The producer will have to provide economic incentive for the refiner to assume the offtake commitment and commodity price exposure, but this may seem like a bargain to the producer whose alternative is to shut down or sell out.

Relationships between blenders and producers will strengthen from cooperation in tolling and other long-term arrangements. In addition, blenders will gain understanding of the ethanol industry, including the corn market, and the stage will be set to forge more permanent arrangements with producers, including joint ventures.

Refiners, marketers, and ethanol producers all have the opportunity to profit by recognizing the coming changes and opportunities and acting on them in a timely fashion. ✦

The author

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US group earnings up in 2006, down in year's fourth quarter

Marilyn Radler
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Fourth-quarter and full-year 2006 earnings results were mixed for oil and gas firms based in the US and Canada. Factors cited by companies reporting earnings declines included lower production volumes, increased expenses, and lower refining margins.

A group of US-based oil and gas producers and refiners reported lower collective earnings for the final 2006 quarter, but each group's combined net income for the year climbed.

For a sample of service and supply companies, most based in the US, earnings made sharp gains for 2006 and for the fourth quarter. These firms benefited from strong demand for equipment and supplies, and drilling contractors reported increased day rates and utilization.

Prices, margins

Average oil prices in the fourth quarter of 2006 were little changed from the fourth quarter of 2005. On the New York Mercantile Exchange, the near-month futures price of crude averaged $60.21/bbl during the final 2006 quarter, compared with $60.02/bbl a year earlier.

Natural gas prices, however, were much lower in the fourth quarter of 2006 than a year earlier. On the NYMEX, the average front-month price during the recent quarter was $7.263/MMbtu vs. $12.861/MMbtu in the final 2005 quarter.

Refining margins dropped sharply as well. For the fourth quarter of 2006, the US Gulf Coast cash refining margin declined 41% from a year earlier, while the US West Coast margin moved 26% lower, according to Muse, Stancil & Co.

US-based firms

Collectively, a sample of oil and gas producers and refiners based in the US recorded a 10% decline in earnings for the fourth quarter of 2006. Revenues of the firms declined 12% for the period.

Full-year 2006 earnings for this sample of companies climbed 19%, though, on 6% stronger revenues.

One of the biggest gainers for the fourth quarter and for the full year was Anadarko Petroleum Corp., while ExxonMobil Corp. reported a 9% gain in annual earnings to a record $39.5 billion. Meanwhile, Cheniere Energy Inc. posted a loss for the fourth quarter and for the year.

Following the acquisitions of Kerr-McGee Corp. and Western Gas Resources Inc. in the third quarter of 2006, Anadarko posted 96% stronger earnings for the year and 119% higher earnings for the final quarter of 2006.

Anadarko reported that its sales volumes of gas, oil, and natural gas liquids for 2006 totaled 178 million boe, up from 2005 volumes of 138 million boe. And for the fourth quarter, sales volumes were up from the third quarter of 2006, due to a full quarter of production related to acquisitions and record production rates from the company's Greater Natural Buttes and Powder River basin properties in the Rocky Mountain region and Haley gas field in West Texas.

Strong upstream and chemicals earnings drove the fourth-quarter results of ExxonMobil. Still, net income declined 4% from the fourth quarter of 2005.

ExxonMobil's upstream earnings of $6.22 billion were down $818 million from the fourth quarter of 2005, primarily on lower natural gas realizations and lower gas production volumes driven by lower European demand.

Chemical earnings were $1.24 bil-

US OIL AND GAS FIRMS' FOURTH QUARTER 2006 REVENUES, EARNINGS

	4th quarter Revenues 2006	4th quarter Revenues 2005	4th quarter Net income 2006	4th quarter Net income 2005	Full year Revenues 2006	Full year Revenues 2005	Full year Net income 2006	Full year Net income 2005
	Million $							
Anadarko Petroleum Corp.	3,179.0	1,917.0	1,917.0	875.0	10,187.0	6,187.0	4,854.0	2,471.0
Apache Corp.	1,966.7	2,101.7	520.8	788.2	8,288.8	7,584.2	2,552.5	2,623.7
Basic Earth Science Systems Inc.[1]	1.6	1.7	0.3	0.8	5.6	4.9	1.8	2.0
Berry Petroleum Co.	116.2	116.1	19.1	30.4	486.3	406.7	107.9	112.4
Bill Barrett Corp.	90.5	111.2	11.0	23.3	375.3	288.8	62.0	23.8
Black Hills Corp.	173.6	179.7	20.8	26.6	656.9	613.5	81.0	33.4
Cabot Oil & Gas Corp.	171.7	225.1	32.1	58.5	762.0	682.8	321.2	148.4
Cheniere Energy Inc.	0.8	0.9	–93.3	–18.5	2.4	3.0	–145.9	–29.5
Chesapeake Energy Corp.	1,867.6	1,751.0	471.4	452.5	7,325.6	4,665.3	2,003.3	948.3
Chevron Corp.	47,746.0	53,794.0	3,772.0	4,144.0	210,118.0	198,200.0	17,138.0	14,099.0
Cimarex Energy Co.	295.6	429.5	58.7	168.4	1,267.1	1,118.6	345.7	328.3
Comstock Resources Inc.	126.8	93.4	8.4	41.3	511.9	303.3	70.7	60.5
ConocoPhillips	42,535.0	52,173.0	3,197.0	3,679.0	188,523.0	183,364.0	15,550.0	13,529.0
Delta Petroleum Corp.	44.1	31.2	–10.5	1.6	176.6	107.5	0.4	5.7
Devon Energy Corp.	2,609.0	3,188.0	582.0	970.0	10,578.0	10,622.0	2,846.0	2,930.0
El Paso Corp.	913.0	814.0	–166.0	–162.0	4,281.0	3,359.0	475.0	–606.0
EOG Resources Inc.	932.5	1,213.7	242.6	463.7	3,904.4	3,620.2	1,299.9	1,259.6
Equitable Supply	216.5	212.3	72.2	72.8	763.6	742.6	220.3	260.1
ExxonMobil Corp.	90,028.0	99,344.0	10,250.0	10,710.0	377,635.0	370,680.0	39,500.0	36,130.0
Forest Oil Corp.	183.9	272.5	30.8	57.2	820.0	1,072.0	168.5	151.6
Frontier Oil Corp.	1,087.3	1,150.3	52.4	63.0	4,796.0	4,001.2	379.3	275.2
Gasco Energy Inc.	6.6	8.3	–1.8	2.0	25.7	16.9	–55.8	0.0
GMX Resources Inc.	10.3	8.7	2.4	3.6	32.0	19.2	9.0	7.2
Harken Energy Corp.	6.3	9.5	0.3	0.6	29.0	39.2	–0.9	42.7
Hess Corp.	7,209.0	7,146.0	359.0	452.0	28,720.0	23,255.0	1,916.0	1,242.0
Holly Corp.	941.0	814.9	47.7	39.9	4,033.0	3,053.2	266.6	167.7
Houston Exploration Co.	76.7	154.6	–19.4	19.8	531.6	621.5	67.8	105.2
Marathon Oil Corp.	13,986.0	17,215.0	1,079.0	1,265.0	65,449.0	63,345.0	5,234.0	3,032.0
McMoRan Exploration Co.	56.2	37.2	–8.8	–25.7	209.7	130.1	–26.0	–39.7
Murphy Oil Corp.	3,363.8	3,195.4	87.6	154.6	14,307.4	11,877.2	638.3	846.5
Newfield Exploration Inc.	427.0	443.0	82.0	184.0	1,673.0	1,762.0	591.0	348.0
Noble Energy Inc.	714.2	701.0	165.0	221.9	2,940.1	2,186.7	678.4	645.7
Occidental Petroleum Corp.	4,144.0	4,182.0	928.0	1,152.0	17,661.0	14,597.0	4,182.0	5,281.0
Panhandle Royalty Co.[2]	8.9	12.2	2.0	4.9	NA	NA	NA	NA
PetroQuest Energy Inc.	45.6	40.7	0.3	8.3	200.5	124.6	24.0	21.4
Pioneer Natural Resources Co.	389.8	486.2	27.7	140.8	1,632.9	1,544.6	739.7	534.6
Plains Exploration & Production Co.	207.6	274.4	383.6	70.8	1,018.5	944.4	597.5	–214.0
Pogo Producing Co.	343.1	419.6	–16.5	114.5	1,745.0	1,225.7	446.2	750.7
Questar Corp.	772.9	941.4	121.5	104.0	2,835.6	2,724.9	444.1	325.7
Quicksilver Resources Inc.	102.0	102.9	19.7	34.7	390.4	310.4	93.7	87.4
Range Resources Corp.	184.1	166.4	0.4	42.7	779.7	535.8	158.7	111.0
Southwestern Energy Co.	214.0	220.7	33.8	48.9	763.1	676.3	162.6	147.8
Stone Energy Corp.	179.2	135.6	–298.5	26.4	686.3	636.2	–254.2	136.8
Sunoco Inc.	9,036.0	9,270.0	123.0	287.0	38,715.0	33,764.0	979.0	974.0
Swift Energy Co.	158.6	122.5	35.3	34.7	615.4	423.2	161.6	115.8
The Williams Cos.	2,770.3	3,676.1	146.4	66.8	11,812.9	12,583.6	308.5	313.6
Ultra Petroleum Corp.	166.2	184.6	60.6	82.2	592.7	516.5	231.2	228.3
Unit Corp.	299.3	293.1	81.2	84.5	1,162.4	885.6	312.2	212.4
United Heritage Corp.[1]	0.3	0.2	–0.6	–0.4	0.9	0.4	–2.0	–16.5
Valero Energy Corp.	19,792.0	25,894.0	1,114.0	1,347.0	91,833.0	82,162.0	5,463.0	3,590.0
Whiting Petroleum Corp.	186.6	186.0	28.0	38.3	778.8	540.4	156.4	121.9
XTO Energy Inc.	1,199.0	1,177.0	429.0	453.0	4,576.0	3,519.0	1,860.0	1,152.0
Total	**261,282.1**	**296,639.2**	**26,000.6**	**28,904.7**	**1,127,215.2**	**1,061,647.5**	**113,214.2**	**95,027.3**

[1]Third quarter, 9 months. [2]First quarter.

lion, up $407 million from the fourth quarter of 2005 due to improved margins and higher volumes. Downstream earnings were $1.96 billion, down $430 million from the fourth quarter of 2005 due to lower refining and marketing margins.

For the year, ExxonMobil's spending on capital and exploration projects was $19.9 billion, up 12% over 2005. The company's fourth-quarter spending on capital and exploration projects was $5.1 billion, down 5% from a year earlier.

Cheniere Energy Inc. reported a net loss of $93.3 million for the fourth quarter of 2006 compared with a net loss of $18.5 million during the corresponding period in 2005. The primary reasons for the increase in net loss are related to the early extinguishment of debt, termination of interest rate swaps associated with the early termination of debt, and an increase in general and administrative expenses mostly related to increased personnel costs.

These same factors were behind the company's results for the full year. And in 2005, Cheniere recorded a $20.2 million gain on the sale of its investment in Gryphon Exploration Co.

Without the losses related to the early extinguishment of debt and termination of interest rate swaps, Cheniere said it would have reported a net loss of $30.1 million for the fourth quarter of 2006.

Service, suppliers

A sample of 31 companies that provide service and supplies to oil and gas producers posted strong gains in

Canadian oil and gas firms' fourth quarter 2006 revenues, earnings

	Revenues (4th quarter)		Net income (4th quarter)		Revenues (Full year)		Net income (Full year)	
	2006	2005	2006	2005	2006	2005	2006	2005
	Million $ (Can.)							
Canadian Oil Sands Trust	646.0	519.0	128.0	174.0	2,432.0	1,967.0	834.0	831.0
Enbridge Inc.	2,785.7	2,667.8	172.9	175.8	10,644.5	8,453.1	622.3	562.9
EnCana Corp.	4,244.3	6,850.2	765.5	2,731.8	18,934.3	16,826.0	6,525.8	3,955.7
Husky Energy Inc.	3,084.0	3,207.0	542.0	669.0	12,664.0	10,245.0	2,726.0	2,003.0
Imperial Oil Ltd.	5,631.0	7,743.0	794.0	1,016.0	24,788.0	28,214.0	3,044.0	2,600.0
Nexen Inc.	1,281.0	1,445.0	77.0	303.0	5,386.0	4,827.0	601.0	1,140.0
Petro-Canada	4,550.0	4,838.0	384.0	714.0	18,669.0	16,779.0	1,740.0	1,791.0
Shell Canada Ltd.	3,581.0	4,043.0	223.0	611.0	14,806.0	14,394.0	1,738.0	2,001.0
Suncor Energy Inc.	3,787.0	3,521.0	358.0	693.0	15,829.0	11,129.0	2,971.0	1,158.0
Talisman Energy Inc.	1,901.0	2,227.0	598.0	533.0	7,944.0	7,489.0	2,005.0	1,561.0
TransCanada Corp.	2,091.0	1,771.0	269.0	350.0	7,520.0	6,124.0	1,079.0	1,209.0
Total	**33,582.0**	**38,832.0**	**4,311.4**	**7,970.6**	**139,616.8**	**126,447.1**	**23,886.1**	**18,812.6**

net income for the fourth quarter and for the year. Their combined full-year 2006 earnings climbed 77%, while quarterly earnings were up 41% from a year earlier.

The companies in this group benefited from continued strong demand for drilling rigs, equipment, and services that accompany increased exploration and drilling activity. At the same time, these firms have been hit with higher operating and labor costs.

Six of the firms reported lower earnings for the quarter, including Drill-Quip Inc., Halliburton Co., and Rowan Cos. Inc., but none of the companies in the sample recorded a loss for the last 3 months of 2006 or for the year.

Diamond Offshore Drilling Inc. announced strong gains in net income for the fourth quarter and for 2006. For the quarter, Diamond Offshore reported higher day rates and utilization for its high-specification floating rigs compared with the final 2005 quarter. Meanwhile, day rates for its other semisubmersibles and jack ups were higher than a year earlier, but utilization declined slightly.

Rowan reported a 39% increase in earnings for the year and a 10% decline in fourth quarter earnings. Rowan's land rig utilization was 95% during the fourth quarter of 2006, up from 89% in the comparable 2005 period.

Meanwhile, the company said its offshore rig utilization decreased to 81% during the fourth quarter from 93% during the comparable 2005 period. The company realized 164 net fewer operating days during the recent quarter from five rigs that were either preparing for or mobilizing to overseas assignments.

Canadian companies

Eleven oil and gas firms based in Canada recorded a larger collective decline in fourth-quarter earnings than their counterparts in the US sample, but their collective gain in annual earnings was stronger that that of the US-based companies.

Full-year 2006 earnings results for this group of companies climbed

Service–supply companies' fourth quarter 2006 revenues, earnings

	Revenues – 4th quarter		Net income – 4th quarter		Revenues – Full year		Net income – Full year	
	2006	2005	2006	2005	2006	2005	2006	2005
	Million $							
Baker Hughes Inc.	2,452.7	1,989.4	326.2	257.9	9,027.4	7,185.5	2,419.0	878.4
BJ Services Inc.[1]	1,183.9	956.2	207.1	159.7	NA	NA	NA	NA
Cameron Corp.	1,076.7	738.5	96.5	54.7	3,742.9	2,517.8	317.8	171.1
Dawson Geophysical Co.[1]	53.7	35.5	5.4	2.3	NA	NA	NA	NA
Diamond Offshore Drilling Inc.	578.2	368.3	221.4	106.9	2,052.6	1,221.0	706.8	260.3
Dril-Quip Inc.	94.9	118.3	11.7	24.9	340.8	442.7	32.6	86.9
Foster Wheeler Ltd.	1,193.3	618.5	63.1	(122.2)	3,495.0	2,200.0	262.0	(109.7)
GlobalSantaFe Corp.	950.6	603.5	349.4	180.2	3,312.6	2,263.5	1,006.4	423.1
Grant Prideco	518.1	388.7	140.1	78.4	1,815.7	1,350.0	464.6	189.0
Grey Wolf Inc.	243.4	205.4	52.5	38.2	957.0	700.6	220.0	120.6
Halliburton Co.	6,016.0	5,572.0	658.0	1,102.0	22,576.0	20,240.0	2,348.0	2,358.0
Hercules Offshore Inc.	114.7	48.0	35.5	(2.2)	344.3	161.3	119.1	24.5
Horizon Offshore Inc.	116.7	124.4	13.8	(30.9)	547.3	325.0	67.0	(71.1)
Hornbeck Offshore Services Inc.	70.7	59.9	17.0	15.1	290.6	185.8	76.1	37.4
Hydril Co.	129.6	113.3	23.9	21.4	503.0	376.7	91.3	73.2
Itron Inc.	160.0	160.0	7.3	16.9	653.5	553.0	33.8	33.1
Lone Star Technologies Inc.	334.8	337.5	18.1	70.9	1,377.6	1,285.1	108.2	223.6
Nabors Industries Inc.	1,329.1	1,046.8	276.1	210.6	4,942.7	3,551.0	1,059.0	648.7
Noble Corp.	558.8	360.6	199.7	101.3	2,100.2	1,382.1	731.9	296.7
Oceaneering International Inc.	342.4	288.7	29.8	19.7	1,280.2	998.5	124.5	62.7
Parker Drilling Co.	146.3	149.6	37.2	56.7	586.4	531.7	81.0	98.9
Patterson-UTI Energy Inc.	638.4	531.2	156.3	134.2	2,546.6	1,740.5	673.3	372.7
Pioneer Drilling Co.[2]	113.3	74.9	24.0	13.8	315.8	202.7	69.0	32.6
Pride International Inc.	669.2	551.0	68.9	40.6	2,495.4	2,033.3	296.5	128.6
Rowan Cos. Inc.	410.9	317.4	62.4	69.5	1,510.7	1,068.8	318.2	229.8
RPC Inc.	160.3	117.6	29.5	21.5	596.6	427.6	110.8	66.5
Schlumberger Ltd.	5,350.0	4,023.0	1,131.0	661.0	19,517.2	14,717.0	3,709.9	2,207.0
Smith International Inc.	1,999.0	1,530.4	143.6	88.6	7,333.6	5,579.0	502.0	302.3
Superior Energy Services Inc.	319.1	188.0	62.2	16.2	1,093.8	735.3	188.2	67.9
Transocean Inc.	1,193.0	777.0	621.0	152.0	3,903.0	2,911.0	1,385.0	716.0
Weatherford International Inc.	1,807.6	1,461.4	272.0	243.8	6,578.9	4,333.2	896.4	467.4
Total	**30,325.4**	**23,855.0**	**5,360.7**	**3,803.7**	**105,837.4**	**81,219.7**	**18,418.4**	**10,396.2**

[1]First quarter. [2]Third quarter, 9 months.

27%, as seven of the firms reported earnings gains.

For the final quarter of 2006, the group of Canadian firms posted a combined 46% decline in net income, while their collective revenues were down 14% from a year earlier.

Talisman Energy Inc. is the only company in the group that recorded a gain for the quarter. The Calgary oil and gas producer reported $598 million (Can.) in earnings for the fourth quarter of 2006, up 12% year-on-year.

Talisman's production volumes were lower for the fourth quarter but higher for 2006 compared with the prior year's volumes. In addition, the company's revenues for the quarter declined, and its expenses rose. But Talisman paid less tax in the recent quarter: $156 million vs. $439 million a year earlier. ✦

FTC: US energy markets kept competitive in 2006

Nick Snow
Washington Correspondent

The US Federal Trade Commission aggressively used its authority during 2006 to keep US retail energy markets competitive, FTC Chairwoman Deborah Platt Majoras told a US Senate subcommittee Mar. 7.

An investigation kept Chevron Corp. from acquiring most of California's largest remaining chain of independently owned retail gasoline outlets. The oil major and USA Petroleum on Nov. 17, 2006, terminated Chevron's planned purchase of 122 of the independent gasoline retailer's California outlets.

"The FTC was concluding its investigation of the proposed acquisition at the time, and USA Petroleum's president acknowledged that the parties abandoned the transaction because of resistance from the FTC," Majoras said in written testimony submitted to the Senate Judiciary Committee's Antitrust, Competition, and Business and Consumer Rights Subcommittee.

She said FTC also required Texas Eastern Products Pipeline Co. LLC in November to sell its interests in a natural gas liquids storage facility at Mont Belvieu, Tex., to a buyer approved by the government competition regulator as a condition of clearing EPCO Inc.'s proposed $1.1 billion acquisition of TEPPCO's gas liquids storage business.

On Feb. 23 the commission approved the proposed divestiture to Louis Dreyfus Energy Services LP.

The commission monitors retail gasoline and diesel fuel prices in 360 cities and wholesale prices in 20 major markets across the country to determine if a law enforcement investigation is warranted, Majoras said. "If FTC staff members detect unusual price movements in an area, they research the possible causes and consult, where appropriate, with state attorneys general, state energy agencies, and the federal Energy Information Administration. If evidence of anticompetitive conduct is found, the commission will open an investigation and pursue all appropriate law enforcement action," she added.

Majoras noted that FTC found no evidence of illegal market manipulation of gasoline prices in the months following Hurricane Katrina's landfall in 2005 but did find 15 examples of pricing at the refining, wholesale, or retail level that fit relevant federal legislation's definition of price gouging. "Other factors, such as regional or local market trends, however, appeared to explain these firms' prices in nearly all cases," she said.

FTC in December issued its second annual report on US ethanol protection and the current market, which concluded that market concentration decreased by 21-35% during 2006, Majoras said.

The study also examined possible concentration effects resulting from agreements between ethanol producers and third-party marketers and estimated market concentration, using both capacity and production data, she said.

"The study concluded that the level of concentration in ethanol production would justify a presumption that a single firm, or a small group of firms, could wield sufficient market power to set or coordinate price or output levels. The report notes, however, that staff cannot rule out the possibility that future mergers within the industry may raise competitive concerns," Majoras said. ✦

WATCHING GOVERNMENT

Nick Snow, Washington Correspondent

Budgets snub oil, gas R&D

Once considered a national investment, federal support for oil and gas research and development has fallen out of political favor. The R&D emphasis now is on alternative and renewable energy sources. Oil and gas programs are zeroed out when US President George W. Bush's administration prepares budget requests for the Department of Energy.

Oil and gas projects within DOE's Office of Fossil Energy (OFE) continue because Congress each year has restored much of the funding. That did not happen during 2006 because Congress did not approve a federal budget for the fiscal year ending Sept. 30. It simply passed continuing resolutions through the end of the calendar year.

Soon after the new Congress arrived in January, its leadership decided to pass another continuing resolution for the rest of fiscal 2007 and concentrate on preparing fiscal 2008's final budget. Oil and gas R&D programs within OFE have been operating at fiscal 2005 funding levels in the meantime.

Passage of the latest continuing resolution did not make federal oil and gas R&D funding more certain. The White House's Office of Management and Budget demanded a new breakout of DOE's entire budget for a new report to Congress, OFE Budget Director Chuck Roy told me. He would not disclose how much of the approximately $592 million for OFE would go to oil and gas R&D because DOE's full budget has not been finally approved.

No shutdowns yet

"There's definitely uncertainty about continuation of the oil and gas R&D program," confirmed Guido DeHoratiis, who has charge of it within OFE. Congress's failure in 2006 to specify amounts for it didn't help, but minimal funds went into projects so they didn't have to shut down immediately, he said.

Progress continues to be made despite this uncertainty, DeHoratiis said. He cited research into recovering energy from methane hydrates, microhole and other new drilling technologies, and increasing enhanced recovery's role in carbon sequestration.

A former DOE official says many policymakers don't realize that DOE's participation has a major impact on oil and gas R&D. "The microhole drilling program is a good example. Coiled tubing orders are taking off," said Tom Williams, a special assistant to the assistant secretary for fossil energy at DOE during the presidency of George H.W. Bush. Williams is now with Noble Corp.

Congressional stirrings

Several US House and Senate members are paying attention. "We have been working diligently to raise the issue with as many of them as we can," said Lee O. Fuller, vice-president, government relations, at the Independent Petroleum Association of America.

Congress and the administration are hearing how independent producers and universities' petroleum engineering programs—and not major oil companies—directly benefit from federal oil and gas R&D support.

"We're making inroads. The question is what will happen once Congress starts pushing the final DOE budget through the final appropriations process," Fuller said. ✦

BLM revises onshore public land regulations

Nick Snow
Washington Correspondent

The US Bureau of Land Management has published final revised regulations for oil and gas activity on onshore public lands. The revised rule, effective Apr. 6, establishes requirements all companies must meet to operate on federal and Native American lands, except land held by the Osage Tribe.

The rule updating Onshore Order No. 1 incorporates changes resulting from the 2005 Energy Policy Act (EPACT), the 1987 Federal Onshore Oil and Gas Leasing Act, legal opinions, court cases, and changes in policies and procedures since the order was last revised in October 1983, the US Department of the Interior agency said.

Major changes involve procedures for processing drilling permit applications, use of best-management practices in developing leases, and regulations and procedures for operating in split estate situations.

The revised order contains a complete drilling permit application package that establishes as a regulation the definition already commonly used in many BLM field offices, according to the agency. It also codifies the current BLM practice requiring joint on-site inspection by the agency and operator before a drilling permit application is considered complete. In addition, it ensures that drilling permit application processing will take place within the timeframes contained in Section 386 of the 2005 EPACT.

It also codifies the current BLM policy of encouraging lease operators to use best management practices as they develop their leases, clarifying that such practices may be included as conditions for drilling permit approval. The revision reorganizes the order so that permit processing requirements and timeframes now are found in one section because several conditions, policies, procedures, regulations, and requirements have changed since the order was last revised more than 23 years ago, BLM said.

Regulations and procedures used when operating in split estate situations also are clarified in the revision, which requires subsurface leaseholders to make good faith efforts to reach surface access agreements with private surface owners. Where such efforts fail and an agreement cannot be reached, the revised order provides for a bond to be posted against damages to the surface.

In addition, said BLM, the order provides opportunities for private surface owners to participate in on-site inspection meetings. It said this change resulted from comments surface owners made at public hearings in four western cities and Washington, DC, during 2006. Split estate lands where the surface is owned by Native Americans will be subject to the same provisions applying to private surface owners.

The revised order incorporates a 1988 opinion by the DOI solicitor that on split estate lands, BLM must comply with cultural and endangered species regulations in essentially the same manner it uses when the surface is federally owned. A more recent opinion from the solicitor, in 2004, allows clarification in the updated rule that BLM has authority to require bonding for additional off-lease facilities that are necessary to develop a lease, such as impoundments for water produced from coalbed methane wells, the agency said. ✦

Spending rising for Canadian oil sands projects

Canadian oil sands projects recently have seen a major increase in capital costs per peak flowing barrel, which is putting pressure on returns on investment in an area where project economics are already considered relatively marginal, said Wood Mackenzie in its report, "The Cost of Playing in the Oil Sands."

The report shows that since 2005 overall costs per peak flowing barrel have increased by about 55%.

Additionally, in 2006, many of the main oil sands companies announced either changes to their original development plans or cost increases, resulting in an average rise of 32% in outlays per peak flowing barrel over the year for integrated mining projects. For in situ developments, the average rise in cost was 26%.

Conor Bint, WoodMac upstream research analyst, Canada and Alaska, said, "Entrance into the highly competitive oil sands market does not come cheap. Despite rocketing land prices, the cost of acquiring acreage is negligible compared to the investment required for a commercial development."

He said, "Marginal economics have always been a concern for companies operating in the oil sands," adding that breakeven prices are high and rates of return relatively low compared with conventional projects, "particularly for mining projects."

WoodMac estimates that mining projects have an average breakeven price of $28/bbl and an internal rate of return of just 16%. Rates of return are more favorable at the less capital intensive in-situ projects, averaging 22%.

WoodMac expects some $125 billion (Can.) to be spent in oil sands by 2015. This represents a 42% increase on its early 2006 forecast of $88 billion (Can.) for the same period. The significant cost increase is due largely to labor shortages and increased material costs, which have created a hyper-inflationary environment within the oil and gas industry in Alberta.

Oil sands projects are relatively labor-intensive, requiring as many as 5,000 workers to bring a project to peak production. "With the sheer number of oil sands projects, together with the future arctic pipelines and conventional oil and gas developments in Alberta, labor demands in Canada will be pushed to their limits," Bint said.

Cost increases are also linked to the immaturity of oil sands developments, according to the report, which points out that companies are learning best practices during development phases and still gaining experience in managing large scale projects.

Costs are set to continue increasing, the report concludes. And to sustain the current pace of development, Bint said, "Companies in the oil sands will have to control capital expenditures going forward to ensure that project breakeven prices do not exceed current levels in order to remain profitable." WoodMac suggests this may point to project management and contractor scheduling as key factors in oil sands success. ✦

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WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Sugar in the ethanol bank

These days, everyone's getting on the bandwagon for increased production of ethanol, from World Bank Pres. Paul Wolfowitz to US corn farmers.

Just last week, as US President George W. Bush toured Latin America, Wolfowitz said the US should lower or even remove its trade tariffs from Brazil, until recently the world leader in the production of ethanol.

"Barriers to the international trade in ethanol need to be examined," said Wolfowitz at a conference in London on financing low-carbon energy. And he made no bones about saying the Bush administration should take part in that examination.

Not listening

Asked by one reporter whether his remark meant that the US should lower or remove its import tariff of 54¢/gal on ethanol from Brazil, the World Bank president—never known for mincing his words—snapped back: "That's what I said. Weren't you listening?"

But the Bush administration may not have been listening, even though it reportedly wants the US to increase the use of biofuels in order to reduce its dependence on imported oil. The problem?

Despite research from the Energy Information Administration showing that Bush's target of reducing US consumption of gasoline by 20% in 10 years cannot be met from US farms alone, the US president has refused to countenance tariff changes that might be unpopular with his country's farmers.

And the Wolfowitz proposal might indeed upset those farmers quite a lot.

Unlike Brazilian ethanol, which is made from sugar cane, US ethanol comes from grain, mostly corn. Indeed, thanks to booming ethanol production, corn prices have risen to 10-year highs and turned around the financial fortunes of many US corn farmers.

That's based on current usage. But farmers are also looking to projections that suggest their corn may become even more lucrative.

Sweet projections

The US is phasing in a federal mandate for sale of 7.5 billion gal/year of renewable vehicle fuel by 2012. Most such fuel now is ethanol blended with gasoline to a concentration up to 10%. Bush wants to raise the mandate for renewable and alternative fuel to 35 billion gal/year by 2017.

Automotive engineers say they eventually will be able to build car engines superior to gasoline engines thanks to ethanol's high octane.

For farmers, the results are predictable.

The US Department of Agriculture forecasts that the US, already the world's largest producer of corn, will boost land dedicated to the crop by 8.7 million acres in the year to Aug. 31, 2008, to 87 million acres. Some expect land committed to corn to rise to as high as 90 million acres.

That may mean a lot of sugar in the bank for US corn farmers, but some other US businesses have complaints. As crop prices soar due to the increased demand for ethanol, US soft-drink makers say they soon may not be able to afford sweeteners made from corn. ✦

MMS proposes revisions in its OCS requirements

Nick Snow
Washington Correspondent

Offshore lessees would be required to measure all flared and vented natural gas on facilities producing more than 2,000 b/d of oil under changes the US Minerals Management Service proposed to its Outer Continental Shelf production requirements.

The proposals, "Oil and Gas Production Requirements, 1010-AD 12," would also eliminate unnecessary production rate restrictions and clarify requirements for documents that must be submitted to MMS. It said the proposed requirement for operators to install meters to measure flared or vented gas is based on a recommendation contained in a July 2004 Government Accountability Office report, "Natural Gas Flaring and Venting—Opportunities to Improve Data and Reduce Emissions" (GAO-04-809).

The report recommended that more accurate records were needed to determine the amount of flared and vented gas, and the volume of greenhouse gas such releases contribute to the atmosphere. MMS said it currently collects information on the total gas flared and vented, but operators are not required to differentiate between the two categories. To improve data collection, the proposed rule would require operators to report flaring and venting volumes separately to MMS.

The proposals also would eliminate some previous requirements that MMS considers unnecessary in today's petroleum industry. For example, in 1974, the federal government required operators to establish maximum production rates (MPRs) for producing well completions, and maximum efficient rates (MERs) for producing reservoirs, in OCS Order No. 11. This was during a period of oil shortages and energy crises, MMS observed. In 1988, the agency reduced the MER requirement. Currently, MMS requires MERs only on sensitive reservoirs. ✦

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Technique identifies maximum depth for commercial deepwater production

Don Timko
Petrophysical Consultant
Houston

Millions of dollars are spent drilling and completing Gulf Coast and Gulf of Mexico wells that have no chance for commercial hydrocarbon recovery.

Knowing the maximum depth from which commercial production is possible would be invaluable, particularly in deepwater areas. This article points out a technique that can be used to establish these maximum depths for commercial production using a relatively simple petrophysical approach.

The author has been defining and refining the technique for the past 40 years. All previously published work was initiated before deepwater drilling began, so the emphasis of this article will be to apply these techniques to deepwater prospect areas.

The author's attention has been piqued recently as to why much deeper commercial production is possible in deepwater areas than is possible in shelf and onshore areas.

The commerciality of oil and gas production along the Gulf Coast, both onshore and offshore, can be determined using petrophysical data in a nonconventional manner. In fact, conventional log analysis and associated data can lead to erroneous conclusions regarding the quality of production.

Reservoirs that look exceptionally good from log analysis sometimes don't produce as expected and cause disastrous financial results. In other words, we need to include readily available formation pressure and temperature data to assist in determining reservoir quality.

Commercial envelope

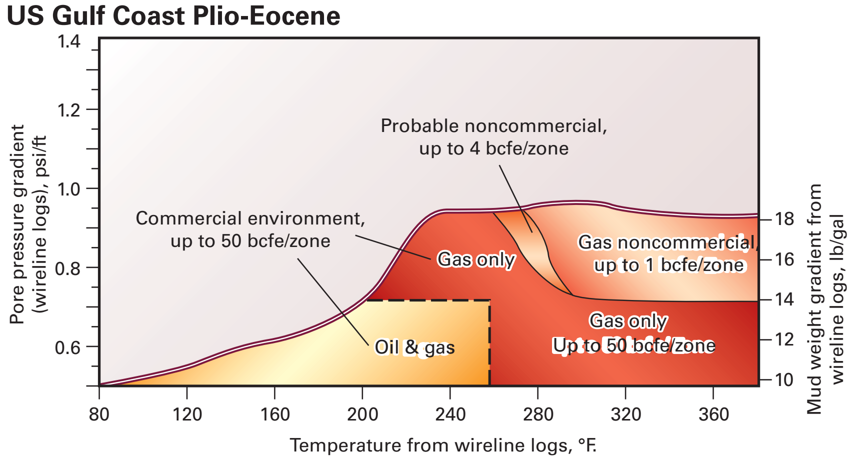
Fig. 1 is a plot of formation pore pressure gradient vs. formation temperature as derived from wireline logs. With few exceptions, the expected quality of production can be determined from the plot. All commercial production must fall within the bell-shaped curve envelope.

Using this pressure/temperature relationship, we can actually quantify expected hydrocarbon recoveries as indicated on the figure. Note that commercial volumes of oil are limited to areas where formation temperatures do not exceed 270° F. and formation pressure gradients do not exceed 0.7 psi/ft.

Commercial gas, however, can be found in most all pressure/temperature environments. The majority of fields are limited to areas where the temperatures

HYDROCARBON RELATIONSHIP WITH PRESSURE, TEMPERATURE*

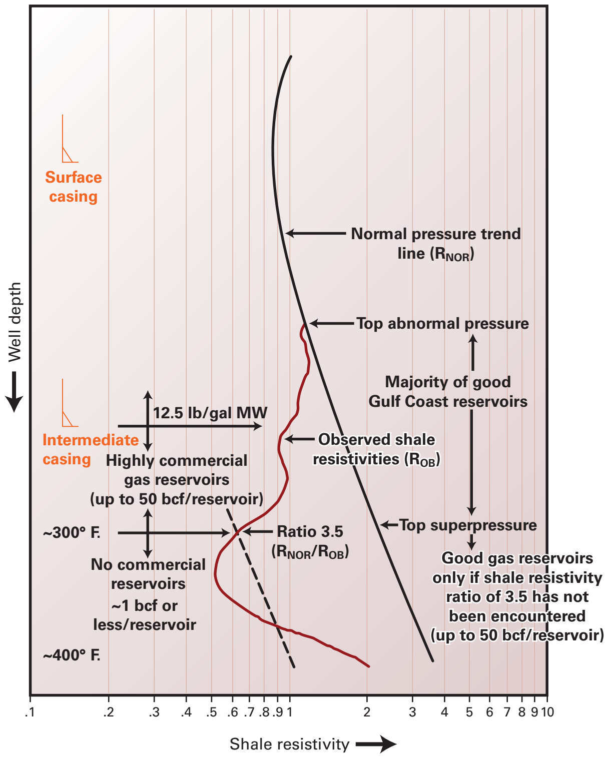
Fig. 1



*Revised December 2006.

Typical Gulf Coast shale resistivity profile

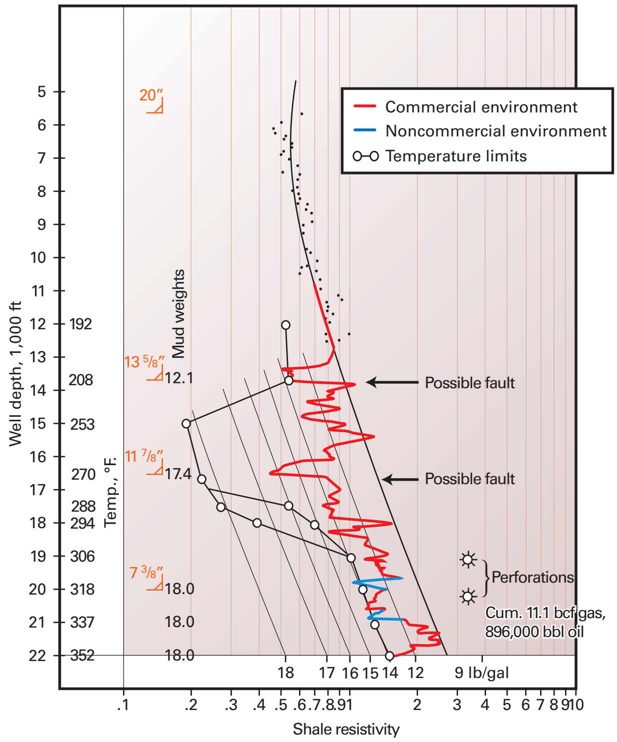
Fig. 2



Extremely HP/HT environment 1 of 2

Fig. 3

South Marsh Island 223, 2002



are less than 300° F. and pressures are lower than a 0.73 psi/ft gradient as determined by log pore pressure plots.

There are exceptions to this rule, as commercial gas can be produced from areas with temperatures exceeding 300° F. and pressures well above the 0.73 psi/ft gradient. These exceptions, however, are recognizable using petrophysical data in the manner discussed in detail below.

Shale resistivities

Fig. 2 is an example of a typical Gulf Coast shale resistivity versus depth plot for onshore and shelf wells. Usually, the top of the abnormal pressure transition is encountered between 6,000 ft and 10,000 ft. With surface pipe normally set at around 3,000 ft, the intermediate string is set in the pressure transition zone in a pore pressure gradient of about 12.5 ppg mud weight equivalent.

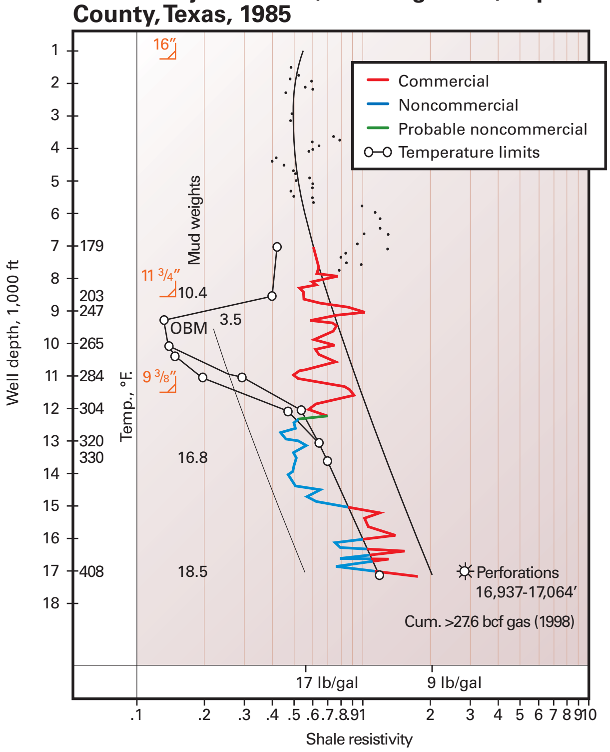
It should be noted that 90% of Gulf Coast commercial oil is found above this intermediate pipe-setting depth. This is not true in deepwater areas, where the intermediate pipe may be set for reasons other than formation pressure and fracture gradients. It is interesting to note that except for deepwater area wells, when intermediate pipe depth is reached and pipe is set to drill deeper, about 50% of the total well costs have been spent and below this depth we are drilling for gas and not oil.

Below the intermediate pipe depth, highly commercial gas

Extremely HP/HT environment 2 of 2

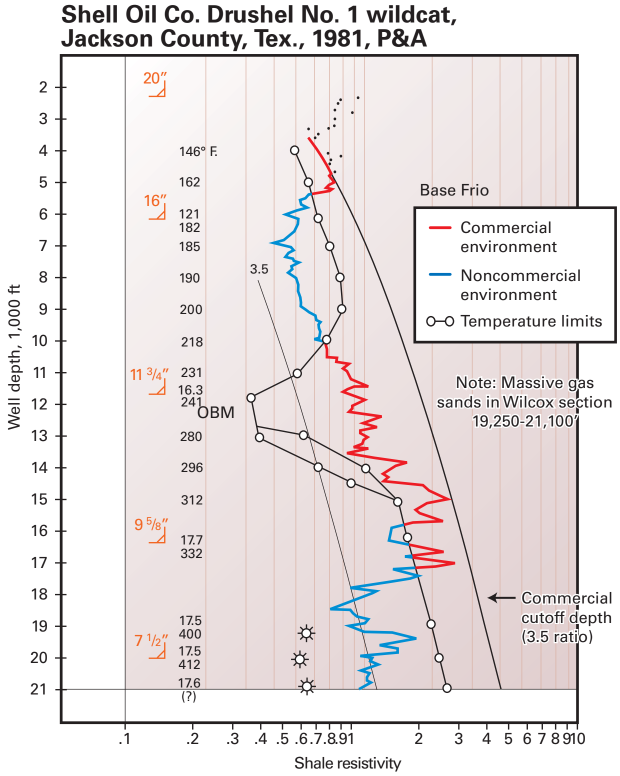
Fig. 4

Shell Hinojosa No. 13, Fandango field, Zapata County, Texas, 1985



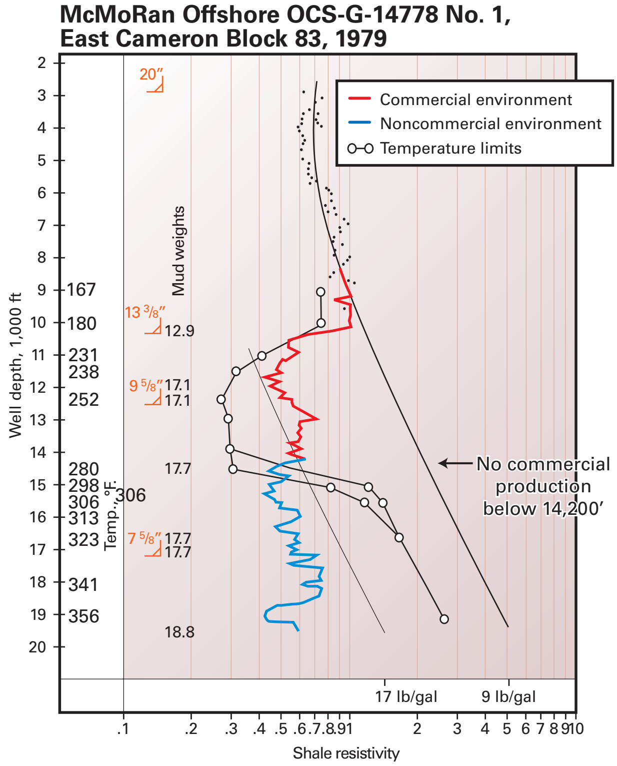
False indication of productivity below 19,200 ft

Fig. 5



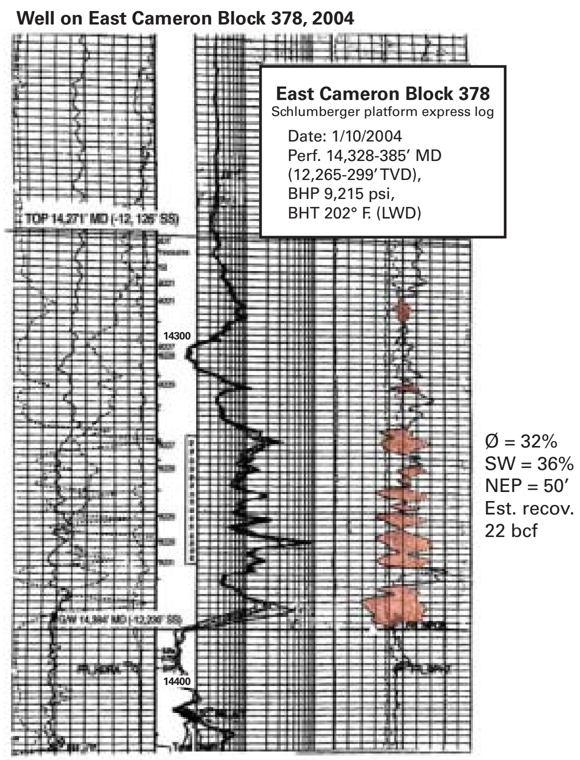
No commercial production below 14,200 ft

Fig. 6



Noncommercial gas reservoirs can look good

Fig. 7



and gas-condensate reservoirs are present. Shale resistivities will generally continue to decrease with increasing depth and formation pore pressure.

If the shale resistivities decrease to a value where the extrapolated normal trend value is 3.5 times greater than the actual value, commercial production below this point cannot be encountered. This cutoff point is usually at a reservoir temperature near 300° F. and a pore pressure gradient equivalent to a 17 ppg mud weight as determined by well logs. Any gas reservoir found below this 3.5 ratio cutoff will be breached, as the formation fracture gradient at one time in the past has exceeded the overburden stress and gas has been lost.

With deeper drilling, the shale ratio usually decreases (shale resistivities increase) below the 3.5 ratio cutoff, giving the appearance of a pore pressure regression.

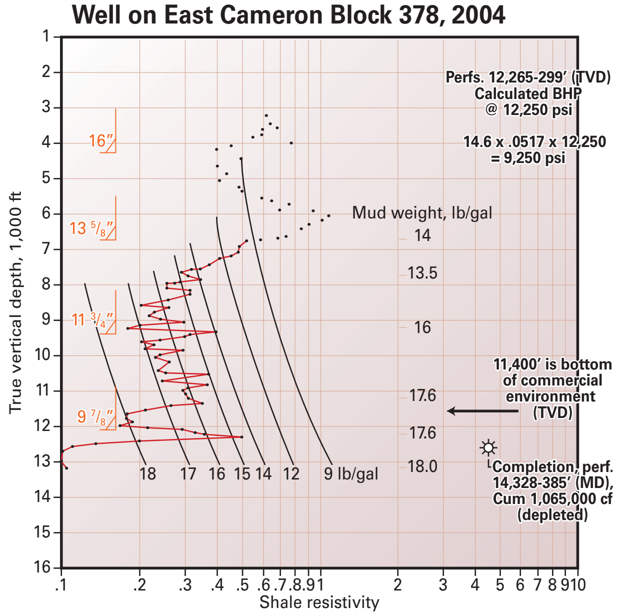
Quality looking gas sands, as indicated by mud logs, wireline logs, and such predrill data as geophysical "bright spots," will be in error regarding expected recoveries. When put on production, these zones will deplete in a short time without having produced commercial volumes of gas.

Gas recovery is almost always less than 1 bcf/zone, and exploration people are prone to say that engineers have "messed up the well." Unfortunately, subsequent wells get drilled based on these "excellent shows," and further dollars are spent needlessly.

PAY IS BELOW SHALE RESISTIVITY CUTOFF DEPTH*

Fig. 8

Well on East Cameron Block 378, 2004

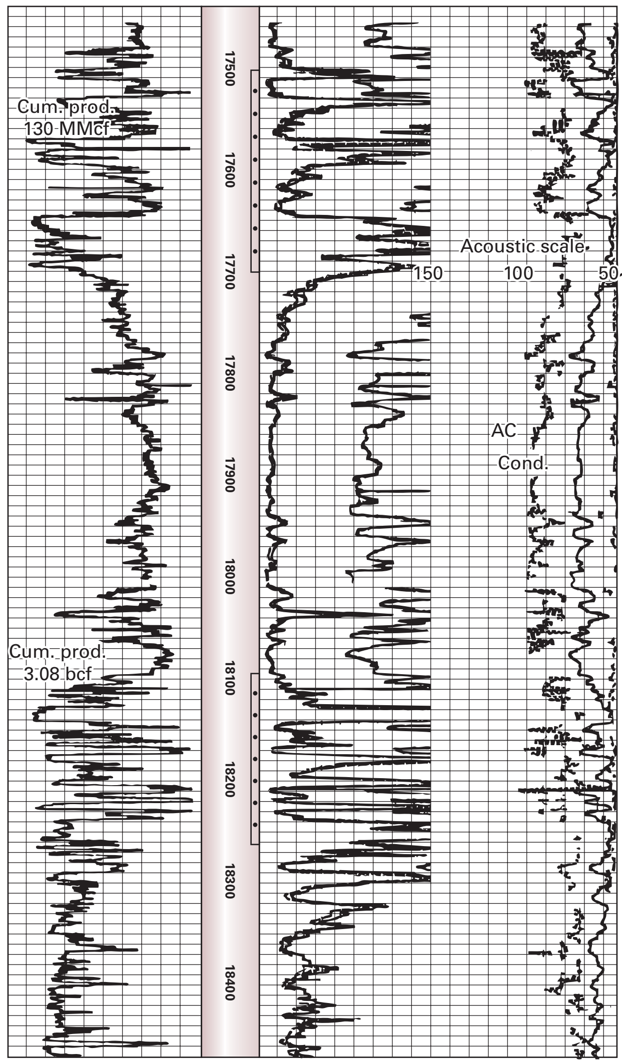


*LWD log temperature data not available.

EFFECTS OF LOW POROSITY AND PERMEABILITY

Fig. 9

Union Oil Co. of California well, West Cameron Block 292, 1993



HP/HT environments

Figs. 3 and 4 are examples of shale resistivity plots in extremely high pressure and temperature environments.

Superimposed on these figures is the bell shaped P/T curve envelope from Fig. 1. This curve is easily included once we have determined the temperature gradient from the log-measured bottomhole temperature. The maximum pressure gradient, in terms of mud weight, for any temperature can be included.

Fig. 3 is the shale resistivity of a shelf well from South Marsh Island Block 223. This well encountered thick commercial pays below 19,000 ft in a very high P/T environment. Note that the 3.5 shale ratio value (17 ppg gradient) was never reached in the shallower part of the well. Any gas reservoirs, therefore, found in this well down to 22,000 ft are potentially commercial, although commercial oil is not possible.

This is a good example of "nonbreached reservoirs." Also note that the shale resistivity values in the vicinity of the pay sands fall within the commercial envelope of Fig. 1, indicating pore pressures of 14 ppg equivalent or less. This appearance of moderate pore pressure is erroneous and is one of the pitfalls in using well logs to accurately determine formation pore pressure.

Fig. 4 is the profile of a highly commercial South Texas Eocene producer in a HP/HT environment to 17,200 ft. This well finished with 18.5 ppg mud weight and log measured temperature exceeding 400° F. The well was completed with perforations at 16,937-17,064 ft and produced 27.6 bcf of gas from 1985 to 1998. Note that the shale resistivity ratio never reached 3.5.

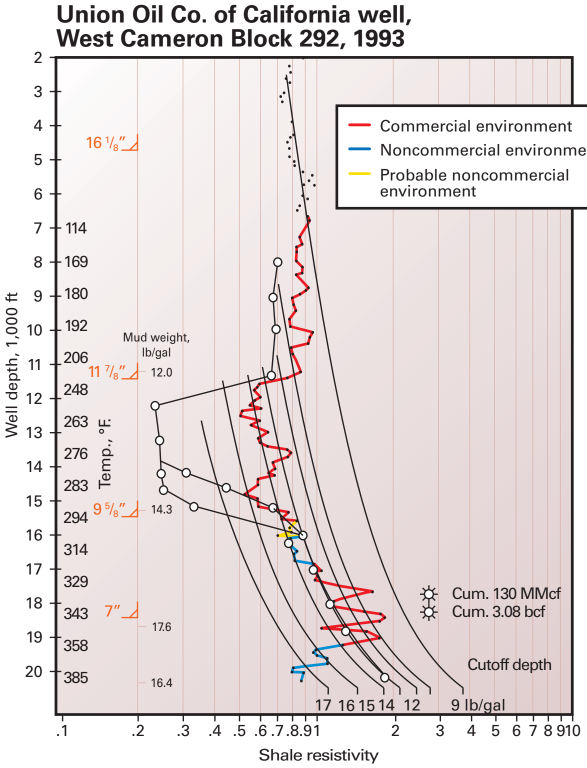
This well is also an example of the condition that commercial reservoirs, as in this case, are most always sandwiched between shales that from logs indicate pore pressures less than 14 ppg gradients. This again fits within the commercial envelope of Fig. 1. These commercial intervals below 15,000 ft are colored in red in Fig. 4. Any sands with gas within these intervals can be commercially productive, which is the case in Fandango gas field, Zapata County, Tex.

Nonproductive drilling

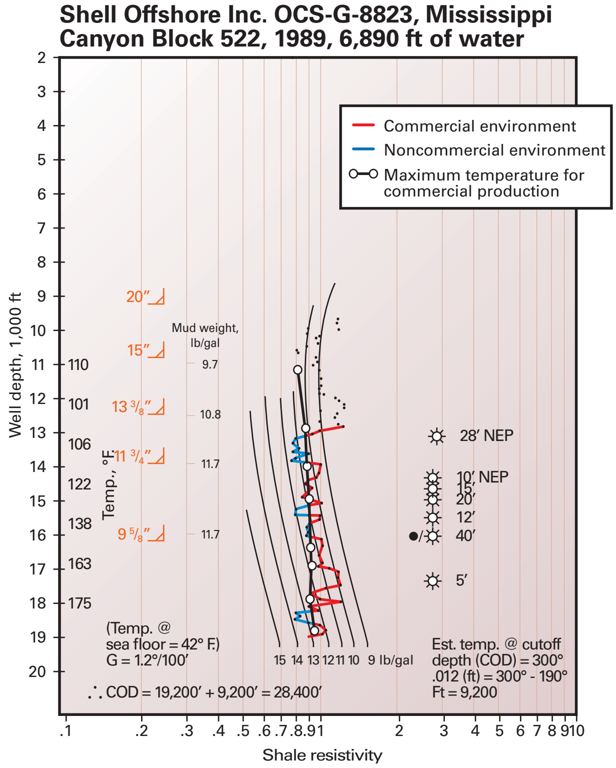
Fig. 5 is another deep Eocene test in Jackson County, Tex., that is potentially productive to 18,100 ft. Unfortunately, the massive gas sands present from 19,250 ft to TD are not commercially prospective even though geological and geophysical data could possibly indicate otherwise.

Fig. 6 is another story. This offshore shelf well from East Cameron Block

CUTOFF SHALE RESISTIVITY RATIO OF 3.5 BELOW PAY Fig. 10



MORE GAS PAYS LIKELY BELOW TOTAL DEPTH Fig. 11



83 has no potential for commercial production below 14,200 ft. At this depth, the shale resistivity ratio reached and exceeded 3.5. This is the maximum depth in this area for commercial production.

Even if pore pressure did appear to decrease with depth, it would make no difference once the shale ratio cutoff value has been encountered at a shallower depth, as in this well at 14,200 ft. Any gas sands found in this well below 14,200 ft would deplete before producing commercial volumes, less than 1 bcf as indicated by Fig. 1.

The lesson learned here is that the money spent drilling from 14,200 ft to TD at 19,500 ft could be better spent on another prospect.

False positives

Unfortunately, the gas reservoirs present in these noncommercial environments can look good on mud logs, cores, wireline and LWD logs, and wireline formation tests.

An example of the above is Fig. 7, which is the log section of the pay interval of a well drilled in East Cameron Block 378. By conventional log analysis and wireline formation tests, the well looks exceptionally good. Unfortunately, the shale resistivity profile indicates this pay at 12,265-299 ft TVD (14,328-365 ft MD) is well below the 3.5 shale resistivity cutoff depth at 11,400 ft TVD (Fig. 8).

As expected, this well depleted after producing about 1 bcf in 4 months. Fig. 8 is a plot from an LWD log. Temperature data were not available. The shale resistivity data alone, however, are sufficient to make our conclusion.

Fig. 9 is a log section of gas pay intervals in a West Cameron Block 292 well, and Fig. 10 is the P/T profile. Note that these two gas pays fall into the commercial envelope of Fig. 1. Also note from Fig. 10 that the cutoff shale resistivity ratio of 3.5 was not reached until 19,800 ft.

The deeper sand was perforated at 18,086-260 ft and produced a total of 3.08 bcf, which at best is borderline commercial. The upper zone was perforated at 17,476-684 ft and produced only 130 MMcf.

Quantitative interpretation of the logs indicates a maximum porosity of 16% and water saturation of 30% with a log-estimated permeability of less than 1 md.

This well performed poorly because of the low porosity and permeability, even though it is in a good P/T environment. Many onshore fields along the Gulf Coast exhibit the same reservoir characteristics and produce at commercial rates and volumes only after fracture stimulation. This well, therefore, would be such a candidate.

Deepwater attributes

Recently, the industry has uncovered the fact that in deepwater drilling areas commercial oil and gas can be found in reservoirs much deeper than on the shelf or onshore areas. The basic

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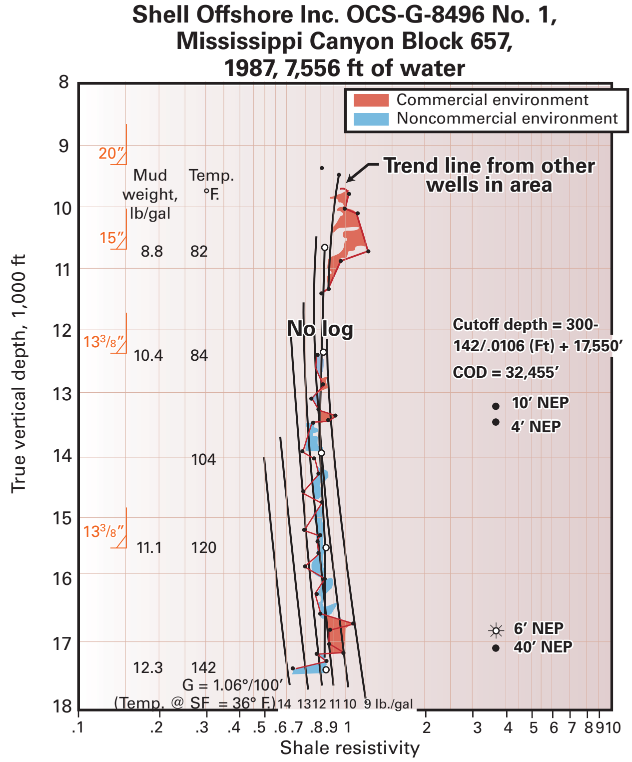
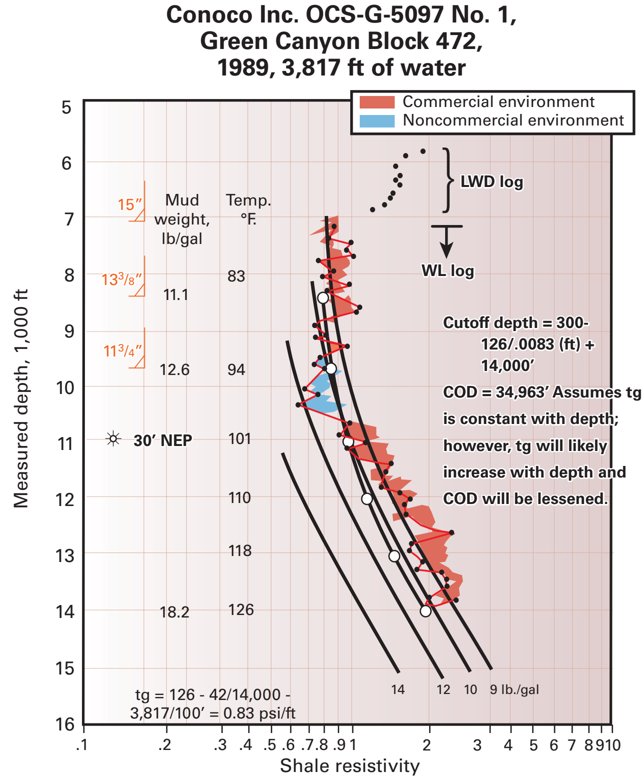
PAY POSSIBLE FAR BELOW WELL'S TOTAL DEPTH 1 OF 2 Fig. 12



PAY POSSIBLE FAR BELOW WELL'S TOTAL DEPTH 2 OF 2 Fig. 13



reason for this is that lower pressure and temperature gradients are present at comparable depths to shelf and onshore areas. To date, although data are limited, the author has not found a well that has reached the shale resistivity cutoff depth for commercial production.

It is expected that commercial production can be achieved to ±30,000 ft before reaching cutoff P/T levels. Also, commercial oil zones can be achieved to much deeper depths in the deepwater drilling areas than the shelf and onshore areas.

The US Minerals Management Service has reported that 60% of the deepwater hydrocarbon production is oil. In other words, we do not reach the borehole temperature cutoff of 270° F. and the pore pressure gradient of 0.7 psi/ft for oil until about 20,000 ft.

Another reason for finding more prolific hydrocarbon production in deepwater areas is that the pressure transition, on average, is extended over a longer depth interval than shelf and onshore areas, and therefore there is the probability of encountering more and thicker pay sands.

Deepwater examples

Fig. 11 is an example from a well drilled in 6,890 ft of water in Mississippi Canyon Block 522.

The well was bottomed at 19,200 ft in about a 13 ppg mud weight gradient environment. The measured wireline BHT was 190° F., and this temperature is equivalent to a gradient of 1.2° F./100 ft. This well, therefore, is still in a commercial oil environment at 19,200 ft.

Note that the pore pressure transition is topped at 12,900 ft and extends to TD. Through this interval, the shale pore pressure is relatively constant until about 18,400 ft, where there is a slight increase. There are seven pay sands in this transition zone with a cumulative pay thickness of 120 ft.

With the temperature gradient of 1.2 at 19,000 ft, we can estimate that we will reach the commercial cutoff temperature of 300° F. at about 28,400 ft. Also, we can speculate that the pore pressure will probably reach the 17 ppg gradient (3.5 shale ratio) at this depth.

This well, therefore, has an additional commercial pay interval of 9,222 ft below the present TD. However, since we are approaching the maximum pore pressure for oil at 19,200 ft, any pay zones encountered would most likely be gas.

Even in this low P/T environment as exhibited by Fig. 11 and subsequent figures of wells drilled in deepwater areas, the pay sands still fall within the commercial envelope of Fig. 1. Note that the shales immediately above and below the hydrocarbon pay sands show a decrease in shale ratios (decrease in shale pore pressures) from shales more distant from the pays.

The commercial pay environments are colored red on the figures, and the

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noncommercial environments are indicated in blue.

It is apparent that the sands and shales in the transition zone are not at the same pore pressure, and the sands have less pressure than the shales. These blue colored shale zones with temperatures that fall above the temperature envelope of Fig. 1 are usually the "gumbo type" and are sensitive to water-base muds. Caliper logs run through these intervals almost always show hole enlargement over bit size.

Deepening desirable

Here are examples of two wells at which the potentially commercial environment extends far deeper than the depth at which drilling stopped.

Fig. 12 is a well drilled in Mississippi Canyon Block 657. This well is in slightly deeper water than the Block 522 well, and the estimated commercial cutoff depth is 32,455 ft.

Although this well has an apparent cutoff depth deeper than the Block 522 well of Fig. 11, the log measurement depths are not TVD, and depth corrections must be made before a direct comparison is possible.

Two factors that would affect any depth differences in the wells are that there probably is a structural difference between the wells and the sea floor is cooler at the Block 657 location.

The shale plot from a Green Canyon well drilled in Block 472 in 3,817 ft of water is shown in Fig. 13. This well was drilled to 14,000 ft and did not reach nearly its potential productive depth. The measured wireline BHT was only 126° at TD, and the temperature gradient calculates to be 83°/100 ft. Extrapolating this gradient deeper would indicate a maximum commercial cutoff depth of 33,036 ft.

These estimated cutoff depths for wells drilled in deep water should be considered as the maximum possible depths for commercial production. It is probable that the temperature gradient would increase with depth, which would lessen the calculated cutoff depth somewhat.

The only absolute conclusion that can be made is that in deepwater areas, commercial oil and gas reservoirs can be found at much deeper depths than in shelf and onshore areas. ✦

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The author

Donald J. Timko (phylko@aol.com) is a consultant specializing in defining reservoir production quality from petrophysical data. He initiated work on pressure, temperature, and hydrocarbon relationships during almost 2 decades with Conoco Inc. From 1973 to 2000 he was an independent operator. He has been an SPE distinguished lecturer, was president of SPWLA, and has taught seminars on well log interpretation. He is a graduate of the University of Pittsburgh.

Bahrain

National Oil & Gas Authority and Bahrain Petroleum Co. will launch a bid round on Mar. 12 for Bahrain offshore exploration blocks and onshore field reactivation projects.

The round, to close in September 2007, will include four exploration blocks that take in the country's entire offshore acreage in the Persian Gulf. Fugro Robertson Ltd., North Wales, UK, will promote the exploration blocks.

Germany

Considerable oil potential remains in the German North Sea, said RWE Dea AG, Hamburg.

The company in 2006 was exploring for hydrocarbons off Schleswig-Holstein with Wintershall Holding AG, Kassel, and off the coast of Lower Saxony with Gaz de France.

Mittelplate tidelands field, source of most of RWE Dea's production, produced 17.5 million tonnes of crude from October 1987 through the end of 2006 (OGJ Online, Mar. 7, 2006). RWE Dea and Wintershall have 50-50 interests in Mittelplate, Germany's largest oil field.

Meanwhile, onshore in northern Germany, RWE Dea analyzed cuttings from chalk reservoirs in wells on the Heide and Hennstedt concessions and found them unsuitable for commercial production presently. It began field preparations for a 3D seismic survey aimed at measuring oil potential on the Hahnenhorn concession east of Hanover.

Utah

Delta Petroleum Corp., Denver, plans to drill two more exploration wells in the Utah Hingeline play in 2007 in its program with Armstrong Oil & Gas Corp., private Denver independent.

The unsuccessful Delta-operated Joseph Federal-1 well, spud in late 2006, encountered the Jurassic Navajo formation at 12,523 ft, about 7,000 ft deeper than prognosis. The well encountered an unanticipated igneous intrusive that distorted the initial geophysical interpretation, Delta said.

The company is processing an aeromagnetic survey shot over the Hingeline and said it sees no evidence of such an igneous body at 18 of the 20 other identified prospects. Only one other well in the trend has encountered an intrusive of any significant size, Delta added.

Mexilhao development includes largest fixed platform off Brazil

The Mexilhao nonassociated gas development in the Santos basin includes the largest fixed platform to date off Brazil.

Petroleo Brasileiro SA (Petrobras) plans to install the 230-m tall PMXL-1 platform in 172 m of water (Fig. 1). The platform has a 182-m jacket.

The company expects the field to go on stream in 2009, with full production starting in 2010 or 2011. The platform will have a capacity to produce and treat about 15 million cu m/day of gas and 3,200 cu m/day of condensate.

Petrobras plans to market the gas in southern and southeastern Brazil, regions that have the largest industrial parks in the country.

Mexilhao field

Mexilhao field is in Block BS-400 of the Santos basin, about 140-km from the coast. Petrobras discovered the field in 2003.

Petrobras says the reservoirs in Mexilhao field are different from those encountered in the Campos basin. The reservoirs have high temperatures and pressures, are at 5,000-6,000 m depths, and have low permeability.

Field development includes subsea-completed gas wells drilled in 320-550 m of water and tied back about 20 km to the platform (Fig. 2).

Development calls for installing subsea production systems that separate produced water at the seafloor and reinject it into nearby reservoirs. Another feature of the development plan is the injection of monoethylene glycol (MEG) into the wells to prevent formation of hydrates that could block flow lines.

The development also will process the gas at high pressure on the platform, thereby eliminating the need for installing export compressors.

A 145-km, 34-in. pipeline will transport the produced gas to a gas processing plant in Caraguatatuba, in the Brazilian state of Sao Paulo. From there, another 100-km pipeline will move the gas to Taubate, where the pipeline connects to the Campinas-Rio de Janeiro pipeline.

Petrobras estimates that the Mexilhao project will require an investment of more than $2 billion.

Mexilhao, the Portuguese word for clam, is a type of mussel served as seafood.

Santos basin

In the Santos basin, Petrobras currently produces about 1 million cu m of gas and 1,600 bo/d from Merluza field, a field discovered in the 1980s and put on stream in 1993.

Petrobras has initiated a Santos basin natural gas and oil production development master plan that expects to invest about $18 billion in the next

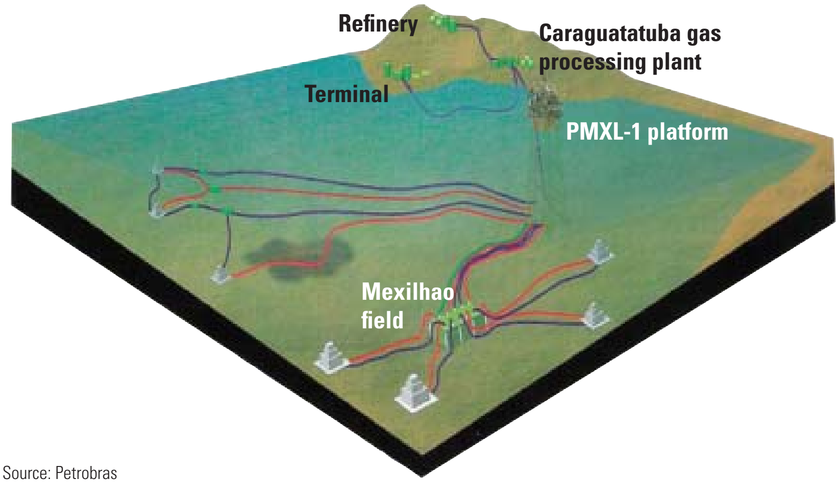
MEXILHAO PMXL-1 PLATFORM

Fig. 1

Source: Petrobras

Mexilhao development

Fig. 2



Source: Petrobras

10 years (OGJ, Nov. 20, 2006, p. 43). The company's forecast shows that gas production from the basin may reach 30 million cu m/day by 2011 and oil production may increase in the next 4-5 years to 100,000 b/d from the current 10,000 b/d.

Petrobras plans to integrate the Mexilhao development with currently producing Merluza and Coral fields. This plan includes the building of a gas-treatment plant in Caraguatatuba. It initially will have two modules, each capable of processing 7.5 million cu m/day of gas produced from Mexilhao, Cedro, and other Santos basin fields.

From the Merluza area Petrobras expects additional gas production of 8 million cu m/day of gas and 25,000 b/d of oil and condensate after installation of the Merluza-2 platform. This additional gas production will require expansion of the Caraguatatuba gas processing capacity to 22.5 million cu m/day.

Another expected production increase from the Santos basin is from the interlinking of Lagosta field and the SPS-25 area with the Merluza system. This work will increase natural gas production to 2.5 million cu m/day from the basin by 2008.

Petrobras also estimates discoveries in the BS-500 development, including Urugua and Tambau fields, may produce 20 million cu m/day and 150,000-200,000 bo/d.

Another region from which Petrobras expects additional production is the Southern area that includes the Coral platform, in Parana. The field currently produces about 9,000 bo/d.

In the Southern area, Petrobras expects Cavalo-Marinho field to go on line in 2008 with production similar to the Coral platform and other new projects eventually producing 140,000 bo/d and 3 million cu m/day of gas. ✦

Shifting global product specs push more refinery investment

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Refiners throughout the world are increasing investments to deal with changing specifications for gasoline and diesel fuel.

The global refining sector has begun to emerge from a short period of tight capacity and high margins with refining investments being made all over the world. After a year of remarkably profitable margins, refiners are facing a somewhat more bearish marketplace. Meanwhile, petroleum product demand continues to grow even as the specifications for transport fuels in particular become more complicated.

The once-fungible petroleum product markets are increasingly fractured and "Balkanized." The evolution of petroleum product demand, both in terms of quantity and quality, and the

concomitant expansion of global refining will determine the demand for crude oil not only by volume but also by quality.

This article focuses specifically on signals from gasoline and diesel markets that will influence refining investment and the further effects of that investment on crude demand.

The most important developments on the demand side are in the three main consuming regions—the US, Europe, and Asia.

Gasoline

US demand will continue to dominate the global gasoline market, representing slightly more than 40% of global demand through 2020. The region with the fastest growth will be Asia, but because this region is starting from a much smaller base, Asian demand will still be less than half of US demand by the end of the forecast period. Finally, Europe will continue to see gasoline demand erode, with 2020 demand just 70% of its current level.

For all three regions combined, demand should grow by 5 million b/d during the next 15 years, or roughly 1.4%/year.

The global gasoline picture becomes more complex, however, if one overlays changes in quality specifications. For the sake of simplicity, this analysis focuses strictly on the sulfur content of gasoline and divides global gasoline demand into four different categories based on sulfur content.

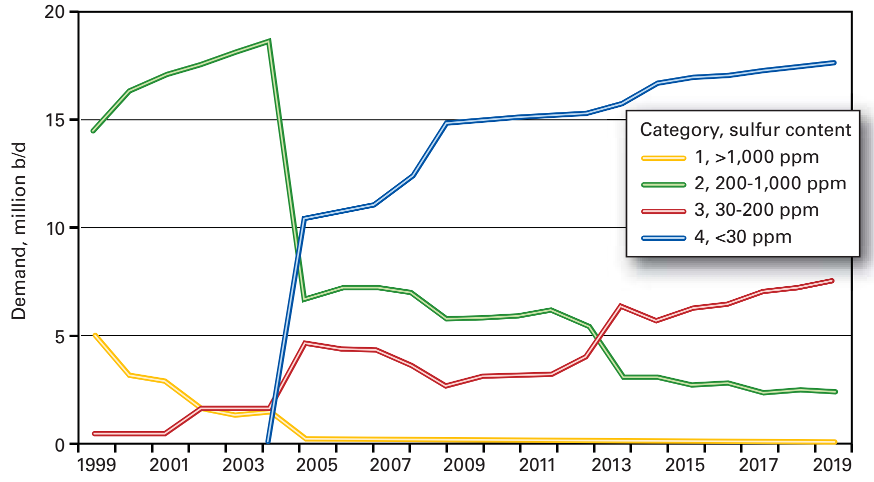
Fig. 1 shows that the highest-sulfur gasoline (Category 1—greater than 1,000 ppm) is disappearing rapidly and should be eliminated from the market shortly. At the other end of the quality spectrum, demand for low-sulfur gasoline (Category 4—less than 30 ppm) is rising quickly, reaching 15 million b/d by the end of the decade.

The significant shift in gasoline volumes from Category 2 (200-1,000 ppm) to Category 4 is largely due to the mandated reduction in gasoline sulfur content in the US in 2005. Another shift in demand by quality is anticipated in 2014-15 when China and a number of African and Asian developing countries are expected to move from Category 2 (200-1,000 ppm) to Category 3 (30-200 ppm).

Fig. 1 shows that, after representing 100% of demand in 2001, Categories 1 and 2 fall to less than 10% by 2020.

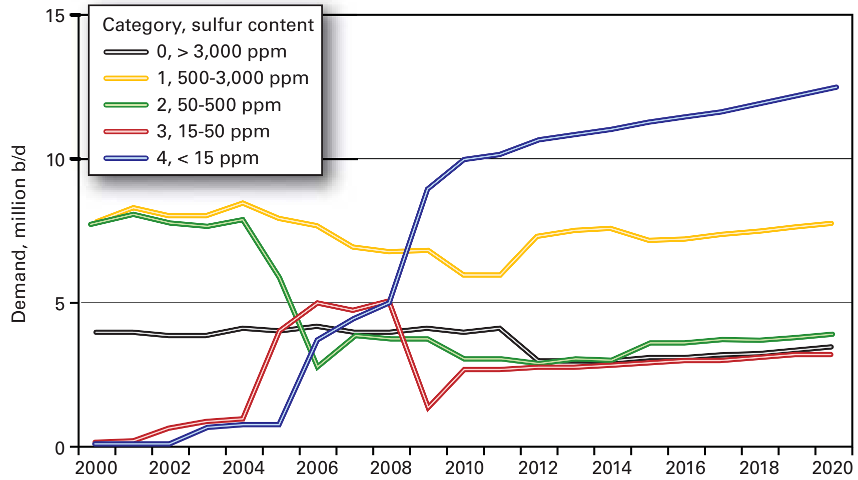
Global gasoline demand

Fig. 1



Global diesel demand

Fig. 2



Diesel

For the global diesel markets, demand growth will be even stronger than for gasoline. In fact, global diesel demand will exceed global gasoline demand by 2020, whereas in the current market, diesel demand is more than 2 million b/d less than gasoline demand.

Diesel demand will likely grow in every region during the forecast period. The fastest growth will be in Asia, which will see demand rise by 150,000 b/d/year through 2020. The next fastest growth will be in North America, which should see yearly demand growth of roughly 125,000 b/d.

Even the slowest growing regions such as the FSU and Africa will experience average growth of more than 25,000 b/d/year. Altogether, global diesel demand will likely rise to 26.25 million b/d by 2020.

Like gasoline, diesel is in the midst of a worldwide shift to primarily low-sulfur specifications, though not as completely as in the gasoline market.

Fig. 2 shows, with the US shifting to 15 ppm ultralow-sulfur diesel (ULSD) this year, and the EU following by the end of the decade, diesel demand in the lowest-sulfur category (Category 4—less than 15 ppm) will climb to nearly 12 million b/d by 2020, becoming the largest category.

Demand for the next cleanest category (Category 3—15-50 ppm) has risen to nearly 5 million b/d, but when Europe moves to ULSD it will drop off sharply. Demand for Category 2 (50-500 ppm) diesel has dropped sharply in recent years and will remain near current levels of 4 million b/d through the forecast period.

Demand for Category 1 (500-3,000 ppm) diesel will remain the second largest, between 7 and 8 million b/d. Many large consumers in Asia and Latin America will remain in this less stringent group.

Finally, demand for the highest-sulfur diesel (Category 0—greater than 3,000 ppm) will fall to about 2.5 million b/d. Clearly, there will continue to be demand for a variety of diesel qualities, even as the largest category of demand becomes ULSD.

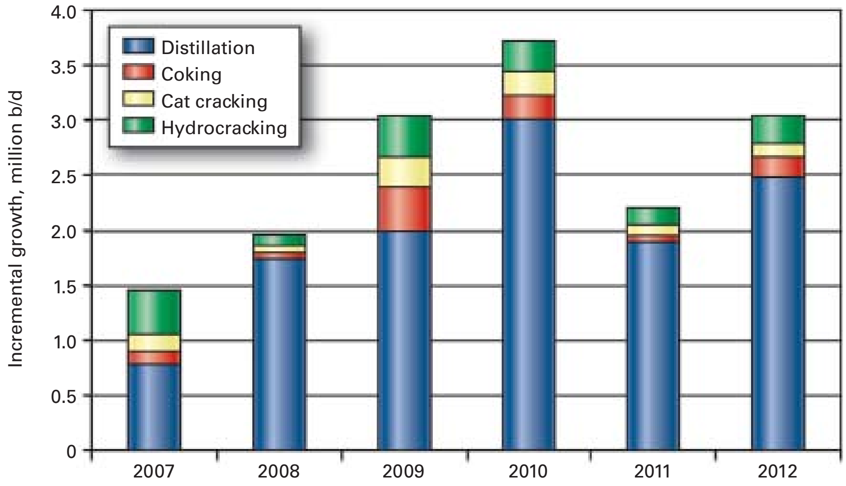
Required refining investment

After several decades of structural overcapacity, the recent tightness in global refining capacity, combined with healthy demand for cleaner fuels, has led to strong refining margins in recent years. This, in turn, has triggered a surge in investment.

ESAI estimates that global distillation capacity rose by about 2 million b/d in

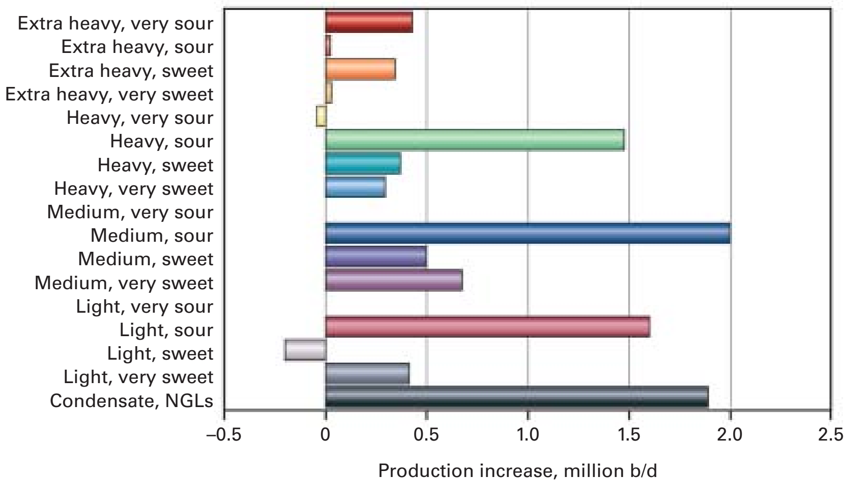
GLOBAL CAPACITY GROWTH

Fig. 3



INCREASE IN GLOBAL CRUDE PRODUCTION, 2005-15

Fig. 4



2006, nearly double the pace of growth in 2005 (Fig. 3). 2007 will see a brief pause in growth, as expansions fall to just 775,000 b/d. The pace should then accelerate, with capacity rising 1.7 million b/d in 2008.

After 2008, this trend increases and refiners will add nearly 2 million b/d of distillation capacity in 2009 and a whopping 3 million b/d in 2010. This will be followed by more expansion—roughly 1.9 million b/d in 2011 and 2.5 million b/d in 2012.

As expected, the bulk of this growth will occur in Asia, near the primary sources of demand growth. Chinese capacity alone will likely expand 1.25 million b/d between now and 2010. During the same period, Indian capacity should increase by a total of 1 million b/d. The new Reliance Industries Ltd. refinery alone will represent 580,000 b/d of this growth. Outside of Asia, capacity will grow more slowly.

The other major region for new capacity will be the Middle East, although the new plants there target more the export market than internal demand as do their Asian counterparts. Massive growth will occur 2010-11, when nearly 2 million b/d of capacity will be added in Saudi Arabia, Kuwait, and other countries.

In addition, there will be some steady capacity creep in North America, particularly weighted toward the later years of this forecast. North American expansions will average 500,000 b/d/year in 2010-11. Another source of new crude distillation capacity in these later years will be the FSU, which could see as much as 500,000 b/d of capacity added before 2010.

Regarding expansion plans for upgrading units, hydrocracking capacity should increase significantly. This is unsurprising when one considers the dramatic growth rates in diesel demand.

In 2007, for example, as much as 400,000 b/d of new hydrocracking capacity will come online. A major portion of this additional capacity will be in Europe, while the transport fuel market continues its long-standing transition to diesel. Several refiners such as Total AS, Preem Petroleum AB, and Fortum Corp. have added hydrocracking capacity recently.

A second large source of hydrocracking capacity expansion is in Asia, which has seen strong diesel growth, particularly in China. Future planned expansion is somewhat more modest than recent years, but average global growth of 250,000 b/d/year will continue for 2007-12.

Another growth region will be the countries of the former Soviet Union, which are exporting gas oil to the European market. FSU capacity will increase 230,000 b/d during 2008-12.

Meanwhile, the shift to lower sulfur in transport fuels has encouraged a notable volume of new hydrotreating capacity, with expansions in North America alone rising 2.6 million b/d in the past 3 years (2004-06). This investment was largely fueled by the shift to lower sulfur specifications in the gasoline market, as well as the recent shift to ULSD.

Another major source of new hydrotreating capacity has been in Asia, which has seen capacity rise by 400,000 b/d/year during the same 3-year period in response to tightening

regional specifications. In addition, Europe moved to a tighter diesel specification; hydrotreating capacity there rose by more than 450,000 b/d in 2005 and nearly half that pace last year.

Globally, hydrotreating capacity should rise at least 500,000 b/d/year during the next several years, when refiners continue to invest to produce ULSD from high-sulfur crudes.

Finally, with gasoline demand rising more slowly than diesel and with Europe's gasoline surplus growing, investment in coking and catalytic cracking should be much lower than for hydrocracking or hydrotreating. Coking capacity will likely rise by an average of 200,000 b/d/year through the end of the decade, while catalytic cracking capacity will rise by roughly 225,000 b/d/year.

This growth will largely be in Asia and North America, although Latin America will see some increase in coking as well. This will largely occur in Mexico and Brazil in response to heavy domestic crude production and also target the growing US gasoline market. An increase in catalytic cracking will take place in the Middle East, primarily due to the runaway gasoline deficit in Iran.

Although the pace of expansion in these various downstream units is impressive, it is clearly dwarfed by the pace of growth in distillation capacity. Fig. 3 clearly shows this imbalance.

Although more investment will likely be announced for complex units, investment currently appears quite skewed to crude distillation. This is surprising considering the continuing shift to light clean products.

Crude quality

The future of crude quality or at least the valuation of different qualities of crude oil is influenced from two sides.

On one side is the growing demand for cleaner petroleum products. There is significant investment in refinery distillation capacity to make petroleum products, but the relative underinvestment in refining units that manufacture clean transport fuels. These factors alone will encourage the premium valuation of light sweet crudes, although not to the same extent as experienced during 2003-06 when distillation capacity was in short supply.

On the other side is the significant growth in medium, light, and heavy sour crude production capacity (Fig. 4). This will also encourage a higher valuation of sweet crude relative to sour.

In sum, the quality spreads of the last few years were extraordinary but due to tight distillation capacity relative to demand growth as much as to petroleum product specifications.

In the next decade, distillation constraint will be largely eliminated, which should ease the light-product crunch and weaken the premium of light crudes. In the meantime, however, investment in upgrading and desulfurization capacity in refining is lagging tremendous investment in distillation. The quality spreads, therefore, will not collapse as sweet crude retains some, but certainly not all, of the premium of recent years. ✦

The author

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GTL production will partially ease regional diesel, naphtha imbalances

Aileen Jamieson
Gordon McManus
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Edinburgh

Several commercial gas-to-liquids (GTL) projects will come on stream during the next decade. Their effect on the global downstream market, however, should be slight. Following the reported recent cancellation of ExxonMobil Corp.'s GTL project in Qatar, the successful start-up of the remaining projects currently in development would result in only around 11 million tonnes/year (tpy), or 250,000 b/d, of GTL diesel and 4 million tpy (100,000 b/d) of GTL naphtha coming into the market by 2015.

Although the announcement by ExxonMobil clearly illustrates the cost pressures being felt by the GTL industry, Wood Mackenzie still believes GTL can be a viable proposition with companies (such as Royal Dutch Shell PLC, Sasol, and SasolChevron) that are best placed to develop projects owing to their operational experience in GTL. All three of the major demand regions (North America, Europe, and Asia-Pacific) should develop large diesel deficits by 2015. In Europe and North America, the diesel deficits will be 54 million tpy and 14 million tpy, respectively. In Asia, the combined diesel and gas oil deficit is forecast to reach almost 23 million tpy. Planned production of GTL diesel should therefore readily find a market.

Fig. 1 shows some regional demand deficits and expected GTL product supplies.

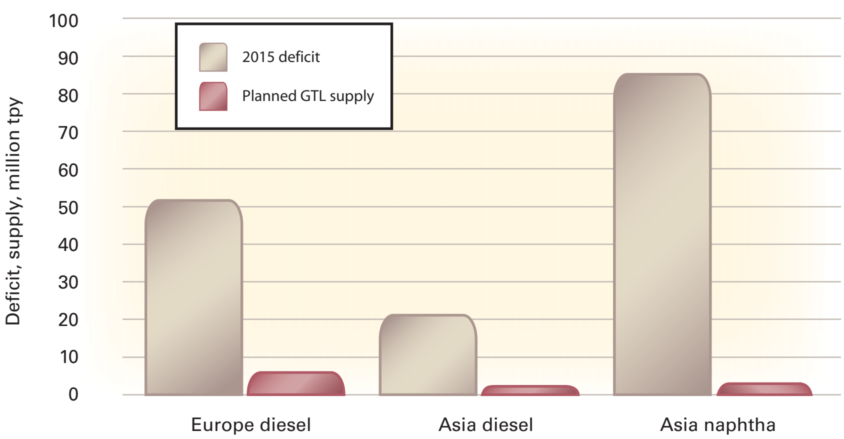
Based on netback pricing, the most likely destination for GTL diesel produced in Qatar, Nigeria, and Algeria is Europe. This 8 million tpy of GTL diesel supply could lower Europe's deficit in 2015 by 15% to around 46 million tpy. The remaining 3 million tpy of GTL supply would have a slighter effect on the deficit in Asia-Pacific.

The key demand region for naphtha is Asia-Pacific, which already has a rising deficit due to growing demand for basic petrochemicals. This deficit should reach nearly 90 million tpy by 2015. Both North America and Europe will be broadly balanced naphtha at that time.

Based on netback pricing, there should be greater variations in the destination for GTL naphtha than for diesel.

REGIONAL SUPPLY-DEMAND BALANCES

Fig. 1



The potential 3 million tpy of product from Qatar and Australia, however, which is likely to be exported to Asia will make minimal impression on the large deficit.

Why GTL?

GTL technology has been in development since the start of the 1900s, but its large-scale, worldwide application remains limited to only a handful of plants. The past decade, however, has brought renewed vigor to the field and several commercial fuels-oriented projects will come on stream during the next decade.

Some of the main forces for GTL as a gas-monetization strategy are:

• Large, liquid markets for products. The two key products from a GTL plant are diesel and naphtha. Global diesel and gas oil demand is currently more than 1.1 billion tpy (22 million b/d). With global demand currently growing at around 3%/year, it is the fastest growing part of the demand barrel. Naphtha demand is more than 200 million tpy (4.7 million b/d), most of which is due to increasing demand for basic petrochemicals.

• High-quality products. Diesel, naphtha, and lubricant basestocks produced using GTL technology exhibit unique high-quality characteristics. Diesel produced is low in sulfur, has a very high cetane number, and low aromatics content. The naphtha is highly paraffinic, giving higher ethylene yields when cracked vs. typical refinery naphthas.

• Potentially higher value. GTL investment returns are more strongly influenced by the prevailing crude oil price than LNG; therefore, it can achieve a higher return in a high oil price environment.

EXISTING, PLANNED GTL PLANTS

Table 1

Plant location	Owners	Capacity, 1,000 b/d	Status as of Jan. 2007	Actual expected start-up
Mossel Bay, South Africa	PetroSA	36	Commissioned 1993	1993
Bintula, Malaysia	Shell	15	Commissioned 1993, recommissioned 1999	1993
Ras Laffan, Qatar	Oryx GTL (Qatar Petroleum, Sasol)	34	Start-up	2007
Escravos, Nigeria	SasolChevron	34	Under construction	2009
Ras Laffan, Qatar	Pearl GTL (Qatar Petroleum, Shell)	*140	Front-end engineering and design	2010/2012
Ras Laffan, Qatar	ExxonMobil	*154	Reported canceled, Feb. 20, 2007	—
Tinhert, Algeria	Qualified bidders are SasolChevron Shell and a consortium including BHP Billiton, Statoil, and Petro SA	34	Bidder selection to be completed during 2007	2012
North-West Shelf, Australia	SasolChevron	66	Feasibility study commenced	2012
Ras Laffan, Qatar	Oryx GTL Expansion (Qatar Petroleum, Sasol)	65	Memorandum of understanding	2013

*In two phases.
Source: Wood MacKenzie

Who is active?

Almost all of the world's major international oil and gas companies now have some interest in GTL through demonstration plants or projects at various stages of commercialization. There remain, however, only two examples of GTL plants producing commercial products—those of Shell at Bintulu, Malaysia, and PetroSA at Mossel Bay, South Africa. The long-term future of the current plant at Mossel Bay is in some doubt due to a potential lack of gas supplies.

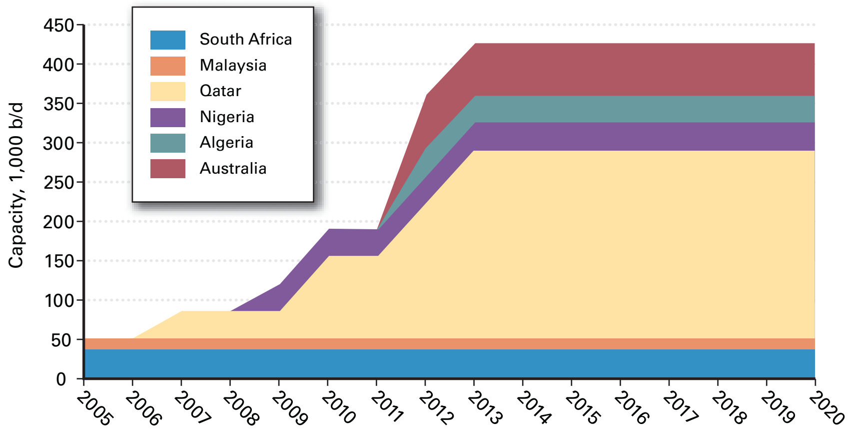
Shell's plant at Bintulu has a capacity of 14,700 b/d and produces a range of specialty products. Having gained invaluable experience in the operation of a commercial GTL plant and in the marketing of the products produced, Shell is embarking on the next stage of its GTL strategy through the launch of the Pearl GTL project in Qatar. The first 70,000 b/d of GTL capacity at this integrated upstream and downstream project should be commissioned towards the end of the decade with 70,000 b/d of additional capacity coming on stream about a year later.

Sasol has developed great expertise in the production of synthetic fuels through its coal-to-liquids (CTL) plants in South Africa. It formed a joint venture with Chevron Corp. (SasolChevron) in 1999 to help globalize the application of its technologies. Both companies have GTL projects at advanced stages of development.

Chevron's joint venture with Nigerian National Petroleum Corp. now has its 34,000-b/d GTL plant at Escravos, Nigeria, under construction. Sasol formed another joint venture with Qatar Petroleum in 2001 called Oryx GTL for the construction of a GTL plant at Ras Laffan, Qatar. This 34,000-b/d plant, currently in the commissioning phase, will be the first of a new wave of commercial GTL plants. In conjunction with Qatar Petroleum, SasolChevron has announced plans to expand this plant to 100,000 b/d and is also pursuing the potential for another 130,000-b/d integrated plant in Qatar.

GLOBAL GTL CAPACITY, 2005-20

Fig. 2



ExxonMobil had signed an agreement with Qatar's government to build a 154,000-b/d plant at Ras Laffan by 2011. In February 2007, however, both companies decided not to progress the GTL project in favor of pursuing the development of the Barzan project in the North Field to supply domestic gas.

Marathon Oil Corp. is planning to build a 120,000-b/d GTL plant in Qatar, possibly in conjunction with partners including Petro-Canada, although this project has currently been put on hold by the Qatari government.

ConocoPhillips Co. is planning a two-phase project in Qatar to produce a total of 160,000 b/d of products, although this also has been put on hold by the Qatari government.

BP PLC has evaluated several potential sites for a commercial plant but has yet to make any positive project announcements.

Table 1 lists existing GTL capacity and the projects in development that we consider to have the strongest chances of coming to fruition. Three projects, representing the next generation of GTL, are likely to come on stream be-

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5 Heat Recovery Steam Generators
3 250-MW+ Steam Turbine Generators
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Potential GTL product trade flows

Fig. 3

fore 2010 and others will follow close behind.

In addition to the projects listed in Table 1, many other projects have been proposed, covering most regions of the world with substantial stranded gas reserves. Further projects using gas from Qatar's huge North Field have strong potential, with SasolChevron, ConocoPhillips, and Marathon the main contenders to develop this.

Australia's Northwest Shelf is also a good prospect for GTL development. Other projects have been proposed in South America, Russia, Indonesia, and other parts of the Middle East. These projects, however, are not firm enough for us to include in our forecasts of additional diesel and naphtha supply from GTL.

Where and when?

Fig. 2 shows our assessment of the likely timing of the proposed GTL projects. The successful development of these projects would result in 425,000 b/d of GTL products coming onto the market by 2015, of which half would be from Qatar.

GTL remains capital-intensive compared to refining or LNG, and there is technical risk associated with GTL. In a high oil-price environment, however, the economics of GTL have the potential to be superior to both refining and LNG.

The Feb 20. 2007, announcement by ExxonMobil that it has cancelled its GTL project in Qatar clearly shows the cost pressure being felt by the GTL industry. Wood Mackenzie, however, still believes that GTL has the potential to create significant economic value, especially in a high oil price environment. Assuming that the first few projects are implemented successfully, we expect that it will catalyze development of more projects by giving confidence in the technology to the key stakeholders: host governments, finance providers, and project developers. There is certainly the scope for more projects to be developed within this time period, taking GTL capacity beyond that shown in Fig. 2.

Which markets?

The main products from GTL plants are diesel, naphtha, and lubricant base oils. Smaller volumes of LPG, n-paraffins, and waxes are also produced. The vast majority of these products will be exported from the producing countries.

Determining the most likely destination market requires an analysis of regional supply and demand balances for those products, combined with an assessment of the relative netback prices available to the supplier from the different regions. Netback prices are derived from forecasts of delivered pricing for naphtha and diesel in the respective markets—based on our projections of international refining margins—and analysis

Typical diesel specifications

Table 2

	Conventional ULSD	GTL diesel
Sulfur, ppm	10	<5
Cetane number	48 minimum	~75
Specific gravity	0.82-0.86	~0.78
Polyaromatics	<*11	<5

*European specification.
Source: Wood MacKenzie

of likely freight costs for the movement of clean products from the country of production to target markets.

GTL products can potentially command price premiums vs. traditional diesel and naphtha produced from crude refining due to their better properties. GTL naphtha commands a price premium due to its favorable properties for ethylene production.

GTL diesel, however, is less straightforward. The low specific gravity means that it does not meet current diesel fuel specifications and cannot be used directly as a transport fuel. Its low sulfur content, high cetane number, and low poly-aromatic content, however, make it a valuable blendstock.

Table 2 illustrates the properties of GTL diesel compared to conventional ultralow-sulfur diesel.

GTL diesel's value as a blendstock in Europe will be limited, however, because most refineries have already invested to produce low-sulfur fuels and many will not be cetane constrained or have problems meeting poly-aromatic specifications. In Asia-Pacific, however, where fuel-quality specifications are starting to move towards European standards, the influence of GTL diesel quality could be greater.

A further application for GTL diesel is in fuels marketing; GTL diesel can be blended with conventional diesel to produce premium-priced products marketed as high-performance fuels. Shell has pioneered this approach, using product from its Bintulu facility.

Wood Mackenzie has performed netback analysis for most of the proposed GTL sites in the world. Fig. 3 shows our view of the likely trade flow for GTL products.

Based on netback pricing, the most likely destination for GTL diesel produced in Qatar, Nigeria, and Algeria is Europe. There will be greater variations in the destination for GTL naphtha; product from Qatar and Australia is likely to be exported to Asia. The US will be the target market for Nigerian GTL naphtha, and Algerian GTL naphtha will likely flow to Mediterranean Europe.

Global oil product balances

Global diesel demand is expanding faster than total oil demand, driven primarily by the road freight sector and from passenger vehicles switching from gasoline, particularly in Europe. Current global diesel and gas oil demand is around 1.1 billion tpy (22 million b/d) and is projected to grow at an average rate of around 2.7%/year through to 2015 to reach 1.5 billion tpy (30 million b/d).

Our forecast for GTL capacity development shows that about 11 million tpy (0.25 million b/d) of GTL diesel could hit the market, less than 1% of total demand. All three of the major demand regions should develop large diesel deficits by 2015. In Europe and North America, the diesel deficits will be 54 million tpy and 14 million tpy, respectively (Fig. 1).

In Asia, the combined diesel plus gas-oil deficit could reach nearly 23 million tpy. The planned production of GTL diesel should therefore readily find a market.

Based on netback pricing, the most likely destination for GTL diesel produced in Qatar, Nigeria, and Algeria is Europe. The planned GTL plants in those countries would produce just more than 8 million tpy of diesel, potentially lowering Europe's diesel deficit in 2015 by 15% to around 46 million tpy. The remaining 3 million tpy of GTL supply would have a lesser impact on the deficit in Asia-Pacific.

Global naphtha demand is also increasing due to growing demand for basic petrochemicals. Demand is currently more than 220 million tpy (5 million b/d) and will grow to more than 310 million tpy (78 million b/d) by 2015. The projected GTL naphtha supply of 4 million tpy (0.1 million b/d) would meet less than 2% of total global demand.

The key demand region for naphtha is Asia-Pacific, which already has a growing deficit. This deficit will reach nearly 90 million tpy by 2015. North America and Europe will remain broadly balanced in naphtha at that time.

Based on the resulting netback price forecasts, we expect greater variations in the destination for GTL naphtha than for diesel. The potential 3 million tpy of product from Qatar and Australia will likely be exported to Asia, making a small dent in the huge deficit there. The US will be the target market for Nigerian GTL naphtha, and Algerian GTL naphtha will likely flow to Mediterranean Europe.

In summary, GTL products will meet a small percentage of global oil product demand in the next decade. The influence of GTL diesel and naphtha on regional supply-demand balances will be small.

The effect of GTL diesel imported to Europe is the most significant, potentially reducing the forecast deficit of 54 million tpy by about 15%. The relevance of naphtha supply into Asia, however, is negligible. ✦

The authors

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Testing explores SET for transport pipelines

Kevin Waddell
Enventure Global Technology
Houston

Tom Miesner
Miesner LLC
Katy, Tex.

Pipeline operators have begun considering the transfer of solid expandable tubular (SET) technology, widely used upstream, into pipeline repairs and restorations. This article examines the potential benefits of this transfer and outlines its testing and progress to date.

Pipelines

Pipelines

Three pipe features determine maximum pipeline operating pressure: OD, WT, and metallurgy (SMYS). Adjusting this calculation to account for one (or more) safety factors yields maximum allowable operating pressure (MAOP):

MAOP = (2t × SMYS × SF) / OD

Where:

MAOP = Maximum allowable operating pressure

t = Wall thickness

SMYS = Specified minimum yield strength

SF = Safety factor

OD = Outside diameter

OD, WT, and metallurgy are all set when the pipe is produced, so that the only remaining variables affecting MAOP are safety factors. WT, however, can change in areas, primarily as a result of corrosion or third-party damage. Sleeves (steel as well as composite wraps) and liners (primarily plastics) were developed to restore wall thickness or reinforce pipe in isolated locations.

Few options existed for increasing MAOP outside of replacing, sleeving, lining, or wrapping the entire pipeline.

The pipeline could be hydrostatically tested to higher pressures, but stressing the pipe carries its own set of problems.

Decreasing safety factors is the final solution but is likely to be seen as a higher risk than use of more conservative safety factors and will require expensive risk remediation.

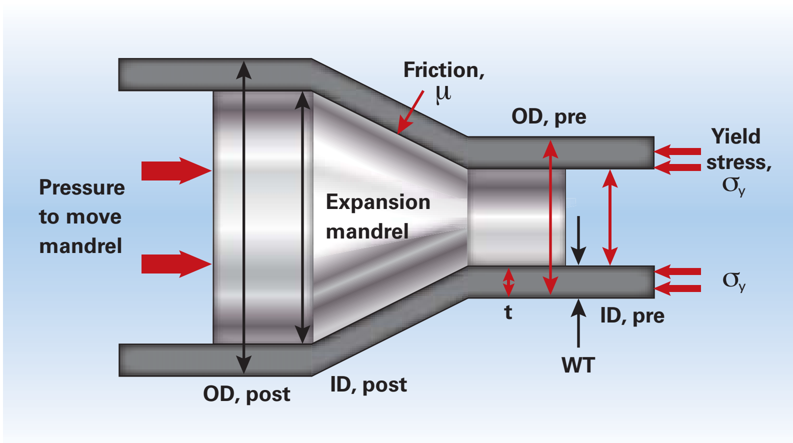
Local distribution companies (LDCs) have used lining technology extensively in settings where lines operate at much lower pressure than most transmission lines.

Steel lining, however, is new. The concept is simple: insert a smaller pipe inside a larger pipe and, using pressure, drive a specially designed mandrel through the smaller pipe to accomplish a controlled expansion to fill the annular space between the two (Fig. 1).

But the expansion process is difficult. Driving the mandrel through the pipe cold works the steel, increasing its strength while decreasing its ductility. Extensive metallurgy, joining (girth weld), and expansion research have overcome these problems. Pipe joints, produced to rigid metallurgical speci-

Pipeline SET expansion interfaces

Fig. 1



An end view (photo on left) of postexpansion pipe shows the completeness with which the annular space between the inserted steel tubing and preexisting pipe is filled during the cold-drawing radial enlargement process (Fig. 2). This side view (photo on right) of an end of pipe treated by SET technology shows how ID is maintained even as WT and strength are increased: by expanding the preexisting pipe. The left end of the pipe shows the inserted tubing (Fig. 3).

fications, can be welded together using qualified welding processes, tested, inserted, and expanded such that they meet API 5L and 1104 specifications after expansion (Figs. 2-3).

The market

Market research shows this technology has ideal applications in areas where traditional excavate-and-repair techniques are impossible to use, cost prohibitive, or would attract significant public attention (Fig. 4). In such settings, the two broad categories SET technology would address most effectively are capacity restoration and anomaly repair.

Capacity restoration includes areas that would be difficult or expensive to excavate.

Natural gas transmission lines in the US possess a class location (1, 2, 3, or 4) based on criteria established by the Office of Pipeline Safety (OPS). The class location assigned is essentially a function of nearby buildings and occupation levels.

Class location dictates the safety factor used to calculate the MAOP of a given section of natural gas pipeline.

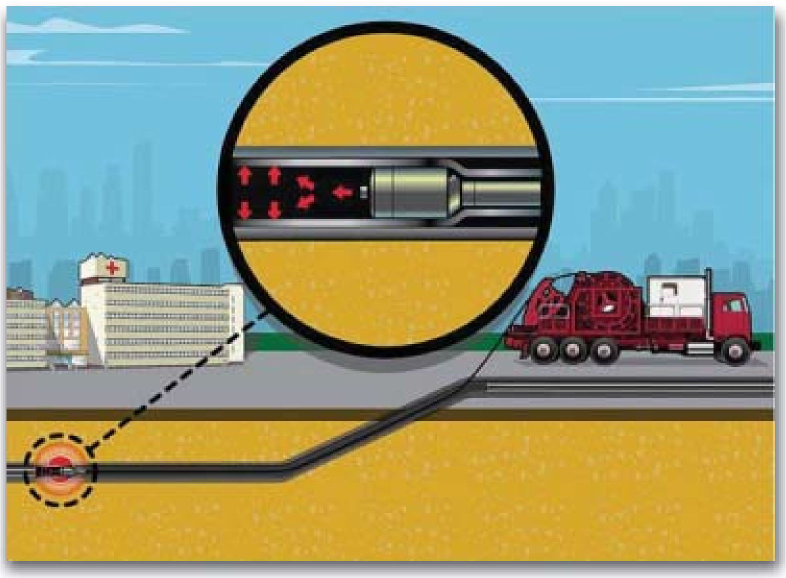
When class locations change—usually due to population encroachment—the operator must use a more conservative safety factor, and unless it can take other measures to reduce the likelihood of pipeline failure, the operator must accordingly lower the MAOP of the pipeline.

Lower MAOP leads to lower capacity and therefore lower revenues for the operator. SET can restore MAOP and, through this, revenues (Figs. 5-6).

Current industry options for maintaining capacity (and revenues) at the lower MAOP include looping the line or replacing it with a larger line or one with a greater WT or higher grade steel.

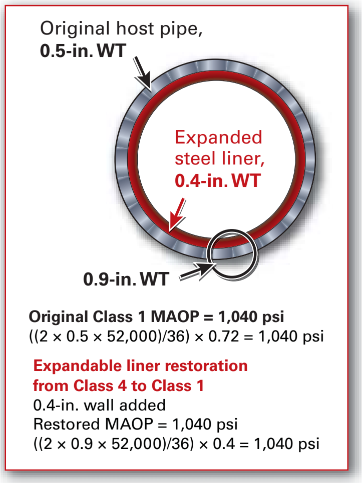
Operators may also request a waiver from the OPS to continue operating at the current MAOP. When such waivers are granted, however, the OPS requires the operator take additional protective measures to reduce the likelihood of a failure.

SET REPAIRS, DIFFICULT EXCAVATION SITE Fig. 4



SET RESTORES MAOP

Fig. 5



Looping, replacing line, and seeking waivers are all costly activities, and expandable technology has the potential to cut these costs, reduce permitting time, and increase operating time, while at the same time improving public perception.

Anomaly repair applications, especially in locations that are difficult or expensive to excavate, include:

- Nonoffshore waterways.
- Interstate highways, other highways, and roads.
- Railroads.
- Locations where disrupting the surrounding area would be logistically complex or expensive (such as environmentally sensitive areas, parking lots, and areas with nearby pipelines, buildings, cables, or other congested infrastructure).

Feasibility

The value propositions that attract the pipeline industry to SET include its permanent, steel, pipe-in-pipe ability to improve structurally at-risk or derated pipelines with only nominal ID loss. And because expandables would enable operators to increase pressures and thereby regain the pipelines' more favorable classifications and throughput, several operators favor the concept.

Value proposition

The absence of trenches and minimal disruption to surrounding infrastructure and environment reduce operator costs, as does the reduced permitting time.

Cost, time, and risk are three key common components in evaluating various solutions to a problem. Like any other potential solution, expandables must outperform the next best alternatives.

Potential key benefits in using expandables in capacity restoration include cost and time savings stemming from:

- Minimal environmental impact shortening permitting and solution cycle time.
- Minimal public relations exposure.
- Alternatives to waiver processes.
- Flexibility for pipeline conversions.

Using expandables can also reduce risk and potential liabilities. Limited excavation minimizes exposure to potential environmental problems or damages to surrounding lines and infrastructure, leading to:

- Less disruption to population and industry.
- Increased operating safety factors and throughput.

Expandables also use environmentally friendly fluids and provide an alternative to abandonment.

In difficult-to-excavate areas, expandable pipeline repair often requires a smaller footprint than alternatives, allowing work within limited right-of-ways, minimizing permitting time, and reducing overall job time and risk.

Compared to a conventional re-drill that uses horizontal directional drilling (HDD), SET technology saves both cost and time by eliminating:

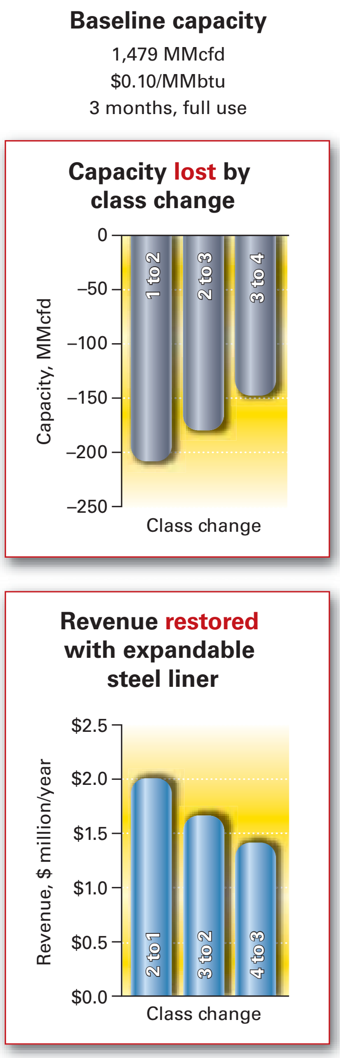
- Geotechnical studies.
- Containment pit for mud returns.
- Pilot and back-reaming runs.
- Drilling fluids.
- Mud processing equipment.
- Contaminated mud or water.

SET also reduces risk and potential liabilities by removing:

- Environmental and regulatory concerns about drilling fluids containment and disposal.
- Concerns about a structural fracture resulting in an uncontrolled fluid release and contamination.
- Settlement damage to surrounding structures such as houses, highways, and railroads.

CAPACITY, REVENUE CHANGES

Fig. 6



Upstream experience

Since 2000, operators have been successfully using SET technology in upstream applications, where it is subject to far harsher temperature and pressure parameters than are found in transport pipelines. Of the now hundreds of SET installations completed around the world, Burlington Resources' application demonstrates the benefits of the technology well.

Burlington wanted to achieve a slimmer well profile while maximizing hole size at total depth (TD) in deep and ultradeep land gas wells, with the ultimate purpose of reducing field development costs of a multiinstallation program in a tight services market environment. Incorporating a 6 × 7.625-in. expandable openhole liner into the base well design let the operator drill a 14.75-in. surface hole instead of a 17.5-in. hole, allowing drillout of surface pipe 1 day earlier.

Below the surface pipe, the operator drilled a 9.875-in. hole (at a rate of 3 days/1,000 ft) vs. a 12.25-in. hole (4.8 days/1,000 ft). The operator reduced drilling time to TD by 21%; to 74 days from 94 days. Running the SET liner below this section allowed for 4.5-in. production casing at TD, allowing production at planned rates.

The value of using SET systems, rather than a conventional casing program, included:

• Increasing the rate of penetration by 37%.

• Lowering equivalent-circulation densities.

• Increasing flow rates.

• Saving more than $1 million/well by reducing drilling time for each well by about 4 weeks.

These savings translated into every sixth well being drilled at no cost.

Testing has shown that SET technology can successfully be used in pipeline contexts through bends up to 20° (Fig. 7).

Pipeline testing

Phase 1 testing of solid expandables for safety, reliability, and predictability in a variety of pipe grades has included:

• Reviews to ensure expandables comply with Code of Federal Regulations, Canadian Standards Association, American Petroleum Institute, American Society of Mechanical Engineers, and National Association of Corrosion Engineers specifications.

• An API 5L engineering study, for specification compliance pre and post-expansion.

• An API 1104 pipeline weld assessment, to determine the expandability of specification-compliant defective welds.

• A fusion-bonded epoxy coating study of 30% expansions of 10 coatings.

• A 20° bend prototype laboratory test of a standard 1,400 km river crossing, to gauge the impact of bends on the pipe and expansion process (Fig. 7).

JIP

Joint industry partnership (JIP) organizational meetings are under way between the expandables supplier and pipeline operators, aimed at addressing such key pipeline engineering issues as cathodic protection, annulus space treatment, hot tapping, piggability, and inline inspection.

The objectives of the JIP are to further develop, engineer, design, test, and deploy SET pipeline repair and construction technology, which is regulatory and code-compliant, providing the means to repair pipelines from the inside with steel tubulars. The JIP schedule consists of three phases: development; system design and proof testing; and field appraisal testing, which would initially involve installation in an abandoned pipeline, followed by field appraisals by participating operators in multiple operating pipelines. ✦

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Equipment/Software/Literature

New line of disposable maintenance utility pigging tools

Here's the XPig multipurpose, disposable pipeline utility pigging tool.

Features include:

- Three basic configurations (4-12 in.).
- One cup and five disks.
- Two cups and four disks.
- Five disks-bidirectional option.
- Durable urethane.
- RealSeal cup options.
- Designed to seal around 1.5 DR bends.
- Three durometer choices: 75, 80, 85 (standard).
- Undersized front disk or cup for easier launch.
- Hollow body can carry transmitter or trip magnets.
- Stainless steel or polybrush options.
- Gauging option.
- Bypass option keeps solids in suspension.
- Optional solid core.
- Optional offshore design.

The tool's cast body is made of TDW Formula SI urethane, which provides superior physical properties, the firm says.

Source: **T.D.Williamson Inc.**, 6801 S. 65th W. Ave., Tulsa, OK 74131-2444.

New reservoir management tool

A newly launced uncertainty management tool operates within modeling software IRAP RMS (see OGJ, Sept. 18, 2006, p. 68) and will allow for uncertainties to be quantified across the complete reservoir characterization and development work flow.

Through the new module, uncertainties in depth conversion, structural modeling, geological property modeling, and dynamic reservoir simulation can all be simultaneously evaluated helping to ensure that the full impact of these often independent uncertainties is captured through realistic 3D static and dynamic reservoir models.

The launch of the new uncertainty management module follows the company's acquisition of Surrey, UK-based Energy SciTech Ltd.'s EnABLE history-matching and uncertainty estimation software product.

As opposed to some 3D model work flows that ignore uncertainty in the data, IRAP RMS and EnABLE will examine and history-match numerous geological scenarios to create simulation models that are fully consistent with their underlying geological interpretation, the company points out.

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

Services/Suppliers

Axens

Rueil-Malmaison, France, has announced the opening of Axens (Beijing) Trading Co. Ltd. with a ceremony in Beijing.

Axens has been active in China for more than 30 years, with more than 100 Axens processes in the fields of hydrogenation, catalytic reforming, oligomerization, and aromatics production operated in the region.

Axens, a subsidiary of Institut Français du Pétrole (IFP), is an international provider of advanced technologies, catalysts, and services to the hydrocarbon industries.

Energy Maintenance Services Group (EMS Group)

Houston, has announced its acquisition of Zaval-Tex, a pipeline maintenance company based in Beaumont.

EMS Group is a leading provider of integrated operations and maintenance services to energy industry customers through six service lines: pipeline management, pipeline integrity management, production and pipeline projects, power services, LNG/natural gas services, and data management.

Over the past year EMS Group has acquired and transitioned four companies, and acquired majority of the third party contracts from a fifth company.

Gray Energy Services

Fort Worth, has announced the acquisition by its subsidiary, Gray Wireline Services Inc., of Falcon Wireline LLC.

Falcon, based in Woodward, Okla., is a leading provider of cased hole wireline services for customers in western Okla. and the Panhandle region of northwest Tex.

Gray Energy Services LLC was formed in early 2006 by Centre Partners, Centre Southwest Partners, and Gray Wireline Service Inc., as a platform to build a leading diversified provider of production enhancement solutions across the North American natural gas and oil production industry.

SBM Offshore

Houston, has announced integration of two of its Houston group companies, Atlantia Offshore Ltd. and SBM-Imodco Inc. The new company will be called SBM Atlantia.

Bernard van Leggelo, current president of SBM-Imodco, has been appointed president of SBM Atlantia. Tony Mace, president of Atlantia, will transfer to the SBM Offshore offices in Monaco.

SBM Atlantia is an integrated provider of complete floating production solutions for the deepwater market.

API IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4		District 5		Total US		
	3-9 2007	[1]3-2 2007	3-9 2007	[1]3-2 2007	3-9 2007	[1]3-2 2007	3-10 2006
	1,000 b/d						
Total motor gasoline	321	279	0	0	321	279	509
Mo. gas. blending comp.	562	447	78	14	640	461	589
Distillate[2]	295	329	52	14	347	343	320
Residual	255	293	43	44	298	337	355
Jet fuel-kerosine	68	59	274	125	342	184	176
LPG	284	227	1	3	285	230	270
Unfinished oils	586	513	101	24	687	537	488
Other	277	480	99	18	376	498	452
Total products	**2,648**	**2,627**	**648**	**242**	**3,296**	**2,869**	**3,159**
Canadian crude	1,580	1,607	89	203	1,669	1,810	1,810
Other foreign	7,678	6,792	744	497	8,422	7,289	7,934
Total crude	**9,258**	**8,399**	**833**	**700**	**10,091**	**9,099**	**9,744**
Total imports	**11,906**	**11,026**	**1,481**	**942**	**13,387**	**11,968**	**12,903**

[1]Revised. [2]Includes No. 4 fuel oil.
Source: American Petroleum Institute.
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

	*3-9-07	*3-10-06	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	76.96	69.91	7.04	10.1
Brent crude	60.59	59.71	0.88	1.5
Crack spread	16.36	10.20	6.16	60.4
FUTURES MARKET PRICES				
One month				
Product value	76.76	70.90	5.86	8.3
Light sweet crude	60.85	60.89	–0.04	–0.1
Crack spread	15.91	10.01	5.90	58.9
Six month				
Product value	77.42	74.44	2.97	4.0
Light sweet crude	65.02	65.19	–0.17	–0.3
Crack spread	12.39	9.26	3.14	33.9

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

API CRUDE AND PRODUCT STOCKS

	Crude oil	Motor gasoline Total	Motor gasoline Blending comp.[1]	Jet fuel Kerosine	Fuel oils Distillate	Fuel oils Residual	Unfinished oils
	1,000 bbl						
PAD I	14,494	54,590	26,351	9,258	47,765	14,345	8,364
PAD II	69,501	50,784	15,483	7,294	27,839	1,647	13,967
PAD III	175,350	64,878	28,065	13,093	32,856	15,875	44,784
PAD IV	13,372	6,469	1,866	586	3,533	442	2,656
PAD V	[1]50,475	27,220	20,621	9,202	11,517	6,200	21,067
Mar. 9, 2007	**[1]323,692**	**203,941**	**92,386**	**39,433**	**123,510**	**38,509**	**90,838**
Mar. 2, 2007[3]	**317,434**	**204,442**	**93,067**	**40,994**	**127,783**	**39,708**	**89,138**
Mar. 10, 2006	**338,166**	**217,162**	**81,330**	**43,219**	**127,267**	**39,328**	**88,151**

[1]Included in total motor gasoline. [2]Includes 4.680 million bbl of Alaskan crude in transit by water. [3]Revised.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

API REFINERY REPORT—MAR. 9, 2007

District	REFINERY OPERATIONS Total refinery input	Crude runs	Input to crude stills	Operable capacity	Percent operated	REFINERY OUTPUT Total motor gasoline	Jet fuel, kerosine	Fuel oils Distillate	Fuel oils Residual
	1,000 b/d					1,000 b/d			
East Coast	3,044	1,217	1,243	1,618	76.8	1,650	60	414	121
App. Dist. 1	78	78	78	95	82.1	24	0	17	0
Dist. 1 total	**3,122**	**1,295**	**1,321**	**1,713**	**77.1**	**1,674**	**60**	**431**	**121**
Ind., Ill., Ky.	2,313	1,279	2,271	2,355	96.4	1,134	157	587	31
Minn., Wis., Dak.	353	338	353	442	79.9	298	30	110	9
Okla., Kan., Mo.	707	562	608	786	77.4	342	32	201	2
Dist. 2 total	**3,373**	**3,079**	**3,232**	**3,583**	**90.2**	**1,774**	**219**	**898**	**42**
Inland Texas	933	538	622	647	96.1	482	34	177	6
Texas Gulf Coast	3,852	3,275	3,364	4,031	83.5	1,398	292	878	218
La. Gulf Coast	3,413	3,256	3,265	3,264	100.0	1,217	405	831	138
N. La. and Ark.	223	153	189	215	87.9	70	9	47	5
New Mexico	155	97	97	113	85.8	61	2	35	0
Dist. 3 total	**8,576**	**7,319**	**7,537**	**8,270**	**91.1**	**3,228**	**742**	**1,968**	**367**
Dist. 4 total	**614**	**537**	**545**	**596**	**91.4**	**295**	**27**	**162**	**12**
Dist. 5 total	**2,591**	**2,139**	**2,282**	**3,173**	**71.9**	**1,630**	**350**	**449**	**101**
Mar 9, 2007	**18,276**	**14,369**	**14,917**	**17,335**	**86.1**	**8,601**	**1,398**	**3,908**	**643**
Mar. 2, 2007*	**18,039**	**14,363**	**14,763**	**17,335**	**85.2**	**8,707**	**1,410**	**3,958**	**691**
Mar. 10, 2006	**16,769**	**14,323**	**14,712**	**17,115**	**86.0**	**8,346**	**1,433**	**3,625**	**642**

*Revised.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

OGJ GASOLINE PRICES

	Price ex tax 3-7-07	Pump price* 3-7-07	Pump price 3-8-06
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	204.7	244.4	230.7
Baltimore	201.4	243.3	230.7
Boston	199.2	241.1	226.7
Buffalo	200.3	260.4	243.7
Miami	210.7	261.0	251.2
Newark	203.3	236.2	218.6
New York	191.3	251.4	247.2
Norfolk	197.2	234.8	221.7
Philadelphia	209.2	259.9	241.3
Pittsburgh	196.3	247.0	232.1
Wash., DC	209.2	247.6	245.6
PAD I avg.	202.1	247.9	235.4
Chicago	221.1	272.0	263.8
Cleveland	198.3	244.7	231.1
Des Moines	198.0	238.4	226.6
Detroit	199.8	249.0	236.7
Indianapolis	203.3	248.3	235.4
Kansas City	201.9	237.9	221.7
Louisville	207.8	244.7	233.0
Memphis	195.3	235.1	225.3
Milwaukee	197.4	248.7	240.3
Minn.-St. Paul	205.7	246.1	236.6
Oklahoma City	200.8	236.2	219.7
Omaha	203.3	249.7	234.6
St. Louis	202.9	238.9	216.2
Tulsa	198.7	234.1	221.2
Wichita	195.7	239.1	225.0
PAD II avg.	202.0	244.2	231.1
Albuquerque	203.8	240.2	235.3
Birmingham	196.6	235.3	225.3
Dallas-Fort Worth	198.6	237.0	231.3
Houston	195.6	234.0	225.3
Little Rock	196.4	236.6	225.3
New Orleans	200.3	238.7	235.1
San Antonio	190.1	228.5	221.0
PAD III avg.	197.3	235.8	228.4
Cheyenne	192.3	224.7	214.3
Denver	198.4	238.8	224.9
Salt Lake City	185.4	228.3	224.8
PAD IV avg.	192.0	230.6	221.4
Los Angeles	240.0	298.5	258.6
Phoenix	214.9	252.3	234.6
Portland	231.3	274.6	229.6
San Diego	245.5	304.0	264.5
San Francisco	264.5	323.0	258.5
Seattle	224.9	277.3	240.9
PAD V avg.	236.8	288.3	247.8
Week's avg.	**205.5**	**249.1**	**233.5**
Feb. avg.	**184.4**	**228.0**	**229.6**
Jan. avg.	**181.7**	**225.3**	**227.3**
2007 to date	**185.2**	**228.8**	—
2006 to date	**186.3**	**228.7**	—

*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

	3-2-07 ¢/gal		3-2-07 ¢/gal
Spot market product prices		Heating oil	
Motor gasoline		No. 2	
(Conventional-regular)		New York Harbor	176.33
New York Harbor	192.52	Gulf Coast	172.33
Gulf Coast	183.52	Gas oil	
Los Angeles	215.50	ARA	173.37
Amsterdam-Rotterdam-Antwerp (ARA)	174.36	Singapore	170.95
Singapore	183.74	Residual fuel oil	
Motor gasoline		New York Harbor	98.52
(Reformulated-regular)		Gulf Coast	105.36
New York Harbor	190.52	Los Angeles	128.15
Gulf Coast	184.00	ARA	94.79
Los Angeles	221.50	Singapore	110.04

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

BAKER HUGHES RIG COUNT

	3-9-07	3-10-06
Alabama	3	5
Alaska	13	10
Arkansas	43	20
California	31	32
Land	29	28
Offshore	2	4
Colorado	99	76
Florida	1	0
Illinois	0	0
Indiana	1	0
Kansas	14	6
Kentucky	11	6
Louisiana	198	183
N. Land	60	58
S. Inland waters	24	21
S. Land	37	34
Offshore	77	70
Maryland	0	0
Michigan	2	2
Mississippi	18	6
Montana	20	23
Nebraska	0	0
New Mexico	77	99
New York	8	4
North Dakota	30	29
Ohio	13	9
Oklahoma	187	169
Pennsylvania	15	16
South Dakota	1	0
Texas	813	688
Offshore	9	14
Inland waters	1	3
Dist. 1	25	17
Dist. 2	33	25
Dist. 3	51	60
Dist. 4	93	77
Dist. 5	159	123
Dist. 6	124	102
Dist. 7B	45	32
Dist. 7C	55	38
Dist. 8	105	72
Dist. 8A	25	31
Dist. 9	37	27
Dist. 10	51	67
Utah	44	28
West Virginia	29	26
Wyoming	77	93
Others—ID-1; NV-1; TN-4; VA-2	9	2
Total US	**1,757**	**1,532**
Total Canada	**553**	**690**
Grand total	**2,310**	**2,222**
Oil rigs	287	238
Gas rigs	1,465	1,292
Total offshore	89	89
Total cum. avg. YTD	**1,731**	**1,509**

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 (3-9-07)	Percent footage* (3-9-07)	Rig count (3-10-06)	Percent footage* (3-10-06)
0-2,500	70	5.7	62	3.2
2,501-5,000	110	61.8	107	42.0
5,001-7,500	216	20.3	213	14.5
7,501-10,000	418	3.5	330	2.7
10,001-12,500	415	4.0	358	2.2
12,501-15,000	273	0.7	275	—
15,001-17,500	119	1.6	121	0.8
17,501-20,000	75	—	69	—
20,001-over	34	—	18	—
Total	**1,730**	**8.7**	**1,553**	**6.1**
INLAND	42		39	
LAND	1,623		1,457	
OFFSHORE	65		57	

*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]3-9-07	[2]3-10-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	19	21
Alaska	792	793
California	693	685
Colorado	52	60
Florida	8	6
Illinois	31	28
Kansas	97	92
Louisiana	1,435	1,188
Michigan	15	15
Mississippi	53	46
Montana	93	97
New Mexico	164	157
North Dakota	107	104
Oklahoma	173	172
Texas	1,350	1,288
Utah	45	46
Wyoming	142	142
All others	65	70
Total	**5,334**	**5,010**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	3-9-07
Alaska-North Slope 27°	44.93
South Louisiana Sweet	61.25
California-Kern River 13°	48.80
Lost Hills 30°	56.70
Wyoming Sweet	56.05
East Texas Sweet	58.19
West Texas Sour 34°	50.65
West Texas Intermediate	56.75
Oklahoma Sweet	56.75
Texas Upper Gulf Coast	53.50
Michigan Sour	49.75
Kansas Common	55.75
North Dakota Sweet	49.75

*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]	3-2-07
United Kingdom-Brent 38°	60.87
Russia-Urals 32°	57.29
Saudi Light 34°	56.70
Dubai Fateh 32°	58.02
Algeria Saharan 44°	62.43
Nigeria-Bonny Light 37°	63.47
Indonesia-Minas 34°	61.16
Venezuela-Tia Juana Light 31°	56.05
Mexico-Isthmus 33°	55.94
OPEC basket	59.11
Total OPEC[2]	57.98
Total non-OPEC[2]	57.64
Total world[2]	57.83
US imports[3]	55.18

[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]

	3-2-07	2-23-07	Change
	Bcf		
Producing region	586	592	–6
Consuming region east	820	898	–78
Consuming region west	225	243	–18
Total US	**1,631**	**1,733**	**–102**
	Dec. 06	**Dec. 05**	**Change, %**
Total US[2]	**3,070**	**2,635**	**16.5**

[1]Working gas. [2]At end of period.
Note: Current data not available.
Source: Energy Information Administration
Data available in OGJ Online Research Center

International rig count

Region	Feb. 2007 Land	Feb. 2007 Off.	Feb. 2007 Total	Feb. 06 Total
WESTERN HEMISPHERE				
Argentina	87	0	87	76
Bolivia	2	0	2	5
Brazil	18	23	41	32
Canada	633	2	635	715
Chile	1	0	1	0
Colombia	28	0	28	21
Ecuador	12	0	12	12
Mexico	58	37	95	79
Peru	7	1	8	2
Trinidad	3	5	8	2
United States	1,651	85	1,736	1,533
Venezuela	58	18	76	79
Other	2	0	2	1
Subtotal	**2,560**	**171**	**2,731**	**2,557**
ASIA-PACIFIC				
Australia	10	8	18	16
Brunei	0	2	2	3
China-offshore	0	18	18	16
India	53	32	85	81
Indonesia	31	17	48	54
Japan	1	0	1	2
Malaysia	0	16	16	16
Myanmar	8	3	11	10
New Zealand	4	1	5	6
Papua New Guinea	3	0	3	3
Philippines	1	0	1	2
Taiwan	0	0	0	0
Thailand	4	7	11	10
Vietnam	0	7	7	9
Other	2	3	5	2
Subtotal	**117**	**114**	**231**	**230**
AFRICA				
Algeria	24	0	24	21
Angola	3	2	5	4
Congo	2	2	4	0
Gabon	3	0	3	2
Kenya	0	0	0	0
Libya	12	1	13	9
Nigeria	2	4	6	9
South Africa	0	0	0	1
Tunisia	3	0	3	1
Other	3	3	6	2
Subtotal	**52**	**12**	**64**	**49**
MIDDLE EAST				
Abu Dhabi	8	4	12	14
Dubai	1	0	1	3
Egypt	29	10	39	32
Iran	0	0	0	0
Iraq	0	0	0	0
Jordan	1	0	1	1
Kuwait	13	0	13	13
Oman	44	0	44	32
Pakistan	17	0	17	13
Qatar	2	9	11	14
Saudi Arabia	68	6	74	52
Sudan	0	0	0	0
Syria	26	0	26	22
Yemen	13	0	13	14
Other	1	0	1	2
Subtotal	**223**	**29**	**252**	**212**
EUROPE				
Croatia	1	0	1	3
Denmark	0	2	2	3
France	0	0	0	1
Germany	4	0	4	4
Hungary	3	0	3	4
Italy	4	0	4	3
Netherlands	2	4	6	5
Norway	0	17	17	19
Poland	2	0	2	2
Romania	2	0	2	2
Turkey	4	0	4	2
UK	1	24	25	30
Other	4	0	4	5
Subtotal	**27**	**47**	**74**	**85**
Total	**2,979**	**373**	**3,352**	**3,133**

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	282	2.37
Caribbean	Houston	Resid.	380	187	1.76
Caribbean	Houston	Resid.	500	197	1.85
N. Europe	New York	Dist.	200	312	4.17
N. Europe	Houston	Crude	400	204	4.01
W. Africa	Houston	Crude	910	121	2.62
Persian Gulf	Houston	Crude	1,900	52	2.08
W. Africa	N. Europe	Crude	910	111	1.79
Persian Gulf	N. Europe	Crude	1,900	56	1.64
Persian Gulf	Japan	Crude	1,750	62	1.49

*February 2007 average.
Source: Drewry Shipping Consultants Ltd. Data available in OGJ Online Research Center.

US LNG imports

Country	Dec. 2006 (MMcf)	Nov. 2006 (MMcf)	Dec. 2005 (MMcf)	Change from a year ago, %
Algeria	0	0	8,630	—
Brunei	0	0	0	—
Malaysia	0	0	0	—
Nigeria	3,082	5,732	0	—
Oman	0	0	0	—
Qatar	0	0	0	—
Trinidad and Tobago	36,718	24,583	31,394	17.0
Others	11,440	16,921	11,264	1.6
Total	**51.240**	**47,236**	**51,288**	**–0.1**

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

Baker Oil Tools workover rig count*

Region	Feb. 2007	Feb. 2006	Change, %
Gulf Coast	278	332	–16.3
Midcontinent	265	220	20.5
Northeastern	73	82	–11.0
Rocky Mountains	198	237	–16.5
Southeastern	198	215	–7.9
West Texas	332	310	7.1
Western	136	139	–2.2
Total US	**1,480**	**1,535**	**–3.6**
Canada	826	821	0.6
Total N. America	**2,306**	**2,356**	**–2.1**

*Wells over 1,500 ft deep and tubing out of the wellbore. Excludes rigs on rod jobs. Definitions, see OGJ Sept. 22, 1997, p. 46. Source: Baker Hughes Inc. Data available in Oil & Gas Journal Energy Database.

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. 2007						
Product revenues	71.64	67.86	71.78	83.54	66.01	64.35
Feedstock costs	–57.75	–59.55	–54.52	–50.84	–55.69	–59.25
Gross margin	13.89	8.31	17.26	32.70	10.32	5.10
Fixed costs	–2.04	–2.36	–2.29	–2.67	–2.29	–1.78
Variable costs	–2.13	–1.41	–1.88	–3.21	–1.98	–0.77
Cash operating margin	**9.72**	**4.54**	**13.09**	**26.82**	**6.05**	**2.55**
Jan. 2007	7.57	1.80	8.33	18.97	5.18	2.79
YTD avg.	8.65	3.17	10.71	22.90	5.62	2.67
2006 avg.	12.49	6.01	15.00	23.72	5.88	1.06
2005 avg.	12.53	6.98	12.31	20.55	5.51	1.52
2004 avg.	6.16	3.70	6.64	11.76	5.08	1.83

Source: Muse, Stancil & Co. See OGJ, Jan. 15, 2001, p. 46.
Data available in OGJ Online Research Center.
NOTE: The refining models that comprise the basis for the Muse refining margins have been updated to reflect changing crude slates, product specifications, and market pricing. All current and historical margin series have been revised.

Propane prices

	Jan. 2007 (¢/gal)	Feb. 2007 (¢/gal)	Jan. 2006 (¢/gal)	Feb. 2006 (¢/gal)
Mont Belvieu	89.35	97.55	98.86	91.89
Conway	86.96	96.77	96.72	89.51
Northwest Europe	92.58	100.83	119.68	108.17

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

Muse, Stancil & Co. gasoline marketing margins

Jan. 2007	Chicago* (¢/gal)	Houston (¢/gal)	Los Angeles (¢/gal)	New York (¢/gal)
Retail price	224.44	213.60	255.28	241.61
Taxes	51.63	38.40	56.26	48.77
Wholesale price	154.80	158.62	184.92	163.98
Spot price	137.91	144.68	170.15	147.69
Retail margin	18.14	16.58	14.10	28.86
Wholesale margin	16.89	13.94	14.77	16.29
Gross marketing margin	**35.03**	**30.52**	**28.87**	**45.15**
Dec. 2006	23.82	16.40	13.60	22.36
YTD avg.	35.03	30.52	28.87	45.15
2006 avg.	19.74	20.34	18.03	27.90
2005 avg.	19.77	16.26	20.39	27.13
2004 avg.	22.40	17.49	23.61	30.38

*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.

Muse, Stancil & Co. ethylene margins

	Ethane (¢/lb ethylene)	Propane (¢/lb ethylene)	Naphtha (¢/lb ethylene)
Feb. 2007			
Product revenues	48.01	83.07	98.98
Feedstock costs	–24.32	–55.59	–87.77
Gross margin	23.69	27.48	11.21
Fixed costs	–5.38	–6.36	–7.19
Variable costs	–5.22	–6.16	–8.29
Cash operating margin	**13.09**	**14.96**	**–4.27**
Jan. 2007	16.65	17.29	2.47
YTD avg.	14.87	16.13	–0.90
2006 avg.	19.55	22.53	1.77
2005 avg.	14.43	20.68	1.28
2004 avg.	9.00	12.03	0.51

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. 2007	Gulf Coast ($/Mcf)	Mid-continent ($/Mcf)
Gross revenue		
Gas	7.79	6.43
Liquids	0.99	2.66
Gas purchase cost	8.67	8.63
Operating costs	0.07	0.15
Cash operating margin	**0.04**	**0.31**
Jan. 2007	0.18	0.53
YTD avg.	0.11	0.43
2006 avg.	0.26	0.97
2005 avg.	–0.06	0.25
2004 avg.	0.07	0.33
Breakeven producer payment, % of liquids	93%	87%

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

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From the Subscribers Only area of OIL&GAS JOURNAL online research center www.ogjonline.com

Political culture mangles energy and ruins lives

Who in the oil and gas industry has never marveled at the ability of high-voltage politics in Washington, DC, to mangle energy issues?

An energy-hungry country gulls itself with fantasies about price-gouging and energy independence when its political culture craves power more than truth.

The distorting potential of this culture has been on ugly display recently in a controversy unrelated to energy.

The Editor's Perspective

by Bob Tippee, Editor

Political reaction was shrill to the Mar. 6 conviction of I. Lewis Libby, former chief of staff of Vice-President Dick Cheney, for perjury and obstruction.

"It's about time someone in the Bush Administration has been held accountable for the campaign to manipulate intelligence and discredit war critics," said Senate Majority Leader Harry Reid (D-Nev.) after the verdict.

House Speaker Nancy Pelosi (D-Calif.) declared, "The testimony unmistakably revealed—at the highest levels of the Bush Administration—a callous disregard in handling sensitive national security information and a disposition to smear critics of the war in Iraq."

Politics is politics. But these statements are delusional.

Reid and Pelosi want to make the conviction serve prejudgment that Libby retaliated against Bush administration critic Joseph Wilson by telling reporters that Wilson's wife worked at the Central Intelligence Agency. In this view, Libby's trial confirms suspicion—important to Democratic ambitions about the White House—that the administration tricked the US into an unpopular war with lies.

Facts from the trial refute the retaliation scenario. Partly because the supposedly retaliatory disclosure came from the State Department, Libby wasn't even charged with divulging CIA secrets, if there were any. He faced five counts of lying to leak investigators and was convicted on four.

He might simply have remembered trivial events of a busy past differently from journalists whom jurors found more persuasive—and faces prison because of it.

But a ruined life matters no more than relevancy does when Washington has a conviction that half-truths and lies can spin into political advantage.

When a culture in which this can happen takes up a subject like gasoline prices, it has no use for real market analysis, which lacks political potency. But price-gouging? Now there's something.

(Online Mar. 9, 2007; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Energy prices seesaw in early March

Energy prices dipped in profit taking Mar. 2, ending a stretch of consecutive gains over the seven previous trading sessions that pushed the April contract for benchmark US light, sweet crudes to a closing of $62/bbl Mar. 1 on the New York Mercantile Exchange.

Such a long stretch of consecutive gains previously had not occurred "since last year early in the summer," said Olivier Jakob, managing director of Petromatrix GMBH, Zug, Switzerland. Although market fundamentals remained strong with rising demand for gasoline and continued geopolitical concerns about Iran's nuclear program, a slide in Asian and European equity markets triggered a steeper drop in crude prices Mar. 5 to a near 2-week low of $60.07/bbl. Coming on the heels of the Mar. 1 fall in equity prices on the Shanghai Composite Exchange, the later market losses increased fears of a global economic weakness that could adversely affect oil demand.

However, energy prices rebounded Mar. 6, regaining some of the losses over the two prior sessions, as global stock markets partially recovered from their weeklong declines. The April crude contract climbed to $62.10/bbl in intraday trading Mar. 7 before closing at $61.82/bbl, up $1.13 for the day, following reports of unexpected large drops in US crude and gasoline inventories.

Energy inventories

Gasoline inventories fell by 3.75 million bbl to 216.4 million bbl in the week ended Mar. 2, vs. industry expectations of a 1.5 million bbl draw. Crude stocks dropped 4.85 million bbl to 324.2 million bbl vs. an anticipated build of 1.8 million bbl. The Energy Information Administration said commercial US distillate fuel inventories declined by 1.3 million bbl to 123.2 million bbl, with a drop in heating oil more than compensating an increase in diesel. Propane and propylene inventories dropped by 3.2 million bbl to 28.7 million bbl (OGJ Online, Mar. 7, 2007).

Imports of crude into the US fell by 650,000 b/d to less than 8.9 million b/d during that period, due in part to fog delays along the Houston Ship Channel. Yet the input of crude into US refineries increased by 141,000 b/d to nearly 14.8 million b/d, with units operating at 85.8% of capacity. Gasoline production declined slightly to 8.6 million b/d, while distillate production increased above 4 million b/d.

"Total inventories, adjusted for demand, are below the 3-year average. In total, refined product inventories declined by 5.4 million bbl last week and are now at 25.2 days of forward demand cover, below the 3-year average of 25.9 days," said Jacques Rousseau, senior energy analyst at Friedman, Billings, Ramsey Group Inc., Arlington, Va.

The fall of crude inventories was counter-seasonal and primarily the result of a 540,000 b/d decline in imports along the Gulf Coast, due to weather-related delays in lightering operations in the Houston Ship Channel. "But there is also a genuine compression of imports in progress. On a 4-week average, US crude oil imports are now down to what is a 2-year low outside of hurricane–affected weeks [in 2005]," said Paul Horsnell at Barclays Capital Inc., London. "Much of the latest draw in crude might work its way back into the data, [although] inventories have never recovered even close to their levels before the Houston Ship Channel delays of December," he said.

"The larger-than-expected draw in gasoline inventories, with motor gasoline demand above 5-year highs, stoked investor concerns surrounding supplies as we approach the summer driving season," said analysts in the Houston office of Raymond James & Associates.

"The latest US weekly data have now shown product inventories falling by 5 million bbl or more relative to their 5-year average for 3 straight weeks. Initial figures for the whole of February show demand growing at the fastest rate for more than 10 years," Horsnell said. "The overall level of inventories has over the past 4 weeks now drawn by 28.2 million bbl faster than the normal seasonal pattern, (i.e., at a rate of 1 million b/d). This has taken the total of US commercial inventories down to its lowest level since May 2005."

EIA subsequently reported the withdrawal of 102 bcf of natural gas from US underground storage in the week ended Mar. 2. That was within the consensus of Wall Street analysts and compared with withdrawals of 132 bcf the previous week and 85 bcf during the same period a year ago. It reduced US gas storage to 1.6 tcf, down by 268 bcf from year-ago levels but 194 bcf above the 5-year average. However, Raymond James analysts expect gas storage to end the winter season at 1.3-1.4 tcf despite moderate temperatures.

(Online Mar. 12, 2007; author's e-mail: samf@ogjonline.com)

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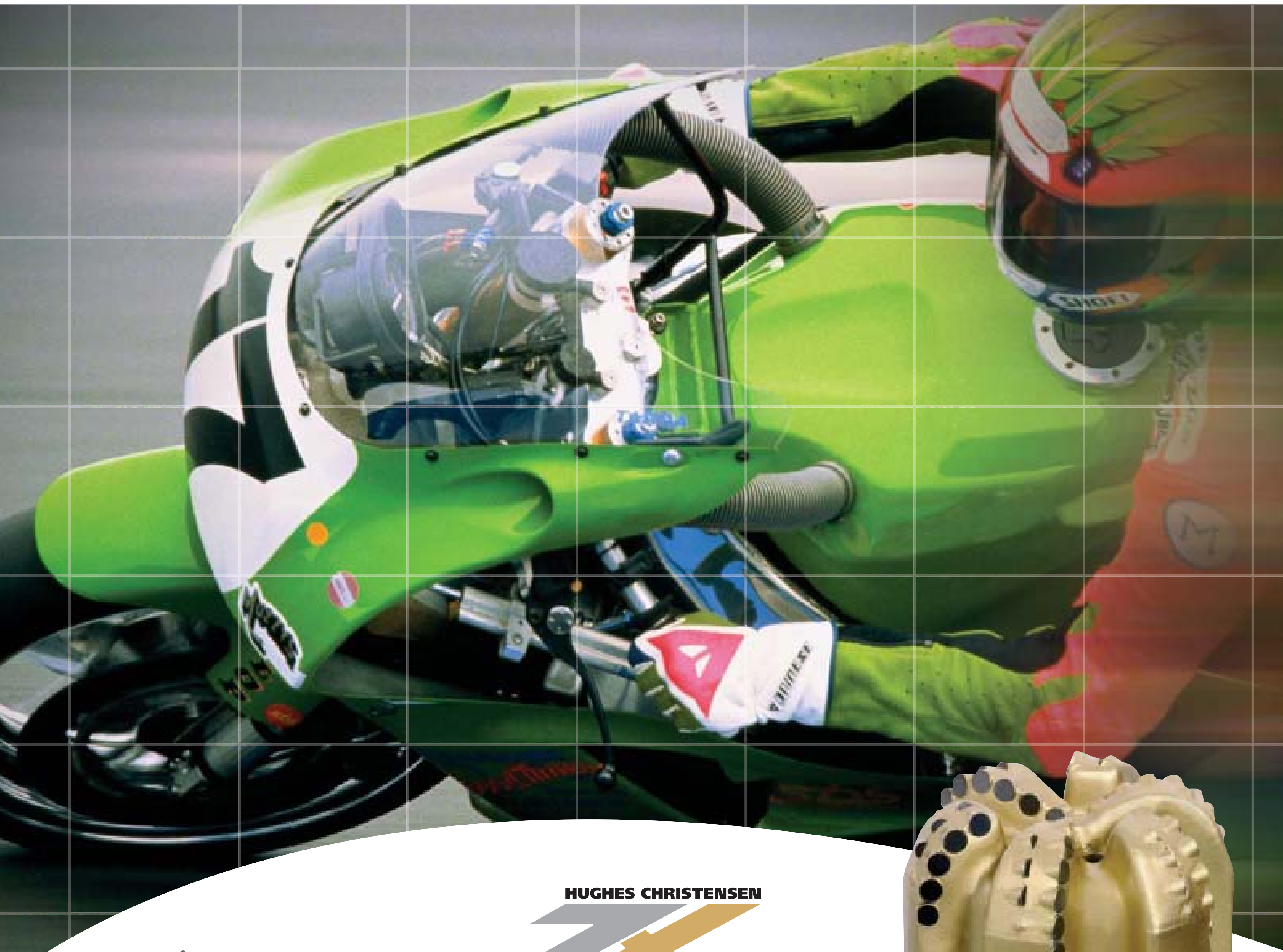

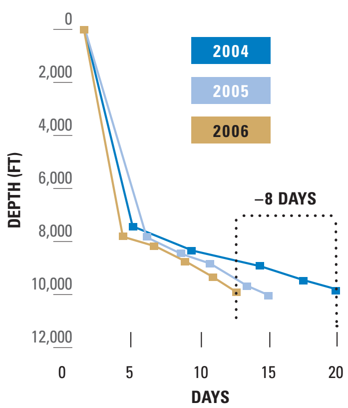

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