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The Oil Industry and Alternative Energy

Method helps find hydrocarbons, optimize seismic planning
Operators plan more drilling after third Libyan bid round
US olefins producers struggle despite lack of major storms
China applies WEPP lessons as natural gas demand grows

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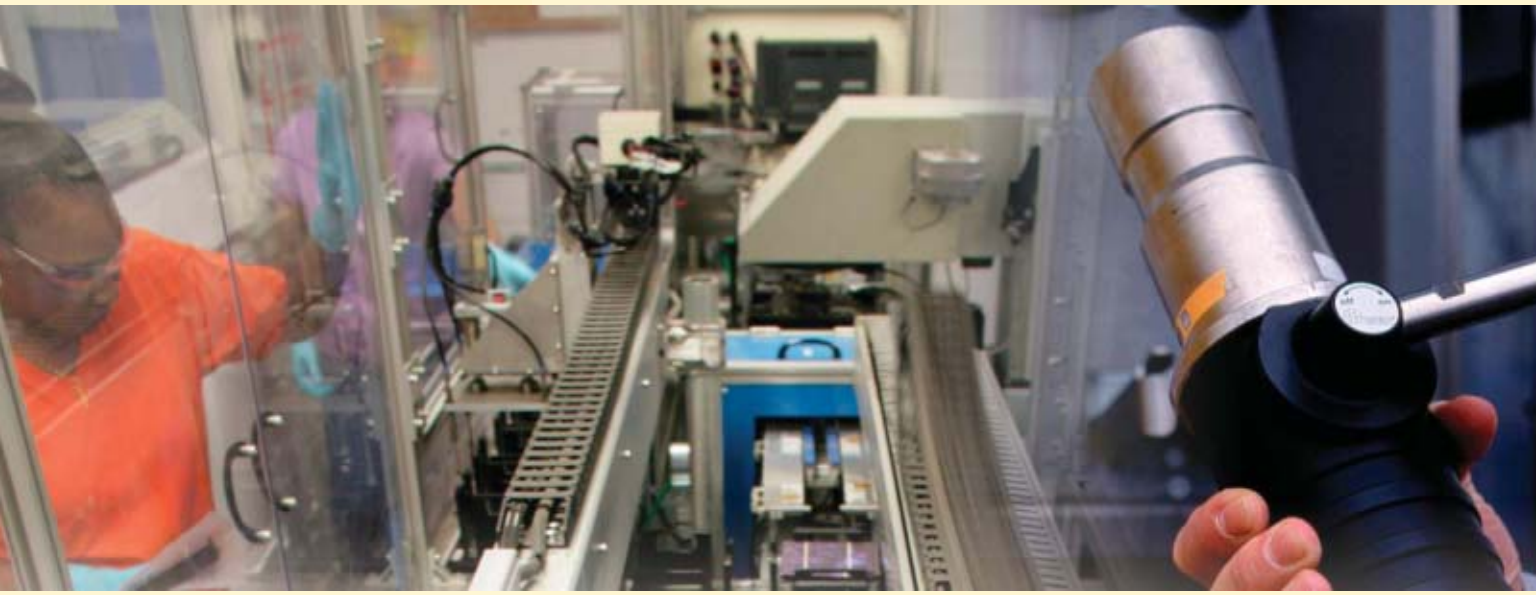
Feb. 5, 2007
Volume 105.5

THE OIL INDUSTRY AND ALTERNATIVE ENERGY



REGULAR FEATURES

COVER

Integrated oil and gas companies are investing in alternative and renewable energy sources through their subsidiaries. Shown here are two workers standing alongside solar panels in Solarmine, a 6-acre photovoltaic facility that provides electricity for daytime operations in Chevron Corp.'s section of Midway-Sunset oil field, 40 miles from Bakersfield, Calif. The fuel cell buses shown in the background are part of a Luxembourg demonstration in which Shell Hydrogen BV participates. Solarmine photo from Chevron Energy Services. Bus photo from Shell Hydrogen.

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Transportation

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PennWell, Houston office
1700 West Loop South, Suite 1000, Houston, TX 77027
Telephone 713.621.9720/Fax 713.963.6285/Web site www.ogjonline.com
Editor Bob Tippee, bobt@ogjonline.com
Chief Editor-Exploration G. Alan Petzet, alanp@ogjonline.com
Chief Technology Editor-LNG/Gas Processing Warren R. True, warrent@ogjonline.com
Production Editor Guntis Moritis, guntism@ogjonline.com
Drilling Editor Nina M. Rach, ninar@ogjonline.com
Refining/Petrochemical Editor David N. Nakamura, davidn@ogjonline.com
Pipeline Editor Christopher E. Smith, chriss@ogjonline.com
Senior Editor-Economics Marilyn Radler, marilynr@ogjonline.com
Senior Editor Steven Poruban, stevenp@ogjonline.com
Senior Associate Editor Judy R. Clark, judyrc@ogjonline.com
Senior Writer Sam Fletcher, samf@ogjonline.com
Senior Staff Writer Paula Dittrick, paulad@ogjonline.com
Survey Editor Leena Koottungal, lkoottungal@ogjonline.com
Associate Editor Angel White, angelw@pennwell.com
Editorial Assistant Linda Barzar, lbarzar@pennwell.com

Petroleum Group President Michael Silber, msilber@pennwell.com
Vice-President/Group Publisher Bill Wageneck, billw@pennwell.com
Vice-President/Custom Publishing Roy Markum, roym@pennwell.com

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

London
Tel +44 (0)208.880.0800
International Editor Uchenna Izundu, uchennai@pennwell.com

Washington
Tel 703.963.7707
Washington Correspondent Nick Snow, nsnow@cox.net

Los Angeles
Tel 310.595.5657
Senior Correspondent Eric Watkins, hippalus@yahoo.com

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

PennWell Corporate Headquarters
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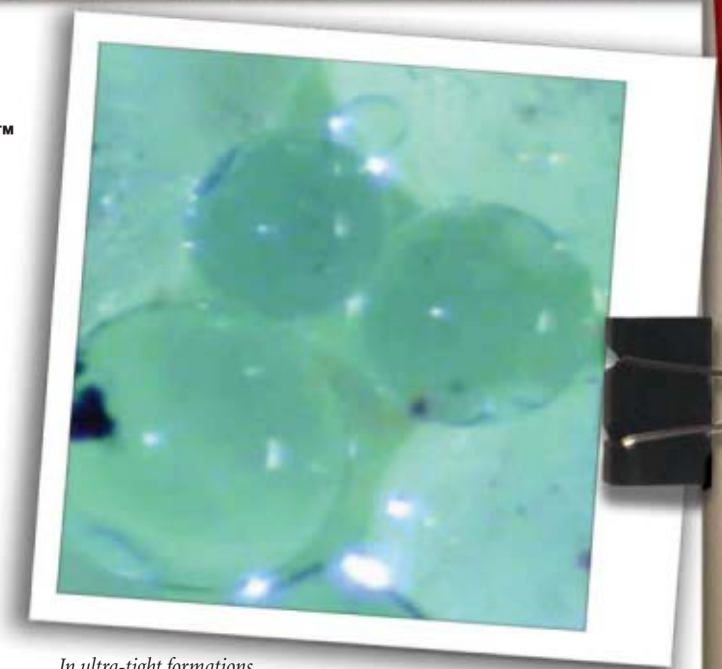
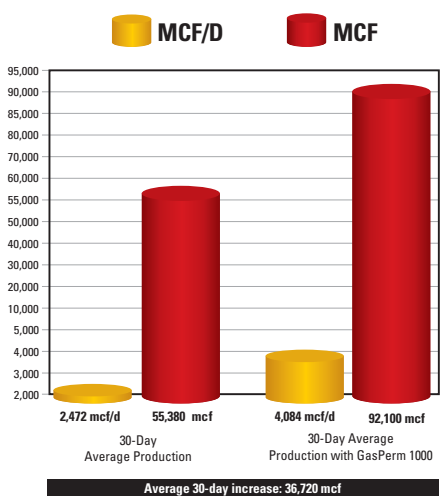
New AquaStim℠ Water Frac Service with GasPerm 1000™ Technology Helps Major Independent Operator Boost Gas Production.



In ultra-tight formations, water imbibition and phase trapping can greatly reduce gas production. GasPerm 1000 surfactant helps reduce this damage.

The Challenge:

Texas Panhandle—Recently, Halliburton introduced its specially formulated **SandWedge®** enhancer and **OptiKleen-WF™** agent to the Operator's normal four-stage water frac completions in the Granite Wash play in the Texas Panhandle. The results were a major uplift in efficiency and total well productivity,with less sand production, improved fluid recovery and fewer post-stimulation completion issues. To build on this success, the company asked Halliburton for new ideas to further enhance the economics of the company's prospects in the area.



The Solution:

After a review of existing conditions, Halliburton recommended the new AquaStim water frac service which includes the breakthrough GasPerm 1000 technology. GasPerm 1000 service helps control fracture face damage and boost production from unconventional gas wells, including tight gas, shale and coalbed methane.

The Results:

The average initial production of gas had been 2,472 mcf/d, with the total for the first 30 days averaging 55,380 mcf. The introduction of AquaStim service with GasPerm 1000 technology resulted in initial production of 4,084 mcf/d and a 30 day average total of 92,100 mcf. The average 30-day increase was 36,720 mcf, creating an economic value of approximately $782,000. Based on these results, Halliburton's AquaStim service has been integrated into the Operator's completion process for use on other unconventional gas wells.

Halliburton has the energy to help. For more information about how AquaStim water frac service can help make unconventional gas assets more profitable, e-mail stimulation@halliburton.com.

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HALLIBURTON

Production Optimization

Performance Profile 98

OGJ Newsletter

Feb. 5, 2007

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General Interest — Quick Takes

UK N. Sea operators eye international markets

A growing number of UK North Sea operators are focusing on building their businesses in international markets, which could threaten future investment in the UK North Sea, according to a survey published Jan. 30 by the Aberdeen and Grampian Chamber of Commerce.

The survey found that 65% of operators are looking to invest their money elsewhere, in North and West Africa, Russia, and Australia, for example. High UK petroleum taxation, soaring technical and resource costs to develop mature areas in the UK North Sea, and a lack of long-term legislative policies are the main reasons operators give for expanding into international markets.

The UK Offshore Operators Association estimates that the oil services and goods export market in the UK is worth £6 billion. Chamber Chief Executive Geoff Runcie welcomed the opportunity for Aberdeen-based companies to grow their businesses internationally but stressed, "We need continued investment at home in exploration levels and both our offshore and onshore infrastructure to ensure the longevity of our indigenous oil and gas industry."

About 87% of North Sea operators and contractors are working at or above optimum levels, indicating strong investment in the mature UK North Sea, the survey said. In 2005 the UK sourced 3 million boe/d from the North Sea for its energy needs. The UK produces over 90% of its own gas and nearly 100% of its oil from the UK Continental Shelf.

Companies in the supply chain are moving towards having longer and collaborative contracts and have reduced their focus in 2004-06 on cost reduction, risk sharing, and penalty clauses in their contracts. The survey said operators and contractors continue to be concerned about safety and environmental issues.

According to the survey, 44% of contractors said UKCS exploration-related activity levels rose over the last 4 months, and 39% expect this trend to continue over the next year. However, last year oil prices hit a high of $75/bbl and have now fallen to $50/bbl.

The survey looked at North Sea activities from September 2006 to January of this year.

Ortiz, head of Bolivia's YPFB, resigns

Juan Carlos Ortiz, head of Bolivia's state-owned Yacimientos Petroliferos Fiscales Bolivianos (YPFB), has resigned over disagreements with the government.

Ortiz said he had resigned because of differences with the government of President Evo Morales over its oil and gas nationalization policies.

Ortiz is the second head of the company to resign since Morales nationalized Bolivia's gas industry on May 1, 2006 (OGJ Online, May 2, 2006).

The country has the second-largest natural gas reserves in South America after Venezuela.

Ortiz previously worked for foreign energy companies, including Brazil's state-owned Petroleo Brasileiro SA (Petrobras), the biggest investor in Bolivia's gas and oil industry, analysts said.

It is thought that Ortiz was given the task of smoothing relations with the country's largest gas customer, Brazil, which imports 26 million cu m/day of gas from Bolivia via the 3,150-km Bolivia-Brazil gas pipeline. Morales wants to increase the cost of gas to $5/MMbtu from $4.

Petrobras officials, speaking under the condition of anonymity, told OGJ that Ortiz was trying to convince Morales to limit the price increase of gas exported to Brazil to $4.50/MMbtu.

Last year Bolivia negotiated a price hike to $5/MMbtu for the 5 million cu m/day of gas it exports to Argentina. Meanwhile, it sells gas for $1.09 to a thermoelectric plant in Cuiaba, western Brazil, delivered via a 267-km pipeline in which Royal Dutch Shell PLC holds a 38% stake.

Morales omitted, however, that gas volumes supplied to the Cuiaba plant usually average little more than 1 million cu m/day.

Morales recently said that Bolivia "can no longer continue subsidizing natural gas to Brazil." He began nationalizing Bolivia's energy industry in May 2006 after winning an election campaign pledging to increase state control of natural resources.

Ortiz's resignation comes after Morales suspended key parts of the role of YPFB in the state takeover of Bolivia's oil and gas resources in a move analysts said highlighted the company's lack of money and technical expertise.

The implementation of the energy nationalization has been delayed, while a cash-strapped YPFB struggles to assume control of the sector.

As part of the nationalization, Bolivia also hiked taxes to as much as 82% from 18% on some multinational companies and ordered YPFB to hold a majority stake in several foreign-owned refineries. The additional revenue is expected to breathe fresh financial life into YPFB.

Georgia chooses Azerbaijan as main gas supplier

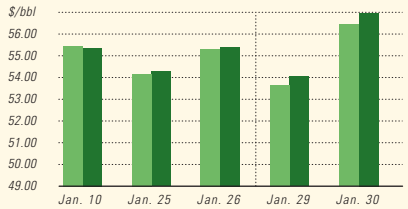
Georgian President Mikheil Saakashvili has announced that neighboring Azerbaijan will be his country's main supplier of natural gas, but that he would still like to keep Russia as a supplier to ensure diversity.

About one third of Georgia's gas is already on its way from Azerbaijan, and by February-March, about 80% will be coming from that country, Saakashvili told Russia's Ekho Moskvy radio station.

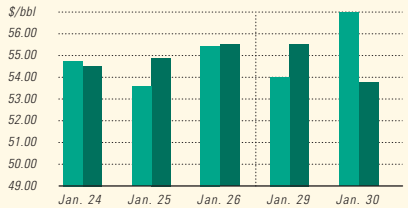
He said, "It is not good to have just one channel, even if it is a very friendly one, as there may be many technical and other"

Industry Scoreboard

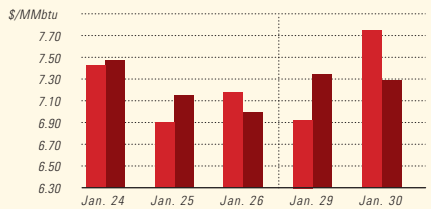
IPE BRENT / NYMEX LIGHT SWEET CRUDE



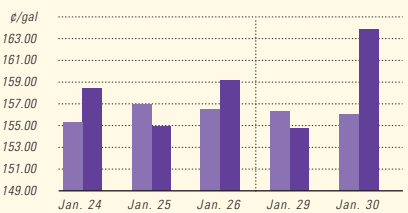
WTI CUSHING / BRENT SPOT



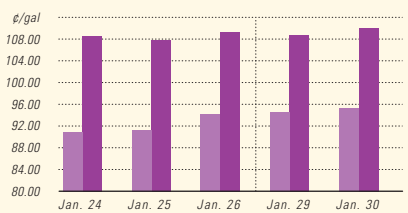
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



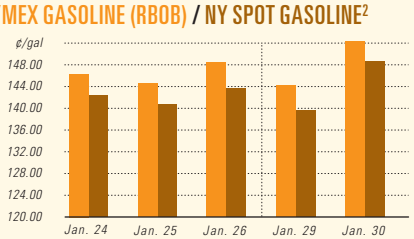
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



[1] Nonoxygenated regular unleaded.

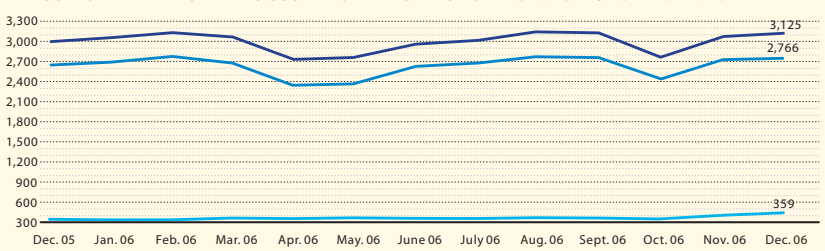
US INDUSTRY SCOREBOARD — 2/5

Latest week 1/26	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	8,983	8,767	2.5	8,983	8,727	2.9
Distillate	4,265	4,174	2.2	4,265	4,161	2.5
Jet fuel	1,608	1,545	4.1	1,608	1,529	5.2
Residual	599	872	–31.3	599	861	–30.4
Other products	4,837	4,850	–0.3	4,837	4,833	0.1
TOTAL DEMAND	20,293	20,209	0.4	20,293	20,110	0.9
Supply, 1,000 b/d						
Crude production	5,342	5,043	5.9	5,342	5,047	5.8
NGL production	2,430	1,668	45.6	2,430	1,684	44.2
Crude imports	9,715	9,733	–0.2	9,715	9,713	0.0
Product imports	3,281	3,841	–14.6	3,281	3.863	–15.1
Other supply[2]	1,033	1,232	–16.1	1,033	1,240	–16.7
TOTAL SUPPLY	21,800	21,516	1.3	21,800	21,548	1.2
Refining, 1,000 b/d						
Crude runs to stills	14,914	14,823	0.6	14,914	14,806	0.7
Input to crude stills	15,353	15,092	1.7	15,353	15,080	1.8
% utilization	88.6	87.1	—	88.6	87.0	—

Latest week 1/26	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	327,150	321,453	5,697	324,227	2,923	0.9
Motor gasoline	219,106	217,820	1,286	216,212	2,894	1.3
Distillate	142,372	143,385	–1,013	137,468	4,904	3.6
Jet fuel	40,818	40,756	62	43,548	–2,730	–6.3
Residual	45,839	46,530	–691	39,315	6,524	16.6
Stock cover (days)[3] **1/19**			**Change, %**		**Change, %**	
Crude	21.1	20.8	1.4	21.3	–0.9	
Motor gasoline	24.2	23.6	2.5	23.9	1.3	
Distillate	35.2	34.5	2.0	33.2	6.0	
Propane	33.0	37.9	–12.9	34.0	–2.9	
Futures prices[4] **1/26**			**Change**		**Change**	**Change, %**
Light sweet crude, $/bbl	55.02	51.48	3.54	67.01	–11.99	–17.9
Natural gas, $/MMbtu	7.28	6.52	0.76	8.47	–1.19	–14.0

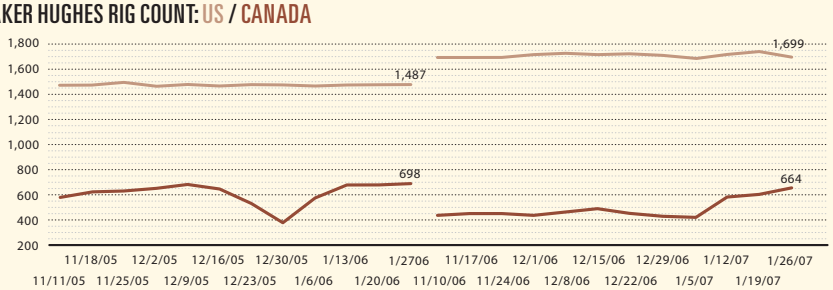
[1] Based on revised figures. [2] Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [3] Stocks divided by average daily product supplied for the prior 4 weeks. [4] Weekly average of daily closing futures prices.
Sources: Energy Information Administration,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

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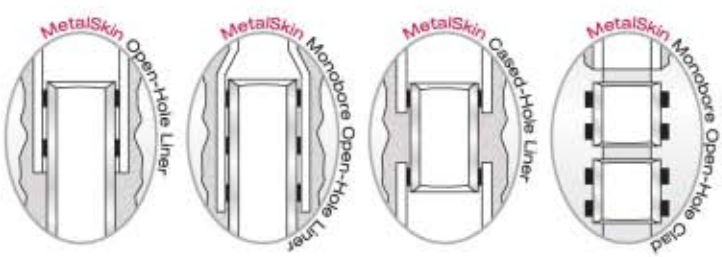

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problems. As a result, he said, "we would like to keep the Russian channel" but that it is "hard to predict, and prices there are completely crazy."

Azerbaijan's Azarigaz began exporting gas Jan. 11 along the Haciqabul-Qazax-Tbilisi trunkline to Georgia, which is seeking to reduce its dependence on increasingly expensive Russian supplies (OGJ Online, Jan. 11, 2007).

EPA issues state underground tank guidelines

Underground storage tank manufacturers and installers must have financial resources to clean up a site if a leak or spill occurs due to improper manufacturing or installation, the US Environmental Protection Agency said as it issued two final grant guidelines for states on Jan. 24.

The guidelines, which implement key underground storage tank provisions in the 2005 Energy Policy Act (EPACT), also require a state's public record to include the number, sources, and causes of releases; tank compliance records; and data on equipment failures, EPA said.

The first set of guidelines describes the minimum financial responsibility and installer certification provision requirements for states to comply with EPACT. These include definitions, requirements, criteria, and options for states in implementing the provision.

By Feb. 8, states receiving federal funds under Subtitle I of the Waste Disposal Act must implement either these guidelines or the second containment grant guidelines that EPA issued in November 2006, the federal agency said.

EPA will assist states as they implement programs in appropriate cases if the states demonstrate good faith and progress toward meeting the requirements.

The public record guidelines describe minimum requirements for states meeting the public record provision under EPACT. They include developing and updating the public record, making it available, describing the minimum public record content, ensuring data quality, and demonstrating and ensuring compliance with guidelines, EPA said. ✦

Exploration & Development — *Quick Takes*

Chevron unit finds oil on Block 14 off Angola

Chevron Corp. subsidiary Cabinda Gulf Oil Co. Ltd. (Cabgoc) and its partners reported an oil discovery on deepwater Block 14 off Angola. The well, Lucapa-1, found more than 280 net ft of oil in Miocene-age sands.

Lucapa-1 was drilled in October 2006 in 3,940 ft of water to a 10,958 ft TVD. The well, which was tested in November 2006, flowed 24° gravity oil from high-permeability sand in the main target interval.

The discovery is the 10th exploration well drilled on Block 14 since 1997.

Also under development on Block 14 is the $2.3 billion Benguela Belize-Lobito Tomboco (BBLT) project, which started up in January 2006. Once fully developed, BBLT will produce an estimated 200,000 b/d of oil in 2008.

Also, in June 2006, Chevron began production from the Landana North reservoir in the Tombua-Landana development area of Block 14 by producing through the BBLT facility. When developed, Tombua-Landana is expected to achieve peak production of 100,000 b/d of oil by 2010 through its own facility.

Cabgoc, with 31% interest, serves as operator of the Block 14 contractor group, which includes Total E&P Angola 20%, Sonangol 20%, Eni Angola Exploration BV 20%, and GALP 9%.

BP makes 12th oil find on Angola's Block 31

BP PLC and its partners made a 12th oil discovery, Terra, on Angola deepwater Block 31. BP, the operator, drilled the well using GlobalSantaFe's Jack Ryan ultradeepwater drillship to 6,118 m TVD. The well flowed more than 5,000 b/d of oil on test.

This is the third discovery on Block 31 where the exploration well was drilled through salt to access the oil-bearing reservoir beneath.

Block 31 covers 5,349 sq km and is 411 km northwest of Luanda in 1,500-2,500 m of water. The Terra discovery is 30 km northwest of the recently announced Titania discovery (OGJ, Nov. 6, 2006, Newsletter).

BP Exploration (Angola) Ltd. holds 26.67% and its partners are Esso E&P Angola (Block 31) Ltd. 25%, Sonangol EP 20%, Statoil Angola AS 13.33%, Marathon International Petroleum Angola Block 31 Ltd. 10%, and Tepa (Block 31) Ltd., a subsidiary of Total SA, 5%.

BP discovers gas with Egypt's Giza North-1 well

BP has found an estimated 1 tcf of natural gas with its Giza North-1 exploratory well in the North Alexandria concession off Egypt in the Mediterranean Sea. The well encountered a significant gas accumulation as part of a large channel complex, BP said.

The partners, BP, RWE Dae AG, and EGPC/EGAS, will drill an appraisal well to evaluate the large complex in April.

Sameh Fahmi, the Egyptian petroleum minister, said that the well penetrated an 80 m gas-bearing layer that was a Pliocene formation. BP has made three previous discoveries in that formation: Taurus, Libra, and Fayoum. The company also drilled the Raven discovery well in the deeper pre-Pliocene formation.

The group will move the rig to the next appraisal well site in the Taurus field as part of a planned four-well appraisal program in the North Alexandria concession.

Giza North-1, 56 km north of Alexandria City, was drilled to 2,040 m in 668 m of water.

BP is operator of the North Alexandria concession, holding a 60% shareholder interest. RWE Dea holds the remaining interest. EGPC/EGAS has an entitlement under the concession's production-sharing arrangements.

Bongkot partners make gas finds off Thailand

Total SA reported three gas discoveries at exploration wells Ton Chan-1X, Ton Chan-2X, and Ton Rang-2X drilled on Blocks 15 and 16 in the Gulf of Thailand.

The two Ton Chan area wells are on Block 16 in the Bongkot concession, 5 km from each other and 15 km southeast of the Bongkot Central Complex (BCC).

Ton Chan-1X found gas-bearing reservoirs with a total of 143 m net pay thickness, while Ton Chan-2X found gas with a total of 44 m net pay thickness.

Ton Rang-2X is on Block 15 of the Bongkot concession, 5 km south of the Ton Rang-1X discovery and 20 km northwest of the BCC. Ton Rang-2X found gas-bearing sand of 72 m.

Total said a development plan for the three discoveries is under study and that production could start in 2009. Bongkot produces 600 MMcfd of gas and 18,000 b/d of condensate. Member companies of the Bongkot joint venture are Total 33.33%, Thailand's PTT E&P (operator) 44.45%, and BG Group 22.22%.

Ecopetrol sets $2 billion E&P budget for 2007

Colombia's state-owned Ecopetrol plans to invest $2 billion this year to explore for and produce oil and gas. Ecopetrol spent $1.3 billion in 2006, the company reported.

Colombia will produce 520,000 b/d of oil in 2007. Ecopetrol and other companies must invest to sustain that level of production in the future, said Ecopetrol Finance Minister Alberto Carrasquilla.

The investment is needed to recover the country's proved reserves that topped 3 billion bbl in years' past, dropped to 1.5 billion bbl in 2004, remained at that level in 2005, and increased a bit in 2006, Carrasquilla said.

Ecopetrol target is to invest $12.5 billion over the next 5 years to sustain the country's output levels. Oil is currently Colombia's leading export and source of foreign income, constituting one third of the country's foreign revenues.

All oil production is undertaken by Ecopetrol in contracts of association with foreign companies.

Most of the Colombian oil industry runs through joint ventures between Ecopetrol and international companies, some of which have heavily financed the construction of pipelines. Investment from these multinational corporations has led to the creation of the oil infrastructure that exists in Colombia today. BP PLC and Occidental Petroleum Corp. are among the largest international companies in the Colombian oil sector.

Colombia has become a hot spot for oil and gas exploration in Latin America as energy multinationals face increasing hostile business conditions elsewhere in the region, industry experts say. Key attractions include a steep, sustained fall in guerrilla attacks under President Alvaro Uribe—now in his second 4-year term—and a reduction of taxes.

The government has drawn up incentives to attract oil companies, including cutting Ecopetrol's mandatory stake to 50-55% in any exploration contract with a private-sector company. This compares with the 70% required over the past 30 years. ✦

Drilling & Production — *Quick Takes*

Shell inks deal with NIOC, Repsol YPF for LNG

Royal Dutch Shell PLC has signed an upstream services agreement with National Iranian Oil Co. (NIOC), the Iranian state-owned oil company, and Repsol YPF SA to further investigate the feasibility of the upstream element of their proposed Persian LNG project.

A Shell spokesman told OGJ that Shell would look at constructing gas production facilities, hand them over to NIOC, and recoup its expenditure once gas production has started under a buyback contract.

The consortium hopes to build an 8.1 million-tonne/year liquefaction plant that could be expanded with a second train to target markets in India, the Far East, and Europe.

Shell emphasized that this was not a final investment decision to go ahead with Persian LNG and that Shell is about a year or so away from taking that step. Persian LNG covers Phases 13 and 14 of South Pars gas field.

The services agreement will help to inform the final investment on Persian LNG. According to Iranian reports, the deal is worth $10 billion for both upstream work and the LNG infrastructure.

Shell's move defies pressure from Washington, DC, on non-US companies to stop investment in Iran because of its uranium enriching activities, which Washington fears is the basis for nuclear weapon development.

Iran only offers buyback contracts to attract energy investment in the country, but many western companies have found the terms limiting and have not invested.

Eni: Kashagan field more 'generous' than thought

Kashagan oil field in Kazakhstan is more "generous" than expected, said Eni SPA's Chief Executive Paolo Scaroni Jan. 25, indicating that Kashagan may have higher production rates than originally anticipated.

The Eni-led project in the North Caspian Sea has been delayed by environmental problems and technical challenges. Production, planned to start in 2005, has been postponed to 2009.

Kazakh state-owned energy company KazMunaiGaz is investigating the project to determine why higher costs and delays have occurred. Scaroni said audits are normal, and Eni is not worried by the checks. Within coming weeks, it will publish a schedule and cost structure for starting commercial oil extraction at Kashagan, he added.

Eni in 2004 estimated field development at $29 billion over 15 years. Last March, Eni increased costs for Kashagan by $4-5 billion because of a weakened dollar and higher equipment costs.

The Caspian Sea is shallow and freezes from November-February, posing access problems for the consortium. Meeting stringent environmental standards is proving costly and time-consuming, and the field's high pressures and levels of hydrogen sulfide are complicating field development.

Kashagan has recoverable reserves of 13 billion bbl. It will be developed in multiple phases: Under Phase I, production will reach 75,000 b/d and gradually increase to 450,000 b/d. Production will increase during the following stages at an expected plateau of 1.2 million b/d. ✦

Processing — Quick Takes

Irving starts filings for second St. John refinery

Irving Oil Ltd., St. John, NB, started the permitting process with provincial and federal authorities to build a second refinery at St. John.

A filing was made to initiate the necessary environmental impact assessments, Irving said Jan. 25.

The proposed $5-7 billion facility, to be built near the Irving Canaport deepwater crude receiving terminal, would have a designed capacity of as much as 300,000 b/d.

It would be the first major refinery built in North America in nearly a quarter century (OGJ, Oct. 23, 2006, Newsletter).

A review by authorities under the New Brunswick Environmental Impact Assessment Regulation and the Canadian Environmental Assessment Act could take as long as 24 months.

Irving continues to invest in its existing, 250,000 b/d refinery at St. John. That refinery, Canada's largest, supplies more than 75% of Canada's gasoline exports to the US and 19% of all US gasoline imports.

Oryx plant produces GTL products for first time

The Oryx GTL plant in Qatar has produced its first gas-to-liquids products under its start-up plan, and its products will be ready for international markets by the end of March.

Sasol Ltd., a major partner in the $950 million project, said in January that the plant was producing waxy synthetic crude, the intermediate result of the Fischer-Tropsch (F-T) process in creating GTL products, and it would move on to testing the product workup unit. This is the world's first GTL plant on a commercial scale using the proprietary, low-temperature Sasol slurry phase distillate process based on F-T technology (OGJ, Mar. 14, 2005, p. 18).

The plant will convert 330 MMcfd of lean gas from Qatar's vast North gas field into 34,000 b/d of ultralow-sulfur diesel: 24,000 b/d of diesel, 9,000 b/d of naphtha, and 1,000 b/d of liquid petroleum gas. Diesels will be sent to Europe and naphtha to the Far East. LPG will be used for local consumption.

The plant was officially inaugurated in June last year and has undergone a sequential plan to test the processes. The partners have proposed expanding capacity at Oryx to 100,000 b/d in the future.

Oryx GTL is a joint venture of state-owned Qatar Petroleum Co. 51%, and Sasol 49%.

Contract let for Songo Songo plant expansion

Globeleq, an operating power company and operator of the Songas gas-to-electricity project, has let an engineering and project management consultancy contract to Foster Wheeler South Africa (Pty.) Ltd. for the expansion of the Songo Songo Island gas processing facility in Tanzania. The value of the contract was not disclosed.

The Songo Songo Island gas processing facility is part of the Songas integrated gas-to-electricity facility. With the planned expansion of the gas processing plant, capacity will double to 140 MMscfd.

The processing plant processes gas from Songo Songo Island gas fields. The gas is then transported via a 225-km subsea and onshore pipeline to the Ubungo electric power station in Dar es Salaam and to other industrial users (OGJ Online, July 26, 2004, Newsletter). ✦

Transportation — Quick Takes

Gassco plans Nordic gas pipeline

Norwegian gas pipeline operator Gassco AS has submitted a plan to the Norwegian energy ministry to develop a 3 billion cu m/year gas pipeline from Kårstø in western Norway to eastern Norway, western Sweden, and Denmark.

Plans call for 463 km of 24-in. pipeline to be laid from Kårstø to the Grenland industrial region in eastern Norway and a 270-km, 18-in. section to be laid from Grenland to Sweden. From Sweden to Denmark an existing pipeline operated by Nova Naturgas will be used.

After carrying out a feasibility study for the past 2 years, Gassco has received interests from seven companies to own 70% of the proposed pipeline, while another nine have committed to pay for the right to use it.

A Gassco spokesman told OGJ that 14 companies—from Norwegian, Swedish, and Danish industry and energy sectors—will spend $23.6 million on the preengineering phase that will continue until 2009.

For the project to continue, Gassco needs to secure binding purchase contracts before June 30. "The investing companies can renounce their transport undertakings if such contracts are not in place by then," Gassco said.

Norwegian Minister of Petroleum and Energy Odd Roger Enoksen said the government will discuss how it can contribute to the project. "I will shortly have meetings with my Scandinavian colleagues to discuss the gas pipeline project," he said.

Gassco plans to make a final development decision in 2009 and start operations in 2012.

Lukoil lets pipelay contract for Yuri Korchagin field

OAO Lukoil unit Lukoil-Nizhnevolzhskneft LLC has let a subsea pipeline installation contract to a unit of J. Ray McDermott SA for the Yuri Korchagin oil field pipeline project, 180 km off Russia in the Caspian Sea.

Under the contract J. Ray will install 58 km of 12-in. pipe connecting the ice-resistant fixed platform No. 1 (LSP-1) to a single-point mooring buoy south of Yuri Korchagin field.

J. Ray also will provide design engineering, procurement, installation, and testing of the line. ✦

OIL&GAS JOURNAL

Everybody's Talking About What Bob Said!

And, It's Not Too Late To Hear What Bob Said.

On January 25, 2007, Bob Tippee, Editor of Oil & Gas Journal, presented OGJ's Annual Forecast and Review. His webcast presentation included projections of oil and gas demand – worldwide and US – for the coming year; a comparison of the forecast estimates with actual numbers from last year; as well as a discussion of anticipated 2007 drilling activity for the US and Canada.

Log on to our website and you can review the entire presentation at your leisure.

Find out "what Bob said" at:
www.ogjonline.com (webcast section).

Watch for more exciting and informative PennWell Webcasts scheduled for the months ahead, including:

OGJ - Natural Gas Storage and US LNG Import Trade

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Letters

Controller collaboration

In the article published in the Aug. 21, 2006, issue of Oil & Gas Journal, p. 38, entitled "Smarter clocks automate multiple well plunger lift," the author wishes to clarify that Kerr-McGee (now Anadarko) collaborated with several strategic hardware/service providers, including Production Control Services Inc., Applied Control Equipment, Ferguson Beauregard, and ABB Totalflow, in the Wattenberg field to test prototype multiwell flow controllers. The author did not intend to attribute credit to Ferguson Beauregard or any other vendor with developing the world's first multiwell plunger lift controller, and Kerr-McGee would like to thank all of its hardware/service providers for their service and efforts for Kerr-McGee and Anadarko.

Ted Pagano
Anadarko Petroleum
Evans, Colo.

Calendar

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

OIL&GAS JOURNAL online research center

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

2007

FEBRUARY

IPAA Small Cap Conference, Boca Raton, Fla., (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org/meetings. 5-8.

IADC Health, Safety, Environment & Training Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 6-7.

Russia Offshore Oil & Gas Conference, Moscow, +44 (0) 1242 529 090, +44 (0) 1242 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 7-8.

Multiphase Pumping & Technologies Conference & Exhibition, Abu Dhabi, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.multiphasepumping.com. 11-13.

SPE Middle East Oil & Gas Show & Conference (MEOS), Bahrain, +44 20 7840 2139, +44 20 7840 2119 (fax), e-mail: meos@oesallworld.com, website: www.allworldexhibitions.com. 11-14.

International Petrochemicals & Gas Technology Conference & Exhibition, London, +44

(0) 20 7357 8394, e-mail: Conference@EuroPetro.com, website: www.europetro.com. 12-13.

IP Week, London, +44(0)20 7467 7100, +44(0)20 7580 2230 (fax); e-mail: events@energyinst.org.uk, website: www.ipweek.co.uk. 12-15.

Pipeline Pigging & Integrity Management Conference, Houston, (713) 521-5929, (713) 521-9255 (fax), e-mail: info@clarion.org, website: www.clarion.org. 12-15.

CERA Week, Houston, (800) 597-4793, (617) 866-5901, (fax), e-mail: register@cera.com, website: www.cera.com/ceraweek. 12-16.

International Downstream Technology & Catalyst Conference & Exhibition, London, +44 (0) 20 7357 8394, e-mail: Conference@EuroPetro.com, website: www.europetro.com. 14-15.

Pakistan Oil & Gas Conference, Islamabad, (92-21) 6634795, (92-21) 6634795 (fax), website: www.pakoil-gas.com. 18-20.

SPE/IADC Drilling Conference and Exhibition, Amsterdam, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 20-22.

AustralAsian Oil Gas Conference and Exhibition, Perth, (704) 365-0041, (704) 365-8426 (fax), e-mail: sarahv@imexmgt.com, website: www.imexmgt.com. 21-23.

Pipe Line Contractors Association Annual Meeting, Aventura, Fla., (214) 969-2700, e-mail: plca@plca.org, website: www.plca.org. 21-25.

International Conference and Exhibition on Geo-Resources in the Middle East and North Africa, Cairo, 00202 3446411, 00202 3448573 (fax), e-mail: alisadek@mailer.eun.eg, website: www.grmena.com.eg. 24-28.

Laurance Reid Gas Conditioning Conference, Norman, Okla., (405) 325-3136, (405) 325-7329 (fax), e-mail: bettyk@ou.edu, website: www.lrgcc.org. 25-28.

CERA East Meets West Executive Conference, Istanbul, (800) 597-4793, (617) 866-5992 (fax), e-mail: register@cera.com, website: www.cera.com. 26-28.

SPE Reservoir Simulation Symposium, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 26-28.

Subsea Tieback Forum & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.subseatiebackforum.com. Feb. 27-Mar. 1.

International Symposium on Oilfield Chemistry, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. Feb. 28-Mar. 2.

MARCH

Natural Gas Conference, Calgary, Alta., (403) 220-2380, (403) 284-4181 (fax), e-mail: jstaple@ceri.ca, website: www.ceri.ca. 5-6.

Gas Arabia International Conference, Abu Dhabi, +44 (0) 1242 529 090, +44 (0) 1242 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.theenergyexchange.co.uk. 5-7.

SPE E&P Environmental and Safety Conference, Galveston, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 5-7.

International Pump Users Symposium, Houston, (979) 845-7417, (979) 847-9500 (fax), website: http://turbolab.tamu.edu. 5-8.

Purvin & Gertz International LPG Seminar, Houston, (713) 236-0318 x229, (713) 331 4000 (fax), website: www.purvingertz.com. 5-8.

African Refiners Week, Cape Town, +44 (0)20 7343 0014, +44 (0)20 7343 0015 (fax), website: www.afrra.org. 5-9.

Power-Gen Renewable Energy & Fuel Conference, Las Vegas, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwell.com. 6-8.

Annual Fuels & Lubes Asia Conference, Bangkok, +632 772 4731, +632 772 4735 (fax), e-mail: conference@flasia.info, website: www.flasia.info. 7-9.

✦Plant Maintenance, Tooling & Safety Equipment, Technology & Service Conference, Bankok, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: rowen@oesallworld.com, website: www.allworldexhibitions.com. 8-10.

GPA Annual Convention, San Antonio, (918) 493-3872, (918) 493-3875 (fax), website: www.gasprocessors.com. 11-14.

SPE Middle East Oil & Gas Show & Conference (MEOS), Bahrain, +44 20 7840 2139, +44 20 7840 2119 (fax), e-mail: meos@oesallworld.com, website: www.allworldexhibitions.com. 11-14.

NACE Annual Conference & Exposition, Nashville, (281) 228-6200, (281) 228-6300, e-mail: Jennifer.OReilly@nace.org, website: www.nace.org/nace/content/conferences/c2007/welcome.asp. 11-15.

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Sustainability with gas

Angel White
Associate Editor

Prompted by recently high and volatile oil prices, many countries are questing for sustainability of energy supply. According to Prasert Bunsumpun, president of PTT Public Co. Ltd., Bangkok, sustainable energy supply is "an integral link to economic development, especially for developing countries where energy intensity relative to economic growth is high."

He believes that, for a country to achieve sustainability, "an equilibrium is required that addresses the security of energy supply, the affordability of energy, and the acceptability of environmental impact."

Thailand has had trouble realizing this equilibrium in the past, Bunsumpun said at the December 2006 Gastech conference in Abu Dhabi.

For several years imported oil filled more than 90% of Thailand's total energy demand. The country decreased dependency on oil to 50%, mostly still imported, by developing its natural gas industry.

Thailand began developing its natural gas in 1973. The country currently consumes about 3 bcfd of gas, 34% of total energy demand, Bunsumpun said. "To date, the use of domestic natural gas has reduced cumulative equivalent oil imports by about 1.8 billion bbl, equivalent to about $58 billion."

Value of gas

"Our natural gas offers a secure domestic energy supply, competitive costs relative to imported oil, and an environmentally clean alternative to coal," Bunsumpun said.

He pointed out that initially Thailand's gas was valued as fuel—mainly as an oil substitute for power plants and industrial businesses. Through development of processing capacity, the rich gas now yields products such as LPG for industrial fuel and home use and feedstock for the petrochemical industry.

The Thai petrochemical industry has grown rapidly. According to Bunsumpun, it is capable of producing about 6 million tonnes/year of basic petrochemicals.

Over the next 5 years Thailand's petrochemical industry will expand to become truly world-scale, Bunsumpun said. "We will become a top player in the region with a combined upstream production capacity of more than 10 million tonnes/year."

Other industries

Gas has been key to Thailand's economic growth and the development of one of the most advanced manufacturing industries in the region, Bunsumpun said, adding, "We plan to do significantly more with this strategic resource."

In industrial markets, he said, gas will continue to replace oil in manufacturing facilities along the country's onshore pipeline network. Industrial cogeneration will be promoted to increase energy efficiency.

In transportation, PTT, in cooperation with its partners and the Thai government, has been aggressively promoting the use of gas as an alternative transportation fuel.

"There are about 25,000 NGVs [natural gas vehicles] in the greater Bangkok area," Bunsumpun said. According to government plans, the number will reach 500,000 by 2011. "The number of NGV fueling stations will need to grow from the current level of 90 sites to about 740 by 2010," he said.

Gas still is a major fuel of power generation—the main driver for gas demand in Thailand. Through aggressive development of combined-cycle gas-turbine capacity, gas represents about 70% of the total generation fuel mix—the highest levels of gas penetration in the world, Bunsumpun said.

Maintaining sustainability

"Given limited growth potential of our domestic gas reserves," Bunsumpun said, "we need to look beyond our own indigenous resources to ensure sustainable supply." Among its other projects, PTT is developing an LNG project that will have an import facility with a capacity of 5 million tonnes/year, expandable to 10 million tonnes/year.

The facility is scheduled to distribute LNG to existing and new pipeline networks by 2011. PTT is securing LNG from suppliers in the Middle East, Asia, and Australia.

Bunsumpun said PTT's gas development plan will involve more than $13 billion of investment in the next 5 years.

"Natural gas provides our country access to clean energy, increased national competitiveness, and contributes to the nation's sustainable, economic, and social development," he said. Thailand plans to emphasize gas use for many years and offers many opportunities for investment in gas-related projects. ✦

Editorial

Why expand the SPR?

A plan to double capacity of the Strategic Petroleum Reserve typifies the cascading misjudgment driving US energy policy. In his state-of-the-union address Jan. 23, President George W. Bush announced plans to raise capacity of the SPR to 1.5 billion bbl by 2027. In the same speech, he proposed that the mandate for renewable fuel sold with gasoline, now set to grow to 7.5 billion gal/year by 2012, be expanded to 35 billion gal/year by 2027. In conjunction with an unspecified toughening of fuel-economy standards for new vehicles, this is supposed to cut US consumption of gasoline over the next 10 years by 20% from projected levels.

The administration's rationale for expanding the SPR illustrates recklessly incomplete thinking. A White House fact sheet accompanying the president's address notes that the 691 million bbl of crude oil now in the SPR would cover net imports for "only" 55 days. This it compares with the 118 days of calculated import coverage of 1985, when the SPR contained 493 million bbl. The arithmetic does not establish that 118 days is an optimum level of import coverage. It does not account for changes that the oil market has undergone since 1985. And it does not explain why import coverage should determine how much oil the government holds in noncommercial inventory or—most importantly—would be willing to pay for.

'Insurance policy'

The administration's fact sheet redundantly calls the SPR "an insurance policy in the event of a severe supply disruption, such as from a natural disaster or a terrorist attack, in the energy supply chain." The US has sustained natural disasters and terrorist attacks, not one of which has come close to testing the drawdown rate or duration limits of the SPR at its current size. To argue that the inventory needs to grow on these bases is specious.

The SPR's main historic value in fact has been to discourage major exporters from manipulating oil supply to influence global politics. In the decade or so after the Arab oil embargo of 1973-74, the argument for hoarding crude oil as a geopolitical counterbalance carried weight. If anything, subsequent market changes have weakened the case.

Development and population growth have made exporters more dependent on oil sales than they were in the 1970s. Furthermore, the market is much more flexible than it was then and better able to accommodate disruption. The oil export weapon, therefore, isn't what it used to be. The energy policies of major importing nations should have adapted to these changes long ago.

A new look at the SPR, not a random expansion, is in order. The government should assess drawdown capacities against supply disruptions of the size and nature that might really occur. Then it should examine the costs of buying oil that no one can do anything with except under extreme conditions. Those costs are considerable. A realistic assessment might well conclude that the US has more protection than it needs against probable supply jolts and that the SPR should shrink. The willy-nilly assertion that the strategic inventory needs to double looks like a fiscally irresponsible distraction from serious energy policy-making.

Raising costs

But cost receives little attention in Bush's energy plan. The government can't lower consumption of gasoline without raising costs through new taxes or substitution of something more expensive. Bush has chosen the latter, politically easier course, which camouflages the costs. In case anyone has forgotten, the Energy Information Administration has calculated that ethanol, at the substance's current level of subsidy, deprives the federal treasury of 44.9¢/gal. Ethanol production is raising the price of corn. And ethanol distribution will keep pressure on the price of diesel. Expanding the mandate will multiply the economic damage.

The US enjoyed a couple of good decades during which markets set fuel prices and the main government intrusions were government-imposed limits on supply. To the peril of consumers and taxpayers, the government is reentering the energy business, raising costs needlessly under several dangerous pretenses, prominent among which is the assertion that political leaders know how much energy people should use. ✦

Oil industry researching diverse energy sources

Paula Dittrick
Senior Staff Writer

Integrated oil and gas companies have established subsidiaries to research and develop alternative and renewable energy sources, anticipating a global need for diverse new supply.

Simultaneously, the majors are working to improve energy efficiency and lower operational costs throughout their production, shipping, refining, and marketing segments.

Since 2000, Chevron Corp. has spent $1.5 billion on geothermal, hydrogen, biofuels, advanced batteries, wind, and solar technologies. It plans to spend a further $2 billion on these efforts by yearend 2008.

BP PLC launched BP Alternative Energy (BP AE) in November 2005, and the parent company expects to invest up to $8 billion over 10 years on the subsidiary, which is based in Sunbury, Middlesex, the UK.

ExxonMobil Corp. invested $712 million in 2005 in research and development, a category from which it does not break out spending on renewable energy. Although 2006 numbers were not available at press time, the company has invested more than $600 million/year on R&D since 2001.

Investments in this category are split between technology extensions for use in existing operations and breakthrough technology to help meet future demand and reduce greenhouse gas (GHG) emissions, an ExxonMobil spokesman said.

In 2002 at Stanford University, ExxonMobil cofounded the Global Climate and Energy Project (GCEP), in which ExxonMobil, General Electric Co., Schlumberger Ltd., and Toyota Motor Corp. together plan to invest up to $225 million over 10 years.

Thirty research projects are under way at GCEP, including research into hydrogen; advanced internal combustion; solar energy; carbon dioxide capture, storage, and separation; biomass; and advanced materials and catalysts.

Royal Dutch Shell PLC formed Shell Renewables and has invested more than $1 billion since 2000 on alternative energy.

"We have focused our alternative-energy portfolio on the most promising technologies: two for transport (biofuel and hydrogen) and two electricity sources (wind and thin-film solar)," a Shell spokeswoman said.

Low-carbon energy

Vivienne Cox, BP chief executive of Gas, Power & Renewables, said worldwide corporate interest is escalating in a quest by oil companies and others toward producing low-carbon energy.

"At the moment, alternative energy can sound like a fringe activity," Cox said. "But 200 years ago so did coal, 100 years ago so did oil, 30 years ago so did natural gas. The mix is constantly changing and is responsive to price, technology, and need."

One motivation behind BP AE was the realization that there are consequences to what type of electric generation is built. This is key to tackling GHG emissions, Cox said, noting that power plants now generate 40% of the world's CO_2 emissions, double the transportation sector's emissions.

"We don't tend to feel so guilty about the kettle as the car, do we?

Shell WindEnergy operates the 80-Mw, 80-turbine White Deer wind farm northeast of Amarillo, Tex. The wind farm is surrounded by agriculture, oil wells, and natural gas pipelines. Photo from Shell WindEnergy.

We should," Cox told a conference at the London Business School last year. "Worldwide, around half of the power capacity needed in 2030 is still to be built.... Replace a traditional coal-fired power station with a gas one, and you halve the emissions. Replace it with a series of wind farms, and you eliminate [carbon emissions]."

Rex W. Tillerson, ExxonMobil chairman and chief executive officer, told the Chief Executives Club of Boston in 2006 that fossil fuels will remain dominant for decades, although energy from alternate sources will play a growing role.

"Some—such as wind and solar—are likely to see double-digit growth over the next 25 years, due in large part to government mandates and subsidies," Tillerson said. "However, these alternatives build upon a relatively small base...and are expanding within a world energy system that is itself expanding significantly. For this reason, they will not fundamentally change the world energy mix, despite their impressive growth."

In its "Outlook for Energy, A View to 2030," ExxonMobil forecast that global energy demand will increase almost 60% by 2030 from its 2000 level. Energy demand growth is driven by economic progress and population growth.

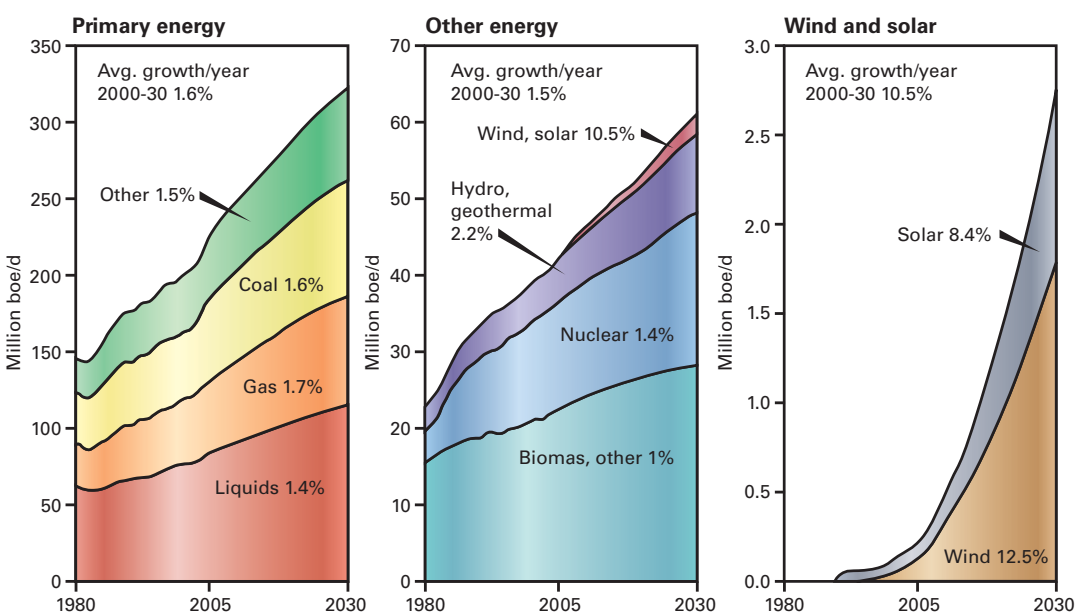
Oil, gas, and coal are forecast to remain the predominant energy sources, maintaining about an 80% share of total energy demand through 2030. Biofuels, wind, and solar will grow rapidly, contributing about 2% of total energy supply by 2030, ExxonMobil said.

Alternative energy sources must achieve economies of scale and overcome cost and technical challenges before they can contribute significantly to overall energy supply, Tillerson said, adding that no such source now offers the availability, affordability, and adaptability of fossil fuels.

Chevron Chairman and Chief Executive Officer David O'Reilly emphasizes conservation, calling it the easiest, cheapest, and most reliable near-term energy source.

"If we want to continue to promote economic growth, conservation will help keep energy supplies plentiful and affordable," O'Reilly said in comments posted on Chevron's web site. "There are environmental benefits to conserva-

Global energy demand by source



Source: ExxonMobil Corp.

tion as well. It may be the single most effective way to reduce greenhouse gas emissions."

Wind power increasing

A fast-growing source of alternative energy worldwide is wind power.

In the US, wind power generating capacity increased by 27% in 2006 and is expected to increase an additional 26% in 2007, the American Wind Energy Association (AWEA) said in a forecast released Jan. 24.

The US wind industry installed 2,454 Mw of new generating capacity in 2006, representing a $4 billion investment. Wind was second to natural gas for a second consecutive year as the largest source of new US power generation, AWEA said.

"Wind is a proven, cost-effective source of energy that also alleviates global warming and enhances our nation's energy security," said AWEA Executive Director Randall Swisher. Wind energy continues to attract both public and private funding.

Shell WindEnergy is a partner in 750 Mw of global wind capacity, of which Shell's share is 350 Mw. The company belongs to London Array Ltd., a consortium planning to build a 1,000-Mw wind farm off Kent. Other partners are E.On UK Renewables Ltd. and CORE Ltd., a joint venture of Farm Energy, the project's originator, and Danish utility DONG Energy.

The UK government recently issued a preliminary authorization for the offshore section of the wind farm, which could displace nearly 2 million tonnes/year of CO_2 emissions.

Andrew Murfin, a London Array director, said, "The UK government has a target of 10% of energy generation from renewables by 2010 and an aspiration to double that by 2020. To help reach these targets, it is imperative that large-scale wind farms such as London Array get the go-ahead and are built in the not-too-distant future."

Elsewhere, Shell signed a memorandum of understanding in 2006 with Guohua Energy Investment Corp. to examine potential wind energy developments in China. In the US, Shell has projects in Texas, Wyoming, Idaho, West Virginia, California, and Hawaii.

BP plans major wind-power investments and holds interests in two operating wind farms, both in the Netherlands. One is a three-turbine wind farm at Amsterdam, and the other is a nine-turbine wind farm at the Netherlands Refining Co. BV's Rotterdam refinery. Chevron also holds interest in that 22.5-Mw wind farm at Nerefco.

"These are small-scale, industrial-setting wind farms, to give us experience of the technology, planning processes, operational issues, etc.," said a BP spokesman in London. "We also have a planning application in for a seven-turbine farm in the southeast of England at the site of our former Kent refinery, now a fuel terminal."

BP AE accelerated its US wind-power business in two transactions last year. In July, BP AE reached an agreement with wind developer and wind-turbine manufacturer Clipper Windpower to acquire a 50% stake in a 2,015-Mw wind development involving projects in New York, Texas, and South Dakota.

In a separate turbine-supply agreement, BP committed to buy up to 900 Clipper Liberty turbines over 5 years. Last year, BP AE bought two US wind-development companies: Greenlight Energy Inc. and Orion Energy LLC.

Construction is under way on the 300-Mw Cedar Creek project in Weld County, Colo. Developers BP and Babcock & Brown Operating Partners LP expect the 274-turbine Cedar Creek wind farm to become operational in the second half of 2007.

Also this year, BP AE plans construction on the 20-Mw Yaponcha project involving an existing wind farm in California's San Gorgonio Pass, a 65-Mw project in North Dakota, a 60-Mw joint project with Clipper in central Texas, and a 10-Mw project in West Texas.

Solar investments

Major oil companies have invested widely in solar energy. Shell and BP affiliates manufacture solar cells. And Chevron Energy Solutions Co. (CES) has installed Solarmine, a 500-kw solar photovoltaic installation, at an oil field near Bakersfield, Calif. (see story, this page).

CES also has installed photovoltaic arrays at service stations in Guatemala City, London, and Rio de Janeiro.

BP Solar plans a $70 million expansion of its photovoltaic-cell manufactur-

Solar energy powers

Paula Dittrick
Senior Staff Writer

A 500-kw solar photovoltaic project, Solarmine, provides daytime electricity to Chevron Corp.'s part of Midway-Sunset heavy oil field in California's San Joaquin Valley.

Chevron is among the largest landowners of numerous companies operating in the field, which produces 13° gravity oil. California statistics indicate the field produced 84.5 million bbl of oil and condensate and 3.3 bcf of natural gas during 2005.

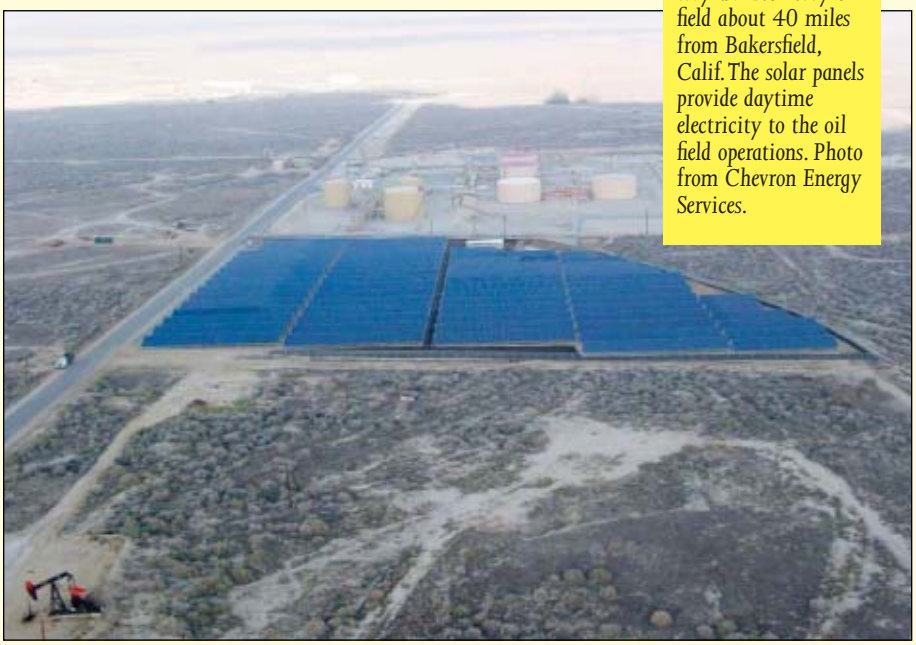
Solarmine is a collaboration of Chevron and an Energy Conversion Devices Inc. (ECD) subsidiary, United Solar Systems Corp. (Uni-Solar). Uni-Solar manufactured the solar panels. Chevron owns 20% of ECD. Texaco Technology Ventures initiated Solarmine before Texaco merged with Chevron.

An array of 4,800 amorphous-silicon solar panels, each about 1.3 ft by 18 ft, are mounted on metal frames facing south. The panels are arranged into 400 strings with each string having 12 panel modules. The array area covers 2.8 acres, and the entire Solarmine complex covers 6 acres.

The project cost, excluding the land, was $4.86 million. Chevron recouped half of that expense with a $2.43 million rebate through its participation in the California Energy Commission Emerging Renewable Buydown Program.

Solarmine, operating since late

production of heavy oil in California



This aerial photo shows the Solarmine solar project at Midway-Sunset heavy oil field about 40 miles from Bakersfield, Calif. The solar panels provide daytime electricity to the oil field operations. Photo from Chevron Energy Services.

2002, has no battery backup or storage. It automatically connects with the local electricity grid at sundown and disconnects at sunrise. The panels begin putting out 80 kw at sunrise and reach a 500-kw peak around midday.

On cloudy days when Solarmine puts out less power, other cogeneration power systems make up the difference and provide sufficient power for field operations.

Inside a Solarmine conversion building, an inverter and an isolation transformer convert direct current from the solar modules to alternating current and step it up to 12,000 v for the field's power grid.

An automated tracking system provides real-time data to evaluate Solarmine's performance. Company statistics indicate that 2003 operations saved $83,000 in electricity costs at 6.3¢/kw-hr. The solar energy also was estimated to have avoided 850 tonnes of CO_2 emissions and 1,950 lb of nitrogen oxide emissions during 2003.

Chevron Energy Solutions

Chevron's energy services subsidiary, Chevron Energy Solutions, helped design and install Solarmine. CES projects often are bundled with renewable or alternative power such as solar systems or fuel cells.

CES Senior Vice-Pres. David L. Stone said energy efficiency and reliability are important to Chevron because energy is one of the biggest expenses in oil and gas operations.

"Chevron has achieved a 27% improvement in energy efficiency since 1992 to present," Stone said. "That is about $1 billion/year out of our average cost structure. We lowered energy costs through energy efficiency."

CES works on upstream, downstream, and midstream projects for Chevron and other clients. Customers include federal government agencies, universities, and others.

"We design and build projects, both energy-efficiency and renewable-power projects, for customers as well as for our own facilities," Stone said. "To our knowledge, none of the other oil and gas companies have a business that looks like Chevron Energy Solutions."

CES estimates that in 2005 it saved its customers more than 177 kw-hr of electricity and 1.185 tcf of natural gas, equivalent to avoiding 97,000 tonnes of CO_2 emissions.

Stone said CES is technology-neutral and product-neutral because it does not have any of its own proprietary technology or equipment that it's trying to sell.

"We are familiar with all state-of-the-art best technologies, whether it is alternative energy, renewable power, or energy efficiency. We will apply what is the very best thing to meet the customer's need," Stone said.

ing operation in Frederick, Md., with construction scheduled for 2007. Outside the US, BP Solar has manufacturing facilities in Spain, India, and Australia.

Shell Erneuerbare Energien GMBH formed a joint venture, Avancis KG, with Saint-Gobain Glass Deutschland GMBH to develop nonsilicon solar-panel manufacturing based on copper indium diselenide technology. The European Commission last year approved Avancis, scheduled to start manufacturing in 2008.

In the US, research financed by the US Department of Energy achieved record solar efficiency levels last year. Boeing Co. subsidiary's Spectrolab Inc. converted 40.7% of the sun's energy into electricity. Spectrolab produced a multijunction solar cell that gathered more energy from sunlight than can a single solar cell. Multijunction cells promise to cut solar power costs.

In Australia, GCEP researchers at Stanford University are collaborating and financing solar cell design and fabrication research at the University of New South Wales, said ExxonMobil Australia Chairman Mark Nolan.

Hydrogen infrastructure

Oil companies, accustomed to using hydrogen in refining, say an industrial

Shell Hydrogen provides a hydrogen-fuel dispenser to refuel fuel-cell buses at a station in Reykjavik, Iceland. Photo from Shell Hydrogen.

hydrogen infrastructure exists. Hydrogen currently is derived from natural gas via steam reforming. Research continues into separating hydrogen from water, which is more expensive.

Shell Hydrogen BV's research primarily involves how to use hydrogen as a retail fuel, said Duncan Macleod, vice-president of Shell Hydrogen.

"Shell already has a hydrogen platform of production nodes all over the world. Over 50 million tonnes are produced and consumed every year," Macleod said. "Through existing and planned demonstration projects, Shell Hydrogen is currently building up our experience in connecting these production nodes with our retail infrastructure."

Shell Hydrogen, based in The Hague, participates in retail stations in Amsterdam, Luxembourg, Reykjavik, Toyko, and Washington. The company works with partners to make hydrogen an efficient, everyday fuel.

"My vision is that in 10 or 15 years our children will be driving these vehicles," Macleod said. "When you put all of this together, you are talking about a substantial new energy business."

Shell Hydrogen and Total SA are working jointly with several vehicle manufacturers to advance fuel-cell vehicles and a refueling infrastructure. The group targets commercialization of hydrogen vehicles in Europe, potentially starting around 2015. Separately, Shell Hydrogen and Shell (China) Ltd. signed an agreement with Tongji University to build Shanghai's first hydrogen filling station for fuel-cell vehicles. The station is part of a national program to develop electric vehicles in China.

To help US commercialization of hydrogen, Shell awarded $100 million last year to Ohio State University to study membrane-separation technology in efforts to reduce the cost of producing hydrogen from fossil fuels.

ExxonMobil has research partnerships with Toyota and Caterpillar Inc. to develop improved internal combustion engines and fuel systems. A partnership with DaimlerChrysler Corp. is working to develop lubricants to improve fuel economy, extend oil-change intervals, and lower emissions.

In fuel-cell transportation efforts, ExxonMobil Research & Engineering Co. awarded $2.2 million in contracts to QuestAir Technologies Inc. of British Columbia to develop a hydrogen generator for installation on vehicles.

The DOE organized a consortium, led by Chevron Technology Ventures LLC, to build up to six hydrogen stations by 2010. The goal is to determine which emerging technologies merit development.

Chevron Technology, Hyundai Kia Motors, and a unit of United Technologies Corp. opened the Hyundai-Kai American Technical Center in Chino, Calif., in February 2005. Five fuel-cell vehicles use that demonstration station, which is not open to the public.

Chino station, storing 100 kg of hydrogen at 5,000 psi, uses Chevron's proprietary autothermal reforming technology to produce hydrogen from natural gas onsite, eliminating the need to transport it to the station.

Separately, Chevron provides hydrogen for a public transportation demonstration project with the Alameda-Contra Costa Transit District in Oakland, Calif. Three 40-ft buses and nine other vehicles use the station, which opened last year.

Chevron plans to spend $12 million over 5 years on Georgia Institute of Technology research to study sorbents that remove impurities from hydrogen and to develop cellulosic biofuels.

In partnership with University of California, Davis, research on biochemical and thermochemical conversion, Chevron agreed to spend up to $25 million to develop fuel from crops, forest, agricultural residue, and municipal solid waste.

Other energy sources

Major oil companies are involved in a wide range of research projects and pioneering investments covering other energy sources, including geothermal, batteries, and combined heat and power projects.

The DOE sponsored a recent study by the Massachusetts Institute of Technology of geothermal energy. An 18-member panel prepared a report, "The Future of Geothermal Energy," that runs

more than 400 pages.

It assesses the feasibility, potential environmental impact, and economic viability of using enhanced geothermal system technology to increase output from US geothermal resources. Existing geothermal plants are primarily in isolated western regions. MIT researchers considered the potential for much larger-scale deployment.

"We've determined that heat-mining can be economical in the short term, based on a global analysis of existing geothermal systems, an assessment of the total US resource, and continuing improvements in deep drilling and reservoir stimulation technology," said panel head Jefferson W. Tester, H.P. Meissner professor of chemical engineering at MIT.

Geothermal resources are converted into useful energy outside the US. Chevron, for example, has geothermal operations in Indonesia and the Philippines. In separate battery research for hybrid electric vehicles, Cobasys LLC, a joint venture of Chevron Technology and Energy Conversion Devices Inc., produces advanced battery systems with higher power and longer life than conventional batteries.

Cobasys, of Orion Township, Mich., developed metal hydride (NiMH) technology used in electric and hybrid vehicles and stationary power plants. In 2002, the company received a 2-year DOE contract for the FreedomCAR initiative.

In January 2007, General Motors awarded Cobasys a development contract to test lithium-ion battery models in GM plug-in hybrid vehicle prototypes. Cobasys is working with A123Systems, a Massachusetts technology group.

ExxonMobil, meanwhile, is investing in combined heat and power projects. CHP relies on natural gas and is twice as efficient as traditional means of heat and power generation.

The company's CHP capacity increased by 800 Mw in 2004-05, representing a $1 billion investment. ExxonMobil has interests in 85 CHP facilities at 30 locations worldwide, representing capacity of about 3,700 Mw. These facilities have helped reduce CO_2 emissions by 9 million tonnes/year.

A BP Solar employee assembles a silicon wafer. BP Solar plans to expand its manufacturing plant in Frederick, Md., this year. Photo from BP Solar.

Global discussion

Chevron's O'Reilly calls the delivery of reliable, affordable energy "one of the biggest challenges we face as an industry and as a global community."

He encourages producer-consumer conversation about future energy supply and demand. To this end, Chevron hosts a web site—willyoujoinus.com—inviting public comment on specific topics such as what fuels people desire, where their fuel comes from, and how much they are willing to pay for it.

"Corporations, governments, and every citizen of this planet must be part of the solution as surely as they are part of the problem," Chevron said on the web site. "We call upon scientists and educators, politicians and policymakers, environmentalists, leaders of industry, and each one of you to be part of reshaping the next era of energy."

BP's Cox said she has confidence that oil companies can develop and implement new technologies to meet future demand, and she called upon industry to work with policymakers toward providing specific incentives and regulations.

"We need millions of people to understand the problem and demand change," Cox said. "This is not an obscure policy issue. It's about the future of the world." ✦

Analysis highlights limits on energy promise of biofuels

Donald F. Anthrop
San Jose State University

COMMENT

According to environmentalists and a growing array of politicians, biofuels are going to dramatically reduce our dependence on foreign oil supplies, replace dirty fossil energy with "clean" renewable energy, and sharply reduce carbon emissions. The facts are rather different.

In part because the ethanol industry is already well developed, the promoters of biofuels have focused their attention on ethanol to power the transportation sector. On Dec. 27, 2006, the Governors' Ethanol Coalition, which consists of the governors of 37 states, sent a letter to Congress in which they asked Congress to require that 15% of motor fuels

consumption on a btu basis consist of ethanol and biodiesel by 2015.[1,2]

Analysis of the goal expressed by the coalition helps put into perspective the even more-ambitious targets outlined recently in Congress and in the state-of-the-union address Jan. 23 by President George W. Bush.

Consumption, population

Per-capita gasoline consumption in 2005 was 11.2 bbl—the same as in 1974.[3] Although the average fuel economy of passenger cars on the road increased from 13.6 mpg to 22.4 mpg, this improvement in fuel economy was offset by increases in the number of vehicles and the mileage each vehicle was driven.[4]

If current trends in immigration and population growth remain intact, the US population will reach about 330.5 million in the year 2015.[5] If per-capita gasoline consumption remains constant, US gasoline demand in 2015 will reach 3.72 billion bbl, or about 19.1 quadrillion btu.

Although ethanol can be made from a variety of cellulosic materials, such as straw, virtually all of the ethanol produced in the US today is made from corn, and there is little reason to believe this situation will change in the near future. Replacing 15% of this gasoline demand with ethanol derived from corn would consume 13.6 billion bushels of corn, or 130% of the US corn crop.[6] About 94 million acres of prime farm land would have to be devoted to corn production just for fuel ethanol. These people need a reality check.

In 2005, about 14% of the US corn crop went into ethanol production, and this has caused a sharp increase in corn prices.[7] On Jan. 22, the March 2007 contract price was $4.04/bushel. A year earlier, the March 2006 contract price was $2.08/bushel. Rising corn prices are already affecting both poultry and beef producers, and rising retail meat prices are expected soon.[7]

Water requirements

It is worth noting that approximately 14% of the US corn crop is irrigated and that this irrigated acreage consumes almost 18 million acre-ft/year of water—much of which is overdrafted from the Ogallala aquifer in the Great Plains.[8,9] To put this water requirement into some perspective, the average annual flow of the Colorado River at Lee's Ferry, Ariz., is only about 14 million acre-ft. Furthermore, much of this corn acreage in the Great Plains states is easily erodible land, and numerous studies have conclusively demonstrated that row crops, such as corn, result in much higher erosion rates than cereal grains or forage crops. In one such study, done near Zanesville, Ohio, a continuous corn cropping sequence produced a soil loss nine times that for wheat grown in a rotation sequence with corn.[10]

The potential for expanding corn acreage is limited, and the potential for expanding corn acreage without causing significant environmental damage is even more limited. Harvested acreage, production, and yield date for the major field crops in the US are shown in Table 1.[11] The data shown are averages for the 4-year period 2002-05.[12] The various categories of cropland in the US are shown in Table 2.[13]

YIELDS OF MAJOR US CROPS

Table 1

Crop	Harvested acreage, million acres	Production, millions	Yield, per acre
Corn	72.25	10,494 bushels	145 bushels
Soybeans	72.57	2,855 bushels	39.3 bushels
Wheat	49.75	2,053 bushels	41.3 bushels
Hay	62.37	154.4 tons	2.47 tons
Cotton	12.82	20.65 bales	733 lb
Sorghum (grain)	6.84	407.1 bushels	59.5 bushels
Barley	4.04	249.2 bushels	61.8 bushels
Rice	3.22	21,661 lb	6,721 lb

CROPLAND IN THE US, 2002

Table 2

Category	Acreage, million acres
Cropland used for crops	340
Idle cropland	40
Cropland used only for pasture	62
Total cropland	**442**

Of the 40 million acres of idle cropland shown in the table, about 35 million acres are enrolled in the Conservation Reserve Program (CRP).[14] The CRP was originally authorized by Congress in 1985 for the purpose of protecting erodible land from erosion. Under this program, owners of highly erodible land are paid a per-acre fee by the US Department of Agriculture (USDA) for taking such land out of crop production for a 10-year period and planting a cover crop, such as grass, to reduce soil erosion. About 13.6 million acres of land enrolled in the CRP were converted from wheat in the six states: North Dakota, South Dakota, Montana, Wyoming, Colorado, and Kansas.[14] Without irrigation, this land is too arid for corn production. Because corn generates almost twice the per-acre revenue as wheat, farmers with good soil and adequate rainfall will almost always choose to grow corn rather than wheat. Therefore, most of the 50 million acres of wheat acreage is not suitable for corn production.

As the data in Table 1 show, the big four field crops—corn, soybeans, wheat, and hay—account for three fourths of US cropland used for crops. The only real potential for expanding corn production is at the expense of soybean acreage, since soybeans and corn are often grown in rotation sequence to take advantage of the ability of soybeans to sequester nitrogen in the soil. This rotation reduces natural gas-derived nitrogen fertilizer requirements for the subsequent corn crop. In addition, of course, the soybean meal residual after crushing the beans for oil is used extensively as a high-protein supplement in animal feeds.

A.E. Farrell and colleagues of the Energy Resources Group at the University of California, Berkeley, recently published the results of a study to determine the net energy balance of fuel ethanol.[15] In the course of that work, which concluded that the net energy

balance is positive, the authors found that the renewable-energy (solar) content of corn ethanol was only 5-26%. The balance of the energy input is primarily natural gas and coal. Let's assume the average is 16%. If 15% of the year 2015 gasoline supply is ethanol, then the renewable content of this gasoline is only 0.46 quads, or 2.4%. Worse, this entire renewable contribution will be offset by a population-driven increase in gasoline demand within 3 years.

Biodiesel limits

Although the Governors' Ethanol Coalition report focused largely on corn ethanol, it did include some recommendations on biodiesel. Recently, a number of articles have also appeared in the popular press touting the supposed benefits of biodiesel fuel as a substitute for conventional diesel. However, none of these have addressed the question of potential production of biodiesel.

Biodiesel fuel is produced from fats and oils, but these fats and oils are also consumed in food, animal feed, and chemical production. The only oils that currently can be considered surplus and available for biodiesel production are those that are exported. These exported oils—primarily oilseed oils, such as soybean—could produce about 40 million bbl/year of biodiesel, or about 0.5% of US petroleum consumption.[16]

In order to increase the supply of oils for biodiesel production, the acreage of oilseeds (mostly soybeans or canola) would have to be expanded. The top five soybean-producing states—Iowa, Illinois, Minnesota, Indiana, and Nebraska—are also the top five corn-producing states. Consequently, soybean acreage is in competition with corn acreage for ethanol production, and, indeed, soybean acreage in the top seven producing states declined between 2001 and 2005.[17] Since soybeans require a warm, humid climate, they are not grown in the arid West, even with irrigation. Consequently, the potential for expansion of soybean acreage is limited.

It has been suggested that some CRP land might be planted to canola when the CRP contracts expire. Of the 34.8 million acres currently under CRP contracts, 13.3 million acres, or almost 40% of the total, are in North Dakota, South Dakota, Montana, Kansas, and Colorado.[14] If all 13.3 million acres were planted in canola, 23 million bbl/year of biodiesel could be produced.[18,19] This amounts to just 0.3% of current US petroleum consumption.

It is worth noting that any conversion of CRP land back to crop production would have serious erosion implications. On a silt-loam soil with 12% slope in Ohio, the soil loss from a field of wheat was 57 times the soil loss from a field of second-year grass. The soil loss from a field seeded with canola would almost certainly be greater than from wheat, and CRP land is, by defini-

tion, highly erodible. Growing a crop that results in a fifty-sevenfold increase in soil erosion to produce a minuscule fraction of the US petroleum supply hardly qualifies as environmentally beneficial or sustainable.

Biofuels, energy

As the gasoline data show, biofuels simply cannot provide either the liquid fuels or the total energy required by the US economy. Indeed, even if it were possible to collect all of the aboveground residue from the 200 million acres of corn, soybeans, wheat, oats, and rice in the US, the energy content of that residue is only about 7.4 quads, or about 7.4% of US primary energy consumption. Table 3 shows data used in this calculation.

Note that the 7.4 quads is the total gross energy content of the residues. The net energy available after collection, processing, and replenishment of nutrients removed with the residue would be considerably less.

It is time for politicians to stop pretending that biomass can make any significant contribution to US energy supplies or reduction of carbon emissions. ✦

VALUES USED IN CROP-RESIDUE ENERGY ESTIMATE Table 3

Crop	Average acreage, 2002-05	Residue, lb/acre	Heat value, btu/lb
Corn	72.253	7,300	7,500
Soybeans	72.57	3,600	7,500
Wheat and oat straw	51.72	3,600	7,500
Rice straw	3.22	4,000	7,000

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The author

Donald F. Anthrop is professor emeritus of environmental studies at San Jose State University, San Jose, Calif., where he taught for 34 years. He earned his doctorate in materials engineering at the University of California, Berkeley, and is the author of over 70 papers on energy and water resources, including a pioneering work published in the Bulletin of Atomic Scientists in 1970 entitled, "The Environmental Side Effects of Energy Production." He currently resides in Berkeley and can be reached at dfanthrop@yahoo.com.

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Bush seeks lower gasoline use, expands SPR

US President George W. Bush has set ambitious goals for displacing gasoline with renewable fuels and has announced plans to double capacity of the Strategic Petroleum Reserve (SPR).

In his state-of-the-union address Jan. 23, Bush called for a 20% reduction in gasoline use against projected levels by 2017.

According to a fact sheet accompanying his address, 15 percentage points of the reduction would come from an increase in the federal mandate for use of renewable fuels to 35 billion gal/year by 2017.

A renewable-fuels mandate imposed by the Energy Policy Act of 2005 will reach 7.5 billion gal/year by 2012. The mandate has stimulated an expansion in the US capacity to produce fuel ethanol from corn. Fuel ethanol and corn both receive federal tax subsidies.

Bush proposed to broaden the mandate to include other renewable energy sources, including cellulosic ethanol, biodiesel, methanol, butanol, and hydrogen, plus unspecified "alternative fuels."

He said the other 5 percentage points to be shaved off projected gasoline consumption would come from changes to the corporate average fuel economy (CAFE) program for new vehicles. His plan would give the secretary of transportation authority to set CAFE standards.

Under Bush's SPR expansion, US capacity to store crude oil as a buffer against supply disruptions will reach 1.5 billion bbl by 2027. The SPR currently holds 691 million bbl of crude.

"For too long our nation has been dependent on foreign oil," the president said. "And this dependence leaves us more vulnerable to hostile regimes and to terrorists—who could cause huge disruptions of oil shipments and raise the price of oil and do great harm to our economy."

Industry reaction

Among industry responses to the energy portions of Bush's address, Mike Linn, chairman of the Independent Petroleum Association of America, said, "Our best defense against foreign oil dependency is the vast oil and natural gas resources we have here in America. This energy is our true strategic petroleum reserve, and government policies should encourage its development.

Linn, who also is chairman, president, and chief executive of Linn Energy, expressed regret that "the majority of the nation's oil and natural gas remains off-limits" and said, "Any discussion of federal research and development should also include new technologies that help us recover more American oil and natural gas."

While the US "must embrace conservation, efficiency, and all forms of American energy for the future," he said, "The fact remains that for the foreseeable future, oil and natural gas will be our main fuel source."

Charles T. Drevna, executive vice-president of the National Petrochemical & Refiners Association, also stressed the continuing contributions of oil and gas to US energy supply.

"US energy policy must continue to encourage domestic production of petroleum products and natural gas supplies and the efficient usage of these fuels while maintaining environmental progress," Drevna said. "It is also important that mandates, price controls, and other punitive measures not be adopted as energy policy."

He said biofuels "are not a panacea for America's supply problems, nor can they deliver on the much-touted promise of energy independence." NPRA doesn't oppose ethanol or other alternative fuels, he said, "provided their use is based upon market pricing and not mandates and subsidies, which we do not support."

In a statement, the American Petroleum Institute said ethanol and other biofuels "have an important role in our nation's present and future energy mix." It added, "Attaining the full volumes included in the administration's proposal will require additional technological breakthroughs." ✦

WATCHING GOVERNMENT

Nick Snow, Washington Correspondent

Permit effort wins applause

When the 110th Congress begins to examine the US Department of Interior's proposed budget for fiscal 2008 in a few weeks, it will evaluate programs in DOI agencies. One apparent success is the US Bureau of Land Management's pilot program to improve drilling permit application processing and environmental enforcement.

Section 365 of the 2005 Energy Policy Act (EPACT) directed the interior secretary to establish "oil and gas streamlining projects" at seven BLM offices in Rawlins and Buffalo, Wyo.; Miles City, Mont.; Farmington and Carlsbad, NM; Grand Junction-Glenwood Springs, Colo., and Vernal, Utah. The projects were established in October 2005. BLM's Colorado office hosted two public listening sessions on Nov. 14, 2006, to discuss the effort's first full year of operation.

Several people who testified said the program is making a difference. Marc W. Smith, executive director of the Independent Petroleum Association of Mountain States in Denver, noted that one of its purposes was to coordinate activities by agencies enforcing environmental regulations. "When government agencies work more efficiently, everyone wins," he observed.

'Resoundingly successful'

Noting that the Rocky Mountain region is poised to become the leading gas-producing area of the US this year, Smith called the effort to streamline permitting "resoundingly successful." Alan Kesterke, BLM's duty station officer in Cheyenne and the project's leader for all seven offices, told OGJ: "It has gone very well. The memorandum of understanding with other key federal agencies in October 2005 helped."

Kesterke said about 125 employees have come into the BLM offices from many other federal agencies. One result has been to make an Army Corps of Engineers specialist more readily available to deal with Section 104 permits under the Clean Water Act, or have a Fish and Wildlife Service employee on hand to deal with Section 7 clearances under the Endangered Species Act.

Jim Stovall, associate field manager in BLM's Carlsbad, NM, office, said such local coordination has been important. "Here, the Bureau of Reclamation is based out of Albuquerque, 5 hr away, as is the Fish and Wildlife Service," he pointed out.

Extends to states

Interagency cooperation has extended to states, Kesterke said. Employees from Montana's Department of Environmental Quality and Department of Fish, Wildlife, and Parks are working in BLM's Miles City office.

"All the agencies have been trying to identify ways to more effectively permit oil and gas development and monitor compliance after development occurs," Kesterke said.

And the results? "Our average turnaround time has dropped from 55 days in fiscal 2005 to 37 days in fiscal 2006. That's the most significant indicator. The number of permits processed went up from 870 in fiscal 2005 to 940 in fiscal 2006," responded Steve Heinke, BLM's district manager in Farmington, NM.

"The price of gas was up, so we had increased demand for access. But we were able to respond because we had more staff." ✦

Robust lease revenues

Nick Snow
Washington Correspondent

Federal officials recognized the possibility that increasing royalty rates could reduce future initial deepwater oil and gas bonus bids, a Department of the Interior official told the Senate Energy and Natural Resources Committee Jan. 25.

"We try to determine what will be attractive and produce the most revenue for the US. The first is the bonus bid, which produces immediate income. The second is the royalty rate. If you raise that, you probably will get less on the bonus bid. That was what we were looking at when the president decided to increase the royalty rate to 16⅔%," said C. Stephen Allred, deputy secretary for land and minerals at DOI.

Nevertheless, the federal government anticipates that it will receive significant leasing income in coming years because it expects oil and gas to account for the bulk of US energy through 2030, he said. "Much of the new energy growth will have to be met from the Outer Continental Shelf, especially new areas in the Gulf of Mexico and areas off Alaska," Allred said.

His observations came as the committee examined potential US OCS oil and gas development and issues surrounding it. Other witnesses included Marjorie A. McKeithen, Louisiana Dept. of Natural Resources assistant secretary in charge of mineral resources; Lisa P. Jackson, commissioner of New Jersey's Dept. of Environmental Protection; J. Larry Nichols, chairman, president, and chief executive of Devon Energy Corp.; Paul K. Siegele, vice-president of deepwater exploration and projects for Chevron North America Exploration & Production Co., and Athan Manuel, director of lands protection programs at the Sierra Club.

expected despite higher royalty rates

Estimated potential

Allred said that after DOI assessed potentially recoverable quantities of oil and gas on the OCS as required under the 2005 Energy Policy Act (EPACT), it determined a mean level of 86 billion bbl of oil and 420 tcf of gas.

The estimates represent about 65% for oil and 40% for gas within the total estimated US inventory of remaining economically recoverable oil and gas resources, he said. They do not include areas in the Gulf of Mexico and off Alaska's coast that were opened for leasing in late 2006, Allred added.

"There is great uncertainty regarding the resource potential in areas where leasing has been prohibited and where the last geophysical surveys and drilling exploration occurred more than 25 years ago. Using the information available to us, we estimate that nearly 17.8 billion bbl of oil and 76.5 tcf of technically recoverable gas remain unavailable for leasing consideration," he said.

Nichols said more-current resource estimates are needed to make OCS policy decisions. "As more information is gained, resource estimates can grow substantially. In the 1970s, the original estimate of natural gas in [the central and western Gulf of Mexico] was 50 tcf. We already have produced 150 tcf."

Nichols said that if a hearing had been held 5-7 years ago, people opposed to developing [deepwater] offshore resources would have said there was no evidence of oil and gas resources in these waters. "If you look at it today, however, we do have drilling rigs that can work in 10,000 ft of water, seismic that can determine if the resources are there, and wells that are producing."

Siegele said the deepwater gulf is critical to a diverse energy portfolio because it can produce large volumes of oil and gas. "However, it is a high-cost area that requires new technology and major investments," he noted.

Projects, costs

Siegele said Chevron Corp. is participating in three new offshore projects involving investments of more than $1 billion each, but they are expected to yield about 300,000 b/d of oil within the next 4 years. Two of these projects—Tahiti and Blind Faith, which Chevron operates—represent more than $4.5 billion in capital outlays and are designed to produce 165,000 b/d. The third, the ultradeep Perdido regional development project, is expected to be producing 130,000 b/d of oil near the end of the decade.

"Deepwater exploration and production is risky, and success cannot be guaranteed. Exploratory wells can cost $100 million each and may result in dry holes," Siegele said. "The process of bringing new energy supplies to the marketplace—from leasing through exploration, development, and construction—can take a decade or more. Companies invest billions of

dollars before there is any income from production, and assume all this risk. The Deepwater Royalty Relief Act was successful. Production from the gulf will dramatically increase in the next decade," he said.

McKeithen said Louisiana is looking forward to royalty increases because the state now will receive a share of federal OCS leasing revenues to help it absorb the impact. About 34% of the nation's total gas supply and almost 30% of its crude oil supply is either produced in or off Louisiana or moves through the state, she pointed out.

"We believe oil and gas production and environmental protection can coexist, but we know we can't continue doing it without learning some hard lessons," McKeithen told the committee. "The good news is scientists know how to restore our wetlands and protect our barrier islands. What has been lacking in the past hasn't been the will, but the resources. We have those resources now and look forward to using them."

Garden State goals

Jackson expressed a different view. "Our coast helps drive our tourism economy, which brings in more than $36 billion/year." She said $4.5 billion comes from commercial fishing and aquaculture alone and that coastal revenues represent the state's largest economic sector.

Instead of supporting offshore oil and gas activity, Jackson said, the administration of New Jersey Gov. Jon S. Corzine is proceeding with a commitment to have 22.5% of the electricity consumed within the state come from renewable resources and to reduce total projected electricity demand by 20% by 2020 through conservation, improved building standards, and alternatives.

Virginia officials have expressed some interest in allowing offshore oil and gas development, but Jackson said: "I would prefer to avoid potential environmental impacts rather than learn how to mitigate them." She said Virginia may seem distant from New Jersey but its potential lease area is only 75 miles away.

Virginia has been included in the 5-year OCS plan currently being developed by MMS, and discussions are continuing, but Allred noted that no leasing would occur unless Congress lifts a moratorium currently in place.

Potential spills discussed

Manuel said the Sierra Club continues to oppose additional US offshore oil and gas activity despite new technology because it still can pollute the environment. "Current cleanup methods are incapable of removing all the oil from spills and only a small fraction can be recovered," he said.

"The eastern Gulf of Mexico and America's East Coast, the two areas most coveted by the oil and gas industry, are no strangers to hurricanes and other strong storms. Several pipelines and platforms were severely damaged by hurricanes Katrina and Rita in 2005. We simply think putting more oil and gas rigs in hurricane-prone areas is not a smart policy," Manuel continued.

Allred said that, within federal areas of the OCS in the hurricanes' paths, there were 124 spills totaling a little more than 7,000 bbl of oil from pipelines and 10,000 bbl from rigs.

"As we look at the results, it's amazing. All of the shut-in valves performed as intended. There were no reports of spills from them, although there were spills that reached the ocean from onshore facilities," Allred said.

Uncultivated reserves

Committee chairman Jeff Bingaman (D-NM) asked how to change the fact that 33 million acres on the OCS are leased but not producing. Allred said MMS offshore leases are for 5-10 years, depending on the water depth, with the break point occurring at 400 ft. After companies are awarded leases, they must make decisions based on information they gain about where the most productive resource may be.

"There are payments with regard to rental rates on these leases going forward," he said. "Some may decide to turn the leases back, and they will go back on the market in the area's next lease sale," he explained.

Just before committee members were called to the floor for a vote, Sen. Mary L. Landrieu (D-La.) said there's no reason for an oil company to drill a well if there's no way to get the oil and gas to market. "This is something our colleagues from nonproducing states may not understand." ✦

US House passes repeal of oil, gas incentives

Nick Snow
Washington Correspondent

US House members on Jan. 18 passed HR 6, which would repeal selected oil and gas federal tax incentives, pressure holders of deepwater leases issued without price thresholds to renegotiate, and redirect revenues to a new energy efficiency and alternatives research and development fund.

The measure, which passed 264-163, was the last of six bills designated for consideration by House Speaker Nancy Pelosi (D-Calif.) during the first 100 hr of business in 2007.

Democrats called it an important initial step in reordering national energy priorities. Republican opponents said it would punish oil and gas producers and refiners with additional taxes and redirect revenues into a vaguely structured slush fund (OGJ Online, Jan. 15, 2007).

Opponents objected to the bill's coming to the floor under a closed rule, which prevented amendments. Chief Minority Leader John A. Boehner (R-Ohio) protested with a motion to adjourn, delaying proceedings for half an hour while a vote was taken and the motion was defeated. Minority Whip Roy Blunt (R-Mo.) said the bill does not seriously address US energy issues.

Thirty-six Republicans voted for the measure.

Rep. James P. McGovern (D-Mass.) introduced the enabling resolution, saying oil companies received $7.3 billion in tax breaks in the 2005 Energy Policy Act. He called the breaks "kickbacks to corporations like Big Oil."

Rep. Devin Nunes (R-Calif.) countered, "[This bill] penalizes domestic producers and does nothing to foreign suppliers."

Rep. Judy Biggert (R-Ill.) said she would support HR 6 because she wanted to see more money spent on energy alternatives research, but she opposed the rule bringing it to the floor. "We should know where this money is going to go," she said.

Rep. Steve Pearce (R-NM) questioned the bill's provision that would pressure holders of federal deepwater leases issued in 1998-99 without price thresholds to renegotiate terms. He said the bill could undermine the integrity of government contracts.

Natural Resources Committee Chairman Nick J. Rahall (D-W.Va.), who introduced HR 6 with Ways and Means Committee Chairman Charles B. Rangel (D-NY) on Jan. 12, said deepwater royalty relief was "a giveaway to oil companies to do something they would have done anyway." He said the new bill would not violate contract law because the original Deepwater Royalty Relief Act allows the government to impose additional conditions.

Resources Committee Chief Minority Member Don Young (R-Alas.) disagreed. "This bill is a taking, and it will go to court if it becomes law," he said, adding that he would have tried to amend it to tax imports instead. ✦

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Asian doubts about Russia

A deputy speaker of Russia's upper house of parliament last month said his country is a guarantor of energy stability and energy security for Asia-Pacific countries.

"We should do everything possible to prevent any political speculation, misrepresentation, and distorted scale of assessment of the actions of Russia," said Federation Council Dep. Chairman Dmitry Mezentsev at the 15th session of the Asia Pacific Parliamentary Forum.

Later, in presenting a report to the session, Mezentsev said Russia would build up its oil exports to Asian countries within the next few years.

"After construction of the Eastern Siberia-Pacific Ocean (ESPO) pipeline is over, up to 30 million tonnes of Russian oil will be supplied to the Asian market per year and up to 80 million tonnes in the long term," he said.

Rising exports

He forecast that one third of Russia's oil exports will go to Asia by 2020 and added that Russia would take account of the needs of Asia-Pacific nations in building up its energy infrastructure.

Sure. Tell us another one. Tell the Japanese and Chinese, and get ready for the horse laughs. After all, the Chinese are still smarting over Russian perfidy in connection with the ESPO. It was the Chinese who first brokered the line with Russia.

The Russians soon changed their tune on discovering Japanese interest in having the pipeline extend all the way to the Pacific Ocean instead of stopping at the Chinese border. And the Russians were especially interested as the price of oil steadily climbed.

If the Japanese thought they could rely on Russia as a main energy source, those thoughts began to shift radically when the Russian government started pressuring the Sakhalin-2 partners—two of them Japanese—for a stake in the venture.

We all know how that has turned out, with Russia's OAO Gazprom now owning the controlling stake in Sakhalin-2, leaving markets in Asia-Pacific wondering about the supplies of gas or LNG they had been promised by the erstwhile project partners.

Japanese worries

Indeed, the Japanese are so worried about the state of Sakhalin-2 that the head of the Japanese Natural Resources and Energy Agency, Harufumi Mochizuki, traveled to Moscow recently to meet with Gazprom management to discuss fuel supplies to Far Eastern markets.

Even as he departed, however, it was still unknown who would represent Gazprom at the talks—hardly a reassuring or welcoming prospect for an anxious Japanese delegation.

What exactly are the Japanese looking for in such discussions? Industry sources said Japanese authorities plan to start a full-scale energy dialog with the Russian government and business representatives and seek regular consultations with Gazprom.

While Russian parliamentarians may offer soothing words about the trustworthiness of their country as a source of energy to Asia-Pacific, the reality is otherwise. Russia is playing on Asian-Pacific energy insecurity in order to bolster its own treasury. ✦

White House has mixed review of House energy bill

Nick Snow
Washington Correspondent

The administration of President George W. Bush supports repealing certain tax provisions favoring oil and gas and encouraging holders of deepwater Gulf of Mexico leases issued in 1998-99 without price thresholds to voluntarily renegotiate terms.

But it opposes compelling those leaseholders to renegotiate or pay extra fees or be barred from future lease sales. It also opposes removing the oil and gas industry from a tax reduction applied to other US manufacturers, the White House's Office of Management and Budget said.

OMB made the remarks in an administrative policy statement on Jan. 17, one day before the House passed, by a 264-163 vote, HR 6—the "Creating Long-term Energy Alternatives for the Nation (CLEAN) Act." The statement addresses provisions in the bill.

It said Section 204 of HR 6, the provision aimed at compelling leaseholders to renegotiate, potentially could significantly delay future lease sales while it is litigated.

"Even if a challenge is ultimately held to be unfounded, a court might enjoin sales resulting in significant revenue decreases to the [US] Treasury and disruption of energy supplies to the nation," OMB continued.

It said that while the administration opposes "statutorily forced renegotiations of contracts," it is investigating options to deal with the problem, and it supports voluntary renegotiations under which the leaseholders would accept the addition of price thresholds. OMB said that the administration also "strongly opposes" Section 302, which effectively would raise taxes for oil and gas producers by removing them from a deduction which Congress approved for all US manufacturers in 2004.

"While it is appropriate to eliminate unneeded tax incentives targeted specifically at the oil and gas industries, it is inappropriate to single out this industry from all others for punitive tax treatment. Broad-based tax increases on any industry make that industry less competitive with overseas counterparts," OMB said.

It said the 2005 Energy Policy Act provisions accelerating the write-off of certain geological and geophysical costs and providing mandatory royalty relief and prohibitions on drilling-related user fees are not necessary, and it supports their repeal as outlined in HR 6.

OMB also urged Congress to consider repealing other 2005 energy act provisions directed at oil and gas, such as federal funding for oil and gas research and development. "The industry has the incentives and resources to accomplish such activities without additional federal subsidies, which are unwarranted in today's price environment," the White House office said in its policy statement. ✦

China promotes biofuels as energy alternatives

Promoting biofuels as an alternative to petroleum products, the Chinese government has set a goal of producing 2 million tonnes/year of biofuels by 2010 and 10 million tonnes/year by 2020, reported analyst Lijuan Wang of FACTS Inc., Honolulu.

China has become the third largest producer of bioethanol, following Brazil and the US. By the end of August 2006, it had approved four bioethanol fuel companies, which have completed facilities having a total production capacity of 38,100 b/d, Wang said.

Sinopec and PetroChina produce and distribute bioethanol fuel products through their retail networks. Bioethanol gasoline, sold in 27 regions in nine of China's provinces, accounts for 20% of China's total gasoline consumption, meeting the goals of the government's 10th 5-year plan. China will continue to promote bioethanol fuel use in its plan for 2006-10, Wang added.

The country's biodiesel industry, however, is still in its infancy. China has not yet established unified standards for biodiesel production or officially approved any biodiesel projects, although it is taking steps in both directions. It has encouraged Sinopec and PetroChina to produce biodiesel and introduce it into their retail networks, and Sinopec has set up a biodiesel production standard that is awaiting governmental approval. Six private and local companies produce the country's 4,300 b/d of biodiesel, but many small local biodiesel projects are being planned or are under construction.

China's main challenges in developing both bioethanol gasoline and biodiesel are tightening feedstock supply and price increases.

To encourage bioethanol production, the government created tax incentives, and both national and local governments have provided subsidies promoting the use of old grain. However, these subsidies are being reduced as China encourages a wider range of nongrain feedstock. Future supported bioethanol fuel would be produced by biomass materials, such as sugarcane, cassava, and corn and wheat stalks.

Although both bioethanol fuel and biodiesel in China can continue to expect benefits from preferred governmental policies and loan approvals, such incentives may not guarantee success in meeting the official goals. Feedstock crops require too much land and are at odds with agriculture, and "some projects may fail due to the competition of capital, technologies, and product quality," Wang said. ✦

Method helps find hydrocarbon areas, aids optimum seismic survey planning

Robert S. Foote
Geoscience & Technology Inc.
Euless, Tex.

Most E&P companies have turned to seismic surveys to map rock structure in an attempt to select the optimum position for a drill site, especially in offshore exploration. Even with the use of 3D data, dry holes frequently occur, and the presence of hydrocarbons at depth can only be proven by use of the drill bit.

Much time and effort are spent on seismic surveys over regions that have little probability for oil and gas discovery. Placing seismic surveys above future oil and gas field areas rather than over barren areas saves large amounts of exploration resources and is highly desirable.

An airborne method exists for locating hydrocarbon reservoir areas that does not depend on whether the reservoir is a structural or stratigraphic trap, onshore or offshore.

The method is based on surface detection of magnetic field effects that result from anomalous increases in magnetic properties of certain semishallow rock strata above the reservoir area. The magnetic properties of these strata beyond the reservoir area are not altered.

Rapid advancement of an exploration program is made possible by analysis of airborne magnetic data. Results indicate only the hydrocarbon reservoir area and not depth to oil or gas.

MS method

Verifications of this airborne method are demonstrated by comparing magnetic susceptibility (MS) measurements from oil and gas well cuttings with those from dry holes.[1-5]

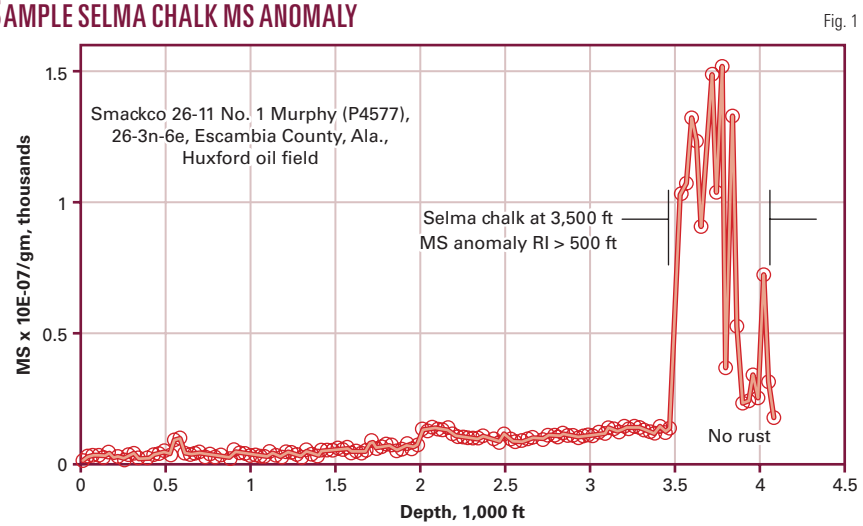
Several thousand well and dry hole cuttings MS measurements have been compared from regions in the US and from various continents, all showing the same result.

The flux density of the magnetic field along the earth's surface varies with changes in rock magnetic properties and depth to magnetic material. The larger the magnetic mineral mass and MS intensity of the anomalous magnetic material, the greater is the increase in density of magnetic field lines of force at the surface, the flux density.

The product of the Magnetic Susceptibility (MS) x altered Rock Interval (RI), the MSRI, when spread laterally to the extent of the magnetic mineral mass, approximates the region of flux density increase in the magnetic field lines of force. Semishallow magnetic

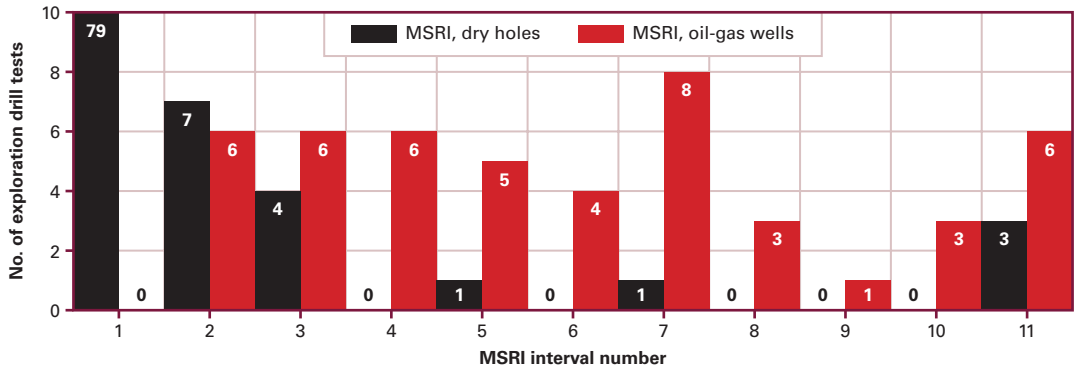
SAMPLE SELMA CHALK MS ANOMALY

Fig. 1



SOUTHERN ALABAMA PRODUCING WELLS AND DRY HOLES

Fig. 2



mineral masses create detectable small changes in the magnetic field flux density that can be measured by high-sensitivity airborne magnetometers.

Removal of that part of the composite magnetic field caused by (1) basement rocks and corrections for (2) diurnal magnetic field changes and (3) aircraft altitude changes gives the patented Sedimentary Residual Magnetic (SRM) field. Survey line-to-line clustering of SRM anomalies creates the patented Magnetic Bright Spot (MBS). The MBS defines the extent and intensity of an authigenic magnetic mineral anomaly. Local increases in the magnetic field correlate with MSRI values created as a result of microleakage.

Alabama MSRI

The State of Alabama required from 1947-2005 that drill cutting samples at 30-ft intervals from surface to TD be stored in the Geological Survey of Alabama sample library.

The GSA sample library, because of its wealth of shallow samples, permits MS evaluation of early exploration wells that were possibly not drilled sufficiently deep or were improperly evaluated. MSRI values have been determined for the 143 exploration drill holes.

In southern Alabama the Selma chalk is the principal MS-altered formation, although more shallow MS-altered carbonates have been found. Samples from many producing wells have been measured to TD, and MS anomalies have not been found deeper than in the Selma chalk.

In the rectangular measurement region bounded by 6n-5e to 1n-16e, the top of the Selma chalk varied in depth from 2,300 to 3,600 ft. Fig. 1 shows an example of a Selma chalk MS anomaly with the MS-altered rock interval greater than 500 ft.

The authigenic magnetic mineral responsible for the MS anomaly in the Selma chalk is maghemite, γFe_2O_3, and maghemite has been the magnetic mineral in most onshore analyses. The offshore magnetic mineral has been analyzed to be greigite, Fe_3O_4. Magnetic minerals have been identified by the Mossbauer effect technique.[6]

MSRI is classified into 11 intensity intervals (Table 1). The MS-altered rock interval, RI, is separated into four depth groups.

MSRI is shown for the 95 dry holes, 79 of which MSRI Intensity Number = 1. All drill holes having the Intensity Number >4 should be evaluated, especially those having Intensity Number of 11 with RI4.

Fig. 2 is a display of Table 1 and shows distribution of wells and dry holes as a function of MSRI intensity number and MS altered rock interval.

MBS CONTOURS, THUNDER HORSE FIELDS, GULF OF MEXICO

Fig. 3

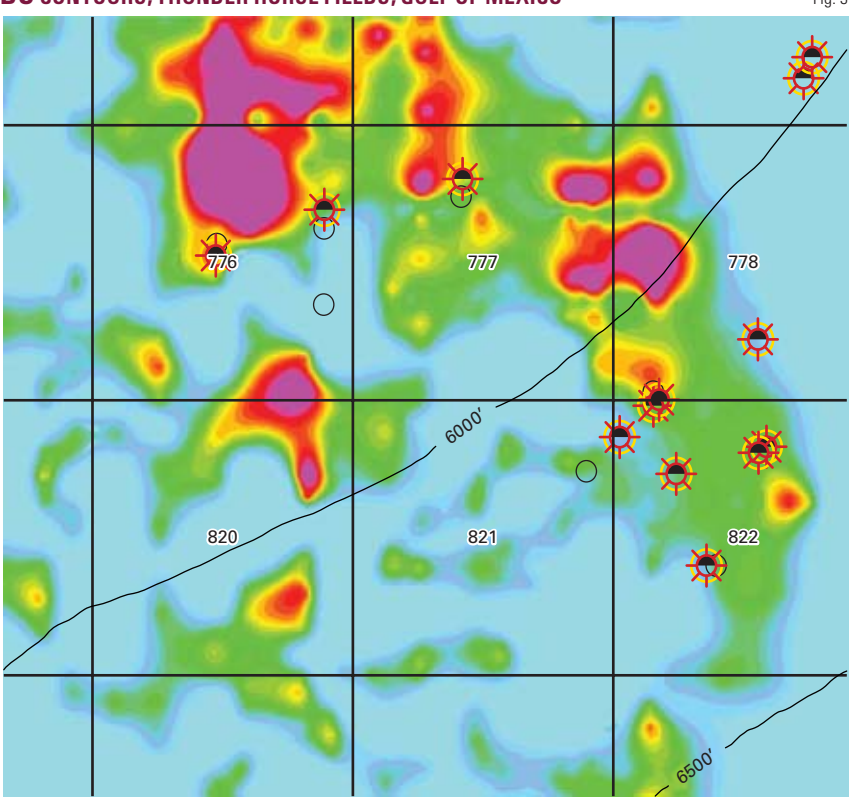


Table 1 demonstrates the association of hydrocarbons at depth with MS anomalies and the lack of MS anomalies with the lack of hydrocarbons. It demonstrates and justifies the use of the MBS to seek out, by use of airborne sensors, those areas having local flux density concentrations.

MSRI, RI CLASSIFICATION OF SOUTHERN ALABAMA PRODUCING WELLS, DRY HOLES*

Table 1

MSRI intensity No.	MSRI/10^3	Dry holes	DH rock interval RI1	DH rock interval RI2	DH rock interval RI3	DH rock interval RI4	Wells	Well rock interval RI1	Well rock interval RI2	Well rock interval RI3	Well rock interval RI4
1	0<25	79	75	2	1	1	—	—	—	—	—
2	25<50	7	—	4	1	2	6	—	—	—	6
3	50<100	4	—	—	3	1	6	—	—	—	6
4	100<150	—	—	—	—	—	6	—	—	1	5
5	150<200	1	—	—	—	1	5	—	—	—	5
6	200<250	—	—	—	—	—	4	—	—	—	4
7	250<300	1	—	—	—	1	8	—	—	—	8
8	300<350	—	—	—	—	—	3	—	—	—	3
9	350<400	—	—	—	—	—	1	—	—	—	1
10	400<500	—	—	—	—	—	3	—	—	—	3
11	500>500	3	—	—	—	3	6	—	—	—	6
		95	**75**	**6**	**5**	**9**	**48**	**—**	**—**	**1**	**47**

*MS units = value x 10^{-7}/gm (ex: nonaltered Selma chalk, ~30 x 10^{-7}/gm). RI1 = 0 ft (no alteration) to < = 30 ft; RI2 >30 ft <100 ft; RI3 = >100 ft <200 ft; RI4 = >200 ft.

Offshore MBS examples

The Thunder Horse fields, Mississippi Canyon area, Gulf of Mexico, present an example of the use of the MBS method in 6,000 ft of water (Fig. 3).

Data have recently been analyzed to evaluate SRM anomaly detection in 7,200 ft of water in the newly discovered Jack field area, Walker Ridge blocks 758-759, Gulf of Mexico. Fig. 4 presents the MBS developed in the Jack field area.

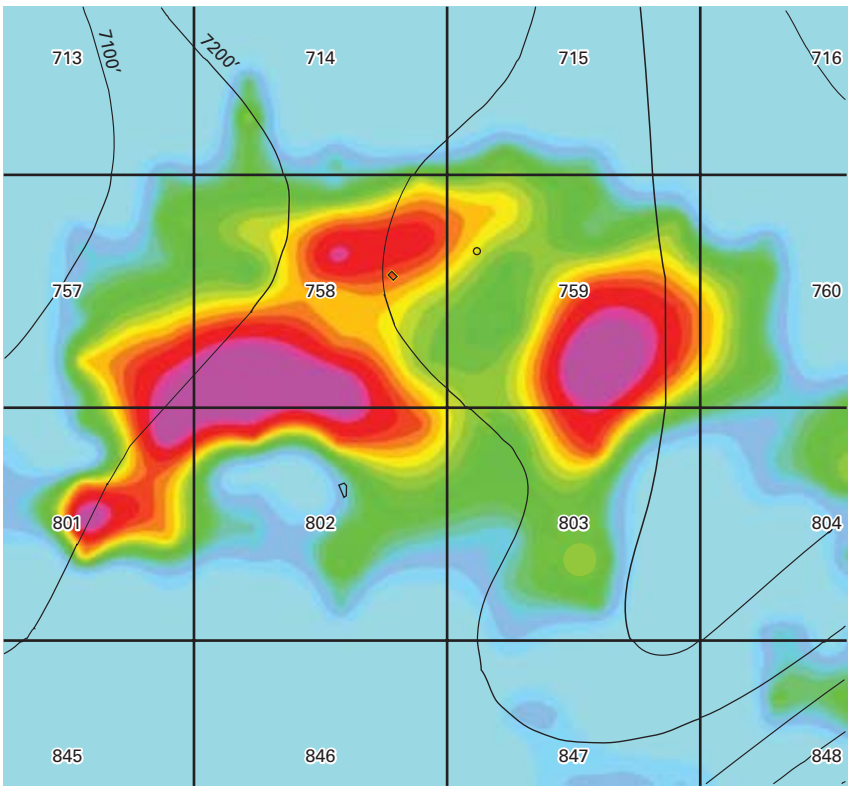
The Jack field MBS anomaly covers more than 40 sq miles and is the largest MBS discovered in the Gulf of Mexico. Data are intensity-normalized to a water depth of 4,000 ft and position-corrected for the inclination angle of the earth's magnetic field.

The advantages

If exploration oil and gas well drill cuttings are accurately captured, saved, and measured for MSRI, a prediction

MBS CONTOURS, JACK FIELD, GULF OF MEXICO

Fig. 4



as to the success or failure at TD can be made.

If no MS anomaly results from accurate sample capture and subsequent measurement at the time of drilling, a decision can be made to terminate the drilling operation and select a new drill site.

In any new area, a sample library search should be made to locate previously drilled oil or gas wells having shallow cuttings. Such cuttings MS measurements will provide (1) anomalous sample MS or lack thereof, (2) surface depth to the altered strata, (3) RI thickness of the MS-altered strata, and (4) MSRI intensity.

The use of the MBS to evaluate a prospective area, onshore and offshore, should precede seismic surveys to eliminate those areas not prospective and define those that are. More than 95% of most areas surveyed will not have an MBS.

Based on the results of the Jack field study, offshore surveys using the cesium vapor magnetometer to detect hydrocarbon prospective areas in 7,000 ft of water are possible where salt thickness variations, such as salt domes and rapidly thinning and thickening salt lenses along a flight line, do not interfere with anomalous SRM detection.

Acknowledgments

The use of Airmag Surveys Inc.'s Thunder Horse area data, of Fugro Airborne Surveys' Jack area data, cooperation of the Geological Survey of Alabama and Lewis Dean, financial assistance supplied by Cs Solutions regarding the Gulf of Mexico data analysis, and the effort given by Nathan Frick and Michael Foote are appreciated. ✦

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The author

Robert S. Foote Sr. is owner of Geoscience & Technology Inc. For more than 20 years, he has developed and subsequently patented SRM technology. Before originating the method, he worked with Texas Instruments' central research laboratory and with Geodata International. He was responsible for operations directed toward oil, gas, and mineral exploration. He has a BS and MS in physics from the University of Illinois.

Guinea

Hyperdynamics Corp., Houston, was attempting to interest potential farmees in a 31,000 sq mile concession in the Atlantic off nonproducing Guinea that it has held for several years.

The block, which the company calls the largest license acreage position off West Africa, lies halfway between oil production off Mauritania and Ivory Coast. The company's SCS Corp. subsidiary holds the block.

Hyperdynamics has shot 5,000 km of 2D seismic, run a geochemical drop core survey, performed a remote sensing satellite study for oil seeps, and completed an independent integrated interpretation of the data.

As part of its production sharing contract, the company plans to acquire and interpret as much as 18,000 km of seismic by late 2008.

A subsidiary of GlobalSantaFe Corp. is nearing completion of a study to identify logistics needed to support future drilling and production operations.

India

Hardy Oil & Gas PLC, London, was testing more zones at an apparent discovery on the CY-OS/2 license in the northern Cauvery basin.

The Fan A-1 well, drilled to TD 4,089 m, encountered several Cretaceous hydrocarbon sands with high pressures, of which the company identified five for potential production and chose three for tests.

The first zone, at 3,755-3,817 m, was perforated across 9 m and flowed gas and 42° gravity oil to surface before test difficulties ensued. Hardy may sidetrack and retest the zone after gauging the shallower intervals.

The second interval, at 3,565-69 m, was under test in early January at an initial 10 MMscfd of gas with 20 bbl/MMscf of condensate on a 52/64-in. choke. Interests in the 859 sq km license are Hardy 75% and Gas Authority of India Ltd. 25%.

Gujarat State Petroleum Corp. and GeoGlobal Resources Inc., Calgary, will soon have three rigs drilling on exploration block KG-OSN-2001/3 in the Krishna-Godavari basin off eastern India.

The Essar Wildcat self-propelled semisubmersible, capable of drilling to 7,600 m in 400 m of water, is to begin drilling in deeper-water parts of the block by April under a 2-year contract with two 1-year extension options.

The Atwood Beacon jack up spud the KG-16 well on Jan. 3, 5 km east of the KG-8 platform where the Saipem Perro Negro-3 jack up is located. KG-16 is a vertical well projected to 5,500 m in 109 m of water to further delineate the KG structure.

Perro Negro-3 is to spud the KG-28, its sixth well of 10 contracted, in early February. It is projected to 5,500 m with 1,500 m of deviation to the east.

The same rig just completed tests of KG-15, where perforations at 4,464-4,587 m stabilized at 8.5 MMscfd of gas and 55 b/d of condensate on a 20/64-in. choke with 3,893 psi flowing wellhead pressure. The companies said the activity shows their resolve to fulfill the KG drilling obligations and place Deen Dayal field on production as soon as possible.

Nicaragua

Norwood Resources Ltd., Vancouver, BC, is drilling two wells on the 845,780-acre Oklanicsa Block in the Sandino basin on Nicaragua's Pacific Coast southwest of Managua.

San Bartolo Rodriguez Cano-1 was projected to 2,700 m with objectives in Oligocene Middle Masachapa and Eocene Upper and Middle Brito. The rig is then to move to Las Mesas Gutierrez Mendez-1.

South Australia

Innamincka Petroleum Ltd., Brisbane, plans to further explore and develop Flax and Juniper oil fields in PEL 103 in the Cooper basin, having completed purchase of a 65% interest in the license from Vernon E. Faulconer Australia Inc., private Tyler, Tex., independent.

Consulting geoscientists in 2006 estimated 4 million bbl to be recoverable from Flax with produced gas reinjection. They estimated 66 million bbl of oil in place at Juniper. Yarrow gas field, just west, was given 22.8 bcf of gas recoverable. The hydrocarbons are in Permian sandstones. The oil is 52° gravity.

More drilling is needed to determine whether Flax and Juniper might comprise a single field covering as much as 40,000 acres. Flax, discovered in 2004, has produced more than 45,000 bbl of oil.

Trinidad and Tobago

Maxim Resources Inc., Vancouver, BC, said it signed a letter of intent to acquire the interests it does not already own in the South Erin Project in Trinidad, where an oil discovery is on production and 10 development locations have been identified.

The operator, private Jasmin Oil & Gas Ltd., placed the Erin-98 well on production in mid-November 2006 at around 200 b/d on a choke from one zone, the Miocene Lower Forest A formation. The well tapped 210 ft of net pay in three zones. The crude is exported from Point Fortin.

The 1,350-acre block is 40 miles southwest of Port of Spain and just west of giant Erin/Palo Seco oil field.

Gulf of Mexico

Royal Exploration Co., private Corpus Christi independent, has brought forward plans to drill on Eugene Island Block 310 in the Gulf of Mexico after securing a rig.

Petsec Energy Ltd., 50-50 partner, said it hopes for first production by the end of 2007 from the well, which is updip from a 1977 undeveloped Transco gas-condensate discovery.

The prospect is in 204 ft of water 87 miles off Louisiana and 45 miles southeast of Petsec's Vermilion 258 gas production platform. The companies also plan to drill a well at Mobile Bay Block 994 in mid-February and six to nine wells at Petsec's Moonshine project onshore Louisiana.

Louisiana

Peoples Energy Production and others are attempting to improve production in Edgerly field in Calcasieu Parish by reworking wells.

The NAL-4 well emerged from a workover making 30 b/d of oil, and the rate is expected to rise as the well cleans up and stabilizes, said participant Texhoma Energy Inc., Houston.

NAL-3, next in line for workover,

is to be equipped with a submersible pump for the first time. The field, 10 miles northeast of Vinton, had four wells making a combined 500 b/d before the rework program, with about half that coming from NAL-3.

Texas

South

Pearl Exploration & Production Ltd., Calgary, plans to attempt initial heavy oil production from the first of two pilot wells at a cyclic steam injection project in the Maverick basin in southern Texas.

The company has injected more than 50,000 bbl of steam into the Lower Cretaceous Upper San Miguel formation at 700-1,100 b/d with 550-650° F. wellhead temperatures. An initial soak period at the first well ended in mid-January. The second well remains on initial steam injection.

Pearl, formerly Newmex Minerals Inc., is operator with 75% interest. The Exploration Co., San Antonio, has 25% (OGJ Online, Dec. 9, 2005).

Washington

A unit of Torrent Energy Corp., Portland, plans to start drilling in the Chehalis basin in the next few months as drilling permits are approved.

Torrent's Cascadia Energy Corp. has leased and optioned more than 155,000 acres of private and state lands in Lewis, Cowlitz, and Skamania counties. The holdings lie south of the Centralia-Chehalis bituminous coal field, site of the state's largest open pit mine and thermal power plant.

Three drilling permits are filed, and more are to be filed soon (OGJ Online, Dec. 28, 2006). The initial wells will target the regional coal seams and investigate potential conventional natural gas prospects similar to those in Mist gas field in Oregon and Jackson Prairie gas storage field in Washington.

The first well will offset a 2001 well that cut several thick coal seams and tested 715 Mcfd of conventional gas from a high-porosity gas sand.

Wyoming

Warren Resources Inc., New York, was drilling a Hanna basin wildcat designed to eventually test the Jurassic Nugget formation at 14,062 ft in late January near the top of Cretaceous Dakota sand. The company holds 7,100 net acres in the basin and shares with Stone Energy Corp., Lafayette, an adjoining 5,600 gross acres on a farmout from Anadarko Petroleum Corp.

A full evaluation of the 14,188-acre South Seminoe prospect in Carbon County is several weeks away, but based on forthcoming results and interpretations it might decide to test the Pennsylvanian Tensleep formation at 16,200 ft, Warren said.

Operators plan more drilling after third Libyan bid round

Nina M. Rach
Drilling Editor

Operators committed to drilling at least 35 new exploration wells under successful bids in Libya's third round.

Libya has the largest oil reserves in Africa (39 billion bbl) and is the eighth-largest oil producer among the members of the Organization of Petroleum Exporting Countries (OPEC). Libya wants to increase oil production to 2 million b/d by 2008-10 and to 3 million b/d by 2015, from 1.6 million b/d today.

Since 1961, Libya has produced high quality, low-sulfur, sweet crude oil, primarily sold into the European market. The country is now the second-largest oil supplier to Europe. Libya's National Oil Corp. (NOC) set up subsidiaries with offices in Europe:

- Umm Al-Jawaby Oil Service Co. Ltd. in London, 1983.
- Mediterranean Oil Services GMBH in Düsseldorf, 1988.

Since the US lifted economic sanctions against Libya in 2004, NOC has reinstituted lease sales, which are again attracting the attention of many international players as well as national oil companies looking to diversify assets abroad.

Rig counts

From 1982 to mid 1986, there were 18-34 land rigs and as many as 2 offshore rigs drilling in Libya (Fig. 1). Drilling began to tail off in the mid-1980s, and rig counts have hovered between 10-15 over the last 20 years. The majority of the drilling has focused on oil, rather than on natural gas.

According to Baker Hughes International rotary rig count, there were 12 land rigs drilling in Libya in December 2006, up from 11 in November 2006 and 9 in December 2005. The BHI count is a snapshot that includes only rigs actually drilling ("turning to the right") as opposed to the total number of rigs on site and under contract.

A single mobile offshore rig, the Pride North Sea, a second-generation semisub, was drilling off Libya but moved west, to Tunisia to drill for British Gas Tunisia Ltd., the largest producer of gas in Tunisia. The Pride Venezuela, a third-generation semisub, had previously drilled off Libya for Eni SPA.

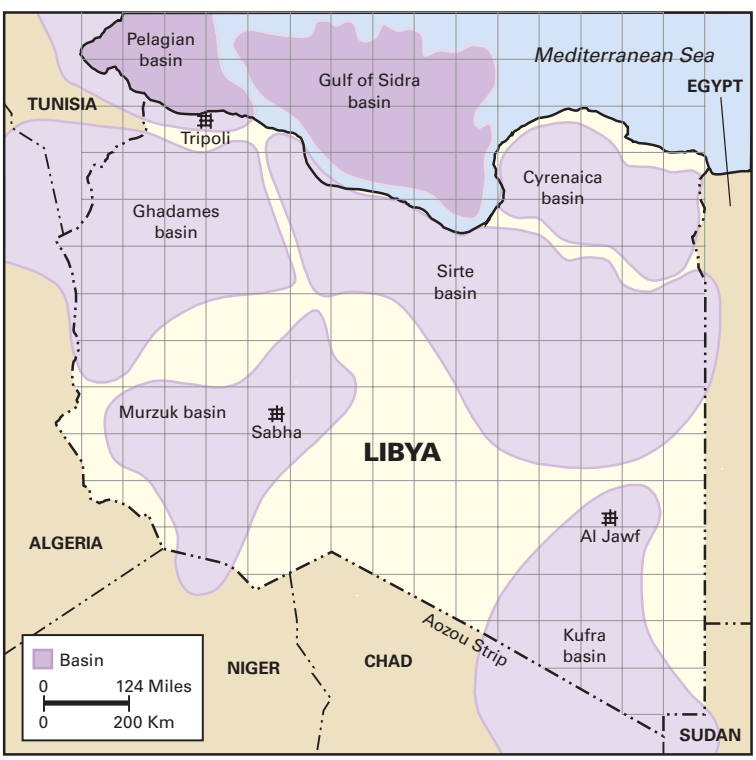
There are three noncompetitive platform rigs busy with workovers in Libya's offshore Bouri field, all managed by KCA Deutag and owned by Agip: Bouri DP-3, DP-4A, and DP-4B.

EPSA IV

Libya's National Oil Corp. recently announced results of the third bid round in the country's EPSA 4 (exploration and production-sharing agreement) program.

Unlike the EPSA 3 program, which required negotiations with the Libyan government, EPSA 4 is based only on competitive bidding.

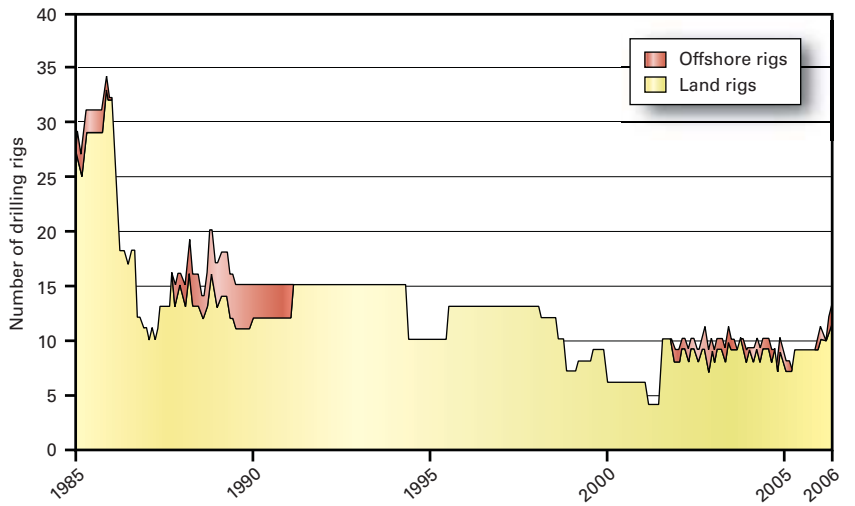
LIBYAN BASINS



Sources: OGJ archives, National Oil Co. of Libya

LIBYAN DRILLING RIG COUNT, 1985-2006

Fig. 1



In Round 1 results, announced in January 2005, US-based firms won 11 of the 15 available leases.

The National Oil Corp. opened bids Oct. 2, 2005, for Round 2 of EPSA 4. Fifty companies bid on 40 of the 44 blocks offered (OGJ, Oct. 24, 2005, p. 39). Based on the bidding for leases covering an area the size of Switzerland, the NOC selected 19 companies to receive licenses for five onshore basins and some offshore areas.

Second round winners included:

- Eight Asian companies: Nippon Oil Corp., Mitsubishi Corp., Japan Petroleum Exploration Co. Ltd. (Japex), Inpex Corp., and Teikoku Oil Co. Ltd. (OGJ, Oct. 10, 2005, Newsletter); PT Pertamina; Chinese Petroleum Corp.
- Six European companies: Total ASA, Norsk Hydro AS, Statoil ASA, BG Group PLC, Eni North Africa, and OAO Tatneft.
- Three Indian companies: Oil India Ltd., Indian Oil Corp. Ltd., and ONGC Videsh Ltd.
- Turkish Petroleum Overseas Co. Ltd.
- ExxonMobil Libya Ltd.

KCA Deutag has been drilling in Libya for more than 50 years. The T-108 rig at left, a Sandmaster K750, is contracted to REMSA Libya, a subsidiary of Repsol YPF. The T-16 Emsco rig at right is contracted to Agip Libya (Fig. 2; photos from KCA Deutag).

The average share of production that companies allotted themselves fell to 13.2% in the second round from 19.5% in the first round.

Third, fourth bid rounds

Libya solicited bids in mid-2006 for its third bidding round (OGJ, Sept. 4, 2006, p. 53). This is the first bidding round under Libya's new oil chief, Shokhri Ghanem, chairman of National Oil Corp.

The acreage on offer covered 41 blocks in 14 exploration areas across the Murzuq, Sirte, Ghadames, Kufra, and Cyrenaica basins, as well as the offshore sector. Most of these areas are relatively untested, with only 9 onshore wells and 1 offshore well in the areas on offer.

The bids were opened Dec. 20 in Tripoli; competitive winning bids were announced that day. Operators did not bid on four of the onshore exploration contract areas: Kufra basin Area 196 (Blocks 2 and 4); Cyrenaica basin Area 57 (Blocks 1-4), Area 59 (Blocks 1 and 2), and Area 77 (Blocks 1-4).

New York-based Barrows Co. Inc. characterized Russian firms OAO Tatneft and OAO Gazprom as the "big winners."[1]

According to a summary of the winning bidders on the Libyan NOC website, Tatneft won licenses for three contract areas (Ghadames and Sirte basins) and Gazprom won a license to explore offshore Area 19 (total $40 million bonus). Taiwan's Chinese Petroleum Corp. (CPC), Germany's Wintershall AG, and a partnership of Petro-Canada and Repsol YPF took one license each (total $18 million bonus).

These companies specified production shares ranging 7.8%-18%, committed to drill 27 wells, acquire 19,100 km (2D) and 4,500 km (3D) seismic data, and pledged signature bonuses totaling $58.1 million (Table 1).

Three single bids by ExxonMobil Libya Ltd., ONGC Videsh Ltd., and Inpex Corp. were held until a meeting on Dec. 24 and subsequently approved by the NOC management committee.

The production share is higher on these three licenses than the competitive group: 22.3% and 28% for offshore areas and 12.9% for the onshore Murzuq basin. These three bids include 22,000 km (2D) and 5,500 km (3D) seismic, 8 wells, and $30 million in signing bonuses (Table 1, italicized lines).

LIBYA, THIRD BID ROUND RESULTS*

Table 1

Basin	Contract area (block)	Existing wells, no.	Winning operator	Operator commitment: 2D seismic, km	3D seismic, sq km	New wells, no.	Production share, %	Bonus, $ million
Offshore	19 (1, 2, 3, 4)	0	OAO Gazprom	4,000	2,000	6	10	10.1
	20 (1, 2, 3, 4)	*0*	*ExxonMobil Libya Ltd.*	*20,000*	*1,000*	*4*	*22.3*	*10*
	43 (1, 2, 3, 4)	*1*	*ONGC Videsh Ltd.*	*1,000*	*4,000*	*1*	*28*	*10*
Ghadames	82 (I)	2	OAO Tatneft	2,000	750	5	10.4	10
	98 (2, 4)	2	Tatneft	2,500	500	5	10.4	10
Sirte	69 (1, 2, 3, 4)	4	Tatneft	5,000	750	6	12	10
	137 (3, 4)	0	Petro-Canada, Repsol YPF	1,000	500	1	18	10
Murzuq	162 (1, 2)	0	Chinese Petroleum Corp.	1,600	0	3	7.8	5
	113 (3, 4)	*1*	*Inpex Corp.*	*1,000*	*500*	*3*	*12.9*	*10*
Kufra	201 (1, 2, 3, 4)	0	Wintershall AG	3,000	0	1	13.5	3
Total		**10**		**41,100**	**10,000**	**35**	—	**88.1**

*Winning bid list from Libya's National Oil Corp., Dec. 20, 2006; Barrows Co. Inc., New York. Italicized rows represent the three single bids approved Dec. 24, 2006.

The total work commitment arising form the third bidding round is 41,100 km (2D) and 10,000 km (3D) seismic and 35 exploration wells.

E&P-sharing agreements (EPSA) were scheduled to be signed in January 2007.

Following the opening of bid in the third round on Dec. 20, Libya's National Oil Corp. announced that a fourth bid round would be held in first-quarter 2007 with "the focus on gas."

Drilling contracts

Although drilling contracts in Libya had tended toward short-term in recent years, there has been a shift toward longer term day-rate contracts due to the shortage of suitable rigs. There is no indication of any turnkey drilling contracts in Libya at this time.

A new drilling challenge is the NOC's emphasis on discovering and developing gas reserves, after 45 years of exploration dedicated toward oil.

On Dec. 15, KCA Deutag, a wholly owned subsidiary of Abbot Group PLC, announced mobilization of its 3,000-hp T-202 rig from Bangladesh to Libya, to begin a 3-year contract in December 2007 with a major international operator to drill deep exploration and appraisal wells for potential gas reserves.

Rig fleets

KCA Deutag, a subsidiary of Abbot Group PLC, has worked in Libya for more than 40 years and is the largest western-owned drilling contractor in country, working for state-owned Waha Oil Co., Italy's Agip, Wintershall Libyen Oil & Gas GMBH, Arab Oil Gas Co., Germany's Veba Oil Co., Canada's Verenex Energy Inc., and Repsol Exploracion Murzuq SA (REMSA) through its ILI Corp. office in Tripoli.

KCAD had five rigs working in Libya before Abbot Group acquired International Air Drilling Co. Ltd. in 2004; IADC had a fleet of 10 workover and drilling rigs in country. Two newbuilds were added to its Libyan fleet in 2005.

The company now has 17 land rigs in Libya and will add an eighteenth rig in third-quarter 2007. The KCAD fleet includes:

- 12 rigs under 1,000 hp—3 Cabot 320; 7 Cabot Franks; 2 Sandmaster.
- 5 rigs 1,000-2,000 hp—1 EMSCO A-800; 1 National 1320 UE; 3 Ideco ED-1200.

Two of the rigs drilling in Libya are Sandmaster desert rigs, the T-107 (Sandmaster K650, contracted to Veba Libya); and the T-108 (Sandmaster K750; contracted to REMSA Libya, a subsidiary of Repsol YPF). A third drilling rig, the T-16, is contracted to Agip Libya (Fig. 2).

In late December, KCA Deutag announced new drilling contracts for Libya, including:

- A $45 million, 3-year contract to commence December 2007, with options to renew, for its 3,000-hp T-202 land rig, which will be mobilized from Bangladesh.
- A well-to-well contract with Veba Oil for the 700-hp workover rig T107, which is estimated to continue for 1 year.

In January 2006, Nabors Industries Ltd. received a term contract to run a new PACE rig in Libya for Occidental Petroleum Corp. (Fig. 3).

Drilling contractor Challenger Ltd. was established in 1991 and began drilling for the Arabian Gulf Oil Co. in the Sarrir field. In 1993-94, Challenger drilled in Wadi Borjuj for London & Scottish Marine Oil Co., and in 1994 at El Zahra for Waha.

Challenger has two offices in Libya,

Nabors F-16 is a new 1,500-hp, Chinese-built PACE rig currently drilling in Libya for Occidental Petroleum Corp. (Fig. 3; photo from Nabors Industries Ltd.).

at Benghazi and in Tripoli, and a fleet of 25 rigs, including 8 rotary drilling rigs, 5 workover rigs, and 12 water well drilling rigs.

Tripoli-based Arab Drilling & Workover Co. (ADWOC), a subsidiary of Arab Petroleum Services Co., has a fleet of drilling and workover rigs in Libya.

Technology

Various international service companies have used some of their newest technologies in Libyan fields.

Weatherford Libya Ltd. successfully used its MetalSkin solid expandable system to isolate a casing leak on a producing oil well in Messla, Libya. It successfully ran a noncemented cased hole liner without losing internal diameter.

According to Weatherford's Hani Qutobl and Anass Al-Chalabi, the company has also provided underbalanced reservoir drilling and controlled pressure air drilling services in Libya.

Weatherford's completion and production services group has a long-term supply and service agreement with Compagnie des Petroles Total Libye (CPTL) for electric submersible pump (ESP) installations.

Weatherford also set an extended-reach setting depth record to 15,569 ft offshore Libya using the Revolution rotary steerable system for CPTL.

In April 2006, BJ Tubular Services Co. announced its first contract to work in Libya providing services on a number of offshore wells for CPTL. BJ is providing hammer conductor-driving services and conductor cold-cutting services on the BD1 platform in Al Jurf field. BJ is using Zone 1 cold-cutting equipment and its S90 Hydrohammer hydraulic pile driving system to drive conductors.

Discoveries

Germany's RWE Dea AG is committed to drilling at least 10 exploration wells on 6 license areas, following an extensive seismic acquisition program. The company discovered 35° gravity oil in its first well, the A1-NC-193, it announced in late October 2006. RWE used the Adwoc Rig 2 to drill the 4,214 ft well in the Sirte basin, about 500 km southeast of Tripoli (OGJ, Nov. 6, 2006, p. 8).

Total has been active in Libya since the 1950s, operating the offshore Al Jurf field and Mabruk field in the Sirte basin. Totla also has a working interest in the consortium operating El Sharara field in the Murzuq basin. In July 2006, Total announced a new discovery at the D1 well in Area NC 191 of the southern Murzuq basin, about 800 km south of Tripoli.

In late December 2006, Verenex announced that it had completed drilling its first Libyan well, under a three-well commitment for the Contract Area 47 license. The A1-47/02 well reached TD at 11,550 ft and showed oil and gas in the Lower Acacus formation (9,010-10,062 ft) and Memountiat formation (near TD). Completion and production testing began in January.

Going forward

We can expect to see new contracts for seismic acquisition in Libya, data processing, and new drilling required under the 5-year EPSA 4 licenses issued in bid rounds 1, 2, and 3. Round 4 will be announced in February or March 2007.

Meanwhile, operators continue work in older fields they have recently regained. ConocoPhillips plans ongoing development of its Waha concession. Statoil inaugurated its office in Tripoli on Dec. 11, 2006.

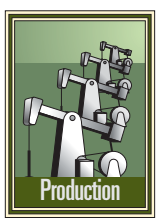
Peter Mellbye, executive vice-president for Statoil's international exploration and production business area, said in 2006, "The Libyan government's approval of our contracts [Dec. 10, 2005] represented a milestone. This marked the start of Statoil's operatorship of a 5-year exploration program in two licenses. The goal is to discover oil and gas resources which can form the basis for a long-term presence in Libya." ✦

Reference

1. Text of Libya's petroleum laws and the EPSA IV model contract published at www.barrowscompany.com.

Baseplate stops wellhead movement in Libyan oil field

Wathik M. Alhashimi
Arabian Gulf Oil Co.
Benghazi, Libya



Installation of a baseplate stopped wellhead movement on wells drilling in the Eastern Libyan Desert. Arabian Gulf Oil Co. operates the wells.

For drilling most of the wells, the company used rigs with a limited 19-24 ft substructure height. The work required a 4-ft cellar, dug prior to spudding the wells, to accommodate the blowout preventer stack.

Fig. 1 shows a typical wellhead used in the area. The cellar houses Section A (13⅝-in., 3,000 psi) and Section B (13⅝ × 11-in., 3,000 psi) of the wellhead.

The 13⅜-in. surface casing, cemented to surface, serves as pile anchor to support the landing weights of subsequent casing and liner strings. Because of insufficient cement slurry volume, slurry channeling, or cement deterioration over time, the casing can become unable to support the aggregate wellhead landing weight, subjecting the wellhead to:

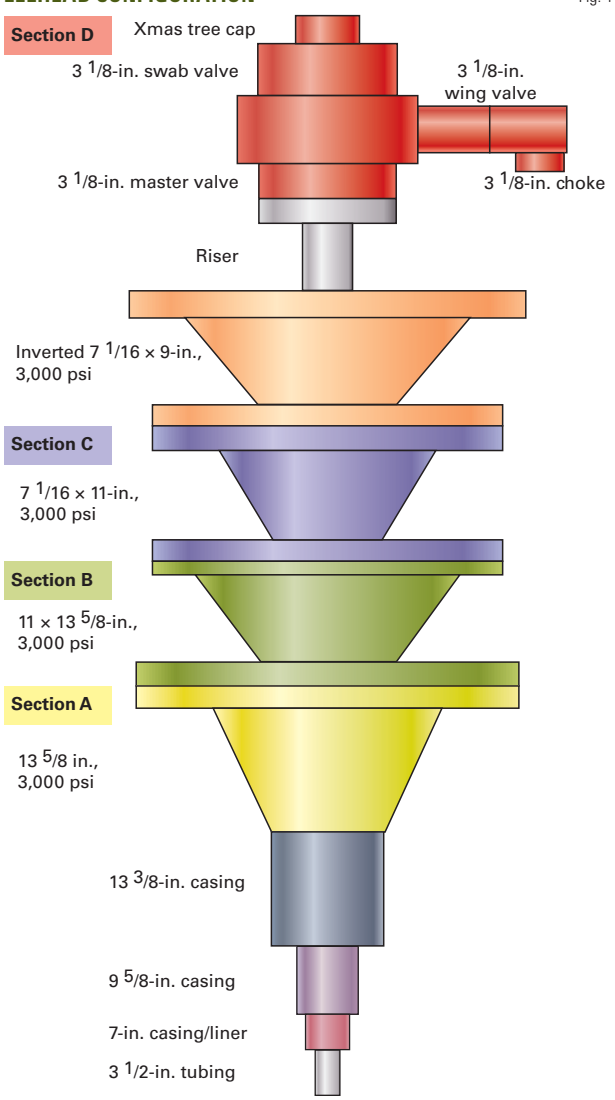
- Vertical movement because of thermal expansion during production periods, thermal contractions during shut-in periods, and subsidence due to unsupported casing
- Horizontal movement because of unsupported surface casing down to a certain depth. In some cases, wellhead subsidence was 2 ft and would increase if not stopped.

These wells produce with natural flow or artificial lift with electric submersible pumps (ESPs)

To stop the wellhead movements, AGOC incorporated a baseplate at the wellhead to reduce loads on the wellhead.

WELLHEAD CONFIGURATION

Fig. 1



Baseplate design

Sizing the baseplate requires taking into account the wellhead load, which is the aggregate weight of all casing and tubing landed on Section A of the wellhead and with an allowance for the buoyancy factor. The following relationship will determine the area of the baseplate, which is set level on desert sand:

$$A_{BP} = (F \times G_{WH})/B_s$$

The terms in the equation are as follows:

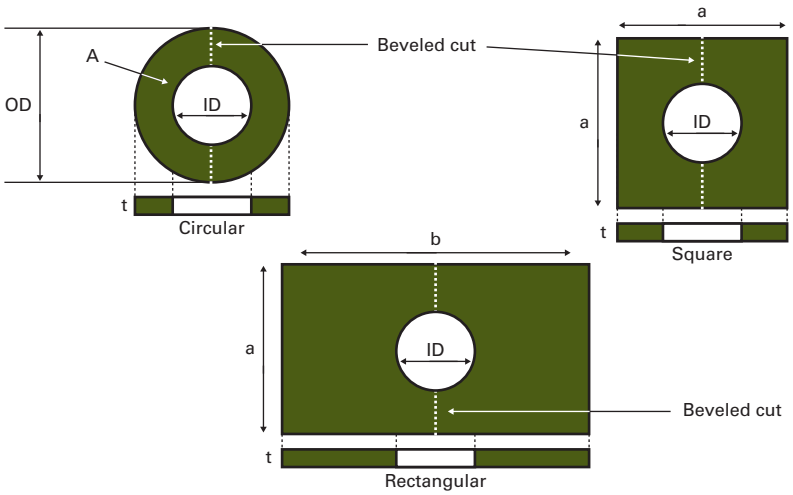
- A_{BP}—Baseplate area (unit area).
- F—Fraction of the wellhead load to be transmitted to baseplate support area (0-1).
- G_{WH}—Wellhead load (unit weight).
- B_s—Soil bearing capacity (unit weight/unit area).

The well's drilling history will contain the intermediate and production casings' landing weights, normally landed as cemented.

The production liner, if any, hangs inside the intermediate casing before being cemented and its weight is also in

BASEPLATE

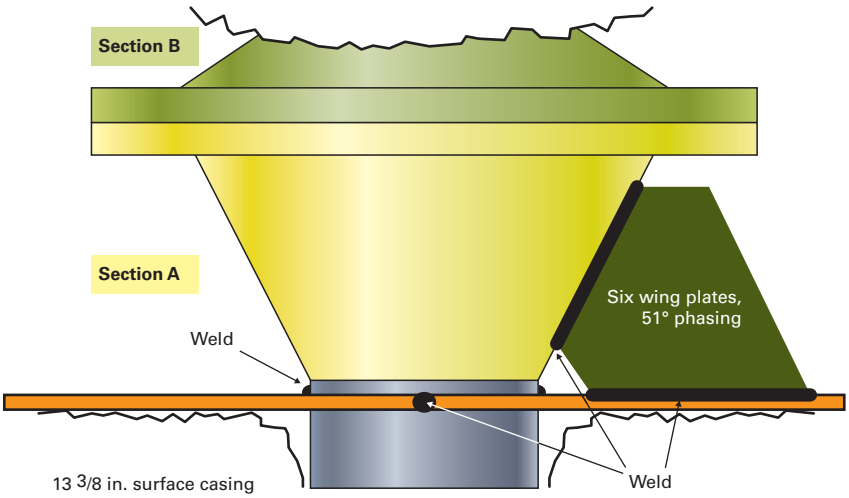
Fig. 2



Installation of the baseplate required digging out the cellar to just below Section A (Fig. 3).

BASEPLATE INSTALLATION

Fig. 3



the well's drilling history.

G_{WH} also has to include the weight of the production tubing.

After calculating A_{BP}, one needs to determine the optimum shape (circular, rectangular, or square) of the baseplate (Fig. 2). The available surface area around Section A allows for an annular shape circumscribing the surface casing.

Baseplate installation

Installation of the baseplate involves digging around the wellhead down to just below Section A (Fig. 3). The excavation needs to expose the surface casing and the ground around it so that the soil just below Section A can be carefully leveled and compacted.

After determining A_{BP}, one can start preparing the plate with an inside cut slightly larger than the casing (OD + 1 in.) before cutting it into two equal halves, with a bevel for welding. The plate then can be installed around the wellhead, just below Section A.

Welding the two halves together again forms one solid plate. The welding beads should be sufficiently thick and applied carefully so that the plate will not bend upwards during the welding. This plate must remain floating relative to the surface casing.

Six support wings welded to Section A allow for load transfer. One side of the wing plates are welded to Section A, while the other side is welded on the top side of the baseplate (Fig. 4).

The welding procedure of the wing plates should be such that it prevents damage from excessive localized heating to Section A and its internal parts, such as the casing hanger. ✦

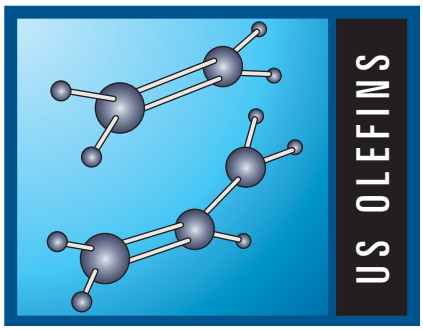
The author

Wathik M. Alhashimi is a senior engineering specialist—drilling, completions, and workovers—for Arabian Gulf Oil Co., Benghazi, Libya. He resides in Calgary. Previously he worked in management and engineering for several other petroleum and oil field service and supply companies in Canada, South America, and the Middle East. Alhashimi holds an MS in petroleum engineering from the Petroleum, Gas, and Geology Institute, Bucharest. He is a member of the Association of Professional Engineers, Geologists, and Geophysicists of Alberta.

SECOND-HALF 2006

US olefins producers struggle despite lack of major storms

Dan Lippe
Petral Worldwide Inc.
Houston



The absence of hurricanes during third-quarter 2006 created problems for US olefin producers in the fourth quarter. These problems, however, were minor compared with problems caused by the fires and hurricanes during third-quarter 2005.

After the disruptions to plant operations and loss of supply in the aftermath of Hurricanes Katrina and Rita in 2005, many petrochemical company buyers decided to be better prepared for the expected instant replay during the 2006 hurricane season. Many olefins producers reported that customers were prebuying and accumulating inventory during the second and third-quarter 2006 to ensure adequate supplies to offset expected supply disruptions due to hurricanes.

The 2006 hurricane season, however, proved to be nearly nonexistent and the Gulf of Mexico saw no hurricanes at all. For those petrochemical buyers that stockpiled in anticipation of hurricanes, accumulated surplus inventories had to be liquidated. The absence of any hurricane-related disruptions, therefore, resulted in a slump in demand during fourth-quarter 2006.

The olefin industry, however, was buffeted by the economic storm caused by the refining industry's abrupt conversion from methyl tertiary butyl ether to ethanol. During second and third quarter, ethanol supply was tight, some areas experienced ethanol supply allocations, and octane values remained extraordinarily strong through yearend 2006.

The sustained strength in octane values directly affected spot prices for propylene and aromatics. The strength in propylene and aromatics prices, in turn, influenced olefin plant feedslate decisions.

Olefin plant feed slates

Ethylene producers increased consumption of ethane and propane to 1.12 million b/d in May 2006. Feedstock demand for ethane and propane in May proved to be the high for 2006.

When the value of octane rose and coproduct prices strengthened, feedstock economics for naphthas and other heavy feeds became more favorable after May. Feedstock demand for ethane and propane, therefore, in third-quarter 2006 declined 93,000 b/d and averaged 1.07 million b/d vs. 1.16 million b/d in the second quarter. Demand for

US ETHYLENE FEED SLATE

Table 1

	Feed type, 1,000 b/d			
2006	Ethane	Propane	n-Butane	Naphthas, gas oils
January	757.7	315.2	16.5	552.4
February	688.5	358.9	31.4	474.7
March	788.7	355.1	57.8	426.8
April	794.3	340.2	83.1	394.3
May	780.9	412.1	84.0	404.8
June	782.2	373.8	119.9	495.6
July	760.4	375.2	139.6	495.3
August	675.4	373.2	122.3	519.9
September	726.6	294.7	87.7	568.8
October	729.5	288.0	78.1	509.0
November	742.5	314.8	68.9	496.1
December (estimated)	750.0	300.0	60.8	513.4

Source: Petral Monthly Olefin Feedslate Survey

ETHYLENE FROM US STEAM CRACKERS

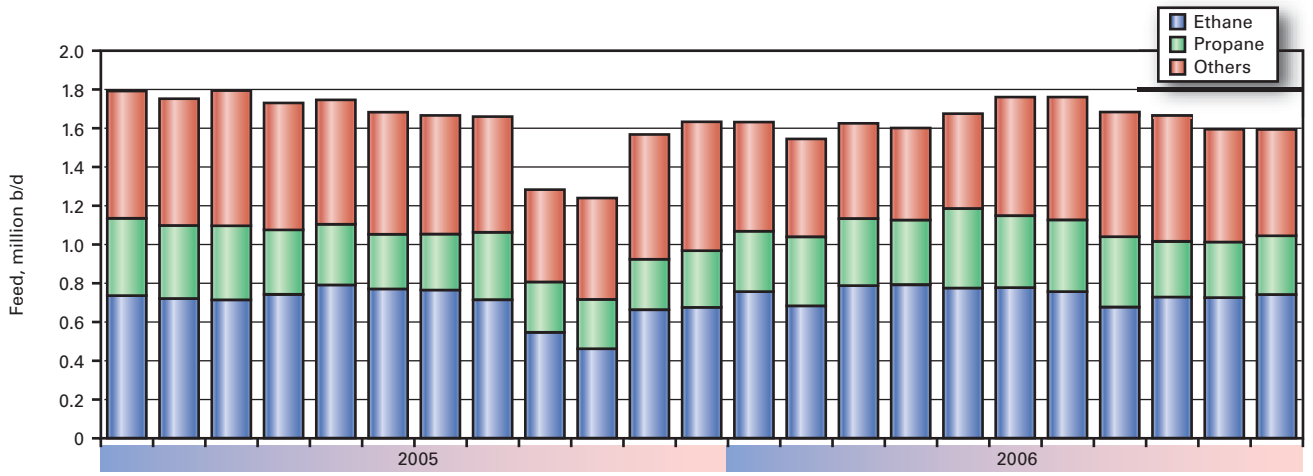
Table 2

	Production, billion lb	
2006	LPG crackers	Multifeed crackers
January	1.6	2.8
February	1.5	2.3
March	1.7	2.8
April	1.6	2.7
May	1.7	2.9
June	1.7	2.9
July	1.8	3.0
August	1.6	2.9
September	1.5	3.0
October	1.6	2.7
November	1.6	2.7

Source: Petral Monthly Olefin Feedslate Survey

US ETHYLENE PLANT FEED SLATE

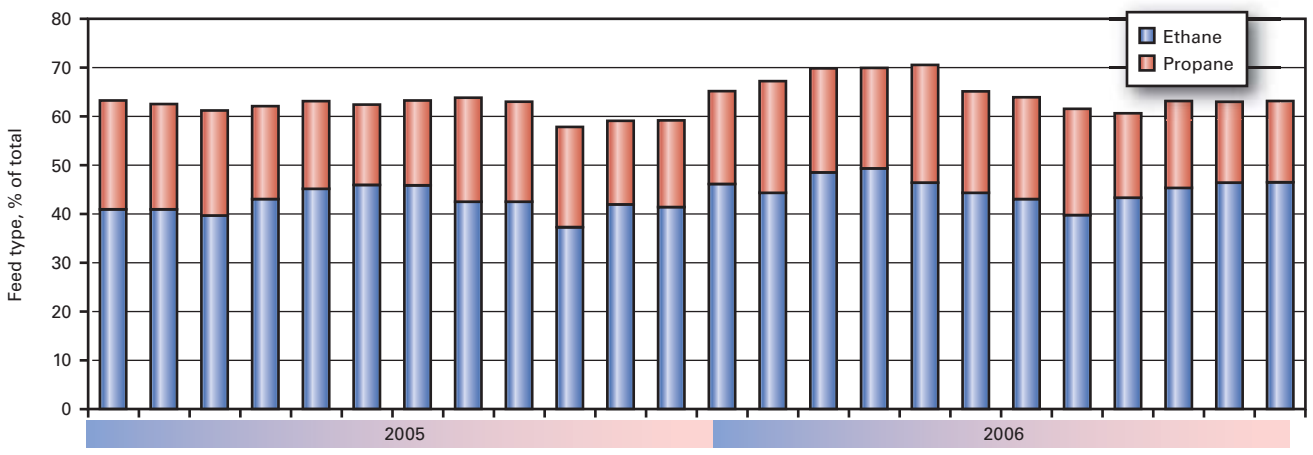
Fig. 1



Source: Petral Monthly Olefin Plant Feedslate Survey

ETHANE, PROPANE SHARE OF FEED

Fig. 2



Source: Petral Monthly Olefin Plant Feedslate Survey

ethane and propane declined again in the fourth quarter, averaging 1.02 million b/d.

Table 1 shows recent trends in olefin plants' feed slates.

Ethane and propane accounted for 69% of the industry's total consumption of fresh feed in second-quarter 2006 but accounted for only 62% in third-quarter 2006 and 63% in fourth-quarter 2006. Ethane's share of fresh feed declined to 42% in third-quarter 2006 but rebounded to about 46% in the fourth quarter.

Propane's share of fresh feed is usually at its highest level for the year during third quarter but generally declines in fourth quarter. In 2006, propane's share of fresh feed averaged 22% in second quarter and 20% in third quarter. Consistent with the historic seasonal pattern, propane's share of fresh feed declined to 19% in fourth-quarter 2006.

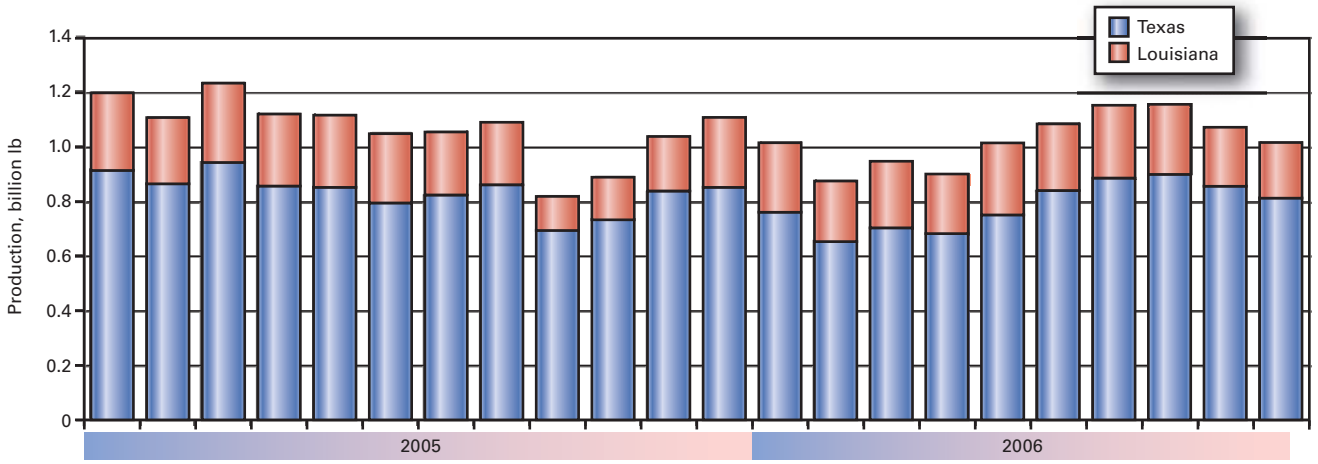
Because the value of coproducts increased and cracking economics for naphthas improved, demand for naphthas and other heavy feeds rebounded in third-quarter 2006. Consumption of heavy feeds averaged 528,000 b/d in third-quarter 2006 vs. 432,000 b/d in second-quarter 2006. Even though total demand for fresh feed declined in fourth-quarter 2006, demand for heavy feeds was nearly constant and averaged 523,000 b/d.

Olefin producers did not operate at full capacity at any time in 2006. Total demand for fresh feed was its highest level during third-quarter 2006; consumption averaged 1.71 million b/d vs. 1.78 million b/d in first-quarter 2005 (the high quarter for 2005).

In response to demand weakness for various olefin derivatives, total demand for fresh feed declined in fourth-quarter 2006 and averaged only 1.61 million b/d.

COPRODUCT PROPYLENE

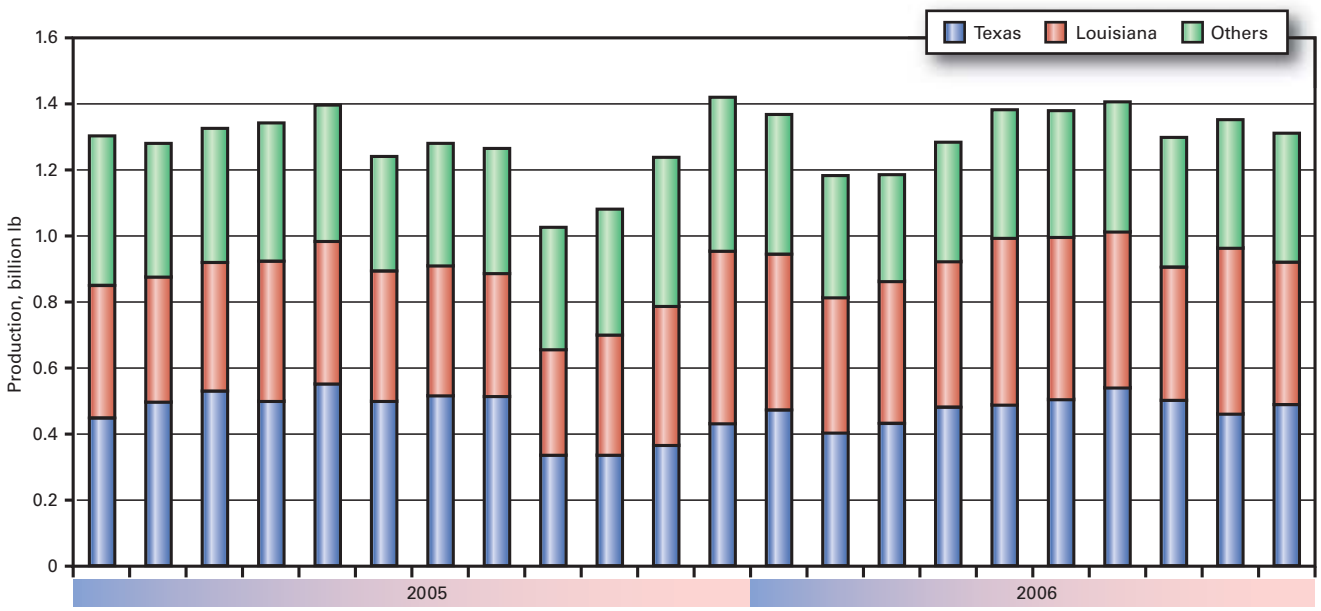
Fig. 3



Source: Petral Monthly Coproduct Supply Analysis

REFINERY PROPYLENE

Fig. 4



Source: EIA Petroleum Supply Monthly

Ethylene plants will run at 90-92% of available capacity during first-half 2007, and total demand for feedstocks will increase to 1.65 million b/d during that period. Retail demand for propane generally declines after January and availability for US Gulf Coast feedstock market improves.

Similarly, refinery demand for normal butane will fall sharply during first quarter and will reach its seasonal low during second quarter. Feedstock demand for propane and normal butane will increase during first-half 2007.

The outlook for ethane demand, however, is somewhat more complicated. For the first time in several years, ethane availability may likely constrain feedstock demand during the first half of 2007.

Figs. 1 and 2 show historic trends in ethylene feed slates.

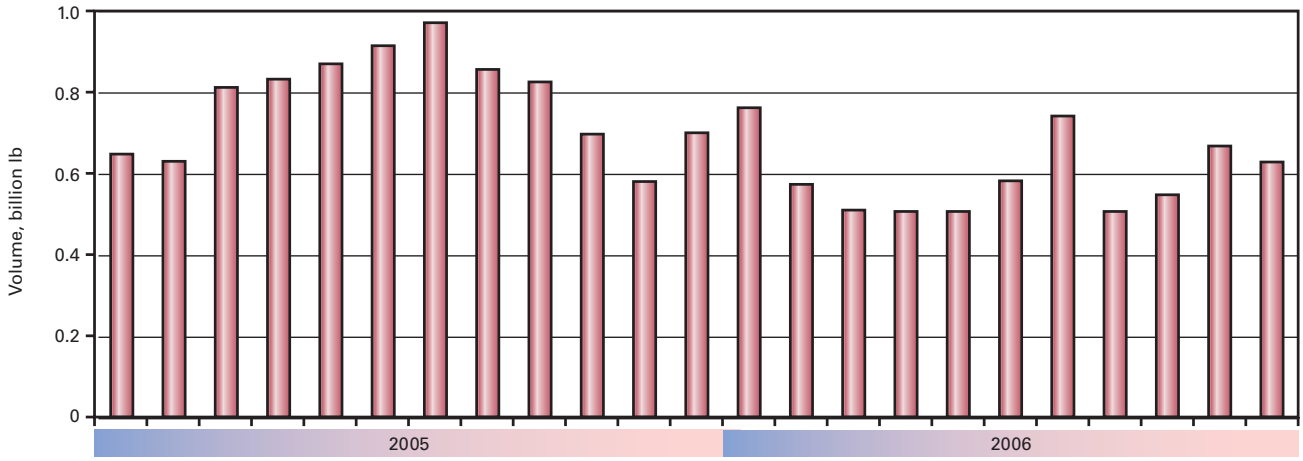
Ethylene production

In second-quarter 2006, available nameplate ethylene capacity averaged 60.2 billion lb vs. the industry's full nameplate capacity of 61.2 billion lb/year.

In April 2006, Formosa Petrochemical Corp. and Innovene LLC completed repairs to their facilities. Huntsman Chemical Co.'s plant at Port Arthur, Tex.,

Refinery proplene inventory

Fig. 5



Source: EIA Petroleum Supply Monthly

however, experienced an explosion and major fire in late April and was out of service for 2006. According to official company statements, this plant will be out of service through at least second-quarter 2007.

Finally, a turnaround in April and May reduced available capacity by 1.9 billion lb/year for about 50 days. In third-quarter 2006, the industry's full nameplate capacity totaled only 59.7 billion lb/year due to loss of capacity at Huntsman's plant.

Ethylene production from U.S. olefin plants totaled 13.5 billion lb in second-quarter 2006 (Table 2). The industry's operating rate averaged 90.2% on a full nameplate basis and 91.8% on an adjusted-capacity basis.

Production in second-quarter 2006 was 0.83 billion lb more than in first-quarter 2006. Ethylene production in second-quarter 2006 was almost equal to prehurricane volumes in first and second-quarter 2005 (13.9 billion lb and 13.7 billion lb, respectively). Ethylene production from LPG crackers increased 0.22 billion lb and production from multifeed crackers increased 0.61 billion lb during second-quarter 2006.

Ethylene production increased again in third-quarter 2006 and totaled 13.8 billion lb, or 0.24 billion lb more than in second-quarter 2006. The industry's operating rate averaged 91.5% on a full nameplate basis (excluding the capacity at Huntsman's Port Arthur plant) and 93.2% on an adjusted-capacity basis (accounting for downtime due to turnarounds). Production from LPG crackers declined 0.16 billion lb but production from multifeed crackers increased 0.4 billion lb.

LPG crackers accounted for 35% of total production in third-quarter 2006 and operated at 90.5% of nameplate capacity. Multifeed crackers accounted for 65% of production and operated

US ethylene by state

Table 3

2006	Production, billion lb — Texas Gulf Coast	Louisiana
January	3.0	1.2
February	2.5	1.1
March	3.0	1.2
April	3.0	1.1
May	3.1	1.2
June	3.2	1.2
July	3.3	1.2
August	3.2	1.1
September	3.1	1.0
October	3.1	1.0
November	2.9	1.1

Source: Petral Monthly Olefin Feedslate Survey

Propylene from US steam crackers

Table 4

2006	Production, million lb — LPG crackers	Multifeed crackers	Coproduct production
January	160.6	889.4	1,050.1
February	159.5	750.7	910.2
March	161.8	822.5	984.3
April	147.2	783.3	930.5
May	179.5	858.8	1,038.3
June	184.6	938.0	1,122.7
July	194.8	988.3	1,183.0
August	189.7	994.9	1,184.5
September	130.8	968.6	1,099.4
October	165.1	879.2	1,044.3
November	146.6	857.6	1,004.2

Source: Petral Monthly Propylene Supply Analysis

US Gulf Coast propylene

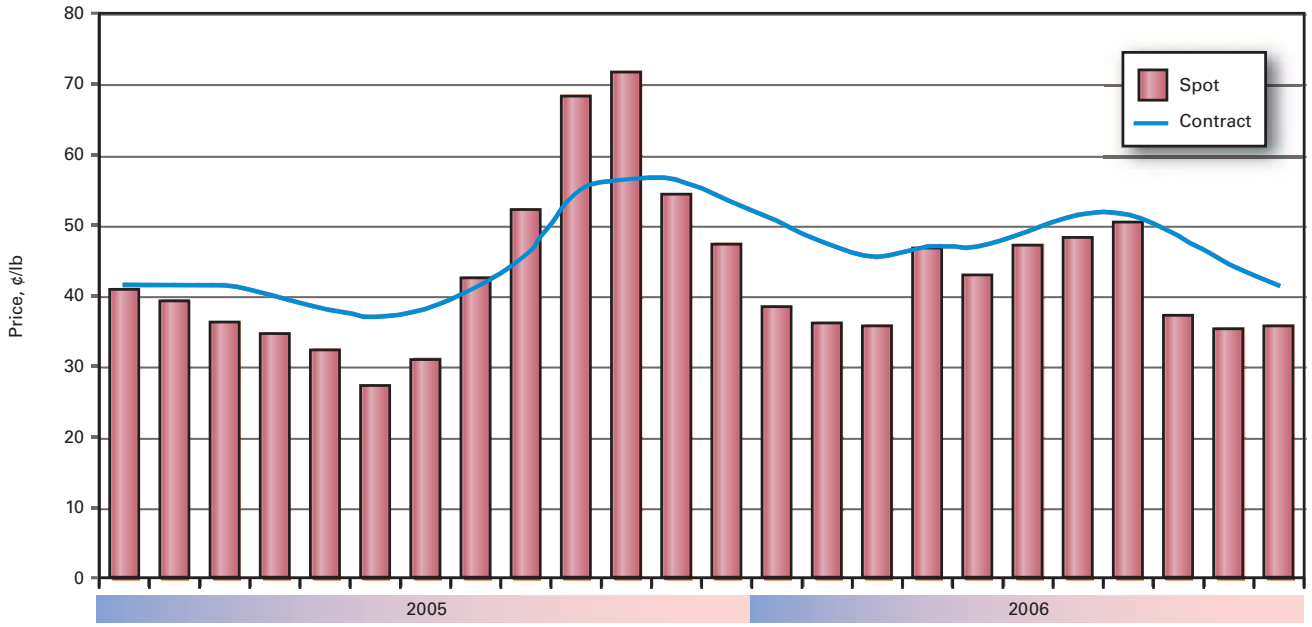
Table 5

2006	Production, million lb — Texas	Louisiana	US Gulf Coast
January	758.5	260.0	1,018.5
February	652.8	227.2	880.0
March	700.1	251.2	951.3
April	680.7	221.4	902.0
May	748.1	267.7	1,015.8
June	835.3	257.2	1,092.4
July	887.0	268.3	1,155.3
August	898.1	262.1	1,160.2
September	855.6	215.6	1,071.2
October	812.7	205.9	1,018.6
November	744.6	234.0	978.6

Source: Petral Monthly Propylene Supply Analysis

ETHYLENE PRICES

Fig. 6



at 92.1% of capacity in third-quarter 2006.

Table 3 shows ethylene production from plants in Texas and Louisiana.

US propylene production

Spot prices for chemical-grade propylene averaged 47¢/lb in second-quarter 2006 and 48¢/lb in third-quarter 2006. Spot prices for chemical-grade propylene were 3.8¢/lb higher than in first-quarter 2006. Despite the increase of almost 4¢/lb in second quarter, propylene price relationships vs. unleaded regular gasoline and alkylate weakened in second quarter but rebounded sharply in third-quarter 2006.

Spot prices for aromatics (especially benzene and xylenes) also increased in second and third quarters. Total coproduct credits for light naphthas increased 5¢/lb in second-quarter 2006 and 2.3¢/lb in third quarter.

Increases in coproduct credits contributed to significant improvements in economic incentives for propane and light naphthas. Feedstock demand, therefore, for propane and heavy feedstocks increased and coproduct propylene production from olefin plants increased in second and third quarters.

Propylene from steam crackers totaled 3.1 billion lb in second-quarter 2006 or 150 million lb more than in first-quarter 2006. In third quarter, coproduct propylene production totaled 3.5 billion lb or 377 million lb more than in second-quarter 2006.

Table 4 shows trends in coproduct propylene production from LPG and multifeed plants.

In second-quarter 2006, propylene production from olefin plants in Texas was 2.28 billion lb (Table 5), and the propylene-ethylene production ratio averaged 24.1% vs. 24.7% in first-quarter 2006. In third-quarter 2006, propylene production from olefin plants in Texas increased 380 million lb and totaled 2.66 billion lb. The propylene-ethylene production ratio averaged 27% in third-quarter 2006.

Propylene production in Louisiana totaled 0.74 billion lb in both second and third-quarter 2006. The propylene-ethylene production ratio averaged 21.2% in second quarter and 22.1% in third quarter.

Fig. 3 shows trends in coproduct propylene production from olefin plants in Texas and Louisiana.

Refinery propylene supply

Merchant sales of refinery-grade propylene usually increase in second and third quarters due to seasonal factors. Refineries generally operate at full capacity after April. Additionally, refineries typically operate FCC units in maximum gasoline mode. By-product propylene yields from FCC units are therefore usually somewhat higher in second and third quarters vs. the first and fourth quarters.

Consistent with typical seasonal trends, merchant sales of refinery-grade propylene totaled 4.06 billion lb in second-quarter 2006, or 307 million lb more than in first-quarter 2006. In third-quarter 2006, however, merchant sales of refinery propylene totaled 4.07 billion lb (Table 6) or almost the same as in second-quarter 2006.

In fourth-quarter 2006, refinery merchant sales of propylene will be 1.40-1.45 billion lb/month and production will total 4.00-4.25 billion lb.

Fig. 4 shows trends in refinery merchant propylene sales.

Propylene inventories

According to the US Energy Informa-

tion Agency's weekly inventory report, refinery-grade propylene inventories were consistently 500-600 million lb during the second and third-quarter 2006 except during July. Inventories of refinery-grade propylene increased 162 million lb and totaled 747 million lb on Aug. 1. During August 2006, inventories declined 234 million lb and totaled only 513 million lb on Sept. 1.

Fig. 5 shows trends in refinery-grade propylene inventories.

Ethylene economics, prices

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

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

Ethylene production costs

During second-quarter 2006, spot prices for most feedstocks and coproducts increased. The rebound in feedstock prices outweighed the increases in coproduct prices and the Houston Ship Channel composite production cost (variable costs plus fixed cash costs) averaged 31¢/lb.

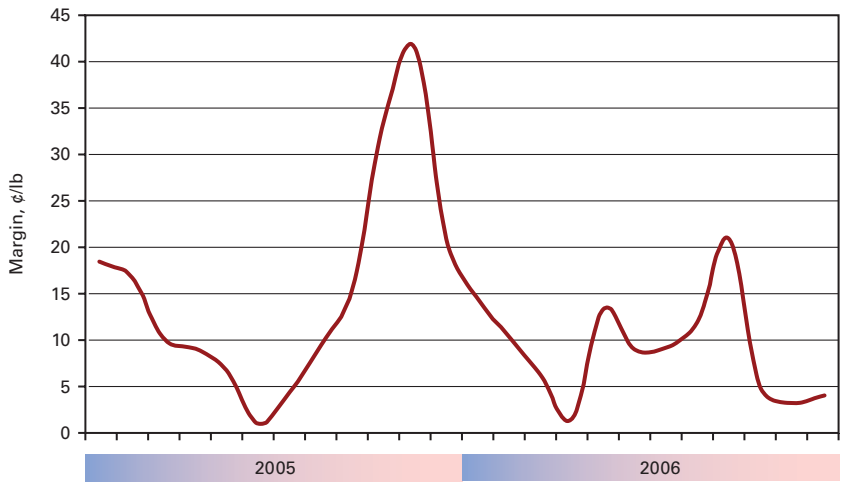
In third-quarter 2006, feedstock prices reached their highs for the year (July and August) but coproduct credits were only modestly higher than in second quarter. The Houston Ship Channel composite production cost therefore rose 1.8¢/lb and averaged 32¢/lb.

A general decline in prices for all petroleum products began in August and accelerated in September; thus, the Houston Ship Channel composite production cost declined by almost 4¢/lb during fourth-quarter 2006 and averaged 28¢/lb.

Table 7 summarizes trends in ethylene production costs.

ETHYLENE PROFIT MARGIN

Fig. 7



US REFINERY MERCHANT PROPYLENE

Table 6

2006	Sales, million lb			
	Texas	Louisiana	Other states	Total
January	480.8	468.6	420.0	1,369.3
February	411.0	409.6	368.7	1,189.3
March	438.4	428.0	325.4	1,191.8
April	492.1	437.9	356.3	1,286.2
May	495.4	510.4	384.9	1,390.7
June	515.1	481.2	384.6	1,380.8
July	546.3	469.1	392.6	1,408.0
August	509.8	400.6	396.2	1,306.7
September	469.6	502.7	383.5	1,355.8

Source: EIA Petroleum Supply Monthly

ETHYLENE COSTS, HOUSTON SHIP CHANNEL

Table 7

	Variable, direct fixed cash costs, ¢/lb				
	Purity ethane	Purity propane	Normal butane	Natural gasoline	Industry composite
2006					
January	28.8	28.8	30.7	34.4	32.8
February	24.4	25.2	26.5	28.3	27.6
March	25.2	26.3	22.2	30.0	26.9
April	29.3	29.4	24.1	35.7	30.9
May	30.1	29.7	24.2	31.2	30.3
June	31.2	32.0	25.8	29.6	31.2
July	36.5	36.1	29.1	34.3	34.6
August	34.6	33.2	27.8	31.1	33.7
September	28.1	27.9	21.9	23.5	27.0
October	27.8	27.9	24.0	23.4	27.3
November	27.1	29.0	24.5	24.4	27.6
December	28.7	30.9	25.3	27.8	29.7
Forecast, 2007					
January	30.8	31.5	25.7	28.2	30.0
February	31.7	32.7	26.8	29.0	30.8
March	28.3	29.0	22.2	23.1	27.3
April	26.2	25.1	18.8	19.5	24.3

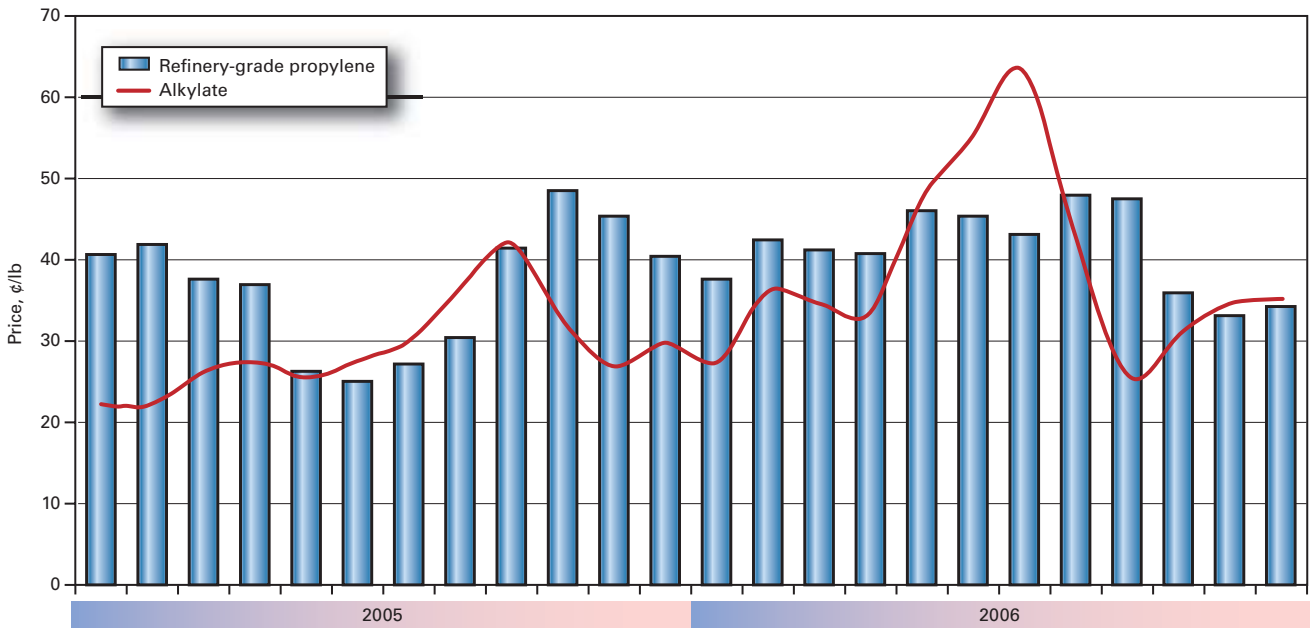
Ethylene prices, profit margins

Contract prices for ethylene averaged 46.5¢/lb in the second quarter, down from 50.5¢/lb in first-quarter 2006. Contract prices rebounded significantly in third quarter and averaged about 51¢/lb. Contract prices, however, fell to 41.5¢/lb in December and averaged almost 45¢/lb in fourth quarter.

During second-quarter 2006, spot prices for ethylene increased to 47¢/lb in May from 36¢/lb in April but then declined to 43¢/lb in June. Spot prices averaged 42¢/lb in second quarter vs. 41¢/lb in first quarter. Despite the increase in spot ethylene prices during second quarter, the industry's profit margin (spot prices minus cash production costs)

PROPYLENE, ALKYLATE PRICES

Fig. 8



averaged only 12.2¢/lb vs. 14.4¢/lb in first quarter.

Spot prices for ethylene staged a strong rally during third quarter and averaged 48.8¢/lb. Spot prices reached a 2006 peak of 50.5¢/lb in September. The rally in spot ethylene prices and the decline in production costs pushed profit margins to 23.1¢/lb in September vs. 11.8¢/lb in July. For third-quarter 2006, profit margins averaged 18.3¢/lb.

Although delayed by 2 months, spot prices for ethylene succumbed to the general decline in spot prices for petroleum products. The end was abrupt and brutal and spot prices in October fell to a low of 32¢/lb at month's end. For fourth-quarter 2006, spot prices for ethylene averaged 34.4¢/lb or 14.4¢/lb lower than the average for third-quarter 2006.

Profit margins based on spot prices and total cash costs collapsed in fourth quarter and averaged only 8.5¢/lb or almost 10¢/lb lower than in third quarter.

Figs. 6 and 7 show historic trends in ethylene prices and profit margins.

Propylene economics, prices

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

During third-quarter 2006, spot prices for refinery-grade propylene prices increased to a high of 48¢/lb in August but weakened slightly in September and averaged about 47.75¢/lb. Spot prices for refinery-grade propylene moved higher even though spot prices for unleaded regular gasoline fell by 26¢/gal in August and an additional 45¢/gal in September. Similarly, spot prices for alkylate declined by 108.5¢/gal or about 18¢/lb during third quarter.

The strength in spot prices for refinery-grade propylene was even more surprising given the increase in total propylene production during third quarter.

Spot prices for refinery-grade propylene finally succumbed to bearish economic and supply prices during October and November. After contract prices for refinery-grade propylene settled at 45.5¢/lb, spot prices fell abruptly and averaged about 36¢/lb or almost 12¢/lb lower than in September. Spot prices continued to decline in November and averaged about 33.5¢/lb.

Contract prices followed suit and settled at 34.5¢/lb in November or 9¢/lb lower than in October. The market for refinery-grade propylene found a temporary equilibrium in December. Contract prices settled at 35¢/lb and spot prices averaged 34.5¢/lb.

Polymer-grade propylene prices usually command a premium of 4-5¢/lb vs. refinery-grade propylene. During third quarter, the premium for polymer-grade propylene (contract-price basis) was 5.5¢/lb in July, narrowed to 4.0¢/lb in August, and recovered to 4.75¢/lb in September. For third quarter, the contract-price premium for polymer-grade propylene averaged 4.75¢/lb.

In October, the contract price for polymer-grade propylene declined 4¢/lb vs. a decline of only 3.25¢/lb for refinery-grade propylene; the polymer-grade premium narrowed to 4.0¢/lb. Merchant splitters recouped the loss in November when the contract premium for polymer-grade propylene widened to 6.0¢/lb. In December, the premium narrowed slightly to 5.0¢/lb and averaged 5.2¢/lb for fourth-quarter 2006.

Octane values

We determine octane's incremental value using the differential between unleaded premium and unleaded regular gasoline prices divided by the difference in octane (87 octane for unleaded regular gasoline and 93 octane for unleaded premium gasoline).

During second quarter, incremental octane values increased to 3.2¢/octane-gal in June vs. 1.3¢/octane-gal in April. The rally in octane values continued into third-quarter 2006 and peaked in August at 4.3¢/octane-gal (about four times greater than the historic average).

In September, however, incremental octane values dipped to 2.6¢/octane-gal. Octane values were nearly constant in October but rebounded to 3.2¢/octane-gal in November and December.

We can evaluate the relative strength in refinery-grade propylene prices by tracking differentials vs. US Gulf Coast spot prices for unleaded regular gasoline, spot prices for unleaded regular gasoline in the Chicago pipeline market, and by comparison with Gulf Coast spot alkylate prices.

Fig. 8 shows trends in spot prices for refinery-grade propylene and alkylate.

During second-quarter 2006, price premiums for refinery-grade propylene vs. spot alkylate weakened significantly and averaged 2.6¢/lb. Premiums ranged from a low of 0.3¢/lb in April to 5.3¢/lb in May.

Differentials between refinery-grade propylene and alkylate were dramatically more volatile during third quarter. Alkylate prices reached a high of about 47¢/lb in July but refinery-grade propylene prices dipped to 43.3¢/lb; therefore, spot prices for refinery-grade propylene averaged 3.8¢/lb less than alkylate in July.

By September, alkylate prices fell to 29.5¢/lb but refinery-grade propylene prices rallied to 47.8¢/lb and the premium surged to 18.3¢/lb. For third quarter, refinery-grade propylene premiums averaged 7.7¢/lb.

Outlook

Crude inventories declined by 4 million bbl during third-quarter 2006 and 2-4 million bbl during fourth quarter. Crude inventories totaled 320 million bbl at yearend and were about the same as year-earlier volumes.

Unless crude producers in the Middle East experience a substantial supply disruption or voluntarily reduce production by 1 million b/d and maintain strict discipline on voluntary production cuts, continued growth in crude production from non-OPEC sources will increase bearish pressures on prices throughout 2007.

Octane values, however, will average 2.25-2.50¢/octane-gal during first-half 2007 vs. 2.95¢/octane-gal in fourth-quarter 2006. In summary, price forecasts for ethylene, propylene, and ethylene feedstocks are based on spot prices for West Texas Intermediate crude in the range of $58-62/bbl during first-quarter 2007 and $55-58/bbl in second-quarter 2007.

The projected decline in WTI prices during second-quarter 2007 will de-

NELSON-FARRAR COST INDEXES

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

	1962	1980	2003	2004	2005	Oct. 2005	Sept. 2006	Oct. 2006
Pumps, compressors, etc.	222.5	777.3	1,540.2	1,581.5	1,685.5	1,706.6	1,777.5	1,787.0
Electrical machinery	189.5	394.7	522.0	516.9	513.6	514.1	530.5	527.7
Internal-comb. engines	183.4	512.6	911.7	919.4	931.1	935.5	965.7	964.5
Instruments	214.8	587.3	1,076.8	1,087.6	1,108.0	1,113.6	1,199.4	1,206.5
Heat exchangers	183.6	618.7	732.7	863.8	1,072.3	1,079.2	1,179.4	1,179.4
Misc. equip. average	198.8	578.1	956.7	993.8	1,062.1	1,069.8	1,130.5	1,133.0
Materials component	205.9	629.2	933.8	1,112.7	1,179.8	1,174.7	1,321.4	1,319.4
Labor component	258.8	951.9	,228.1	2,314.2	2,411.6	2,454.9	2,497.2	2,547.9
Refinery (Inflation) Index	237.6	822.8	1,710.4	1,833.6	1,918.8	1,942.9	2,026.9	2,056.5

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

	1962	1980	2003	2004	2005	Oct. 2005	Sept. 2006	Oct. 2006
Fuel cost	100.9	810.5	934.8	971.9	1,360.2	1,750.1	1,491.5	1,434.7
Labor cost	93.9	200.5	200.8	191.8	201.9	241.8	206.8	219.2
Wages	123.9	439.9	971.8	984.0	1,007.4	1,060.2	1,046.1	1,060.3
Productivity	131.8	226.3	485.4	513.3	501.1	438.5	505.8	483.8
Invest., maint., etc.	121.7	324.8	643.0	686.7	716.0	724.9	750.7	761.7
Chemical costs	96.7	229.2	237.7	268.2	310.5	330.6	371.5	370.0
Operating indexes								
Refinery	103.7	312.7	464.7	486.7	542.1	598.1	576.6	580.8
Process units*	103.6	457.5	612.5	638.1	787.2	938.8	846.8	834.5

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

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

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

crease spot prices for all feedstocks and will reduce composite production costs by 5-7¢/lb.

During first-quarter 2007, cash production costs will be about the same as fourth-quarter 2006, but the expected rebound in demand should boost profit margins by 2-4¢/lb. As a result, spot ethylene prices will average 37-39¢/lb or about 3-4¢/lb higher than in fourth-quarter 2006.

In second-quarter 2007, cash production costs will decline by 5-6¢/lb. Spot ethylene prices will average 35-37¢/lb during second-quarter 2007 and profit margins will improve to 16¢/lb vs. 10¢/lb during first-quarter 2007.

Spot prices for refinery-grade propylene will average 36-38¢/lb during first-quarter 2007 and 37-39¢/lb in second-quarter 2007. Based on these price forecasts, refinery-grade propylene prices will average 4-6¢/lb higher than spot alkylate during first-quarter 2007. Premiums vs. spot alkylate will widen to 7-9¢/lb during second-quarter 2007.

Contract prices for polymer-grade propylene will average 4.75-5.25¢/lb higher than refinery-grade propylene during the first half of 2007. ✦

The author

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

China applies WEPP lessons as natural gas demand grows

Meng-di Gu
Shou-de Li
Shanghai Jiao Tong University
Shanghai

Completion of China's West-East Pipeline Project (WEPP) and its successful operation during the past 2 years has provided valuable experience that China is applying to future natural gas pipelines as the country strives to use more gas in the future.

WEPP is modern China's second-largest infrastructure project after the Three Gorges Dam. It began operations in January 2005, moving natural gas from the Tarim basin in the Xinjiang Autonomous Region of far western China to the eastern China cities of Zhengzhou and Nanjing, with the mainline terminating in Shanghai and lateral pipelines terminating in Hangzhou, Wuhu, and Hefei (OGJ, Mar. 17, 2003, p. 68).

Complicated conditions

The WEPP crosses topographical features that created construction difficulties.

- Crossings of the three largest rivers in China (Yellow, Yangtze, and Huai), including a more than 7-km crossing of the Yellow River in Zhengzhou.
- Tunnels through three mountains.
- Crossing of the vast loess plateau in central China. Loess soils are extremely complex, exist in just a few areas of the world, and are easily eroded once disturbed.
- Crossing of wetlands in eastern China (OGJ, July 21, 2003, p. 58). Work in the wetlands had to balance the pipe's tendency to float in some areas and sink into the mud in others.

WEPP planners and government officials were also concerned about possible environmental effects of the project, both when it was under construction and as it entered commercial operation. Planners redirected the pipeline to avoid damaging natural reserves and places of historical importance. According to the regional Xinjiang Environmental Protection Bureau, the project added 150 million yuan ($18 million) to its cost to take a camel-friendly route through northwest China's Xinjiang Uygur Autonomous Region.

Pipeline plans

Encouraged by the WEPP, and to satisfy rising demand for natural gas, China has built or plans to build more gas pipelines, including:

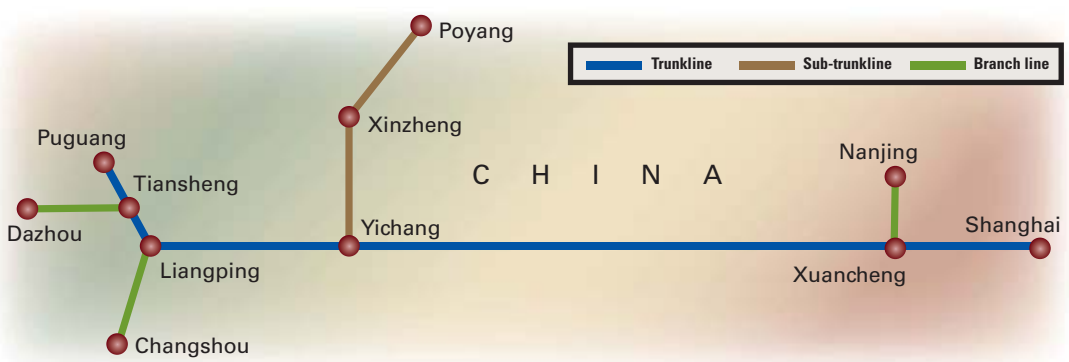
- A second Shaanxi-to-Beijing line.
- A 900-km bridge pipeline from Beijing to Shandong province.
- East China Sea Xihu Gas Field Consortium transmission lines.

China National Petroleum Corp. (CNPC) also plans to invest 4.3 billion yuan to boost capacity of the WEPP itself to 17 billion cu m/year from 12 billion cu m/year. The capacity-boosting project will raise the number of pumping stations along the line to 22 from 10.

Bigger than any of these projects, however, China plans to build the second west-east pipeline by 2010. The draft of Guidelines for the "Eleventh Five-Year Development Plan for National Economic and Social Devel-

CHUANHU PIPELINE SCHEMATIC

Fig. 1



WEST-EAST PIPELINE PROJECT, PROPOSED IMPORT ROUTES

Fig. 2

opment (2006-2010)" submitted for examination and approval by the ongoing fourth session of the 10th National People's Congress (NPC) included a proposal for the second WEPP.

The NPC is still researching the project's feasibility, with no timetable yet set for its construction. The fate, timing, and route of a second WEPP depend directly on supply and demand in China's natural gas market. But an official with CNPC said that the second pipeline would have a larger diameter than the first west-east pipeline and will cost much more than the 46 billion yuan spent on the first one.

The network

China's natural gas pipeline network delivers from three separate resources. Development during the next 20 years will continue to focus on these resources.

- Domestic inland gas. With China's major inland gas fields located in the western part of the country, most domestic gas flows from west to east. Gas arteries following this path include the WEPP, the Shaanxi-Beijing pipeline, and the Zhongwu line, with the Chuanhu line planned to pipe gas out of Sichuan province.

Zhongwu has one 711-mm OD trunkline from Zhong county, Chongqing municipality to Wuhan city, Hubei province. Three branch lines run from Jingzhou to Xiangfan (406.4-mm OD), Qianjiang to Xiangtan (610 and 508-mm), and Wuhan to Huangshi (323.9-mm). The total system extends 1,347.3 km, 718.9 km of which is trunkline, and has a design capacity of 3 billion cu m/year.

Authorities are still considering the Chuanhu project (Fig. 1). As proposed, it would include one 1,674-km trunkline from Pugang, Sichuan, to Shanghai (1,016-mm OD from Pugang to Xuancheng, Anhui; 864 mm from Xuancheng to Shanghai), one 842-km sub-trunkline from Yichang, Hubei, to Poyang, Henan (813 mm from Yichang to Xinzheng, Henan; 711 mm from Xinzheng to Poyang), and three branch lines: 154 km from Liangping to Changshou, Chongqing (559-mm OD), 45 km from Tiansheng pumping station to Dazhou station, Sichuan (323.9 mm), and 148 km from Xuanchang to Nanjing (813 mm).

- Imported gas. China's planners are also considering several cross-border pipelines from Russia and Central Asian nations Kazakhstan, Turkmenistan, and Uzbekistan (Fig. 2).

Gas from Russia will be transported along two routes, a west pipeline will enter China's Xinjiang through Siberia and Altai, before connecting with the WEPP to bring natural gas to China's coastal areas. An east pipeline, yet to be confirmed, might transport natural gas from the Kovykta or Sakhalin and Chayandinskoye gas fields located in Yakut.

Gas pipelines from Central Asia will join the WEPP directly.

The furthest advanced of these is the

proposed Kazakhstan-China gas pipeline, which would traverse nearly 4,400 miles of Kazakh territory before reaching the border with China. Mussabek Issayevich Issayev, managing director of KazMunaiGaz for Kazakh gas projects, disclosed recently that the first phase of the proposed pipeline would enter service in 2009 at an initial rate of 10 billion cu m/year. The second phase, slated to become operational in 2012, will boost capacity 30 billion cu m/year.

- Domestic offshore gas. China plans to develop a coastal pipeline network to transport gas from offshore gas fields in the East China Sea and the South China Sea.

Although a full picture of this network has yet to emerge, some sections are already under construction. In late October 2006 work started on an 813-mm OD gas pipeline crossing the Qiantang River near Hangzhou. This pipeline, including a 2,450-m riverbed crossing, will be part of the coastal pipeline network. ✦

The authors

Meng-di Gu (mdgu@sjtu.edu.cn) is a professor of economics at Shanghai Jiao Tong Univesity, Shanghai. He was an assistant engineer for Guiyang Hydraulic Power Design Institute in China 1982-85. He holds a BS (1982) and MS (1988) from Hohai University in Nanjing and a PhD (1992) from Shanghai Jiao Tong University.

Shou-de Li (sdli@sjtu.edu.cn) is an associate professor of economics at Shanghai Jiao Tong University. Before joining the university, he was a lecturer at Xi'an Jiao Tong University. He holds a BS (1988), MS (1996) and a PhD (2000) from Xi'an Jiao Tong University.

Separator designed for refinery waste water treatment

Enviro Voraxial Technology Inc., Fort Lauderdale, Fla., has delivered a Voraxial 2000 separator to Resource Environmental Group Services LLC (REGS), Commerce City, Colo., for use in refinery waste water stream treatment.

One of the initial applications REGS will focus on with the Voraxial is to improve waste water systems, specifically ahead of API separators. REGS is working with a refinery customer and several engineering firms to develop a water treatment system built around the Voraxial separator.

The continuous flow separator simultaneously separates liquid/liquid, liquid/solid, or liquid/liquid/solid mixtures at high flow rates while achieving high levels of purity, the company says. The separator produces a real-time, high "g" centrifugal force to yield high-purity product at a volume of 3 gpm to more than 10,000 gpm.

Source: **Enviro Voraxial Technology Inc.**, 821 NW 57th Pl., Fort Lauderdale, FL 33309.

Heavy-duty bull ring rotating mandrel

Here's a rotating mandrel with a selection of interchangeable bull rings from 5 in. to 54 in. in diameter. The company says its centering device is engineered to handle the turning, threading, and grinding of thick-walled downhole/through-hole shafts used in the energy industry.

The product is available live for conventional tail stocks, and also in a dead center configuration for live tail stocks. The rings can be changed out without removing the mandrel from the tail stock. Extra heavy duty bearings and robust spindle design help provide high rigidity and guaranteed ring accuracy of ±0.0002 in. TIR.

Source: **Riten Industries Inc.**, 1100 Lakeview Ave., Washington Court House, OH 43160.

Free arc welding safety CD

A new arc welding safety CD (MC06-209), yours free for the asking, features industry and product news, including the new US Occupational Safety & Health Administration hexavalent chromium standards and OSHA's small entity compliance for hexavalent chromium standard. Visit www.lincolnelectric.com for the CD.

The new standard lowers OSHA's permissible exposure limit (PEL) for hexavalent chromium, and for all Cr(VI) compounds, to 5 µg of Cr(VI) per cubic meter of air as an 8-hr time-weighted average.

The new standard requires industries to control worker exposures to Cr(VI) so the new PEL is not exceeded.

Source: **Lincoln Electric Co.**, 22801 St. Clair Ave., Cleveland, OH 44117.

Knowledge Systems

Houston, has made several appointments to fill new software and service positions created as part of the company's recently announced global expansion.

Steve Hobart will transition from his 10-year tenure as principal geopressure analyst to serve as senior technical advisor for global operations. He holds a BS degree in petroleum engineering from the University of Southwestern Louisiana.

Hobart

Arboleda

Alejandro Arboleda, who most recently served as Latin America account manager, will transfer to London as EAME (Europe, Africa and Middle East) business development manager. He is a graduate of the Colorado School of Mines with a BS degree in petroleum engineering.

Sean Mauk, who joins the company from Aker Kværner, has been named Asia-Pacific business development manager, based in Perth.

Mauk

Knowledge Systems is a leading provider of software and services designed to improve well planning and to enhance drilling efficiency for the worldwide oil and gas industry.

InterMoor Inc.

Houston, has announced plans to construct a new facility and expand services at their Port of Fourchon, La. location. The new facility will include more than 1,200 feet of bulkhead waterfront dock space, offices, training center, and living quarters. Completion of the project is scheduled for November.

InterMoor Inc., an Acteon company, designs, provides, and installs integrated mooring systems worldwide for the offshore oil and gas industry.

Acteon is a group of specialist engineering companies serving the global oil and gas industry.

Roxar AS

Stavanger, has announced the signing of a joint venture with Sonar Ltd. of Nigeria, to be named Roxar-Sonar. A service center has been established in Lagos, Nigeria, from which staff will provide sales and customer support across Nigeria and West Africa. The facility will also serve as a training center for Roxar's entire software portfolio. and act as base for Roxar's consultancy services.

Sonar Ltd. provides services to the oil and gas industry, ranging from seismic data processing and reservoir modeling, to business development activities.

Roxar's reservoir modeling and simulation solutions help geologists, geophysicists, and other decision-making executives make better use of their data.

API IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4		District 5		Total US		
	1-19 2007	[1]1-12 2006	1-19 2007	[1]1-12 2006	1-19 2007	[1]1-12 2006	1-20 2006
	1,000 b/d						
Total motor gasoline	189	318	6	0	195	318	443
Mo. gas. blending comp.	598	537	59	1	657	538	549
Distillate[2]	394	284	16	11	410	295	537
Residual	282	270	35	96	317	366	814
Jet fuel-kerosine	97	64	158	113	255	177	98
LPG	303	324	2	2	305	326	382
Unfinished oils	428	534	97	40	525	574	539
Other	651	323	63	67	714	390	487
Total products	**2,942**	**2,654**	**436**	**330**	**3,378**	**2,984**	**3,849**
Canadian crude	1,538	1,950	238	323	1,776	2,273	1,582
Other foreign	6,091	8,024	884	843	6,975	8,867	7,043
Total crude	**7,629**	**9,974**	**1,122**	**1,166**	**8,751**	**11,140**	**8,625**
Total imports	**10,571**	**12,628**	**1,558**	**1,496**	**12,129**	**14,124**	**12,474**

[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

	*1-19-07	*1-20-06	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	58.25	73.58	–15.33	–20.8
Brent crude	51.29	63.82	–12.53	–19.6
Crack spread	6.96	9.76	–2.80	–28.7
FUTURES MARKET PRICES				
One month				
Product value	59.71	75.58	–15.87	–21.0
Light sweet crude	51.68	66.81	–15.14	–22.7
Crack spread	8.03	8.78	–0.74	–8.5
Six month				
Product value	67.22	81.37	–14.15	–17.4
Light sweet crude	55.00	68.52	–13.52	–19.7
Crack spread	12.22	12.86	–0.64	–4.9

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

API CRUDE AND PRODUCT STOCKS

	Crude oil	Motor gasoline		Jet fuel	Fuel oils		Unfinished oils
		Total	Blending comp.[1]	Kerosine	Distillate	Residual	
	1,000 bbl						
PAD I	12,730	57,294	26,942	10,237	64,979	19,940	8,728
PAD II	69,627	53,295	15,386	8,000	29,001	1,635	12,506
PAD III	176,306	68,658	27,983	12,732	34,174	18,387	42,273
PAD IV	13,040	7,075	2,049	558	3,526	389	2,829
PAD V	[1]49,750	31,498	23,777	9,229	11,705	6,179	19,863
Jan.19, 2007	**[1]321,453**	**217,820**	**96,137**	**40,756**	**143,385**	**46,530**	**86,199**
Jan. 12, 2007[3]	**322,285**	**219,813**	**96,637**	**39,342**	**147,542**	**46,211**	**85,974**
Jan. 20, 2006	**318,335**	**212,553**	**72,670**	**44,195**	**138,351**	**39,021**	**87,926**

[1]Included in total motor gasoline. [2]Includes 4.870 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—JAN. 19, 2007

	REFINERY OPERATIONS					REFINERY OUTPUT			
District	Total refinery input	Crude runs	Input to crude stills	Operable capacity	Percent operated	Total motor gasoline	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual
	1,000 b/d					1,000 b/d			
East Coast	3,323	1,457	1,476	1,618	91.2	1,607	93	479	160
App. Dist. 1	108	92	94	95	99.0	34	0	27	1
Dist. 1 total	**3,431**	**1,549**	**1,570**	**1,713**	**91.7**	**1,641**	**93**	**506**	**161**
Ind., Ill., Ky.	2,300	2,138	2,192	2,355	93.1	1,317	174	590	21
Minn., Wis., Dak.	425	409	414	442	93.7	350	28	129	9
Okla., Kan., Mo.	844	711	722	786	91.9	455	33	249	5
Dist. 2 total	**3,569**	**3,258**	**3,328**	**3,583**	**92.9**	**2,122**	**235**	**968**	**35**
Inland Texas	905	521	550	647	85.0	382	41	150	6
Texas Gulf Coast	3,523	2,964	3,042	4,031	75.5	1,185	301	888	110
La. Gulf Coast	3,332	3,028	3,091	3,264	94.7	1,305	392	842	129
N. La. and Ark.	191	154	164	215	76.3	134	9	35	4
New Mexico	178	88	90	113	79.7	163	1	33	0
Dist. 3 total	**8,129**	**6,755**	**6,937**	**8,270**	**83.9**	**3,169**	**744**	**1,948**	**249**
Dist. 4 total	**710**	**556**	**578**	**596**	**97.0**	**326**	**28**	**182**	**14**
Dist. 5 total	**2,661**	**2,518**	**2,658**	**3,173**	**83.8**	**1,702**	**386**	**496**	**169**
Jan. 19, 2007	**18,500**	**14,636**	**15,071**	**17,335**	**86.9**	**8,960**	**1,486**	**4,100**	**628**
Jan. 12, 2007*	**18,993**	**15,066**	**15,521**	**17,335**	**89.5**	**9,162**	**1,594**	**4,165**	**671**
Jan. 20, 2005	**16,363**	**14,305**	**14,853**	**17,115**	**86.8**	**8,683**	**1,457**	**3,677**	**657**

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

OGJ GASOLINE PRICES

	Price ex tax 1-17-07	Pump price* 1-17-07	Pump price 1-18-06
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	181.2	220.9	230.5
Baltimore	182.6	224.5	234.0
Boston	184.8	226.7	230.7
Buffalo	185.5	245.6	250.5
Miami	185.7	236.0	238.8
Newark	186.8	219.7	253.7
New York	175.2	235.3	259.0
Norfolk	177.2	214.8	227.4
Philadelphia	197.4	248.1	240.2
Pittsburgh	180.1	230.8	246.9
Wash., DC	196.7	235.1	244.6
PAD I avg.	184.8	230.7	241.5
Chicago	182.9	233.8	245.3
Cleveland	164.7	211.1	227.3
Des Moines	166.4	206.8	221.8
Detroit	156.2	205.4	226.4
Indianapolis	159.9	204.9	222.4
Kansas City	166.1	202.1	215.9
Louisville	172.1	209.0	220.9
Memphis	173.1	212.9	226.4
Milwaukee	169.1	220.4	232.7
Minn.-St. Paul	164.6	205.0	222.8
Oklahoma City	161.3	196.7	215.4
Omaha	163.4	209.0	219.7
St. Louis	168.7	204.7	225.5
Tulsa	167.5	202.9	216.3
Wichita	156.0	200.0	217.5
PAD II avg.	166.2	208.4	223.8
Albuquerque	176.3	212.7	226.5
Birmingham	177.0	215.7	224.6
Dallas-Fort Worth	179.4	217.8	225.5
Houston	172.8	211.2	220.7
Little Rock	173.6	213.8	226.3
New Orleans	178.2	216.6	238.4
San Antonio	175.2	213.6	223.3
PAD III avg.	176.1	214.5	226.5
Cheyenne	173.3	205.7	213.8
Denver	171.6	212.0	219.9
Salt Lake City	181.2	224.1	218.8
PAD IV avg.	175.4	213.9	217.5
Los Angeles	199.2	257.7	246.9
Phoenix	198.6	236.0	228.8
Portland	222.9	266.2	212.5
San Diego	208.7	267.2	240.1
San Francisco	214.6	273.1	240.4
Seattle	218.3	270.7	231.6
PAD V avg.	210.4	261.8	233.4
Week's avg.	**179.7**	**223.3**	**229.8**
Dec. avg.	**184.9**	**228.5**	**216.5**
Nov. avg.	**180.1**	**223.7**	**229.9**
2007 to date	**183.9**	**227.5**	—
2006 to date	**178.8**	**221.2**	—

*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

	1-12-07 ¢/gal		1-12-07 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	140.50	New York Harbor	146.71
Gulf Coast	137.50	Gulf Coast	146.71
Los Angeles	159.25	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	129.74	ARA	149.93
Singapore	143.81	Singapore	156.43
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	140.00	New York Harbor	86.67
Gulf Coast	137.95	Gulf Coast	90.24
Los Angeles	167.25	Los Angeles	105.91
		ARA	88.95
		Singapore	101.54

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

BAKER HUGHES RIG COUNT

	1-19-07	1-20-06
Alabama	7	4
Alaska	9	11
Arkansas	39	16
California	34	32
Land	32	29
Offshore	2	3
Colorado	98	84
Florida	0	2
Illinois	0	0
Indiana	1	0
Kansas	14	7
Kentucky	10	6
Louisiana	190	174
N. Land	53	59
S. Inland waters	21	19
S. Land	49	36
Offshore	67	60
Maryland	0	0
Michigan	1	3
Mississippi	16	5
Montana	19	24
Nebraska	0	0
New Mexico	89	85
New York	9	4
North Dakota	35	28
Ohio	12	9
Oklahoma	171	156
Pennsylvania	15	16
South Dakota	0	1
Texas	808	658
Offshore	13	11
Inland waters	2	1
Dist. 1	17	19
Dist. 2	23	28
Dist. 3	60	49
Dist. 4	99	74
Dist. 5	144	115
Dist. 6	129	97
Dist. 7B	37	24
Dist. 7C	49	41
Dist. 8	105	81
Dist. 8A	27	24
Dist. 9	42	30
Dist. 10	61	64
Utah	45	29
West Virginia	32	25
Wyoming	82	90
Others—HI-1; ID-1; TN-4; VA-3	9	3
Total US	**1,745**	**1,472**
Total Canada	**606**	**675**
Grand total	**2,351**	**2,147**
Oil rigs	275	247
Gas rigs	1,466	1,222
Total offshore	84	76
Total cum. avg. YTD	**1,719**	**1,468**

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	1-19-07 Rig count	1-19-07 Percent footage*	1-20-06 Rig count	1-20-06 Percent footage*
0-2,500	52	—	35	2.8
2,501-5,000	104	53.8	89	43.8
5,001-7,500	229	21.3	189	16.4
7,501-10,000	414	3.3	321	4.3
10,001-12,500	416	2.6	339	0.5
12,501-15,000	249	0.4	297	0.6
15,001-17,500	126	0.7	116	0.8
17,501-20,000	73	—	61	—
20,001-over	40	—	22	—
Total	**1,703**	**7.7**	**1,469**	**6.1**
INLAND	34		37	
LAND	1,610		1,375	
OFFSHORE	59		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]1-19-07	[2]1-20-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	19	21
Alaska	806	833
California	700	697
Colorado	58	60
Florida	6	6
Illinois	31	29
Kansas	94	95
Louisiana	1,394	1,152
Michigan	13	14
Mississippi	52	49
Montana	94	97
New Mexico	166	161
North Dakota	101	100
Oklahoma	172	170
Texas	1,387	1,243
Utah	44	46
Wyoming	142	140
All others	64	72
Total	**5,343**	**4,985**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	1-19-07
Alaska-North Slope 27°	48.88
South Louisiana Sweet	53.25
California-Kern River 13°	40.45
Lost Hills 30°	48.25
Wyoming Sweet	48.49
East Texas Sweet	50.07
West Texas Sour 34°	39.75
West Texas Intermediate	48.50
Oklahoma Sweet	48.50
Texas Upper Gulf Coast	45.25
Michigan Sour	41.50
Kansas Common	47.50
North Dakota Sweet	42.25

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

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

WORLD CRUDE PRICES

$/bbl[1]	1-12-07
United Kingdom-Brent 38°	51.82
Russia-Urals 32°	47.58
Saudi Light 34°	48.78
Dubai Fateh 32°	52.28
Algeria Saharan 44°	55.22
Nigeria-Bonny Light 37°	55.98
Indonesia-Minas 34°	56.29
Venezuela-Tia Juana Light 31°	48.65
Mexico-Isthmus 33°	48.54
OPEC basket	52.25
Total OPEC[2]	50.75
Total non-OPEC[2]	49.31
Total world[2]	50.12
US imports[3]	47.72

[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]

	1-12-07	1-5-07	Change
	Bcf		
Producing region	913	933	–20
Consuming region east	1,660	1,712	–52
Consuming region west	363	380	–17
Total US	**2,936**	**3,025**	**–89**
	Oct. 06	**Oct. 05**	**Change, %**
Total US[2]	**3,452**	**3,194**	**8.1**

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

API IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4		District 5		Total US		
	1-26 2007	[1]1-19 2006	1-26 2007	[1]1-19 2006	1-26 2007	[1]1-19 2006	1-27 2006
	1,000 b/d						
Total motor gasoline	266	189	0	6	266	195	521
Mo. gas. blending comp.	830	598	48	59	878	657	376
Distillate[2]	382	394	13	16	395	410	397
Residual	169	282	23	35	192	317	661
Jet fuel-kerosine	141	97	163	158	304	255	120
LPG	328	303	2	2	330	305	365
Unfinished oils	503	428	75	97	578	525	520
Other	234	651	9	63	243	714	589
Total products	**2,853**	**2.942**	**333**	**436**	**3,186**	**3,378**	**3,549**
Canadian crude	1,414	1,538	327	238	1,741	1,776	1,811
Other foreign	7,484	6,091	596	884	8,080	6,975	7,951
Total crude	**8,898**	**7,629**	**923**	**1,122**	**9,821**	**8,751**	**9,762**
Total imports	**11,751**	**10,571**	**1,256**	**1,558**	**13,007**	**12,129**	**13,311**

[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

	*1-26-07	*1-27-06	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	61.40	72.00	–10.60	–14.7
Brent crude	54.46	63.95	–9.49	–14.8
Crack spread	6.94	8.04	–1.11	–13.8
FUTURES MARKET PRICES				
One month				
Product value	62.59	f73.81	–11.23	–15.2
Light sweet crude	54.24	67.01	–12.77	–19.1
Crack spread	8.35	6.81	1.54	22.7
Six month				
Product value	69.62	81.31	–11.69	–14.4
Light sweet crude	57.73	68.87	–11.14	–16.2
Crack spread	11.88	12.44	–0.55	–4.4

*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	13,347	58,694	28,865	9,180	64,424	19,715	8,816
PAD II	69,125	53,531	15,195	7,598	29,771	1,328	12,270
PAD III	180,755	68,670	28,156	13,956	33,246	18,127	42,254
PAD IV	12,581	6,717	1,943	484	3,527	353	3,295
PAD V	[1]51,342	31,494	23,551	9,600	11,404	6,316	19,577
Jan. 26, 2007	**[1]327,150**	**219,106**	**97,710**	**40,818**	**142,372**	**45,839**	**86,212**
Jan. 19, 2007[3]	**321,453**	**217,820**	**96,137**	**40,756**	**143,385**	**46,530**	**86,199**
Jan. 27, 2006	**324,227**	**216,212**	**74,985**	**43,548**	**137,468**	**39,315**	**88,465**

[1]Included in total motor gasoline. [2]Includes 7.250 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—JAN. 26, 2007

	REFINERY OPERATIONS					REFINERY OUTPUT			
District	Total refinery input	Crude runs	Input to crude stills	Operable capacity	Percent operated	Total motor gasoline	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual
	1,000 b/d					1,000 b/d			
East Coast	3,312	1,395	1,402	1,613	86.7	1,613	96	495	144
App. Dist. 1	88	74	77	95	81.1	38	0	18	0
Dist. 1 total	**3,400**	**1,469**	**1,479**	**1,713**	**86.3**	**1,651**	**96**	**513**	**144**
Ind., Ill., Ky.	2,265	2,166	2,223	2,355	94.4	1,177	162	542	53
Minn., Wis., Dak.	403	391	401	442	90.7	349	24	127	9
Okla., Kan., Mo.	813	642	645	786	82.1	481	21	234	4
Dist. 2 total	**3,481**	**3,199**	**3,269**	**3,583**	**91.2**	**2,007**	**207**	**903**	**66**
Inland Texas	943	572	585	647	90.4	420	40	164	7
Texas Gulf Coast	3,515	3,007	3,062	4,031	76.0	1,263	267	883	128
La. Gulf Coast	3,491	3,060	3,117	3,264	95.5	1,294	372	765	145
N. La. and Ark.	197	150	167	215	77.7	134	9	39	4
New Mexico	150	85	87	113	77.0	149	0	26	0
Dist. 3 total	**8,296**	**6,874**	**7,018**	**8,270**	**84.9**	**3,260**	**688**	**1,877**	**284**
Dist. 4 total	**685**	**570**	**590**	**596**	**99.0**	**276**	**25**	**182**	**14**
Dist. 5 total	**2,727**	**2,356**	**2,460**	**3,173**	**77.5**	**1,651**	**412**	**474**	**165**
Jan. 26, 2007	**18,589**	**14,468**	**14,816**	**17,335**	**85.5**	**8,845**	**1,428**	**3,949**	**673**
Jan. 19, 2007*	**18,500**	**14,636**	**15,071**	**17,335**	**86.9**	**8,960**	**1,486**	**4,100**	**628**
Jan. 27, 2005	**16,577**	**14,493**	**15,147**	**17,115**	**88.5**	**8,425**	**1,529**	**3,694**	**566**

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

OGJ GASOLINE PRICES

	Price ex tax 1-24-07	Pump price* 1-24-07	Pump price 1-25-06
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	180.5	220.2	231.4
Baltimore	182.2	224.11	235.3
Boston	184.3	226.2	232.2
Buffalo	185.0	245.1	253.4
Miami	183.0	233.3	240.2
Newark	186.3	219.2	256.5
New York	172.9	233.0	261.6
Norfolk	176.6	214.2	227.7
Philadelphia	197.3	248.0	241.3
Pittsburgh	179.5	230.2	248.9
Wash., DC	196.6	235.0	246.1
PAD I avg.	184.0	229.9	243.2
Chicago	175.4	226.3	245.7
Cleveland	163.9	210.3	228.4
Des Moines	165.1	205.5	222.5
Detroit	154.5	203.7	227.4
Indianapolis	157.9	202.9	222.7
Kansas City	165.3	201.3	215.9
Louisville	170.7	207.6	221.6
Memphis	172.4	212.2	226.7
Milwaukee	168.1	219.4	233.5
Minn.-St. Paul	163.2	203.6	222.9
Oklahoma City	160.1	195.5	215.7
Omaha	162.1	208.5	219.8
St. Louis	167.5	203.5	225.8
Tulsa	166.8	202.2	216.7
Wichita	155.2	196.6	217.6
PAD II avg.	164.6	206.8	224.2
Albuquerque	175.8	212.2	227.4
Birmingham	176.5	215.2	225.5
Dallas-Fort Worth	178.8	217.2	226.4
Houston	171.0	209.4	221.5
Little Rock	173.0	213.2	227.4
New Orleans	177.7	216.1	236.7
San Antonio	174.7	213.1	223.7
PAD III avg.	175.4	213.8	227.0
Cheyenne	172.8	205.2	213.9
Denver	172.2	212.6	219.9
Salt Lake City	181.1	224.0	218.9
PAD IV avg.	175.3	213.9	217.5
Los Angeles	198.0	256.5	248.2
Phoenix	198.5	235.9	228.9
Portland	222.7	266.0	211.4
San Diego	208.5	267.0	240.6
San Francisco	211.1	269.6	240.7
Seattle	215.1	267.5	231.8
PAD V avg.	209.0	260.4	233.6
Week's avg.	**178.6**	**222.2**	**230.5**
Dec. avg.	**184.9**	**228.5**	**227.3**
Nov. avg.	**180.1**	**223.7**	**216.5**
2007 to date	**182.6**	**226.2**	—
2006 to date	**184.9**	**227.3**	—

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

REFINED PRODUCT PRICES

	1-19-07 ¢/gal		1-19-07 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	136.05	New York Harbor	149.33
Gulf Coast	134.80	Gulf Coast	148.08
Los Angeles	141.30	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	130.31	ARA	150.97
Singapore	136.36	Singapore	151.43
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	136.05	New York Harbor	88.69
Gulf Coast	134.80	Gulf Coast	83.33
Los Angeles	149.30	Los Angeles	109.30
		ARA	89.33
		Singapore	96.66

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

BAKER HUGHES RIG COUNT

	1-26-07	1-27-05
Alabama	3	5
Alaska	9	10
Arkansas	38	15
California	33	32
Land	31	29
Offshore	2	3
Colorado	99	86
Florida	0	2
Illinois	0	0
Indiana	1	0
Kansas	15	7
Kentucky	10	6
Louisiana	174	171
N. Land	49	56
S. Inland waters	12	19
S. Land	45	39
Offshore	68	57
Maryland	0	0
Michigan	1	3
Mississippi	16	5
Montana	16	25
Nebraska	0	0
New Mexico	85	91
New York	9	4
North Dakota	31	24
Ohio	12	9
Oklahoma	168	155
Pennsylvania	14	16
South Dakota	0	1
Texas	796	672
Offshore	12	10
Inland waters	1	1
Dist. 1	19	20
Dist. 2	25	25
Dist. 3	52	51
Dist. 4	96	79
Dist. 5	150	121
Dist. 6	129	101
Dist. 7B	31	22
Dist. 7C	48	40
Dist. 8	101	78
Dist. 8A	30	31
Dist. 9	36	27
Dist. 10	66	66
Utah	45	31
West Virginia	32	25
Wyoming	83	89
Others—HI-1; ID-1; TN-4; VA-1	9	3
Total US	**1,699**	**1,487**
Total Canada	**664**	**698**
Grand total	**2,363**	**2,185**
Oil rigs	255	237
Gas rigs	1,440	1,247
Total offshore	83	72
Total cum. avg. YTD	**1,714**	**1,473**

Rotary rigs from spudding in to total depth.
Definitions, see OGJ Sept. 18, 2006, p. 46.

Source: Baker Hughes Inc.
Data available in OGJ Online Research Center.

SMITH RIG COUNT

Proposed depth, ft	1-26-07 Rig count	1-26-07 Percent footage*	1-27-06 Rig count	1-27-06 Percent footage*
0-2,500	57	—	31	3.2
2,501-5,000	100	51.0	94	41.4
5,001-7,500	223	25.1	193	16.0
7,501-10,000	419	3.3	322	4.6
10,001-12,500	405	1.9	335	0.5
12,501-15,000	248	0.4	309	0.6
15,001-17,500	123	1.6	114	0.8
17,501-20,000	72	—	61	—
20,001-over	41	—	22	—
Total	**1,688**	**7.8**	**1,481**	**6.1**
INLAND	32		38	
LAND	1,593		1,388	
OFFSHORE	63		55	

*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]1-26-07	[2]1-27-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	18	21
Alaska	789	832
California	697	699
Colorado	58	60
Florida	6	6
Illinois	31	29
Kansas	94	96
Louisiana	1,375	1,165
Michigan	13	14
Mississippi	52	49
Montana	93	97
New Mexico	164	161
North Dakota	99	98
Oklahoma	170	171
Texas	1,380	1,294
Utah	43	45
Wyoming	140	140
All others	63	72
Total	**5,285**	**5,049**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	1-26-07
Alaska-North Slope 27°	48.88
South Louisiana Sweet	56.75
California-Kern River 13°	43.90
Lost Hills 30°	51.80
Southwest Wyoming Sweet	51.92
East Texas Sweet	53.50
West Texas Sour 34°	43.25
West Texas Intermediate	52.00
Oklahoma Sweet	52.00
Texas Upper Gulf Coast	48.75
Michigan Sour	45.00
Kansas Common	51.25
North Dakota Sweet	45.75

*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]	1-19-07
United Kingdom-Brent 38°	50.98
Russia-Urals 32°	47.26
Saudi Light 34°	46.63
Dubai Fateh 32°	49.97
Algeria Saharan 44°	53.13
Nigeria-Bonny Light 37°	53.54
Indonesia-Minas 34°	52.87
Venezuela-Tia Juana Light 31°	46.27
Mexico-Isthmus 33°	46.16
OPEC basket	49.80
Total OPEC[2]	48.39
Total non-OPEC[2]	47.96
Total world[2]	48.20
US imports[3]	45.29

[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]

	1-19-07	1-12-07	Change
	Bcf		
Producing region	852	913	–61
Consuming region east	1,585	1,660	–75
Consuming region west	320	363	–43
Total US	**2,757**	**2,936**	**–179**
	Oct. 06	**Oct. 05**	**Change, %**
Total US[2]	**3,452**	**3,194**	**8.1**

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

PACE REFINING MARGINS

	Nov. 2006	Dec. 2006	Jan. 2007	Jan. 2006	Change 2007 vs. 2006	Change, % 2007 vs. 2006
	$/bbl					
US Gulf Coast						
West Texas Sour	12.21	9.57	8.57	10.64	–2.07	–19.4
Composite US Gulf Refinery	11.27	10.04	10.30	10.77	–0.47	–4.4
Arabian Light	11.99	10.12	9.50	11.22	–1.72	–15.3
Bonny Light	3.94	1.93	2.55	5.16	–2.61	–50.6
US PADD II						
Chicago (WTI)	11.10	7.64	5.81	4.61	1.19	25.9
US East Coast						
NY Harbor (Arab Med)	7.52	4.81	5.01	6.18	–1.17	–18.9
East Coast Comp-RFG	7.87	6.70	6.24	6.86	–0.62	–9.0
US West Coast						
Los Angeles (ANS)	18.62	17.23	17.44	12.14	5.30	43.7
NW Europe						
Rotterdam (Brent)	1.21	—	2.67	0.02	2.65	14,140.6
Mediterranean						
Italy (Urals)	7.47	7.36	7.80	5.61	2.19	39.0
Far East						
Singapore (Dubai)	–0.43	4.18	8.15	1.39	6.76	486.0

Source: Jacobs Consultancy, Inc. NOTE: Jan. 2007 margins reflect prices through 1-26-2007.
Data available in OGJ Online Research Center.

US NATURAL GAS BALANCE DEMAND/SUPPLY SCOREBOARD

	Oct. 2006	Sept. 2006	Oct. 2005	Oct. change 2006-2005	Total YTD 2006	Total YTD 2005	YTD change 2006-2005
	bcf						
DEMAND							
Consumption	1,655	1,483	1,445	210	17,972	18,212	–240
Addition to storage	246	394	340	–94	2,666	2,699	–33
Exports	56	59	41	15	579	638	–59
Canada	21	23	15	6	240	315	–75
Mexico	32	32	20	12	287	269	18
LNG	3	4	6	–3	52	54	–2
Total demand	**1,957**	**1,936**	**1,826**	**131**	**21,217**	**21,549**	**–332**
SUPPLY							
Production (dry gas)	1,586	1,544	1,417	169	15,378	15,107	271
Supplemental gas	5	5	5	0	51	52	–1
Storage withdrawal	115	37	74	41	1,844	2,194	–350
Imports	320	319	367	–47	3,433	3,573	–140
Canada	284	279	306	–22	2,945	3,048	–103
Mexico	0	0	1	–1	3	3	0
LNG	36	40	60	–24	485	522	–37
Total supply	**2,026**	**1,905**	**1,863**	**163**	**20,706**	**20,926**	**–220**

NATURAL GAS IN UNDERGROUND STORAGE

	Oct. 2006	Sept. 2006	Aug. 2006	Oct. 2005	Change
	bcf				
Base gas	4,217	4,215	4,213	4,206	11
Working gas	3,452	3,326	2,969	3,194	258
Total gas	**7,669**	**7,541**	**7,182**	**7,400**	**269**

Source: DOE Monthly Energy Review.
Data available in OGJ Online Research Center.

WORLDWIDE NGL PRODUCTION

	Oct. 2006	Sept. 2006	10 month average 2006	10 month average 2005	Change vs. previous year Volume	Change vs. previous year %
			1,000 b/d			
Brazil	86	91	86	78	8	10.8
Canada	704	630	677	672	5	0.7
Mexico	405	427	435	428	8	1.8
United States	1,773	1,781	1,732	1,753	–21	–1.2
Venezuela	200	200	200	200	—	—
Other Western Hemisphere	168	173	172	156	16	10.3
Western Hemisphere	**3,335**	**3,302**	**3,302**	**3,287**	**15**	**0.5**
Norway	285	235	282	264	18	6.8
United Kingdom	159	145	151	170	–19	–11.3
Other Western Europe	19	19	19	22	–2	–11.0
Western Europe	**463**	**399**	**452**	**455**	**–4**	**–0.8**
Russia	390	390	395	469	–74	–15.8
Other FSU	160	160	160	160	—	—
Other Eastern Europe	17	16	17	18	–1	–3.9
Eastern Europe	**567**	**566**	**572**	**647**	**–75**	**–11.5**
Algeria	320	320	306	295	11	3.7
Egypt	65	65	65	65	—	—
Libya	60	60	60	60	—	—
Other Africa	190	192	190	170	20	11.7
Africa	**635**	**637**	**621**	**590**	**31**	**5.2**
Saudi Arabia	1,490	1,490	1,478	1,460	18	1.2
United Arab Emirates	400	400	400	400	—	—
Other Middle East	670	670	670	571	99	17.3
Middle East	**2,560**	**2,560**	**2,548**	**2,431**	**117**	**4.8**
Australia	83	84	82	82		–0.2
China	180	180	180	180	—	—
India	38	42	41	44	–3	–5.9
Other Asia-Pacific	220	220	220	218	2	0.7
Asia-Pacific	**521**	**525**	**523**	**524**	**–1**	**–0.2**
TOTAL WORLD	**8,081**	**7,989**	**8,018**	**7,935**	**83**	**1.1**

Totals may not add due to rounding.
Source: Oil & Gas Journal.
Data available in OGJ Online Research Center.

OXYGENATES

	Oct. 2006	Sept. 2006	Change	YTD 2006	YTD 2005	Change
			1,000 bbl			
Fuel ethanol						
Production	10,308	9,992	316	94,302	76,017	18,285
Stocks	9,814	9,727	87	9,814	5,591	4,223
MTBE						
Production	1,575	2,479	–904	27,713	39,501	–48,304
Stocks	1,197	1,665	–468	1,197	3,204	–2,007

Source: DOE Petroleum Supply Monthly.
Data available in OGJ Online Research Center. NOTE: No new data at press time.

US HEATING DEGREE DAYS

	Dec. 2006	Dec. 2005	Normal	2006 % change from normal	Total degree days July 1 through Dec. 31 2006	2005	Normal	% change from normal
New England	871	1,122	1,078	–19.2	2,121	2,297	2,462	–13.9
Middle Atlantic	777	1,081	998	–22.1	1,799	2,030	2,191	–17.9
East North Central	919	1,244	1,135	–19.0	2,266	2,389	2,472	–8.3
West North Central	1,010	1,260	1,248	–19.1	2,462	2,496	2,695	–8.6
South Atlantic	426	627	555	–23.2	968	1,077	1,083	–10.6
East South Central	601	807	715	–15.9	1,342	1,426	1,410	–4.8
West South Central	466	536	520	–10.4	821	869	905	–9.3
Mountain	914	888	928	–1.5	2,033	1,864	2,147	–5.3
Pacific	544	496	563	–3.4	1,123	1,050	1,253	–10.4
US average*	**683**	**857**	**817**	**–16.4**	**1,555**	**1,627**	**1,739**	**–10.6**

*Excludes Alaska and Hawaii.
Source: DOE Monthly Energy Review.
Data available in OGJ Online Research Center.

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Identical forces move prices of oil and oranges

The price of oranges is about to triple in the US, and nobody's complaining.

After all, complaining can't change anything. Freezing weather in California and other citrus-growing areas has damaged winter crops. Shortage looms.

According to a marketer of Californian citrus products quoted in the Houston Chronicle, an orange that recently cost 50¢ soon may cost $1.49.

The Editor's Perspective

by Bob Tippee, Editor

There will be no howls about "price-gouging," however. Congress will summon no citrus growers to accusatory hearings. Newspapers will not write stories about some past conversion of orange-producing land to other use and call it price manipulation.

Americans reserve their vicious suspicion for oil.

They threw a fit when gasoline prices jumped after the twin Gulf Coast hurricanes of summer 2005 idled 30% of US refining capacity.

Seldom is petroleum shortage as visible as it was when refineries were under water, producing platforms were listing, drilling units were adrift, and marine pipelines were dislocated.

Seldom is the reason for prices of crude oil, gas, and petroleum products to rise as evident as it was then. Yet Americans thought they were being gypped.

The oil price spurt of late 2005 and early 2006 was as much a product of cataclysmic weather as the leap of orange prices will be. Yet Americans will continue to believe that some cabal of oil company executives "gouged" them on gasoline prices. And they'll have nothing but well-justified sympathy for citrus growers.

The profits oil companies reported after the gasoline-price jump supposedly explain American pique. Why? Margins rise for any commodity in short supply, lifting profits of producers able to sustain output.

Margins will rise for crops not destroyed by the recent US freeze, as will profits for growers in warmer areas. That's no scandal. It's an incentive to keep oranges moving to market. Similarly, oil margins elevated after the hurricanes attracted foreign products to the US and kept a treacherous supply disruption from becoming disaster.

The orange-oil analogy can be carried too far. But prices of the commodities rise and fall for identical reasons: supply and demand. It's way past time for Americans to understand that.

(Online Jan. 19, 2007; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

US gas production, Canadian exports fall

Supply and demand balance reports issued by Bentek Energy LLC, an energy analyst based in Golden, Colo., have indicated in recent weeks a significant drop in North American natural gas production.

"Total US production declined 5% in a 1-week period, from 51 bcf on Jan. 10 to only 48.3 bcf on Jan. 17. This is the lowest production level indicated by our pipeline flow database since October 2005 when the gulf region was still recovering from [Hurricanes] Katrina and Rita," Bentek Energy reported Jan. 25.

"In the past week, production has recovered back to about 49 bcf as of Jan. 25. However, this level remains 2.6 bcf below the average production rate in January 2006."

Meanwhile, analysts at Friedman, Billings, Ramsey Group Inc. (FBR), Arlington, Va., said in a separate report that Canadian gas exports to the US are expected to decline by 4%, or 400 MMcfd in 2007, following a similar drop in 2006. "We expect exports to decline...as a result of reduced drilling outlook for 2007 and increasing oil sands consumption as existing projects ramp back up and new projects come on line," said FBR researchers.

The weather factor

Based on its canvass of various market participants, Bentek said weather was one of the factors contributing to the current steep decline in US production. Although media coverage has been unusually muted, Bentek analysts said individual operators reported sizeable shut-ins of gas wells because of sustained freezing temperatures, particularly in the Rockies region. "Unusually large snowfalls have disrupted operations. In addition, there is an expected dip in production that occurs about this time each year due to environmental constraints on producing activities," said Bentek analysts. "The Gulf [of Mexico] region started to decline a few days before cold weather set in due to maintenance and operational curtailments on several pipeline systems."

The result is "a double-whammy" for the natural gas supply-demand balance: a huge increase in demand combined with a significant decrease in supply. "Since winter weather finally appeared 2 weeks ago, 352 bcf has been withdrawn from storage. The recent storage withdrawals have resulted in an abrupt shift in market expectations for end-of-season storage inventories. In early January, most market participants expected a large storage overhang to depress prices in the spring. The large storage withdrawals over the past 2 weeks have eased that expectation," analysts said. Bentek's latest weekly market study projected another large withdrawal—195 bcf—for the week ended Jan. 26.

Canadian outlook

Canadian drilling and completion activity is expected to drop 10-15% in 2007 as a result of higher drilling costs, lower crew productivity, lower and more volatile commodity prices, and widening market differentials. "The drop in fourth quarter 2006 drilling activity combined with less drilling activity outlook for 2007 will result in 2007 production declining by 300 MMcfd, according to our estimate. This compares [with] our previous estimate of flat production," said FBR analysts.

"The key demand growth in 2007 will be increasing natural gas consumption in the oil sands as existing projects ramp back up and new projects come on line. We estimate that this will increase gas consumption by another 100 MMcfd, in line with our previous estimate," they said.

Canadian gas exports declined an estimated 400 MMcfd in 2006, with 100 MMcfd accounted for by increased oil sands consumption. Canadian well completions totaled 15,362 in 2006 vs. 15,355 in 2005. However, gas completions dropped significantly in the fourth quarter, down 8% from the previous year's level. "The decreased gas well completion activity was mostly due to fewer shallow gas wells being drilled. The fourth quarter reduced completion activity will be felt in the next few months," FBR analysts said.

Energy prices

Despite volatile trading with seesawing prices, the benchmark US crudes contract climbed back above $55/bbl, jumping by $1.19 to $55.42/bbl Jan. 26 on the New York market, a 4% gain for the week as cold weather rallied heating oil demand in the Northeast.

The front month natural gas contract also climbed back above $7/MMbtu to $7.18/MMbtu as temperatures dropped to 9° F. Jan. 26 in New York City, the lowest level in 2 years. Meanwhile, the FBR group forecast "a 10% decline in refined product inventories over the next 2 months." Analysts said, "Strong gasoline and diesel demand in the first few weeks of 2007, coupled with refinery maintenance and a negative Europe-US East Coast arbitrage spread (limiting imports), indicate that inventories could fall 10% over the next 2 months."

(Online Jan. 29, 2007; author's e-mail: samf@ogjonline.com)

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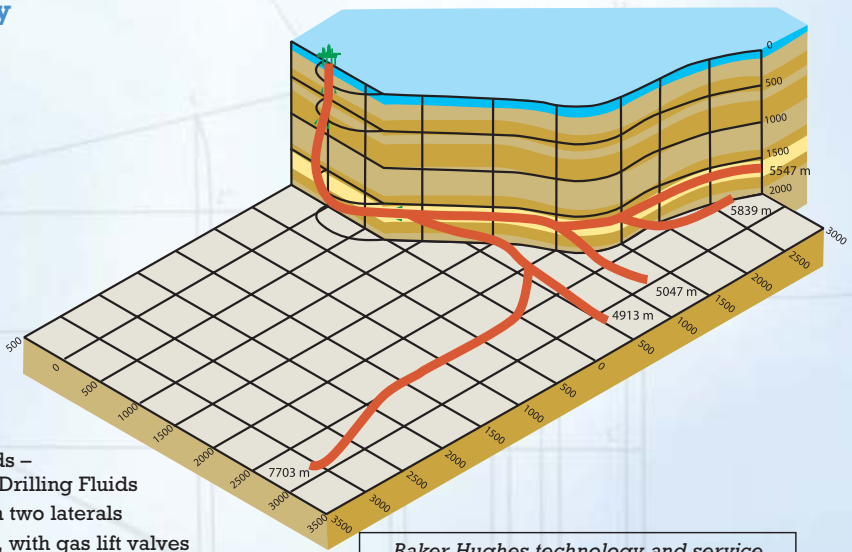

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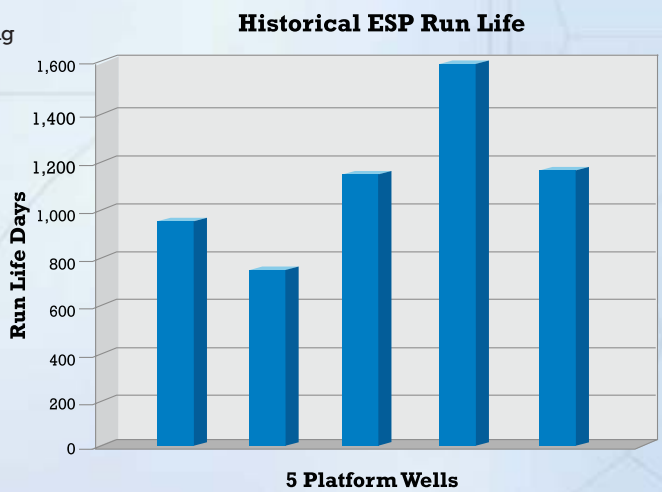

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