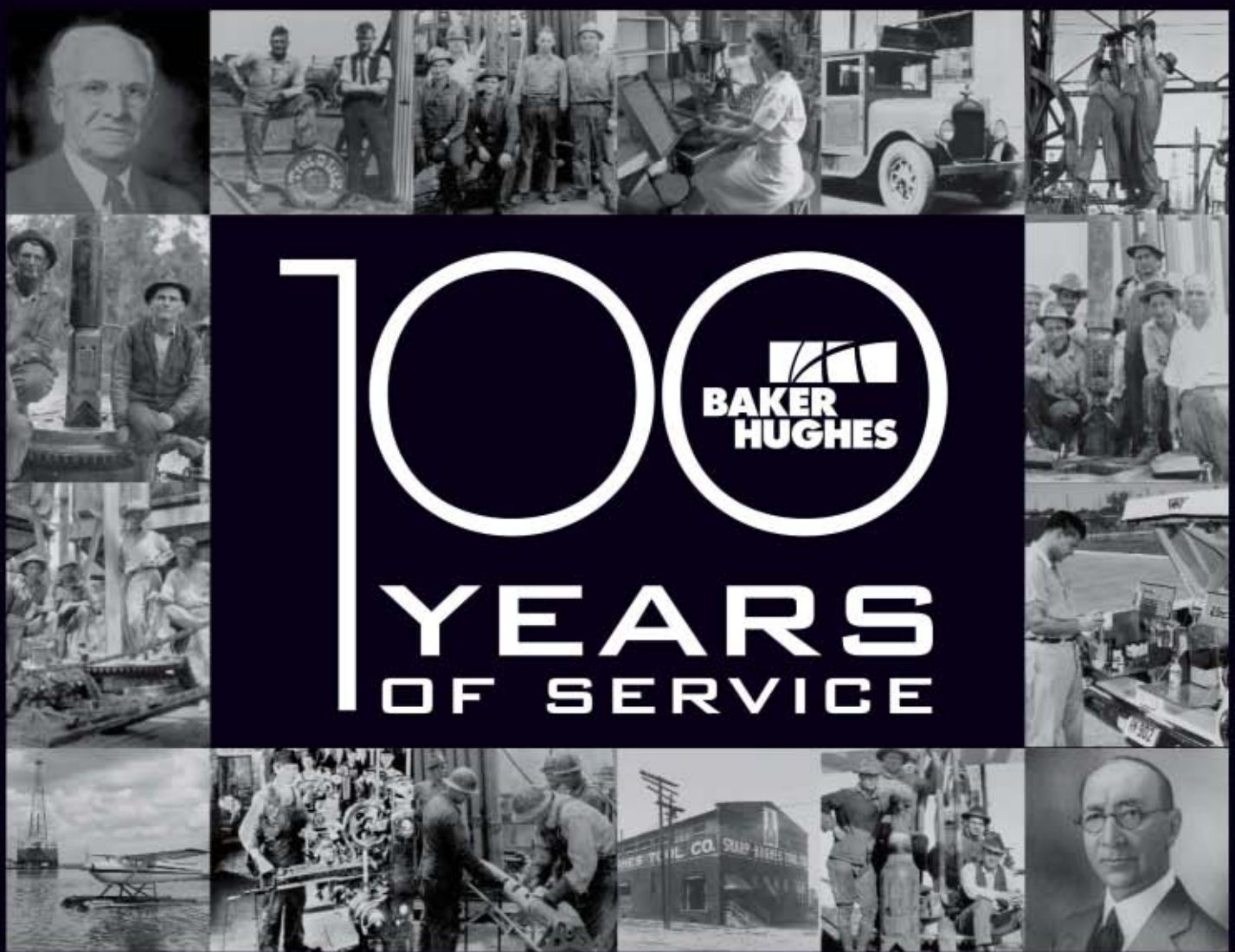
A Century of Innovation



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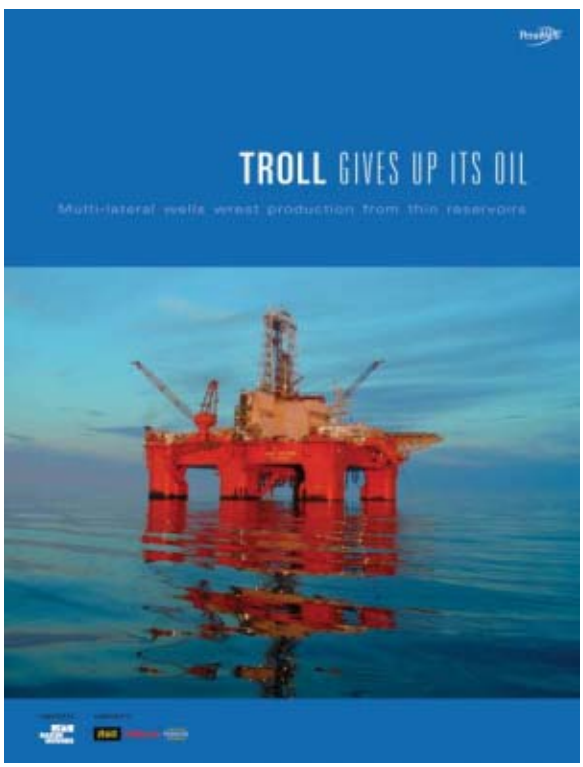

Troll Gives Up Its Oil looks at the offshore Troll field, discovered in 1974 and declared commercial in 1983, is one of Norway's largest gas producers. But today, thanks to joint technical initiatives by operator Norsk Hydro, a number of Baker-Hughes business units and other service providers, Troll's previously "unrecoverable" crude reserves are now flowing into multilateral wells, making it Norway's largest oil field, as well.

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OIL&GAS JOURNAL®

Sept. 3, 2007
Volume 105.33

PIPELINE ECONOMICS

REGULAR FEATURES

COVER

Crews handle concrete-coated 42-in. pipe, each joint weighing about 54,000 lb, for the Sabine Pass Pipeline being constructed for a subsidiary of Cheniere Energy Inc. Work on the pipeline, which includes 16 miles of land lay and push work and a directional drill crossing of 2,200 ft, began in May 2007. The Sabine Pass Pipeline will provide the grid interconnection for Cheniere's 4-bcfd sendout capacity LNG regasification terminal under construction at Sabine Pass in southwestern Louisiana. Oil & Gas Journal's special report on Pipeline Economics, which begins on p. 44, provides more information on similar projects, along with operational and financial data reported to the US Federal Energy Regulatory Commission for 2006-07. Photo from Willbros USA Inc. by Lindy King.

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General Interest

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Drilling & Production

Processing

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

OGJ News
Please submit press releases via e-mail to: news@ogjonline.com

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

PennWell Corporate Headquarters
1421 S. Sheridan Rd., Tulsa, OK 74112

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General Interest — Quick Takes

Kazakh officials suspend Kashagan field permit

Kazakhstan officials Aug. 27 suspended the permit for exploration and development work in Kashagan oil field off Kazakhstan, effectively halting work on the vast field for the next 3 months.

This is the latest in a series of obstacles that the consortium behind Kashagan's development—led by Agip Kazakhstan North Caspian Operating Co. NV (Agip KCO), a unit of Italy's Eni SPA—has had to contend with. Most recently work in Kashagan was snagged by alleged environmental violations that threatened to revoke the consortium's license (OGJ, Aug. 27, 2007, p. 26).

Eni is sole operator and holds an 18.52% interest in the North Caspian Sea production-sharing agreement to carry out exploration, development, and production activities in an offshore area in the northern part of the Caspian Sea, where giant Kashagan field was discovered.

To carry out operations, Eni created Agip KCO, which acts on behalf of the consortium.

The group plans to develop the field by drilling about 280 wells and building offshore platforms and artificial islands.

Oil and part of the natural gas produced will be sent in two separate trains to the treatment plant of Bolashak near Atyrau. Export options for production being considered include using an oil pipeline owned and operated by Caspian Pipeline Consortium, in which Eni holds a 2% interest, that links Atyrau, in Kazakhstan, to the Russian oil terminal of Novorossisysk, in the Black Sea.

Eni also is cooperator and holds a 32.5% interest in Karachaganak Petroleum Operating BV, a consortium created to develop and operate Karachaganak field, one of the world's largest oil and gas fields, in northwestern Kazakhstan.

Ryder Scott: Trinidad and Tobago reserves declining

The Ryder Scott audit of Trinidad and Tobago's natural gas reserves has revealed a 3.83 tcf decline since January 2005.

The report found that Trinidad and Tobago has 17.05 tcf of proved gas reserves, 7.76 tcf of probable reserves, and 6.23 tcf of possible reserves.

The report also found that the twin-island nation's risked 3P reserves would be adequate to supply the demand for gas through 2016 before declining.

Trinidad and Tobago's cabinet made four decisions arising from the survey results, according to Energy Minister Lenny Saith:

- Increase the rate at which decisions are made and blocks awarded for exploration.
- Do not move any gas-based project to the priority A category from the nonpriority B category.
- Get more geological information on potential areas to explore.
- Look at the taxation structure for exploration in high-risk areas.

Saith said, "The survey is saying, 'Look at your taxation for exploration in high-risk areas, not exploration in low-risk areas. Look at your tax policy and determine if there is anything you need to do that will speed up [companies' willingness] to take risk in those high risk areas.'"

Saith said 16 new wells will be drilled within the next 15 months and insisted there would not be any new LNG trains built unless additional gas is discovered.

Trinidad and Tobago has four LNG trains and last year was responsible for 67% of total US LNG imports.

While there was a reduction in the 3Ps, the survey reported a 5 tcf increase in what it says could yet be discovered.

Ryder Scott reported that Trinidad and Tobago has a potential for an additional 37 tcf of gas awaiting discovery.

The increase in the figure resulted from the collection and processing of 3D data by Canada Superior and Petro-Canada that showed there may be larger gas structures than originally thought in the blocks they are exploring.

Indonesia's domestic gas needs remain top priority

Indonesian Vice-President Jusuf Kalla said his country will remain "consistent" in honoring current natural gas supply contracts with Japan, but that its top priority will be to meet domestic needs.

After meeting Aug. 20 with Japanese Prime Minister Shinzo Abe, who was on a state visit to Indonesia, Kalla said his country wanted to increase energy exports, including to Japan, as the country needs more export earnings.

To enable greater export potential, Kalla said improvements in the efficiency of domestic gas use will be made, while exploration will be expanded to increase the production of oil and gas. Kalla said exploration is already under way in Java, Papua, and the Natuna islands.

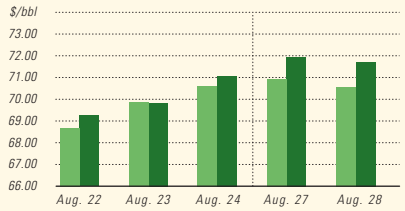
Meanwhile, according to Energy and Mineral Resources Minister Purnomo Yusgiantoro, there was no discussion between Abe and Kalla about any extensions of current LNG supply contracts with Japan.

For some time now, Indonesia has had rising domestic demand for gas. As a result, in June Indonesia said it was reallocating supplies of Tangguh LNG originally earmarked for Sempra Energy LNG in order to boost the amounts available to state-owned utility Perusahaan Listrik Negara (OGJ Online, June 18, 2007).

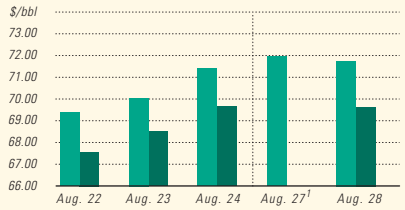
In March, in an effort to obtain higher prices for its LNG exported from Tangguh in Papua New Guinea, Indonesia said it wanted to renegotiate LNG contract terms with South Korea (OGJ Online, Mar. 6, 2007).

Industry Scoreboard

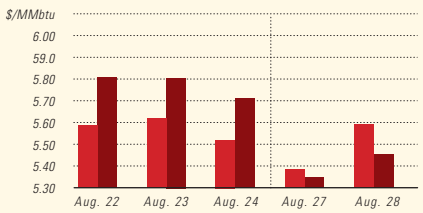
IPE BRENT / NYMEX LIGHT SWEET CRUDE



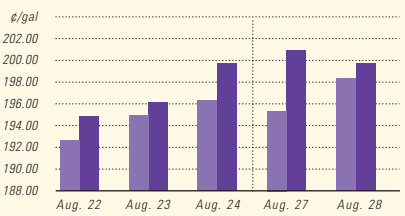
WTI CUSHING / BRENT SPOT



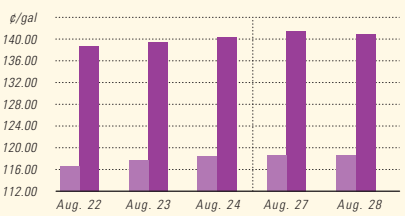
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



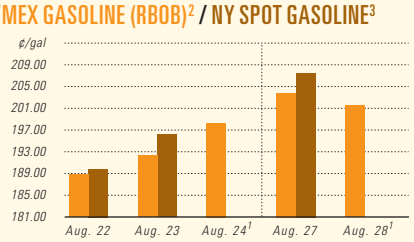
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



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

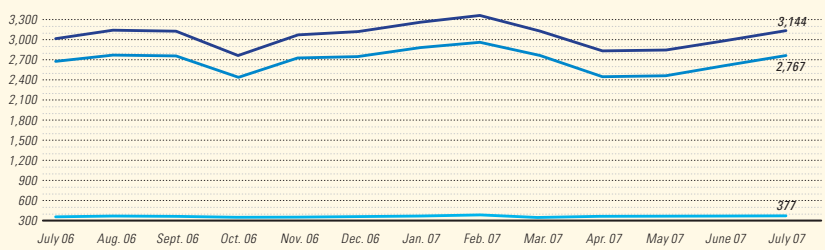
US INDUSTRY SCOREBOARD — 9/3

Latest week 8/17	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	9,643	9,584	0.6	9,310	9,199	1.2
Distillate	4,167	4,083	2.1	4,234	4,147	2.1
Jet fuel	1,617	1,652	–2.1	1,624	1,618	0.4
Residual	733	716	2.4	759	718	5.7
Other products	4,949	4,970	–0.4	4,859	4,859	—
TOTAL DEMAND	21,109	21,005	0.5	20,786	20,522	1.3
Supply, 1,000 b/d						
Crude production	5,165	5,162	0.1	5,183	5,100	1.6
NGL production[2]	2,446	2,306	6.1	2,378	2,186	8.8
Crude imports	10,213	10,373	–1.5	10,136	10,075	0.6
Product imports	3,364	3,908	–13.9	3,561	3,609	–1.3
Other supply[3]	960	1,258	–23.7	933	1,133	–17.7
TOTAL SUPPLY	22,148	23,007	–3.7	22,191	22,103	0.4
Refining, 1,000 b/d						
Crude runs to stills	15,878	16,064	–1.0	15,243	15,221	0.1
Input to crude stills	16,065	16,159	–0.6	15,497	15,577	–0.5
% utilization	92.1	92.9	—	88.9	89.6	—

Latest week 8/17	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	337,118	335,228	1,890	331,002	6,116	1.8
Motor gasoline	196,231	201,940	–5,709	205,393	–9,162	–4.5
Distillate	129,025	127,669	1,356	133,170	–4,145	–3.1
Jet fuel-kerosine	41,918	41,400	518	40,659	1,259	3.1
Residual	36,476	36,977	–501	42,648	–6,172	–14.5
Stock cover (days)[4]			Change, %		Change, %	
Crude	21.2	21.1	0.5	21.2	—	
Motor gasoline	20.4	21.0	–2.9	21.4	–4.7	
Distillate	31.0	31.1	–0.3	33.0	–6.1	
Propane	54.7	51.2	6.8	67.8	–19.3	
Futures prices[5] **8/24**			Change		Change	Change, %
Light sweet crude, $/bbl	69.74	72.17	–2.43	71.93	–2.19	–3.0
Natural gas, $/MMbtu	5.72	6.90	–1.18	6.79	–1.08	–15.8

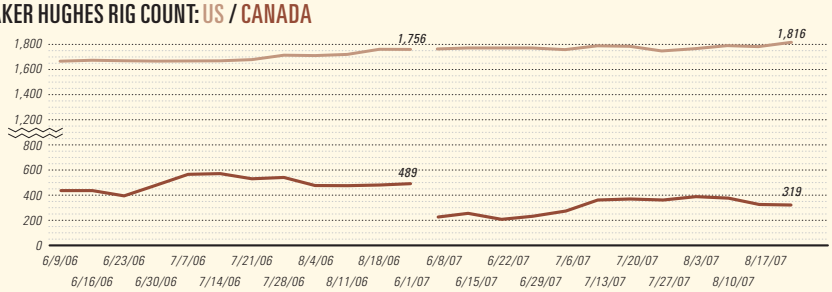
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

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



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

EPA: Current levels of refinery emissions acceptable

The US Environmental Protection Agency reported Aug. 23 that existing levels of toxic air pollutants released from US refineries do not require further controls to protect human health or the environment.

EPA recently conducted an analysis required under the Clean Air Act. The analysis examined potential risks that remain after implementation of maximum achievable control technology (MACT) standards.

MACT standards require industrial facilities to reduce emissions of toxic air pollutants. EPA first issued MACT standards for refineries in 1995.

Now EPA is seeking public comment on two options it proposed for controlling air emissions from refineries. The first option would require no additional emissions reductions because the risks are acceptably low. The second option would require additional emissions reductions for certain storage vessels and wastewater treatment units.

Under this alternative, EPA projects refineries could reduce air toxics emissions by as much as 4,600 tons/year from 153 facilities. EPA will accept public comment for 60 days following publication of the proposals in the Federal Register. ✦

Exploration & Development — *Quick Takes*

Statoil finds gas with Midnattsol well off Norway

Statoil ASA made a deepwater natural gas discovery with its 6405/10-1 exploration well in the Midnattsol 281 production license in the Norwegian Sea. The find lies 40 km north of Ormen Lange field and 30 km south of the Ellida discovery. It is too early to declare the find commercial, Statoil said.

The company plans to drill an additional five exploration wells in the deepwater area in 2008. Three of these it will operate, said Frode Fasteland, acting head of exploration on the Norwegian continental shelf.

The Midnattsol well was drilled to a TD of 3,158 m subsea in 928 m of water by Transocean Inc.'s Transocean Leader semisubmersible. The well found gas in a late Cretaceous reservoir.

Core samples have been taken and an extremely thorough data acquisition program carried out, Statoil said. The collected data will be analyzed to delineate and define the discovery.

Midnattsol will be permanently plugged and abandoned. And the drilling rig will now be taken over by Eni SPA.

The licensees in PL 281, Blocks 6405/4, 7, and 10 are operator Statoil 50%, E.On Ruhrgas 20%, Petoro SA 20%, and ConocoPhillips 10%.

Statoil's interest in PL 281 was recently increased when it acquired Royal Dutch Shell PLC's 20% interest (OGJ Online, Apr. 27, 2007).

Manning promises exploration incentives in 2008

Trinidad and Tobago Prime Minister Patrick Manning reported during his 2007-08 budget presentation that the Caribbean island nation next year will offer incentives to major oil and gas companies to explore for hydrocarbons in marginal fields.

Commenting on the recent Ryder Scott natural gas audit that showed Trinidad and Tobago's production hitting a plateau in about 9 years, Manning said, "What is needed now is a new fiscal regime of incentives to stimulate further drilling in the Deep Marine areas of East Coast, marginal fields, heavy oil, and farm-in, farm-out arrangements."

He added, "We confidently expect... new discoveries of oil and gas and the preservation of Trinidad and Tobago's position as an industrial center in the region."

During a recent energy conference in Port of Spain, the major oil and gas companies asked the Trinidad and Tobago government to review its taxation regime in high risk areas like its deepwater blocks. ✦

Drilling & Production — *Quick Takes*

Ithaca to drill second Athena appraisal well

Ithaca Energy (UK) Ltd. entered into an agreement with Senergy Ltd. to use the Stena Spey semisubmersible and drilling management services to drill the second appraisal well on the Athena oil project in the Outer Moray Firth off Scotland.

Drilling which was scheduled to begin in late August, is part of a work program leading up to a field development plan expected to be filed in this year's fourth quarter.

Well objectives are to evaluate the eastern lobe of the Athena discovery, for which probable undeveloped oil reserves have been independently verified at 28 million bbl (20 million bbl net to Ithaca).

Ithaca will spud the well close to the mapped northern pinchout of the Cretaceous Upper Leek formation. The well site is midway between the 14/18b-11 well, which encountered good reservoir in the Upper Leek below the oil-water contact, and the 14/18b-12 well, which encountered tight reservoir in the Upper Leek sands but had an oil-leg in the Lower Leek sands (OGJ Online, Nov. 30, 2006).

Recent results of seismic processing following the drilling of the 14/18b-15 well have confirmed the selection of the bottomhole location for the planned well, which is designed to be kept as a production well and is in a position to optimally drain the eastern part of Athena field.

Ithaca had expected to drill this well with the Byford Dolphin semisubmersible this summer, but it has been delayed due to operational, scheduling, and weather-related issues on its current program (OGJ Online, Apr. 2, 2007).

Ithaca has decided to delay taking on the Byford Dolphin semisubmersible until later this year to allow the Stena Spey to begin the Athena work as soon as possible, the company said.

Williams studies Canadian oil sands expansion

Williams Cos., Tulsa, is making an engineering study for possible expansion of its Canadian facilities to extract ethane from offgas emissions associated with its oil sands production in Alberta.

The company recovers and purifies natural gas liquids and olefins at its Fort McMurray and Redwater oil sands production facilities in Alberta that it has operated since 2002.

It is contemplating construction of a cryogenic processing plant, addition of a de-ethanizer, and expansion of its existing fractionator at its Redwater complex north of Edmonton, Alta; and addition of a de-ethanizer to the Redwater complex. The de-ethanizer could begin operating in stages as early as 2010; the new off-gas processing plant could start up in 2012, officials said.

"As the only company with facilities in service to recover olefins and natural gas liquids from the Canadian oil sands off-gas, Williams is uniquely positioned to provide these services," said Randy Newcomer, vice-president. "Recovering rather than burning the liquids contained in the off-gas not only increases the value of the off-gas, but also results in a significant environmental benefit."

Williams's current operations at Fort McMurray and Redwater reduce emissions of carbon dioxide—a greenhouse gas—in Alberta by 219,000 tons/year. It also reduces annual emissions of sulfur dioxide—a contributor to acid rain—by more than 3,200 tons.

Williams' contemplated expansion of its off-gas operations and ethane removal would further decrease emissions associated with oil sands production, officials said. The company recently signed nonbinding letters of intent specific to the expansions it will evaluate. It's evaluation of ethane-recovery facilities is the subject of such an agreement with Nova Chemicals Corp.

Leed Petroleum secures rig for Gulf of Mexico work

Leed Petroleum PLC, a London-based oil and gas exploration and production company focused on the Gulf of Mexico, will begin a multiple well drilling program in September initially on its Eugene Island Blocks 183 and 184 in the gulf.

The company has signed a contract with Ensco Offshore Co. for use of Rig 98 to carry out the drilling. Leed is operator of Block 183 and the southern half of Block 184. ✦

Processing — *Quick Takes*

Qatar Petroleum lets contract for refinery

State-owned Qatar Petroleum plans to build a grassroots refinery with 250,000 b/d capacity and other associated facilities in Messaieed, Qatar. QP has let a lump sum front-end engineering design contract to Technip for the work.

The $60 million contract covers the Al Shaheen facility and an oil pipeline that will extend from Al Shaheen oil and gas field 90 km offshore to Messaieed 110 km onshore, as well as other import-export facilities. Technip's operations and engineering centers in Paris and Abu Dhabi will carry out the contract work.

The refinery, which will produce mainly gasoline, diesel, and jet fuel, will incorporate some of the most technologically advanced conversion units for upgrading bottom of the barrel products. The facilities are scheduled to be operational by yearend 2011.

Qatar currently has just one refinery at Umm Said. It has a capacity of 200,000 b/cd and is operated by National Oil Distribution Co.

Qatar's crude production capacity is expected to increase to 1.1 million b/d by late 2008. The increase will come from expansion of Al-Shaheen oil field. A development effort in progress in Al Shaheen field will raise the field's oil production to 525,000 b/d from 240,000 b/d (OGJ, Mar. 26, 2007, Newsletter).

BP won't raise discharge limits at Whiting refinery

BP America Inc. on Aug. 23 promised to operate its 399,900 b/cd Whiting, Ind., refinery to meet the lower discharge limits specified in its previous wastewater treatment permit. BP's pledge came after a new, recently approved permit, which allows for higher discharge limits, met with regional opposition.

"We will not make use of the higher discharge limits in our new permit," said BP America Chairman and Pres. Bob Malone.

The new permit allows BP to increase discharge limits to 1,584 lb/day from 1,030 lb/day for ammonia and to 4,925 lb/day from 3,646 lb/day for total suspended solids. The permit is associated with a $3.8 billion upgrade project that would enable BP's Whiting refinery to increase processing capacity for Canadian heavy crude to 90% from 30% and creates the capacity to increase production of clean fuels by 1.7 million gal/day.

Malone said if BP determines that the refinery cannot operate after the heavy crude project is implemented and still meet the lower discharge limits, the company will develop a project to allow it to do so.

He explained, however, that "if necessary changes to the project result in a material impact to project viability, we could be forced to cancel it."

Malone said the project requires regulatory certainty. And "opposition to any increase in discharge permit limits for Lake Michigan creates an unacceptable level of business risk for this $3.8 billion investment," he said.

During the next 18 months, BP will continue to seek issuance of other permits, continue project design, and explore options for operating within the lower discharge limits.

The company has agreed to participate with the Purdue Calumet Water Institute and the Argonne National Laboratory in a joint effort to identify and evaluate emerging technologies with the potential to improve wastewater treatment across the Great Lakes.

BP will provide a $5 million grant to Purdue University to help underwrite the research effort, Malone said.

Nigeria's DPR assesses 26 refinery applications

Nigeria's Department for Petroleum Resources (DPR) has received 26 applications from private companies wishing to build refineries in Nigeria.

According to DPR's midyear 2007 report, four of the 26 companies had their licenses overturned in March because they failed to build the refinery by the given deadline. The applications are at different stages of processing.

Under DPR's guidelines companies will be required to deposit $1 million for every 10,000 b/d of planned capacity, which would be refundable within 18 months provided the project is carried out to deadline.

The report also said the 210,000 b/d refinery in Port Harcourt operated at just about 38% capacity in the first half of this year. The facility is the only refinery working in Nigeria since Feb. 18, 2006. The Warri and Kaduna refineries remain closed because the Chanomi Creek pipeline, which would otherwise transport oil to both of the facilities, had been damaged by vandals. ✦

Transportation — *Quick Takes*

Germany suffers oil supply shortfall from Russia

During August Germany has suffered a one-third shortfall in oil supplies from Russia via the Druzhba oil pipeline network. The line delivers oil from Russia through Belarus en route to Europe.

Transneft Vice-Pres. Sergei Grigoryev told Interfax that OAO Lukoil and other smaller companies had allegedly cut deliveries and had not given a reason for doing so.

The 220,000 b/d PCK refinery at Schwedt in eastern Germany has sought other sources to make up for the shortfall of supply. The company said it had been informed by suppliers that there would be supply fluctuations and talks are ongoing between the parties.

Nevertheless the refinery is running at full capacity and is using its resources as well as oil supplies from the North Sea.

One possible reason that Lukoil has cut crude shipments to Germany is because it wants to sell directly to the German markets instead of through the traders who it is currently in conflict with, according to media reports. Full supplies are expected to resume this month.

In recent weeks there was speculation that there were problems with the pipeline network, which was why supplies had fallen. This is the second time in the last 8 months that Germany has seen a shortfall (OGJ Online, Jan. 10, 2007).

Kinder Morgan Canada starts Anchor Loop expansion

Kinder Morgan Energy Partners LP unit Kinder Morgan Canada has started construction on the $443 million (Can.) Anchor Loop project—the second phase of the Trans Mountain pipeline system expansion. Kinder Morgan received Canadian regulatory approval for the loop project last year (OGJ Online, Oct. 30, 2006).

The expansion, which will increase Trans Mountain's capacity to 300,000 b/d from 260,000 b/d, is expected to be completed in November 2008.

Trans Mountain transports oil and products from Edmonton, Alta., to marketing terminals and refineries in British Columbia and Washington state. Earlier this year Kinder Morgan Canada commissioned 11 new pump stations, which boosted capacity on Trans Mountain to 260,000 b/d from 225,000 b/d. The pipeline has been operating at capacity since then.

The project entails looping 158 km of the Trans Mountain system through rugged terrain in Jasper National Park and Mount Robson Provincial Park.

Kinder Morgan Canada also continues to have discussions with customers for the next expansion phase (TMX-2) of the Trans Mountain pipeline system.

Questar, Enterprise to build Rockies gas hub

Questar Pipeline Co., Salt Lake City, and an affiliate of Enterprise Products Partners LP, Houston, signed a memorandum of understanding to build a 2.5 bcfd natural gas pipeline hub in the Rocky Mountain area. Questar will construct and operate the 7-mile, 30-in. hub pipeline.

The White River Hub, a header system to be owned equally by the two companies, will connect Enterprise's gas processing complex near Meeker, Colo., with as many as six interstate pipelines in the Piceance basin area, including Questar's.

The pipeline, from Questar Pipeline's Greasewood, Colo., facilities to the nearby Enterprise Meeker gas processing complex, would provide hub-related services for area gas producers, marketers, and buyers.

Other pipelines expected to connect to the White River Hub are the Rockies Express Pipeline, owned by Kinder Morgan, Sempra, and ConocoPhillips; Kinder Morgan's TransColorado Gas Transmission Co.; El Paso's Wyoming Interstate Co. and Colorado Interstate Gas Co.; and the Williams-owned Northwest Pipeline Corp. The system would allow shippers on these pipelines to access markets throughout the country.

As foundation shippers, Enterprise has committed to 1.5 bcfd of firm capacity on the pipeline and Questar to 0.5 bcfd. An open season will be held immediately for the remaining firm capacity.

Assuming receipt of regulatory approvals and a successful open season, the companies expect pipeline construction to start in mid-2008 and for gas transmission to begin in fall 2008.

Petroecuador, Flopec plan LPG terminal, pipeline

Ecuador's state-owned Petroecuador has awarded Dutch trader Trafigura Beheer a 2-year contract to supply LPG while an onshore maritime terminal and 50,000-tonne storage facility is being built in Monteverde, Ecuador.

Petroecuador said Trafigura will supply about 1.6 million tonnes, with monthly deliveries starting in November when Trafigura's current contract expires. Trafigura will need a 40,000-tonne storage vessel and two, 2,500-tonne vessels to transport the LPG to the Tres Bocas terminal in Guayas province.

The contract will help meet demand while Petroecuador and state hydrocarbons maritime transporter Flopec build the Monteverde LPG terminal and pipeline.

Under a 5-year contract, Flopec will build and operate the Monteverde terminal and storage facility, while Petroecuador will build and operate the 146-km, 10-in. La Libertad-Pascuales pipeline and a storage terminal in Pascuales.

The Monteverde terminal will have a capacity to receive vessels exceeding 40,000 dwt.

The Ecuadoran government said the project will reduce operating costs by more than $30 million/year and will provide increased LPG storage efficiency and safety. ✦

Calendar

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

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2007

SEPTEMBER

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Rocky Mountain Crude Oil Market Dynamics Summit, Denver, (405) 525-3556, (405) 525-3592 (fax), e-mail: iogcc@iogcc.state.ok.us, website: www.iogcc.state.ok.us/events.html. 4-5.

Power-Gen Asia Conference, Bangkok, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwell.com. 4-6.

Offshore Europe Oil & Gas Conference and Exhibition, Aberdeen, +44 (0) 208 439 8890, +44 (0) 208 439 8897 (fax), e-mail: oe2007@spearhead.co.uk, website: www.offshore-europe.co.uk. 4-7.

Black Sea Oil & Gas Summit, Istanbul, +90 312 454 00 00-1412, +90 312 454 00 01, e-mail: bsogs2007@flaptour.com.tr, website: www.bsogs2007.org. 5-6.

Iraq Petroleum Conference, Dubai, +44 (0)20 7978 0075, +44 (0)20 7978 0099 (fax) website: www.thecwcgroup.com. 8-10.

Corrosion Solutions Conference, Sunriver, Ore., (541) 926-4211, ext. 6280, website: www.corrosionconference.com. 9-13.

Global Refining Strategies Summit, Houston, (416) 214-3400, x3046, (416) 214-3403 (fax), website: www.globalrefiningsummit.com. 10-11.

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

Annual LNG Tech Global Summit, Rotterdam, +44 (0) 20 7202 7511, e-mail: anne.shildrake@wtgevents.com, website: www.lngsummit.com. 10-12.

SPE Asia Pacific Health Safety Security Environment Conference, Bangkok, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 10-12.

Turbomachinery Symposium, Houston, (979) 845-7417 (979) 845-1835 (fax), e-mail: turbo@turbo-lab.tamu.edu, website: http://turbolab.tamu.edu. 10-13.

Oil Sands Trade Show & Conference, Fort McMurray, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 11-12.

EXPOGAZ Gas Congress, Paris, 01 41 98 40 25, e-mail: lberthier@etai.fr, website: www.congresdugaz.fr. 11-13.

European Gas Forum, Paris, 01 41 98 40 25, e-mail: lberthier@etai.fr, website: www.congresdugaz.fr. 12-13.

AAPG Annual Eastern Meeting, Lexington, (859) 257-5500, ext. 173, website: www.esaapg07.org. 16-18.

United States Association for Energy Economics/IAEE North American Conference, Houston, (216) 464-2785, (216) 464-2768 (fax), website: www.usaee.org. 16-19.

API Fall Refining and Equipment Standards Meeting, San Antonio, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 17-19.

Annual American School of Gas Measurement Technology Event, Houston, (972) 224-5111, (972) 224-5115 (fax). e-mail: asgmt2007@aol.com, website: www.asgmt.com. 17-20.

IOGCC Annual Meeting, New Orleans, (405) 525-3556, (405) 525-3592 (fax), e-mail: iogcc@iogcc.state.ok.us, website: www.iogcc.state.ok.us. 23-25.

Society of Exploration Geophysicists (SEG) Annual Meeting, San Antonio, (918) 497-5500, (918) 497-5557 (fax), e-mail: web@seg.org, website: www.seg.org. 23-28.

Russia & CIS Petrochemicals Technology Conference & Exhibition, Moscow, +44 (0) 20 7357 8394, e-mail: Conferences@EuroPetro.com, website: www.europetro.com. 25-26.

Annual Engineering & Construction Contracting Association Conference, Colorado Springs, Colo., (877) 484-3322, (713) 337-1644 (fax), e-mail: Twilson@EventsiaGroup.com, website: www.ecc-association.org. 26-29.

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OCTOBER

IPLOCA Convention, Sydney, +41 22 306 0230, e-mail: info@iploca.com, website: www.iploca.com. 1-5.

Well Control Gulf of Mexico Conference, Houston, (979) 845-7081, (979) 458-1844 (fax), e-mail: jamie@pe.tamu.edu, website: www.multiphasre-research.org. 2-3.

ISA EXPO, Houston, (919) 549-8411, (919) 549-8288 (fax) website: www.isa.org. 2-4.

Rio Pipeline Conference and Exposition, Rio de Janeiro, +55 21 2121 9080, e-mail: eventos@ibp.org.br, website: www.ibp.org.br. 2-4.

ISA EXPO, Houston, (919) 549-8411, (919) 549-8288 (fax) website: www.isa.org. 2-4.

Kazakhstan International Oil & Gas Exhibition & Conference, Almaty, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 2-5.

Regional Deep Water Offshore West Africa Exploration & Production Conference & Exhibition, Luanda, +31 (0)26 3653444, +31 (0)26 3653446 (fax), e-mail: g.kreeft@energywise.nl, website: www.dowac.com. 2-6.

GPA Rocky Mountain Annual Meeting, Denver, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 3.

IFP Symposium The Capture and Geological Storage of CO2, Paris, +33 1 47 52 70 96 (fax), e-mail: patricia.fulgoni@ifp.fr, website: www.ifp.fr. 4-5.

IPAA OGIS West, San Francisco, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org/meetings. 7-9.

Annual European Autumn Gas Conference, Düsseldorf, +44 (0)20 8241 1912, +44 (0)20 8940 6211 (fax), e-mail: info@theeagc.com, website: www.theeagc.com. 9-10.

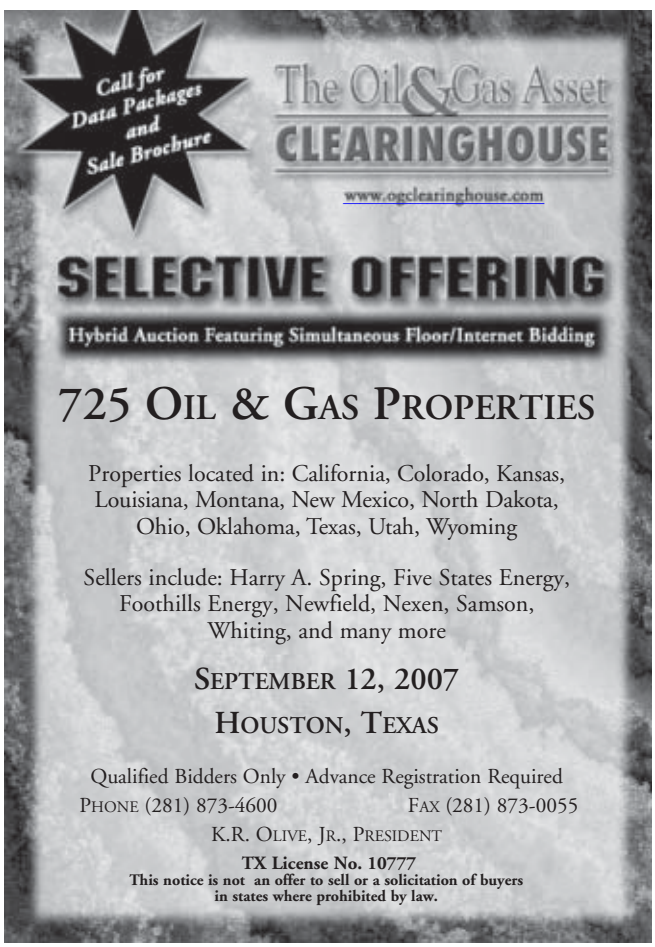
IADC Drilling HSE Europe Conference & Exhibition, Copenhagen, (713) 292-1945, (713) 292-1946 (fax); e-mail: info@iadc.org, website: www.iadc.org. 9-10.

NPRA Q&A and Technology Forum, Austin, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 9-12.

Deep Offshore Technology (DOT) International Conference & Exhibition, Stavanger, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepoffshoretechnology.com. 10-12.

International Bottom of the Barrel Technology Conference & Exhibition, Athens, +44 (0) 20 7357 8394, e-mail: Conferences@EuroPetro.com, website: www.europetro.com. 11-12.

The Athens Summit on Global Climate and Energy Security, Athens, +30 210 688 9130, +30 210 684 4777 (fax), e-mail: jangelus@acnc.gr, website: www.athens-summit.com. 14-16.



Journally Speaking

Managing produced water

Guntis Moritis
Production Editor

Access recently became available to a web site that can assist oil and gas field operators in sorting out the many available methods for handling water production.

Argonne National Laboratory developed the Produced Water Management Information System, http://web.evs.anl.gov/pwmis, through funding from the US Department of Energy.

The web site includes three modules:

1. A technology description module containing basic information on current practices for managing produced water. The module includes fact sheets describing technologies and providing references for additional information.

2. A regulatory module summarizing state and federal regulations or guidelines on produced-water management. It also contains hot links to the relevant US Environmental Protection Agency, US Bureau of Land Management, US Minerals Management Service, and state regulatory agency web pages.

3. A technology identification module containing a series of questions, mostly answered with "yes" or "no." These questions lead the user through a decision tree that suggests the most appropriate option for a given location as a function of such factors as location, regulatory acceptance of the practice, technical feasibility, cost, and availability of infrastructure and equipment.

In June 2004, Argonne launched a similar web site, the Drilling Waste Management Information System (DWMIS), http://web.ead.anl.gov/dwm/, which has similar modules (OGJ, Aug. 2, 2004, p. 31). Argonne says that in 3 years DWMIS has received more than 1.7 million hits and nearly 120,000 visitor sessions representing 57,000 unique visitors.

Water production

Water is the largest waste stream by volume generated by oil and gas producers. Some estimates place worldwide water production at more that 77 billion bbl/year. Argonne estimates that onshore oil wells in the US alone produce about 14 billion bbl/year of water. Total US water production increases to 15-20 billion bbl/year when the estimate includes water from natural gas wells, coalbed methane wells, and offshore wells.

These volumes compare with 30 billion bbl/year of oil produced in the world.

Argonne notes that a complicating factor for handling produced water is the water's variability. Physical and chemical properties depend on geographic location, geological formation, and hydrocarbon produced. Water quality also may change during the producing life of a reservoir.

Water handling

Argonne lists water minimization as an effective way operators can save money and protect the environment. This can be done either with mechanical (packers, plugs, and cement) or chemical (polymer gels) means that prevent water from entering the wellbore. Operators also can reduce water coming to surface through downhole oil-water and gas-water separators as well as seafloor separation modules.

Although looked at mostly as a waste, produced water may have uses. It can enhance oil recovery when reinjected into a producing formation. Argonne notes that tens of thousands of injection wells exist throughout the US and elsewhere for enhancing oil production.

Other uses of water include storage in aquifers for future use and for hydrological purposes such as subsidence control and stream flow augmentation.

In the case of water from coalbed methane wells, the water may have low enough salinity for use without treatment in irrigation, water for livestock and wildlife watering, and wetland management. Argonne also notes that produced water has found industrial uses such as for dust control, make-up water for drilling fluids, and water supply for power generation boilers and cooling units. If treated, the water also can add to drinking water supplies.

If no use is found, operators may also choose to dispose of the water, although this usually requires them to treat the water before disposal. Some disposal technologies that Argonne lists include discharging into a larger body of water, underground injection, evaporation, and offsite commercial disposal.

Argonne says the parameters of greatest concern in disposal are the organic content (oil and grease) and the salt content (salinity, conductivity).

It notes that in some cases the salinity of discharged water such as to the Gulf of Mexico is not a concern, but oil and grease concentration regulations need to be met.

Different technologies can treat the water. Operators can remove salts with membrane processes, including reverse osmosis, filtration, and electrodialysis. Other technologies for removing salts are ion exchange, capacitive deionization, and thermal distillation.

Oil and grease removal technologies include physical separation with hydrocyclones, centrifuges, and filtration. Other options include coalesors, flotation cells, combined physical and extraction process, solvent extraction, and adsorption. ✦

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Editorial

Profits and angry policy

A central motive of energy policy-making in the US is anger at oil companies. The sentiment expresses itself in bills passed this year by both houses of Congress. A Senate bill would make oil prices found to be "unconscionably excessive" a target of criminal prosecution. A House bill would sharply raise taxes on the oil industry.

The anger results only partly from the oil price increases of the past few years. When confronted with explanations for the prices—rising demand, limited supply, hurricanes—angry observers typically note that oil-company profits reported when prices are high are what really peeve people.

For companies that sell crude oil and its derivatives, of course, profits are hard to avoid when commodity and product prices jump. The increases raise revenue if sales volumes hold steady or rise. And the revenue increases lift profits if costs hold still. That so many Americans find this arithmetic outrageous is perplexing. That the outrage so readily influences politics is even more so.

In fact, policy mistakes born of anger outlast price-swollen profits, which inevitably get whittled by rising costs. It's happening now.

As the story on p. 22 reports, second-quarter profits for a group of producers and refiners fell from the same period last year even as revenue increased. For 71 companies based in the US, net income fell 9.6% on total revenue up 2.6%. Fifteen of the companies reported net losses. For a sample of Canadian oil and gas companies, second-quarter earnings dropped by more than 20%.

Profits can decline when revenues rise for many reasons. But the common factor in second-quarter financial reports will surprise no one in the oil and gas business: surging costs.

Contemporaneous industry data on operating costs are scarce. But various proxies make clear that oil field costs have been zooming. For example:

- In a July report, Adam Sieminski of Deutsche Bank, using data from the US Energy Information Administration, estimated that worldwide finding and development costs increased 15%/year in inflation-adjusted terms during 2005-07. He projected the rate of increase at 7.5%/year or more during 2008-10, when the average finding and development cost would reach $18-20/bbl.
- The annual Joint Association Survey on Drilling Costs published by the American Petroleum Institute last April showed average drilling costs per well and per foot, adjusted for activity and inflation, nearly doubled for all US wells during 2000-05. The 2004-05 increases, however, were less than 1%.
- A new index of capital costs—which don't immediately affect profits but rise for many of the same reasons operating costs do—reflects a surge that its producers call "dramatic." For the 6 months ending last Mar. 31, the IHS/CERA Upstream Capital Costs Index, published by Cambridge Energy Research Associates, was up 79% from 2000. The indicated annual rate of project inflation for the period was 14%, down from 30% in 2006 in a trend CERA said might foreshadow a plateau as early as next year.

Everyone in the oil and gas business knows how costs have risen and why: competition for workers, materials, and services. The increases were predictable. Oil and gas price increases since 2001 did more than raise industry revenues and restore profitability, which in the 1990s had become elusive for many companies. They also stimulated activity in an industry with work capacities shrunken by years of financial trouble, an industry suddenly needing to compete with other active businesses for the ingredients of expansion.

So costs have jumped and are eroding profits. The development should begin to comfort industry antagonists who think oil and gas companies ought not to make money. It should, but it won't. The antagonists will just replace anger over profits with the strangely ineradicable suspicion that companies curb supply to drive up oil prices.

Yet behavior consistent with that suspicion is nowhere to be seen. While US profits were falling in this year's second quarter, operators were completing what API estimates to have been the highest number of wells in 21 years, and refiners were working up to their highest rate of gasoline output in history. ✦

Part 1—Complex factors cause recent gasoline price run-ups

Carol Dahl
Rachel Hackney
Anthony Scott
Colorado School of Mines
Golden, Colo.

During 1999-2006, US gasoline prices almost tripled, shocking consumers and spurring public debate about the causes of the increase. Simply put, the debate has pitched those who argue that the price reflects the market response to stronger demand and increasing raw material costs against those who see greedy oil companies using the power of monopoly to withhold output and artificially inflate prices. Critics have argued that:

- Oil companies have consolidated to increase concentration and decrease competition and have deliberately failed to invest in capacity, causing shortages and high gasoline prices.
- Speculation in futures markets has bid up gasoline futures prices, which in turn bids up current gasoline and crude oil prices.
- High gasoline prices are out of line with cost increases, allowing excessive profits in refining.
- US refineries are able to exploit their alleged monopoly power because of low demand price elasticities and because consumers have no alternatives to gasoline.
- Refineries have deliberately reduced their inventories to increase monopoly power, resulting in increased price volatility.

This article examines, in the light of economic theory and available statistical evidence, these and other factors that are causing high gasoline prices.

Gasoline price history

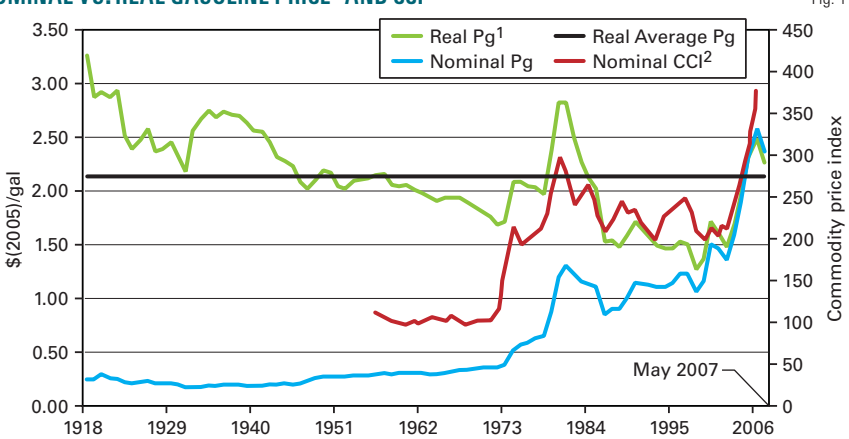
A review of the history of nominal and real gasoline prices in the US since 1918 finds that recent gasoline price levels are by no means unprecedented. The price increases have been shocking because they followed more than a decade of the lowest real prices US markets have ever enjoyed.

Putting the current price run-up in historical context, Fig. 1 shows nominal US gasoline prices since 1918. Prices were relatively stable during 1918-70, when large multinational oil companies controlled much of the oil flow. However, during 1973-82 prices more than tripled in an era of tight markets, wars, revolutions, and the emergence of powerful national oil companies. An almost equally dramatic increase occurred during 1999 through August 2006, when prices almost tripled. So the current run-up is not unprecedented, and the previous increase of this magnitude was followed by a price decline.

The nominal gasoline prices shown in Fig. 1 do not take into account that over time generally all prices were rising with inflation. When the price is adjusted with the consumer price index, we isolate the behavior of gasoline prices relative to other prices in the economy. The adjusted historical real gasoline prices in Fig. 1 show a general downward trend in gasoline prices except during the two periods of sharply rising oil prices in 1973-1982 and 1999-2006. Real prices reached an historical low in 1998 during the Asian economic crisis and did not return to their historical average of $2.13/gal (in 2005 dollars) until 2005. The product-weighted average annual price in 2006

NOMINAL VS. REAL GASOLINE PRICE[1] AND CCI[2]

Fig. 1



[1]Gasoline price (Pg), 1918 to May 2007. [2]Commodity price index (CCI), 1956-2006.
Source: Based on data from American Petroleum Institute

was lower, in real terms, than in the 1930s. Rather than being shocked by recent high prices, one might ask why consumers enjoyed such low gasoline prices in the prior decade.

The run-up in gasoline prices is also not unique among commodities. Fig. 1 also shows the combined price for a range of industrial and agricultural nonpetroleum commodities that make up the Commodity Research Bureau's Commodity Price Index (CPI). This index also rose sharply during 2002-06 to surpass its previous peak of the early 1980s. The similar price increases of nonpetroleum commodities suggest that the recent trend in gasoline prices reflects a strong world economy led by the US, China, and India, rather than specific actions by oil companies.

Demand pull 1999-2007

The demand for gasoline is driven by a steady increase in population and licensed drivers overlaid with short-term fluctuations in gross domestic product (GDP) growth. During 2001-06 GDP showed a positive trend that was not only greater than prior years but also stronger than expected, resulting in demand pressure on the gasoline market.

Statistical studies find that for every 1% increase in income, gasoline consumption increases by about 0.3% in the first year and by even more in the longer term. Unlike changes in population and drivers, however, changes in income tend to be somewhat unpredictable. Since 1973 real US GDP has fluctuated with an average growth rate of 3%/year. Noteworthy are the high rates of growth since 2004. Particularly unexpected were a 3.8 % increase in 2004 and the 5.4% annualized growth rate in first-quarter 2006, a rate that was well above the historical average and higher than in any year since 1984. Refinery managers expecting lower income growth would have planned for slower gasoline consumption growth than actually occurred.

Supply push 1999-2006

To produce and sell gasoline requires a variety of inputs, including crude oil, labor, electricity, catalysts, processing capacity, a normal rate of return on capital investment (ROI), product distribution, marketing, and taxes. In 2005, when refineries were paying about $50/bbl for oil and receiving a $2.27/gal retail price for gasoline, more than half of the retail cost of each gallon of gasoline went to buy the crude oil needed to produce it.

Between 1999 and summer 2006, oil prices to US refiners more than quadrupled, rising from $15.50/bbl to more than $65/bbl. In a competitive market, such increasing costs would necessarily raise gasoline prices.

From 1918 through 2006, the price of gasoline less tax (Pg-t) has closely tracked the price of a barrel of oil. Statistical analysis finds that the crude oil price explains about 97% of the variation in the pretax gasoline price over almost 9 decades and that each $1/bbl increase in the oil price is accompanied by an increase of about 2.7¢/gal in the gasoline price. Fig. 2 compares actual gasoline prices with the prices that were forecast with a regression equation and shows how closely the actual price matches the prediction made from the oil price. The most interesting feature of this figure is that actual prices were higher than the prices forecast over the time that the large multinationals were in control of world oil markets prior to the late 1970s.

Other purchased items have increased as well. During 2000-05, electric power costs increased about 20%, inorganic chemical costs rose about 25%, and organic chemical costs, about 45%. During the summer of 2006, spiking ethanol prices likely added 20¢/gal to reformulated gasoline prices.

New fuel regulations have strongly affected refiners since 1989. In addition to adding investment costs, tighter environmental regulations effectively reduce available refining capacity by reducing throughput and even causing the closure of refineries that cannot comply. Small refineries, in particular, have been challenged in meeting new fuel standards.

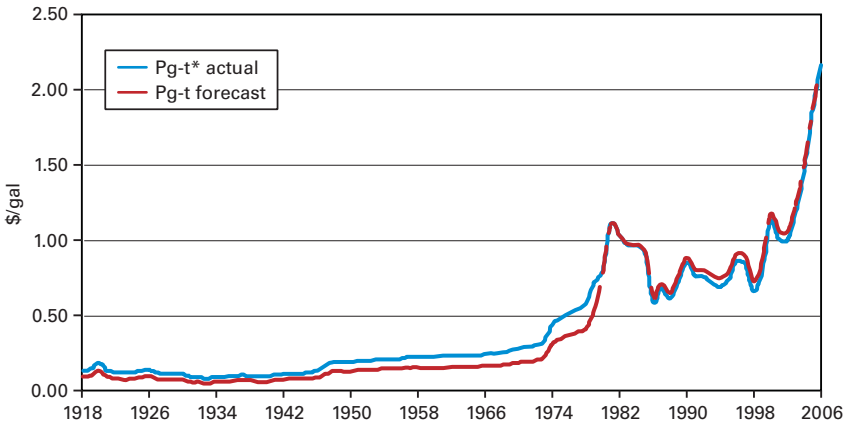
Refiners' profits

Higher oil prices have brought an era of higher oil company profits, causing some media personnel and policymakers to ask whether these profits are excessive. These profits should be examined in an historical context.

The refining industry viewed the early 1990s as a time of hardship, with low capacity utilization, high environmental compliance costs, and inadequate profits (Fig. 3). As a result, in the second half of the decade, the industry undertook massive restructuring aimed

FORECAST VS. ACTUAL GASOLINE PRICE LESS TAX

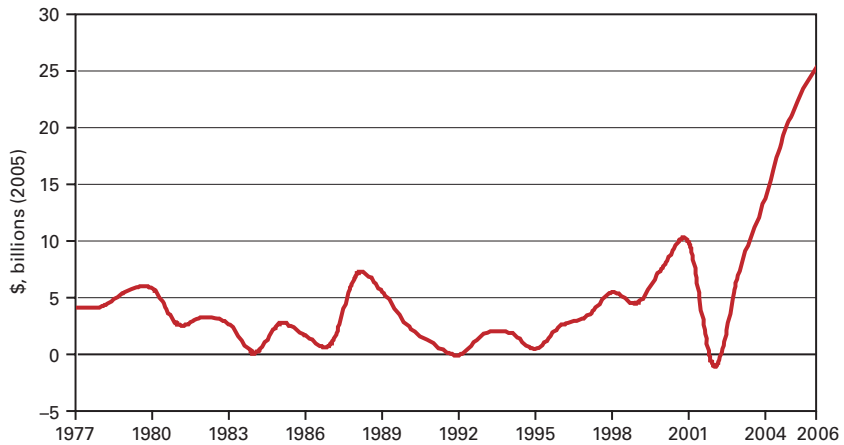
Fig. 2



*Price of gasoline less tax (Pg-t).
Source: Data from American Petroleum Institute

US REFINING, MARKETING REAL NET INCOME*

Fig. 3



*1977-2006.
Source: Energy Information Administration's Financial Reporting System companies reports

at cutting costs, increasing economies of scale, and improving profit margins. At the same time, the vertically integrated majors were spinning off their refining operations, increasing the number of players in the industry. The refining capacity operated by independents more than tripled to over 25% in 2006 from 8% in 1990. Returning the industry to profitability was especially important for the increasing numbers of independent refiners such as Valero, which did not have producing operations with earnings that could offset low profitability in refining. Refiners viewed the increase in utilization rates in the second half of the 1990s as a major accomplishment that made refining once again a viable industry.

After September 2001, US economic growth faltered, and refinery product sales fell in 2002. Refinery utilization and profit margins fell, causing net income to drop precipitously to the greatest loss in more than 30 years.

By 2003, however, refiner profits had risen above their historical average and regained their 2000 level. In 2004, unexpectedly high US economic growth drove profits to a record high level.

Hurricane Katrina, in August 2005, shut down oil production and pipelines and damaged ports and refineries so that by the end of August, 11% of US refining capacity was shut down, and 17% of US refineries were operating at reduced capacity. This temporary disruption brought higher net income. The year-on-year net income increase in second-half 2005 was over 50%, compared with less than 12% in the first half of the year.

In the first half of 2006, US GDP growth was the highest in 22 years, and real refining net income rose 30% from the first half of 2005. Some refineries that had delayed maintenance after the 2005 hurricanes were down in the spring. Refineries were phasing out methyl tertiary butyl ether and phasing in ultralow-sulfur diesel—all of which made refining capacity tight and drove prices higher. These pressures were alleviated by the end of the 2006 summer driving season as prices dropped only to rise again in spring 2007. High crude prices and unexpected outages kept real gasoline prices in the spring level with the high prices of 2006.

Higher prices have led to higher profits. However, these higher profits have come after more than a decade of low and negative ROI rates and restructuring aimed at returning refining to viability.

Part 2 of this article, which will run Sept. 10, 2007, will examine whether these high income levels are excessive and will review refining capacity, inventories, and margins; gasoline market concentration; and the role of futures markets.

For complete bibliographic references and statistical support, see (http://dahl.mines.edu/api.pdf).

Acknowledgement

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The authors

Carol Dahl is professor of mineral economics and director of the Colorado School of Mines-French Institute of Petroleum (CSM-IFP) joint international degree program in petroleum economics and management at the Colorado School of Mines. She received her bachelor's degree from University of Wisconsin and her PhD in economics from University of Minnesota. Dahl has supervised numerous PhD students, published two books and more than 100 articles and conference papers, completed numerous grants and contracts, and traveled to more than 95 countries pursuing her interest in modeling international energy markets.

Anthony Scott is a graduate student in the CSM-IFP joint degree program working on his MS in mineral economics and an MS in petroleum economic management. He also is an intern with Global Energy Inc. Scott received his BS in economics from the Colorado School of Mines. He previously has worked on projects for the Energy Information Administration and the American Petroleum Institute.

Rachael Hackney is an energy research assistant at the Colorado School of Mines, where she recently graduated with a BS in economics and business. She has worked on energy projects for the American Petroleum Institute and Bill Barrett Corp. as well as on various design projects for the Colorado School of Mines. In the fall, Hackney will be advancing her language skills in Paris at the Sorbonne in preparation for her MSc in international finance.

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Second-quarter results tumble for US, Canadian operators

Marilyn Radler
Senior Editor-Economics

Laura Bell
Statistics Editor

The combined second-quarter 2007 earnings of a group of US-based producers and refiners slipped almost 10% from a year earlier, largely because of rising costs. The group's revenues climbed slightly. For the first 6 months of the year, the same companies' collective revenues and earnings declined from the first half of 2006.

Meanwhile, a sample of oil and gas producers and pipeline operators based in Canada posted a 21% drop in earnings for the second quarter as well as a decline in first-half earnings. Revenues for both periods were up.

A group of service and supply com-

US OIL AND GAS FIRMS' SECOND QUARTER 2007 REVENUES, EARNINGS

	Revenues		Net income		Revenues		Net income	
	2nd quarter				Six months			
	2007	2006	2007	2006	2007	2006	2007	2006
	Million $ (US)							
Abraxas Petroleum Corp.	14.9	13.3	56.9	1.0	26.5	26.6	56.2	2.2
Alon USA Energy Inc.	1,186.7	672.3	95.6	43.1	2,152.2	1,257.0	131.2	97.3
Anadarko Petroleum Corp.	3,313.0	1,809.0	652.0	815.0	5,996.0	3,510.0	757.0	1,476.0
Apache Corp.	2,467.7	2,061.5	633.5	723.6	4,465.0	4,060.6	1,126.5	1,384.5
Apache Offshore Investment Partnership	1.8	2.9	1.0	2.1	3.7	6.3	2.2	4.6
Arena Resources Inc.	21.6	14.7	7.9	6.4	38.3	25.1	13.6	10.0
Aurora Oil & Gas Corp.	7.3	5.7	0.2	(1.2)	13.5	11.4	(0.5)	(2.0)
Berry Petroleum Co.	179.2	123.2	52.0	34.2	296.7	240.8	70.8	57.5
Bill Barrett Corp.	101.2	83.2	9.9	8.2	200.1	181.6	24.0	30.3
Brigham Exploration Co.	36.7	26.3	2.3	3.7	61.9	52.5	4.2	9.5
Cabot Oil & Gas Corp.	175.8	190.8	41.4	46.9	367.4	405.6	89.9	100.0
Carrizo Oil & Gas Inc.	33.0	16.8	8.1	2.6	56.0	39.0	5.6	9.2
Cheniere Energy Inc.	25.0	10.7	(41.1)	(3.6)	45.3	20.7	(75.7)	(19.4)
Chesapeake Energy Corp.	2,106.0	1,589.0	518.0	360.0	3,694.0	3,544.0	776.0	984.0
Chevron Corp.	56,094.0	53,536.0	5,380.0	4,353.0	104,321.0	108,160.0	10,095.0	8,349.0
Cimarex Energy Co.	342.1	313.4	78.7	82.9	649.0	648.6	143.3	193.0
Clayton Williams Energy Inc.	92.6	70.3	8.8	18.0	165.1	133.7	(3.5)	21.3
CMS Energy Corp.	1,319.0	1,219.0	36.0	75.0	3,508.0	3,116.0	(175.0)	51.0
Comstock Resources Inc.	174.5	124.4	18.2	15.6	320.9	256.4	30.8	45.2
ConocoPhillips	49,397.0	48,476.0	301.0	5,186.0	92,264.0	96,403.0	3,847.0	8,477.0
Delta Petroleum Corp.	49.0	40.7	(94.2)	4.2	91.5	77.7	(113.0)	18.0
Devon Energy Corp.	2,929.0	2,350.0	904.0	859.0	5,402.0	4,850.0	1,555.0	1,559.0
Edge Petroleum Corp.	53.9	33.9	10.6	5.8	76.8	68.9	4.8	12.7
EnDevCo Inc.	0.5	0.5	(1.5)	(1.2)	0.9	1.0	(2.1)	(1.0)
EOG Resources Inc.	1,055.2	919.1	307.1	331.4	1,930.5	2,003.6	524.7	758.1
Equitable Supply	127.9	119.3	71.2	65.4	253.1	241.8	126.0	137.4
ExxonMobil Corp.	98,350.0	99,034.0	10,260.0	10,360.0	185,573.0	188,014.0	19,540.0	18,760.0
Fieldpoint Petroleum Corp.	1.0	1.1	0.2	0.3	1.9	2.2	0.3	0.7
Forest Oil Corp.	254.7	211.9	76.8	57.0	437.3	433.3	83.7	60.7
Frontier Oil Corp.	1,434.7	1,315.4	243.8	145.9	2,482.6	2,327.6	318.5	203.2
FX Energy Inc.	4.5	2.3	(2.7)	(2.1)	8.7	3.6	(5.3)	(6.2)
Gasco Energy Inc.	6.1	5.8	(66.3)	(53.0)	12.6	13.0	(66.5)	(53.2)
GeoResources Inc.	8.3	4.1	(1.3)	1.1	12.4	8.3	(0.5)	2.7
GMX Resources Inc.	6.5	16.5	1.6	4.6	13.2	29.8	3.7	8.5
Goodrich Petroleum Corp.	28.0	20.2	(3.3)	4.3	51.5	34.9	(2.3)	15.9
Hess Corp.	7,546.0	6,919.0	557.0	566.0	14,920.0	14,385.0	927.0	1,265.0
Infinity Energy Resource Inc.	2.5	3.4	(16.1)	2.7	4.6	5.7	(19.8)	(8.7)
Marathon Oil Corp.	16,887.0	18,290.0	1,550.0	1,748.0	29,889.0	34,829.0	2,267.0	2,532.0
McMoRan Exploration Co.	45.3	53.3	(5.3)	14.5	97.0	93.1	(19.8)	1.4
Murphy Oil Corp.	4,613.6	3,798.9	250.2	216.2	8,048.5	6,790.2	360.9	332.2
Newfield Exploration Inc.	528.0	390.0	150.0	94.0	968.0	821.0	54.0	243.0
Noble Energy Inc.	794.2	772.6	209.1	(30.7)	1,536.8	1,484.6	420.9	195.4
Occidental Petroleum Corp.	4,776.0	4,560.0	1,412.0	860.0	9,387.0	8,882.0	2,624.0	2,091.0
Panhandle Royalty Co.	11.0	7.4	2.9	2.1	28.1	28.4	4.7	9.6
PetroQuest Energy Inc.	66.8	51.5	9.6	8.0	130.8	99.9	20.4	17.1
Pioneer Natural Resources Co.	483.9	413.9	36.5	88.0	890.0	806.4	66.1	631.2
Plains Exploration & Production Co.	255.5	278.4	25.3	(7.1)	480.2	530.0	45.9	(58.8)
Pogo Producing Co.	222.9	237.5	(44.8)	361.9	434.6	481.5	66.0	429.4
PrimeEnergy Corp.	36.1	23.6	2.7	5.3	64.8	46.4	5.9	9.3
Quest Resource Inc.	29.7	16.7	(4.5)	(5.8)	57.0	36.3	(7.8)	2.9
Questar Corp.	559.6	599.6	112.2	90.4	1,434.7	1,513.5	263.3	227.5
Quicksilver Resources Inc.	136.4	89.5	31.7	23.6	253.0	189.1	54.6	51.1
Range Resources Corp.	243.5	169.4	64.2	51.3	396.4	348.6	137.3	106.9
Royale Energy Inc.	4.1	4.6	(0.1)	0.0	6.6	12.0	(1.0)	0.7
Southwestern Energy Co.	270.1	154.0	47.6	37.0	554.7	380.7	98.6	95.4
Stone Energy Corp.	210.6	176.1	72.0	(1.5)	394.7	340.4	82.5	22.6
Sunoco Inc.	10,764.0	10,590.0	509.0	426.0	20,069.0	19,183.0	684.0	505.0
Swift Energy Co.	168.2	147.2	31.5	38.2	309.3	283.3	59.1	75.5
Tengasco Inc.	2.2	2.4	0.3	0.7	4.0	4.5	0.1	1.0
Teton Energy Co.	0.9	0.7	(7.2)	(1.5)	2.0	1.1	(9.0)	(2.8)
The Williams Cos.	2,823.4	2,219.9	433.1	(76.0)	5,191.7	4,607.1	567.1	55.9
Toreador Resources Corp.	10.0	8.4	(25.0)	1.6	16.8	16.6	(33.8)	4.7
Transmeridian Exploration Inc.	11.3	5.6	(12.9)	(13.1)	18.5	8.9	(28.4)	(25.8)
Ultra Petroleum Corp.	157.1	130.7	49.1	50.7	333.7	282.5	115.7	118.1
Unit Corp.	286.6	280.3	65.6	74.8	563.9	563.2	130.0	149.7
VAALCO Energy Inc.	25.1	26.3	3.7	10.5	55.1	58.0	8.3	21.5
Valero Energy Corp.	24,202.0	25,592.0	2,249.0	1,897.0	42,957.0	45,567.0	3,393.0	2,746.0
W&T Offshore Inc.	272.6	165.8	45.5	38.5	519.1	322.7	58.6	94.3
Warren Resource Inc.	13.9	8.9	2.7	2.1	24.2	17.0	4.2	3.6
Whiting Petroleum Corp.	192.9	204.0	26.5	45.9	352.8	384.7	37.1	78.9
XTO Energy Inc.	1,329.0	1,066.0	432.0	597.0	2,498.0	2,281.0	815.0	1,064.0
Totals	**299,380.5**	**291,890.5**	**27,831.4**	**30,771.4**	**557,884.0**	**565,892.5**	**52,137.5**	**55,843.0**

panies reported a strong improvement in earnings for both the quarter and the first half of 2007, extending a streak of gains for these types of firms.

Prices, margins

Oil prices during the second quarter of this year were lower than a year earlier, but natural gas prices and motor gasoline prices were higher on average than during the second quarter of 2006.

Averaging $64.80/bbl during the recent quarter, the near-month futures price of crude on the New York Mer-

CANADIAN OIL AND GAS FIRMS' SECOND QUARTER 2007 REVENUES, EARNINGS

	Revenues — 2nd quarter		Net income — 2nd quarter		Revenues — Six months		Net income — Six months	
	2007	2006	2007	2006	2007	2006	2007	2006
	Million $ (Canadian)							
Bow Valley Energy Ltd.	4.5	3.4	3.6	0.6	8.7	6.8	(4.3)	1.8
Canadian Natural Resources Ltd.	2,821.0	2,739.0	841.0	1,038.0	5,563.0	5,091.0	1,110.0	1,095.0
Enbridge Inc.	2,728.7	2,327.2	148.2	159.6	6,086.9	5,673.9	376.9	352.2
EnCana Corp.	5,972.2	4,173.0	1,538.5	2,295.0	10,692.1	9,250.4	2,067.4	3,863.4
First Calgary Petroleums Ltd.	1.6	2.0	(1.7)	7.0	2.7	3.0	(4.3)	5.6
Husky Energy Inc.	3,163.0	3,040.0	721.0	978.0	6,407.0	6,144.0	1,375.0	1,502.0
Imperial Oil Ltd.	6,744.7	7,116.0	757.6	890.6	13,058.5	13,306.4	1,581.1	1,519.4
Ivanhoe Energy Inc.	10.2	13.9	(7.0)	(4.7)	20.0	24.4	(13.9)	(10.4)
Nexen Inc.	1,698.0	1,415.0	368.0	408.0	3,086.0	2,821.0	489.0	325.0
Petro-Canada	5,478.0	4,730.0	845.0	472.0	10,319.0	8,918.0	1,435.0	678.0
Suncor Energy Inc.	4,358.0	4,070.0	641.0	1,218.0	8,309.0	7,928.0	1,192.0	1,931.0
Talisman Energy Inc.	1,967.0	1,846.0	550.0	686.0	3,887.0	4,035.0	1,070.0	883.0
TransCanada Corp.	2,212.0	1,685.0	257.0	244.0	4,461.0	3,579.0	522.0	517.0
Totals	**37,158.9**	**33,160.6**	**6,662.2**	**8,392.2**	**71,900.9**	**66,780.8**	**11,195.9**	**12,663.0**

SERVICE-SUPPLY COMPANIES' SECOND QUARTER 2007 REVENUES, EARNINGS

	Revenues — 2nd quarter		Net income — 2nd quarter		Revenues — Six months		Net income — Six months	
	2007	2006	2007	2006	2007	2006	2007	2006
	Million $ (US)							
Allis-Chalmers Energy Inc.	144.5	61.4	19.5	9.6	281.1	109.4	31.7	14.0
Baker Hughes Inc.	2,537.5	2,203.3	349.6	1,395.0	5,010.3	4,265.3	724.3	1,734.2
BJ Services Inc.	1,152.5	1,116.9	168.3	212.9	3,523.1	3,151.9	564.3	576.0
Bronco Drilling Co. Inc.	74.7	67.1	8.7	14.7	153.7	123.5	20.1	26.1
Cameron Corp.	1,139.0	857.8	123.2	76.0	2,136.1	1,687.4	224.2	132.0
Diamond Offshore Drilling Inc.	648.9	512.2	251.9	175.7	1,257.1	959.9	476.1	321.0
Dril-Quip Inc.	108.5	114.7	21.3	24.1	206.7	232.4	38.6	48.2
Foster Wheeler Ltd.	1,189.8	745.3	71.9	108.4	2,341.9	1,391.1	186.7	123.0
GlobalSantaFe Corp.	1,073.5	773.4	369.8	248.5	1,977.0	1,452.8	717.2	411.4
Grant Prideco	522.2	431.8	135.0	105.6	1,018.6	846.2	266.5	198.0
Grey Wolf Inc.	227.5	239.6	41.7	57.9	469.5	462.5	100.3	112.2
Gulfmark Offshore Inc.	74.3	58.4	30.7	13.0	139.9	106.1	55.1	19.3
Halliburton Co.	3,735.0	3,116.0	1,530.0	591.0	7,157.0	6,054.0	2,082.0	1,079.0
Helmerich & Payne Inc.	421.3	319.8	115.2	80.0	1,180.2	866.0	322.9	195.4
Horizon Offshore Inc.	117.4	156.9	(6.2)	16.9	204.1	286.9	(4.0)	32.3
Hornbeck Offshore Services Inc.	80.8	74.3	22.6	20.3	154.9	138.4	40.1	35.1
Hydril Co*	136.3	115.5	23.3	22.7	NA	NA	NA	NA
Lone Star Technologies Inc.*	312.4	353.9	9.2	41.3	NA	NA	NA	NA
Nabors Industries Inc.	1,156.9	1,144.1	228.3	233.4	2,458.7	2,326.3	490.5	490.2
Noble Corp.	726.0	517.5	290.0	179.8	1,372.4	979.4	540.4	325.0
Oceaneering International Inc.	432.0	311.1	47.9	30.6	776.0	600.6	81.0	56.1
Parker Drilling Co.	150.3	146.0	16.9	13.8	301.6	293.3	46.9	25.2
Patterson-UTI Energy Inc.	522.6	636.8	139.6	171.7	1,069.7	1,234.5	255.4	330.9
Pioneer Drilling Co.*	103.6	94.6	13.1	19.5	NA	NA	NA	NA
Pride International Inc.	792.0	618.2	146.1	67.8	1,504.7	1,185.9	247.8	138.3
Rowan Cos. Inc.	512.5	389.8	128.1	109.7	980.2	698.0	214.5	168.8
RPC Inc.	171.0	146.1	23.8	27.6	342.1	282.1	51.9	52.5
Schlumberger Ltd.	5,638.8	4,686.8	1,258.5	856.9	11,103.2	8,925.8	2,439.3	1,579.4
Smith International Inc.	2,114.4	1,738.3	153.1	118.8	4,222.1	3,420.4	313.2	226.0
Transocean Inc.	1,439.0	859.0	549.0	249.0	2,772.0	1,681.0	1,102.0	455.0
Weatherford International Inc.	1,815.9	1,538.6	165.3	186.8	3,668.2	3,074.6	446.9	390.2
Totals	**29,271.1**	**24,145.2**	**6,445.4**	**5,479.0**	**57,782.1**	**46,835.7**	**12,075.9**	**9,294.8**

*First quarter

cantile Exchange was 8% less than during the second 2006 quarter. And the refiners' acquisition cost of crude was down 3% from a year earlier, averaging $62.36/bbl in the second quarter of this year.

Cash refining margins were little changed on the US Gulf Coast and East Coast from a year earlier but varied widely for US Midwest and West Coast refiners.

The US Midwest cash margin during the recent quarter averaged $26.95/bbl, up 43% from a year ago, while the US West Coast margin declined 22% to average $28.83/bbl during the second quarter of this year, according to Muse, Stancil & Co.

Average front-month natural gas prices on the NYMEX were $7.663/MMbtu in the second quarter, up 15% from the second quarter of 2006.

US operators

The OGJ sample of US-based oil and gas producers and refiners collectively recorded a 9.6% decline in net income for the second quarter on revenues up just 2.6% from a year earlier.

Hit by rising operating costs, 15 in the group of 71 firms posted a net loss for the second quarter.

Delta Petroleum Corp., for example, reported a $94.2 million loss for the quarter, although its revenues increased 20% from a year earlier to $49 million. Delta's operating income for the recent quarter was hit hard by expenses, primarily $69 million in dry hole costs and impairments. The Denver company's production from continuing operations during the quarter increased 17% from the second quarter of 2006.

Goodrich Petroleum Corp. incurred a $3.3 million loss for the second quarter in spite of posting a 39% gain in revenue from a year ago to $28 million. Its operating loss, too, was primarily due to higher expenses. The company said that its depreciation, depletion, and amortization expense for the second quarter of 2007 was $19.5 million, up from $10 million in the second quarter of 2006.

Another group of 15 firms recorded positive but reduced net income from a year earlier at the same time that revenues climbed. A variety of factors contributed to these results, including higher costs, debt retirements, and accounting adjustments on commodity trades. For some companies, these factors outweighed gains from higher production volumes.

For example, Swift Energy Co. posted a 17% earnings decline to $31.5 million, while revenue increased 14% from the second quarter of last year. Swift said that its production volumes were up 9% from a year earlier but that the company incurred early debt retirement expenses of $12.8 million during the recent quarter. Without this, Swift's net income would have increased 4% for the second quarter of 2007 to $39.5 million.

Chevron Corp. and Occidental Petroleum Corp. recorded increases in earnings for the recent quarter. Chevron's

net income climbed 24%, and Oxy's gained 64% as compared with the corresponding 2006 quarter.

But the other major producers reported reduced earnings. At $557 million in profit, Hess Corp. recorded a 1.6% earnings decline despite higher sales volumes and strong trading and refining results. Higher corporate costs and interest expenses outweighed a 7% gain in oil and gas production volumes.

With net income of $10.26 billion, ExxonMobil Corp. posted a 1% decline in results from the second quarter of 2006. The company reported that higher refining, marketing, and chemical margins mostly offset lower natural gas realizations during the recent quarter.

ConocoPhillips reported second-quarter net income of $301 million, down from $5.2 billion for the second quarter in 2006. Revenues were little changed at $49.4 billion vs. $48.5 billion a year ago.

Second-quarter net income included an after-tax impairment of $4.5 billion in ConocoPhillips's exploration and production segment related to expropriation of the company's oil projects in Venezuela.

ConocoPhillips's refining and marketing segment net income was $2.4 billion in the second quarter, up from $1.7 billion a year earlier. The company said the increase primarily was due to higher worldwide margins, a net benefit associated with asset rationalization, and lower costs associated with turnarounds and Hurricane Katrina impacts in 2006. But these increases were offset partially by lower volumes due to the contribution of assets to the company's downstream business venture with EnCana Corp. (OGJ, Nov. 20, 2006, p. 36).

Independents, refiners

Abraxas Petroleum Corp. recorded $56.9 million in earnings during the second quarter of 2007, during which the company closed a series of transactions that resulted in the repayment of all of its indebtedness. For the second quarter of 2006, the company posted earnings of $1 million.

During the recent quarter, Abraxas formed a master limited partnership, Abraxas Energy Partners LP, to which Abraxas contributed properties in South and West Texas. This and subsequent transactions resulted in the recognition of a pretax gain in the amount of $58.5 million.

Independent refiner Frontier Oil Corp. announced record net income of $243.8 million for the quarter ended June 30, 2007, compared with earnings of $145.9 million a year earlier. For the first half of 2007, net income was $318.5 million, up from $203.2 million a year earlier.

Frontier said its record quarterly results were achieved despite a planned 30-day, plant-wide shutdown at its 52,000-b/d Cheyenne refinery. As a result of the Cheyenne turnaround, total charges of crude and other feedstocks at its two refineries for the second quarter of 2007 fell to 163,991 b/d from 171,426 b/d for the same period of 2006. However, the company stored intermediate and finished products during the first quarter of this year, allowing product sales to average 173,888 b/d for the most recent quarter, nearly unchanged from the second quarter of 2006.

For the recent quarter, the Cheyenne refinery's light-heavy differential averaged $14.17/bbl, and the light-heavy spread at Frontier's 110,000-b/d El Dorado, Kan., refinery averaged $18.78/bbl.

Refiners Sunoco Inc. and Valero Energy Corp. each posted a nearly 20% climb in earnings.

Commenting on Sunoco's performance, analyst Eitan Bernstein of Friedman, Billings, Ramsey & Co. Inc. said, "Operating earnings of $482 million were well above our forecast, primarily due to higher-than-expected refining margins and lower operating costs."

Sunoco's total throughput volumes averaged nearly 900,000 b/d, reflecting turnaround work at the company's refineries, while Midcontinent margins averaged $22.14/bbl, up 48% from a year earlier. Northeast margins averaged

$12.32/bbl, up 7% from the comparable year-ago quarter.

Canadian firms

Led by declines from Suncor Energy Inc. and EnCana, a sample of oil and gas firms based in Canada collectively posted a drop in second-quarter earnings of more than 20%.

EnCana's earnings decline was the result of some one-time items in the second quarter of 2006, which included a gain on discontinuance, mark to market hedging gains, foreign exchange gains, and the impact of tax rate reduction. These items in the second quarter of 2006 accounted for about $1.3 billion of that quarter's net earnings, said EnCana Chief Financial Officer Brian Ferguson.

Suncor said its 47% decrease in earnings was primarily due to lower oil sands production and higher operating expenses, as well as lower income tax rate reductions compared to the second quarter of 2006.

A shutdown of one of Suncor's two oil sands upgraders lowered production volumes, while increased maintenance costs were the main reason for the increase in operating expenses. The shutdown, which began May 31 and ended July 20, reduced production rates to about 121,000 b/d and was required to tie in new facilities related to a planned expansion that will increase production capacity to 350,000 b/d in the second half of 2008.

Services, contractors

The combined earnings of a sample of 31 service and supply companies increased 18% from the second quarter of last year, as revenues climbed 21%. For the first 6 months of this year, the group posted a 30% gain in combined earnings from a year earlier.

Leading the surge in second-quarter profits were Transocean Inc., with earnings up 121% from a year earlier, and Pride International Inc., whose earnings gained 116%. Various factors buoyed these firms' revenues, including higher average dayrates, increased rig activity, and improved shipyard performance.

Louis A. Raspino, president and chief executive officer of Pride International, said partially offsetting recent results was the company's US gulf jack up fleet, which experienced lower utilization and lower average daily revenues in the quarter due to reduced activity combined with an increase in out-of-service time as the company prepared to relocate the Pride Oklahoma and Pride Mississippi to the stronger market in Mexico.

"From a macro perspective, strong global demand for energy is fueling our customers' continued growth in E&P spending, particularly in the deep water," Raspino said.

Halliburton announced that net income for the second quarter of 2007 was $1.5 billion, up from $591 million a year earlier. The results of the recent quarter include a net gain of $933 million from the separation of KBR Inc., which was recorded in discontinued operations.

Baker Hughes Inc. is among the dozen companies in the sample to report a decline in net income from the second quarter of 2006, although the company's revenue was up 15% from the second quarter of 2006. At the same time, the company's net income declined 75% to $350 million.

Chad C. Deaton, Baker Hughes chairman and chief executive officer said, "A 21% year-over-year increase in revenue in the second quarter from outside North America was partially offset by weaker activity in Canada and the US offshore market. Net income in the quarter was impacted by lower profit from our drilling and evaluation business in Canada." ✦

Worldwide E&P spending reaches record, study finds

Paula Dittrick
Senior Staff Writer

Upstream investments worldwide increased 45% to $401 billion in 2006 compared with 2005, according to the 2007 Global Upstream Performance Review released Aug. 29 by John S. Herold Inc. and Harrison Lovegrove & Co. Ltd.

The record capital spending generated a 2% increase in proved reserves volumes to 263 billion boe, while reserves replacement costs climbed 33% to $13.60/boe, the annual report said.

"Revenue growth more than offset higher operating expenses and increased taxes, allowing the industry to report $243 billion in net income, the fourth consecutive record," said Robert Gillon, Herold senior vice-president and a director of equity research.

Gillon noted that rising costs are pressuring investment returns. Net income as a percentage of the book value of oil and gas assets declined in 2006 following 3 years of gains.

Harrison Lovegrove Chief Executive Martin Lovegrove said, "The key challenge facing the petroleum industry continued to be replacing reserves and growing production due to the combination of maturing basins and reduced accessibility to new acreage. With opportunities scarce, proved and unproved acquisition costs increased 85%, while the implied costs for the acquisition of proved reserves soared 55%—more than twice the increase in oil prices."

The Herold-Lovegrove study noted that industry has spent more on repurchasing its own shares than it has acquiring proved reserves during the last 2 years.

The review is based on information that 228 oil and gas companies filed

with the US Securities Exchange Commission and similar agencies worldwide.

Revenues, costs climbing

Worldwide revenues increased by $134 billion, implying an average realized price of $43.62/bbl—a 16% increase from 2005.

Development spending increased 29% and accounted for 52% of total investment, down from the 5-year development investment average of 58%.

Exploration spending increased 39%, the largest jump in 5 years.

A nearly 80% increase in proved reserves acquisition spending produced a 15% increase in purchased reserves. Investment in unproved reserves acquisitions almost doubled to $47 billion in 2006 compared with 2005.

Reserves replacement rates increased modestly in 2006 despite the growth in upstream investment. Finding and development costs surged 29% to $14.42/boe, and industry replaced 111% of production through drilling.

A 31% rise in lifting costs consumed one-third of the increase in realized prices, while income taxes were up 12%. As a result, cash flow advanced 18% during 2006 compared with 2005. That compared with an average cash flow gain of 26% for 2002-05.

Net income was up 17% in 2006 compared with 2005. Net income had jumped 46% in 2005 compared with 2004. ✦

IFC to invest in Chinese coalbed methane project

Nick Snow
Washington Correspondent

World Bank division International Finance Corp. has agreed to invest $15 million to help a Houston overseas producer develop coalbed methane resources in China. Far East Energy Corp. will use the money to help fund exploration and development of more than 5,000 sq km of deposits in the Shanxi and Yunnan provinces, IFC said on Aug. 28.

"Given China's significant coalbed methane resources, this investment has the potential to help the country meet its growing energy needs by using domestic resources in an environmentally conscious manner," said Somit Varma, IFC's director for oil, gas, mining, and chemicals (OGJ, Sept. 18, 2006, p. 30).

He noted that Far East Energy is the third-largest concession holder of CBM deposits in China, which is estimated to have the world's third-largest CBM resource. The company will develop its concession with its local joint venture partner, state-owned China United Coalbed Methane Co. Ltd., Varma said.

Michael R. McElwrath, Far East Energy's president and chief executive, said in Houston that the investment was IFC's first in CBM in China. The financing will allow the company to accelerate its drilling program and act on findings of Netherland, Sewell & Associates earlier this summer that its No. 15 coal seam "has high permeability on the order of 100 md, gas content on the high end of CBM fields, and indications of a potential gas profile of 1-2 MMcfd from horizontal wells," he said.

IFC said its position as an equity investor in Far East Energy gives the financing organization a chance to help the developers establish best practices in local community engagement and a long-term strategy to leverage potential carbon finance opportunities under the Kyoto Protocol, the United Nations' framework, which aims to reduce greenhouse gas emissions. IFC also plans to provide guidance on environmental standards.

Far East Energy has been working in China for more than 3 years (OGJ, Sept. 6, 2004, p. 24). IFC said it also is considering participating in the project's long-term financing when it moves to commercial development. ✦

WATCHING GOVERNMENT

Nick Snow, Washington Correspondent

The Dingell energy plan

As Labor Day 2007 approached, the most persistent question within Washington, DC's energy community was what Rep. John D. Dingell (D-Mich.) is planning. The fiercely independent Energy and Natural Resources Committee chairman applauded as the US House passed its energy bill. But it was apparent that the committee in general, and Dingell in particular, have more to say.

Unlike others who have taken positions demanding aggressive carbon emission reductions and alternative energy research and development, Dingell has remained relatively quiet—publicly. In discussions behind the scenes with the House's Democratic leadership, he apparently has maintained his reputation as a tough negotiator.

It's generally assumed that Dingell, who has held his seat for more than 50 years, knows how Congress works and what it will take to pass new energy legislation. His support is crucial, and his opinions matter.

So far, the only public indication of what he is thinking about upcoming energy legislation is his Aug. 24 breakfast address to the American Jewish Committee's Detroit Chapter. "The issue of global climate change, and its effect on our national energy policies, is critical," he maintained.

'Just the beginning'

Dingell said the House's most recent energy bill was a critical first step with energy efficiency provisions aimed at removing 10.4 billion tons of carbon dioxide from the atmosphere by the end of 2030. "This is just the beginning," he said.

"This fall, I intend to develop a comprehensive, mandatory, economy-wide program to move us further toward the goal of reducing greenhouse gas emissions by 60-80% by 2050. My own judgment is that we are going to have to adopt a cap-and-trade system and some form of carbon emission fee to achieve the reductions we need."

Dingell said his cap-and-trade scheme would use the acid rain trading program which was part of the 1990 Clean Air Act amendments, and not the European approach to controlling greenhouse gases, as a model. He also plans to introduce a bill to tax carbon and petroleum products when Congress returns. "Properly addressing climate change requires us to address the issue of consumption. We do that by making consumption more expensive," he explained.

Includes gasoline tax

Dingell said his proposal would "impose a stiff tax on carbon, increase the tax on gasoline, and remove the mortgage interest deduction on 'McMansions'—homes over 3,000 sq ft." He added that effective energy legislation needs to address motor vehicles and fuels, nuclear power's role, coal's future under carbon constraints, and other issues.

Like many of his past proposals, this one won't be popular. The idea of increasing the federal gasoline tax to fight global warming, for instance, will be even harder to sell than raising it to replace faulty highway bridges.

Dingell appeared undaunted. "I have never introduced legislation with the intent of seeing it fail. I do not intend to start now," he declared. ✦

DOJ will not challenge group's jointly proposed nanotechnology research

Nick Snow
Washington Correspondent

The US Department of Justice will not challenge a proposal by a group of oil and gas producers, oil field service companies, and the University of Texas at Austin to jointly research and develop nanotechnology applications for oil and gas exploration and production.

DOJ announced its position in an Aug. 23 letter from Thomas O. Barnett, assistant attorney general in charge of the department's antitrust division, to attorneys for Advanced Energy Consortium (AEC).

AEC's goal is to develop subsurface nanosensors that can be injected into well bores, DOJ reported in the announcement. It said the sensors' microscopic size should allow them to migrate out of the well bores and into pores of the surrounding geological structure to collect data about hydrocarbon reservoirs' physical characteristics, allowing more-efficient exploitation.

The consortium "appears to be structured so that its proposed business conduct will not create any risks to competition. To the extent that AEC engages in research efforts that would not be undertaken by individual firms, the joint venture may have the procompetitive effect of promoting innovation," Barnett said in his letter.

AEC members are BP America Inc., ConocoPhillips Co., Marathon Oil Co., Occidental Oil & Gas Corp., Shell International E&P Inc., Schlumberger Technology Corp. and Halliburton Energy Services Inc., with UT Austin supplying management, said DOJ. Additional qualifying members may join with approval of two thirds of the members and the university's concurrence, it added.

Consortium's setup

Under the consortium's proposal,

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Old bear, new teeth

If you think Russia is a trustworthy supplier of crude oil and natural gas, think again. That's especially necessary after recent reports that Russia has slashed oil supplies to German refineries, underlining concerns in Europe and around the globe.

On Aug. 24 Russia's OAO Lukoil, the country's second-largest oil producer, said supplies to Germany had been reduced by about one-third in July and August, but the firm refused to explain why the reduction had taken place.

Reports cited analysts who said Lukoil's decision not to provide contract quantities of oil could be aimed at extracting higher prices from German refineries. Then again, the move could be part of Lukoil's efforts to acquire stakes in German and European refineries.

German authorities played down the move, saying the country's energy supplies were not in danger, as refineries could turn to other oil suppliers to make up shortfalls. Said one government spokesman: "The situation is not dramatic."

Remember Druzhba?

He added that one main refinery—owned by Total SA, Royal Dutch Shell PLC, Ruhr Oel, and Agip SPA—recently had managed to increase supplies from the North Sea. Germany's MWV oil industry association said Russian supplies had fallen in June and July but stressed that refinery production had not been hit.

This is hardly the first time that Europe has had concerns over Russia's trustworthiness as a supplier. Remember last January when the International Energy Agency said European oil markets would cope with the halt of Russian oil exports via the Druzhba pipeline but still called for a quick and clear resolution to the problem?

European Union Energy Chief Andris Piebalgs said he might convene a meeting of the bloc's Oil Supply Group to evaluate the situation (OGJ, Jan. 15, 2007, p. 42).

We don't recall that any evaluation was ever done, but our evaluation remains that oil has given the Russian Bear its new teeth. After years of decline, the Russian economy has increased fivefold to nearly $1 trillion.

New teeth

The country is reaping the benefits of buoyant oil and gas prices. State-owned oil firm Gazprom controls much of the country's rich energy resources and thus has the ability to influence or even intimidate customers in Europe. Gazprom lends economic teeth to Moscow's foreign policy goals.

Does that claim somehow give meaning to the cut in Lukoil's supplies to Germany? Let's not forget that Putin knows Germany well, having spent years there as a spy for the former Soviet Union.

But the oil supply cut is hardly the only bit of posturing by the Russians. In another move directed at the West, two Russian Tu-95 bombers recently flew near the US military base in Guam, causing American fighters to scramble to intercept them.

While the bombers are propeller-driven, 1950s-vintage planes, they carry potent nuclear cruise missiles which could be directed at the US mainland. ✦

industry members will contribute financially to the research, which the university will carry out. UT Austin will own all inventions resulting from that research. Each member company contributing to an invention will receive a royalty-free, nonexclusive, irrevocable, worldwide perpetual license to use the invention for noncommercial, internal purposes. The member also will have the independent right to create, use, and sell any patented inventions, subject to the payment of patenting costs, DOJ said.

It said further that UT Austin plans to license its rights to third parties on a royalty-bearing basis, subject to the approval of AEC members, which shall not be unreasonably held. The consortium itself will not license, produce, or market anything, the federal department said. All members will retain the right to conduct independent research and development and to obtain intellectual property rights resulting from its own research, DOJ said.

Barnett said AEC is not designed to restrict price or output of any product on the basis of information it supplies or to limit competitive research by its member companies. The venture's operation should not adversely affect other nanotechnology research, as its participants retain the right to conduct such research, he indicated.

"Moreover, the existence of a substantial number of other entities engaged in nanotechnology research, both in the United States and abroad, indicates that the formation and operation of the AEC is not likely to reduce the amount or variety of such research," Barnett said.

The consortium's structure makes it unlikely that members will share anticompetitive company information, he continued. The agreement limits information-sharing to information that is "reasonably related and necessary to the accomplishment of the research program. It also requires that access to confidential information be limited to individuals who need it to carry out the research program," he added. ✦

Third exploratory well drilling in Washington subbasalt play

Alan Petzet
Chief Editor-Exploration

Operators are consolidating acreage positions in the Columbia River basin as EnCana Corp.'s US unit drills its third subbasalt wildcat in the nonproducing area since 2004.

Exxel Energy Corp., Houston, acquired 12.5% working interest in 390,000 gross acres in the basin in Washington state from EnCana Oil & Gas (USA) Inc. Netco Energy Inc., Vancouver, BC, acquired a 7.5% working interest in the same lands.

The acquisitions included interests in the EnCana Brown 7-24 wildcat in Grant County, which Exxel said is drilling in the sedimentary section below the base of basalt (OGJ, June 11, 2007, p. 53).

EnCana has made public no results from the three wells it has drilled in the basin under an agreement with Shell's SWEPI LP unit.

The others are the Anderville Farms 1-6 in Grant County and the Anderson 11-5 in Yakima County.

Those three wells and Shell's Yakima 1-33 and BN 1-9 wells drilled in the 1980s are evaluating gas potential at 14,000 ft in a basin centered gas accumulation (see map, OGJ, May 2, 2005, p. 53).

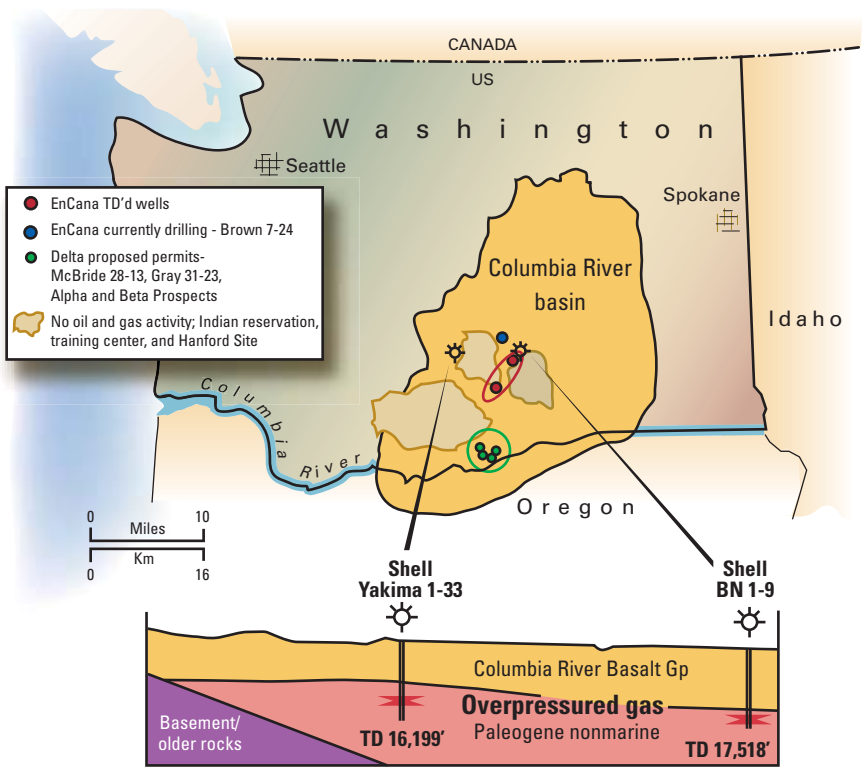
Exxel said the acquisition gives it the "ability to participate on an unpromoted basis in current and future exploration and development of acreage covered by the leases within the CRB, including the Yakima fold belt, Saddle Mountain, and Hog Ranch high."

Exxel said its due diligence of the wells drilled to date, including the Brown well, "confirms our geologic model of the basin."

In July, Exxel approximated Columbia River basin positions as EnCana 850,000 net acres, Delta Petroleum Corp., Denver, 468,000 acres, ConocoPhillips 400,000 acres, and private E&P companies 270,000 acres. The overpressured gas play is believed to

COLUMBIA RIVER BASIN

Fig. 1



Source: Exxel Energy Corp.

underlie 4 million acres.

Exxel said its leases have primary terms of 6-10 years and average more than 8 years. The company has identified several prospects but has no drilling commitment.

Delta, meanwhile, received permits to drill the Gray 31-23 and McBride 28-13 wildcats and is permitting the Mustang 22-11 wildcat, all on separate geologic structures, in Klickitat County, Wash., which borders the Columbia River and Oregon. It plans to drill Gray 31-23 after EnCana's Brown 7-24. ✦

India lowers Krishna-Godavari gas find estimates

Shirish Nadkarni
OGJ Correspondent

India has dramatically reduced the estimated size of recent gas discoveries in the Krishna-Godavari (KG) basin of Andhra Pradesh, which could diminish the area's attraction to the world's top energy players.

The seventh round of bidding for 85 oil and gas blocks under the New Exploration Licensing Policy (NELP-VII), which includes blocks in the Cauvery basin, was originally scheduled for last April, postponed until later this month, and now pushed back again to November.

Two of the country's state-run explorer-producers, Oil & Natural Gas Corp. (ONGC) and Gujarat State Petroleum Corp. (GSPC), earlier had announced discoveries off the hydrocarbon-rich Indian East Coast but later were forced to concede that the finds were much smaller than initially projected.

ONGC cut to less than one-tenth the estimated size of its KG basin find—to 56.6 billion cu m (bcm) from 595 bcm it had forecast in December 2006, while GSPC slashed even more drastically the potential size of its gas finds to 39.1 bcm, from 566 bcm it had reported in June 2005.

The admissions were a victory for Director-General of Hydrocarbons V.K. Sibal, who had been bitterly criticized by ONGC for refusing to accept the size of ONGC's KG basin gas discovery, which it originally compared to the huge gas find of Reliance Industries in the same basin.

The large disparity between the two sets of figures has induced experts to urge the Indian authorities to tighten the norms for announcing oil and gas discoveries to prevent exploration companies from overreporting or extracting economic and political capital from such new finds.

The revised ONGC and GSPC figures also threaten to undermine New Delhi's claims that India will soon have a gas surplus and become a net exporter of the fuel. Gas supply in the country was expected to reach 188 million standard cu m/day (MMscmd) by 2009-10, a significant rise from the present level of 80 MMscmd.

India also has been encouraging power and fertilizer plants to switch to gas from naphtha to cut costs. But those plans may now go awry, given that there will be less domestic gas production than was initially projected.

Gas imports

The country imports 70% of its crude oil requirements and is able to meet half its gas demand of 170 MMscmd via its domestic production. The deficit in gas consumption is covered by LNG imports from countries such as Qatar.

Prospects of accessing international gas sources have brightened with progress in talks on the Iran-Pakistan-India pipeline, a recent agreement with Algeria for LNG, and Indian plans to join the $13 billion trans-Saharan gas pipeline.

Turkmenistan also recently said it is interested in building a gas pipeline across Afghanistan to Pakistan and India (OGJ, July 23, 2007, Newsletter). India is still hopeful of buying gas from Myanmar, despite China's moves to secure supplies from the country on an

exclusive basis.

ONGC has kicked off negotiations with ExxonMobil Corp. to import 8 million tonnes of LNG from Russia's Sakhalin gas fields.

Finally, Indian Petroleum Minister Murli Deora announced in July that the country would import 1.25 million tonnes of LNG from Algeria by 2009. State-controlled Petronet LNG is to secure gas from Sonatrach, a move that would add gas supplies to those already on contract from Qatar.

Despite these moves to secure sufficient gas, India's hopes of selling all blocks in the Cauvery basin at a good price under NELP-VII may suffer a setback because of its laxity in earlier announcements of the size of gas finds. ✦

India

Oil & Natural Gas Corp. Ltd. of India and Canoro Resources Ltd., Calgary, agreed on a work program for six blocks in the Assam-Arakan basin in Nagaland state, northeastern India.

The program includes restoring production from Changpang oil field and shooting 2D and 3D seismic aimed at a subthrust trend on five exploration blocks.

Separately, Canoro recently shot 140 line-km of 2D seismic on its nearby operated AA-ON/7 block and 220 line-km on its nonoperated AA-ONN-2003/2 block looking at the same fold and thrust trend. Preliminary results indicate several prospective structures on each block.

Changpang field was reported to be flowing more than 1,000 b/d of 30° gravity oil from the Paleogene Kopili, Sylhet, Basal sandstone, and fractured basement before production was suspended in 1994.

Besides Changpang, the five exploration blocks are AA-ONN-2001/4, 645 sq km; AA-ONN-2002/4, 1,060 sq km; Singphan, 320 sq km; Bhagty-Bhandari, 620 sq km; and Dimapur, 650 sq km.

Peru

The Peruvian unit of Loon Energy Inc., Calgary, formally signed the exploration license contract for Block 127 in Peru's Maranon basin.

Loon Peru committed to shoot 390 line-km of 2D seismic, reprocess 2,000 km of 2D seismic, and prepare other technical studies in the first 2 years on the 2.4 million acre block.

Portugal

The Portuguese Ministry of Economy awarded Mohave Oil & Gas Corp.,

Houston, five concessions in the Lusitanian basin in west-central Portugal.

Totaling 1.5 million acres are the Aljubarrota 3, Torres Vedras 3, Sao Pedro de Muel 2, Cabon Mondego 2, and Rio Maior 2 concessions. The blocks have an 8-year exploration period and 25-year production period.

Somalia

Africa Oil Corp., Vancouver, BC, formerly Canmex Minerals Corp., plans to start drilling in Puntland state in northern Somalia in early 2008.

The company holds 80% interest in two licenses in the Dharoor and Nogal valleys.

Under way are geological field work, reprocessing of 2D seismic, and review and integration of all geological and geophysical data, the company said.

Tunisia

Atlas Petroleum Exploration Worldwide 55% and Eurogas Corp., Calgary, 45% are progressing development and exploration on the 1 million acre Sfax permit in the Gulf of Gabes off Tunisia.

The companies have a 3½-year farmout in place with Anadarko Petroleum Corp. since 2006.

The work involves development of three oil prospects and an exploration program.

A previous operator tested 612 b/d of oil from the El Garia carbonate in the 1990s at the first development prospect, Ras el Besh. The companies have a 30-year development concession, have taken possession of a production jackup, and are estimating the volume of oil in place before drilling a high-angle well.

The companies shot 60 sq km of shallow 3D seismic over Salloum, which another operator tested at 1,800 b/d of oil in 1997. Processing and interpretation will take 5 months.

A former operator's well on the Jawhara structure tested at 1,200 b/d of oil.

Arizona

PetroSun Inc., Scottsdale, Ariz., said it is acquiring an automated top-drive drilling rig rated to 5,500 ft for delivery later this year for its Arizona exploration program in and near the Holbrook basin.

PetroSun obtained a 985,000-acre oil and gas lease from New Zealand Oil & Gas Ltd. that includes targeted exploration prospects in the Arizona Holbrook basin and the San Juan basin in New Mexico.

The Holbrook basin contains former helium producing fields and promising indications of oil, gas, helium, and carbon dioxide.

California

Venoco Inc., Denver, is preparing to test an extended reach well drilled from shore to evaluate the offshore extent of West Montalvo field in Ventura County, Calif.

Discovered in 1951, West Montalvo has produced 10% of 243 million bbl of oil in place, but its areal extent beneath Santa Barbara Channel state waters has not been probed until now. Only regional seismic data are available over the area.

Separate surface equipment is required for the extended reach well because it is expected to produce from state lands.

While the company reactivates and reworks onshore wells in the field, acquired in May 2007, it is leaning towards a plan to permit several more extended reach wells and likely will drill those one at a time.

New Mexico

Petro Resources Corp., Houston, said it acquired a 10% working interest in the 90,000-acre El Vado East prospect in the Chama basin in northern New Mexico.

Approach Resources Inc., private Fort Worth operator, could spud the first of four vertical test wells in the fourth quarter of 2007 and may later shoot a 3D seismic survey on the property.

Primary objective is Cretaceous Mancos shale, and secondary objectives are the Dakota, Morrison, Todilto, and Entrada formations.

UNCONVENTIONAL GAS—1

Reserves, production grew greatly during last decade

Vello A. Kuuskraa
Advanced Resources International Inc.
Arlington, Va.

From an emerging resource 1 decade ago, and a mostly overlooked resource 2 decades ago, unconventional gas is now a core business of many large independent producers and a growing number of the major oil and gas companies. This resource has become a mainstay of the US natural gas industry (Fig. 1).

The catch phrase "the future is unconventional" appropriately captures the trend for this important domestic hydrocarbon resource.

Unconventional gas includes tight gas sands, coalbed methane, and gas shales.

This first of six articles will describe the growth of the resource during the past decade. The remaining articles in the series will cover:

- How much tight gas, coalbed methane, and gas shale resources remain undiscovered and undeveloped.
- Emerging unconventional gas basins and plays.
- Importance of technology progress for unconventional gas.
- Economics for unconventional gas.
- Outlook for unconventional gas.

These articles will show that the US is not running out of domestic unconventional gas resources. Rather, the nature of the remaining undeveloped unconventional gas resource base is shifting towards more challenging reservoir settings. Continuing and even accelerating progress in technology will be essential to develop this remaining resource base efficiently and economically.

The recent formation of the gas technology institute called RPSEA (Research Partnership for Securing Energy for America) prompts optimism that investments in unconventional gas research and development (R&D) will rebound and technology progress will, once again, keep ahead of resource depletion.

Resource highlights

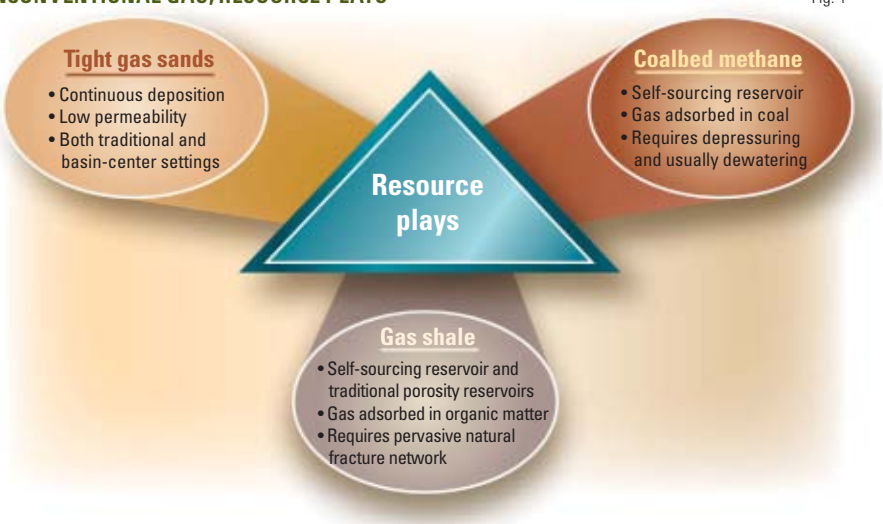
During the decade 1996-2006, unconventional gas achieved notable successes.

Production of unconventional gas reached a new peak of 24 bcfd (8.6 tcf/year) in 2006, up from 14 bcfd (5 tcf/year) 1 decade ago. With a 43% share, it is now the dominant source of domestic natural gas production (Fig. 2).

Annual production for all three unconventional gas sources increased during the past decade (Fig. 3). Tight gas provided the largest production growth, nearly 6 bcfd (2.1 tcf/year). Gas shales had the largest percentage growth, up

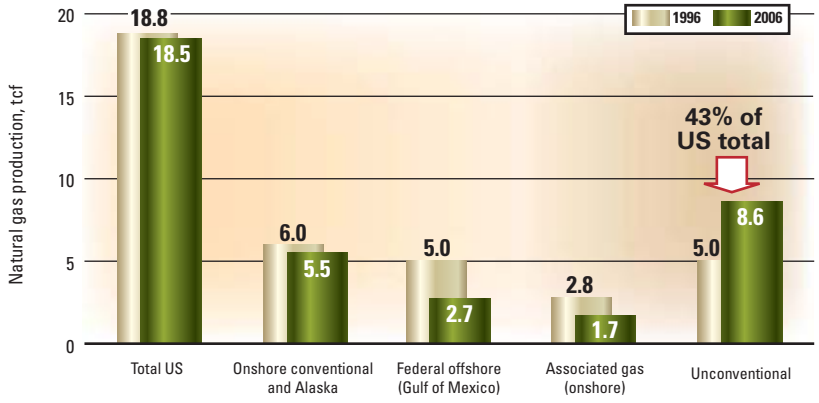
UNCONVENTIONAL GAS, RESOURCE PLAYS

Fig. 1



US NATURAL GAS PRODUCTION

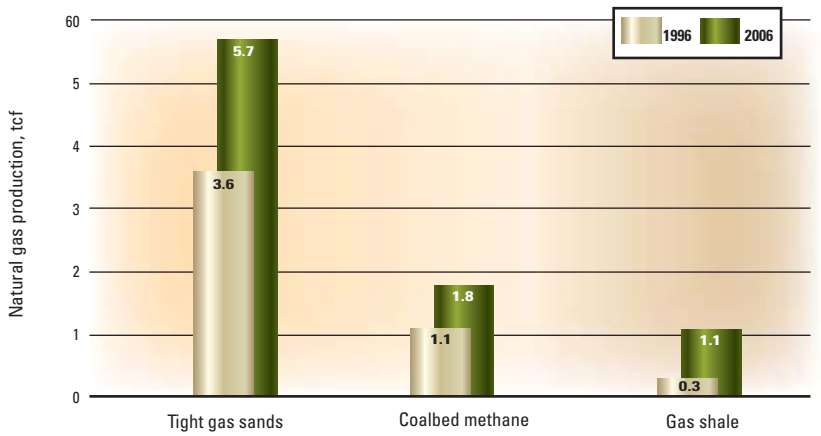
Fig. 2



Source: Conventional and offshore - EIA annual reports
Unconventional - Advanced Resources International database

US NATURAL GAS PRODUCTION GROWTH

Fig. 3



Source: Advanced Resources International database

by more than threefold. Coalbed methane production also increased, to nearly 5 bcfd from 3 bcfd.

Driven by record drilling, proved reserves of unconventional gas also have increased to a new record of 105 tcf at the beginning of 2006, up from 48 tcf in 1996. Today, unconventional gas accounts for more than half of the reported 196 tcf of proved natural gas reserves in the Lower 48 states.[1] Large volumes of probable and possible reserves, as well as a large undiscovered resource base, underlie these proved reserves.

After accounting for production replacement, total unconventional gas reserves additions were an impressive 120 tcf in the past 10 years.

More intense development of emerging gas plays as well as the discovery of several new plays has driven the growth in unconventional gas. For example, with aggressive infill and extension drilling, the Mesaverde formation of the Piceance basin has become a major 1 bcfd tight gas-sand play, up from a modest 0.1 bcfd prospect 1 decade ago.

With expansion of Cotton Valley development, addition of the deep Bossier, and revitalization of the Travis Peak play, the tight gas sands of East Texas now provide 3.6 bcfd, up from 1.5 bcfd 10 years ago.

Finally, no review of unconventional gas can overlook development of the Barnett shale in the Fort Worth basin, producing almost 2 bcfd today, up from less than 0.1 bcfd in 1996.

Gas shales also have been a source of several new unconventional gas plays, particularly the Fayetteville and the Woodford gas shale of the Arkoma basin. Other new and emerging unconventional gas plays include the low-rank coalbed methane play in the Powder River basin and the deep Wasatch-Mesaverde tight gas sands in the Uinta basin.

Motivated by past advances in technology and expectations of continuing high natural gas prices, many producers have entered the unconventional gas arena, driving well drilling and completion to steadily higher levels. From a base of about 5,000 new wells/year from 1996 to 2000, producers have added more than 20,000 new unconventional gas wells in each of the past 2 years (Fig. 4).

Drilling of tight gas sands, at 13,000 wells/year, still dominates the activity with coalbed methane and gas shale each providing 4,000 wells/year. Overall, the industry has drilled 102,000 new productive unconventional gas wells during the past decade, accounting for about two-thirds of all successful natural gas wells drilled.

With production up by 10 bcfd, with 102,000 successful wells drilled and completed, and with 120 tcf of reserves added, unconventional gas has clearly made progress during the last decade.

Potential problems

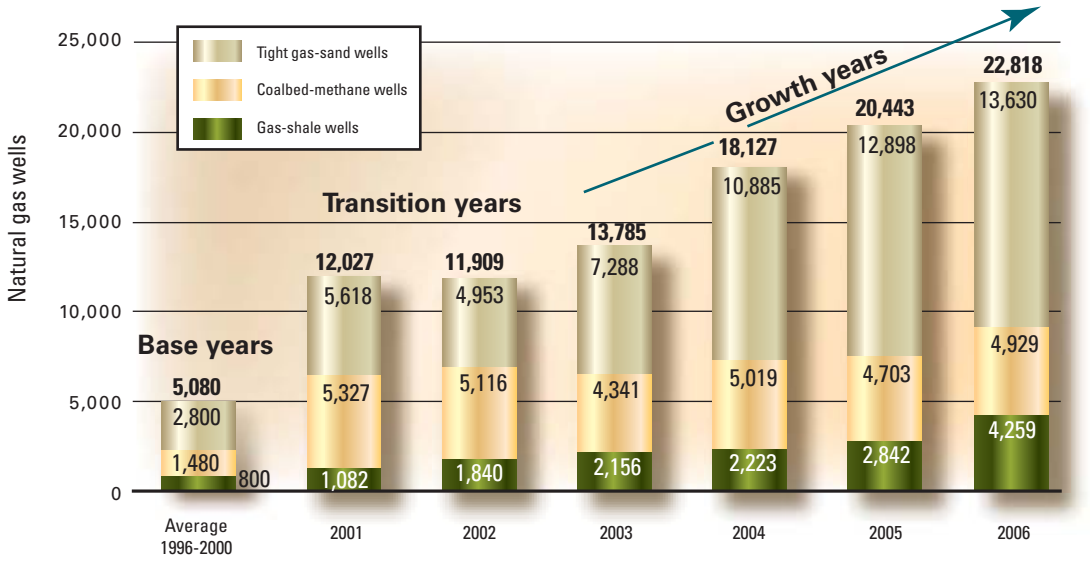
Even with the growth in importance of these resources, dark clouds have begun to appear on the horizon for unconventional gas. For many years, progress in technology countered resource depletion, holding the key performance measure, reserves added/well, relatively constant. This, unfortunately, is no longer the case.

With reductions in unconventional gas R&D and technology investment (including termination of the Gas Research Institute and decline in the US Department of Energy (DOE) gas research and technology program), overall technology progress has slowed considerably.

As a result, since 1996-2000, reserves/well for all three unconventional gas resources have declined sharply (Table 1).

US NATURAL GAS WELLS PLACED ON PRODUCTION

Fig. 4



Source: Advanced Resources unconventional gas database

For tight gas sands, well productivity declined by more than half, to 1 bcf of proved reserves/new successful wells drilled in 2003-05 from the 2.2 bcf/well in 1996-2000. With the rapid change to lower productivity (but also lower cost) Powder River and Mid-Continent coalbed methane plays, reserves/well for this resource have declined even more, to 0.5 bcf/well in the past 3 years from 1.6 bcf/well in 1996-2000.

One partial silver lining is the recent reversal in gas-shale well productivity decline. The increasing use of new technology, such as multiple-stimulated horizontal wells particularly in the Barnett shale, is one reason for this improvement.

Higher natural gas prices and the persistent pursuit of efficiency by operators have enabled lower productivity unconventional gas plays, with lower reserves/well, such as the Clinton-Medina tight gas sands in the Appalachian basin, the Canyon tight gas sands in West Texas, and Wyodak coalbed methane in the Powder River basin, to be more aggressively developed, contributing to the overall decline in reserves/well.

The decline in well productivity, however, appears to be a more fundamental problem. For example, of the 43 tight gas plays that Advanced Resources International Inc. tracks in its model of unconventional gas supply (MUGS) database and model, 20 of these plays had severe declines in reserves/well during the past 3 years.

On the "good" side of the ledger, unconventional gas has achieved a number of impressive successes in the past decade. First, there are the new, large (bcfd) size plays such as the Barnett shale, the Pinedale-Jonah tight gas sands, and Powder River coalbed methane. Ten years ago many in the industry questioned whether any bcfd-size natural gas plays were even left in the Lower 48.

Second, the unconventional gas development experience provides solid evidence that increased drilling can and will lead to increased gas production and reserves, counter to the "soundbite" message by some energy analysts that higher levels of drilling are having no effect. For example, with increased well drilling, unconventional gas has more than replaced the steep, 5.4 bcfd (2 tcf/year) decline in Gulf of Mexico gas production since 2000 (Table 2).

On the "bad" side of the unconventional gas ledger is the decline in technology progress. All key measures of the

UNCONVENTIONAL GAS WELL PRODUCTIVITY

Table 1

	Tight gas sands			Coalbed methane			Gas shales		
Period	Wells	Reserves added, tcf	Well productivity, bcf/well	Wells	Reserves added, tcf	Well productivity, bcf/well	Wells	Reserves added, tcf	Well productivity, bcf/well
1996-2000	14,000	31.5	2.25	7,320	11.6	1.58	4,110	5.2	1.25
2001-02	10,570	19.5	1.84	10,450	5.7	0.55	3,640	2.8	0.76
2003-05	31,080	30.1	0.99	14,830	6.6	0.47	14,990	6.7	0.93

Note: Includes only successful wells.

rate of technology progress that ARI tracks in MUGS are down.

These technology progress measures (levers) include among others:

- Efficiency and volume of reserves added from well recompletions, restimulations, and identification of bypassed pay.
- Ability to reliably identify and delineate the higher productivity, sweet-spot portions of an unconventional gas play.
- Rate of improvements in well drilling and completion efficiency.
- Track record of success in overcoming environmental and other constraints impeding access to undeveloped resources.

Finally, the "ugly" is the sharp rise in costs and economic risk. Because of the reserves decline/well and the upward spiral in well drilling and completion costs, much of the unconventional gas resource has become a high-cost resource play. Even though oil prices (a reasonable proxy for natural gas prices, except in the past year) have increased by 23%/year since 2002, finding costs for US exploration and production companies have increased even faster, by 38%/year during this time.[2]

Should natural gas prices decline and remain at $4-5/Mcf (Henry Hub spot price), as seen in the early years of this decade, many of the unconventional gas plays would become uneconomic. Of course, with a drop in gas prices, well drilling and completion costs may also decrease, and the associated loss in gas production might then provide a price rebound, unless low-cost LNG imports fill the gap. ✦

GULF OF MEXICO NATURAL GAS PRODUCTION, RESERVES Table 2

	Shelf		Slope	
	Proved reserves, tcf	Gas production, bcfd	Proved reserves, tcf	Gas production, bcfd
2000 (beginning of year)	18.3	10.2	7.7	3.3
2005 (yearend)	9.4	5.2	8.0	2.9
Change, 2000-05	–8.9	–5.0	+0.3	–0.4

Source: References 1 and 2

References

1. "U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves 2005 Annual Report," DOE/EIA-0216(2005), US DOE Energy Information Administration, November 2006

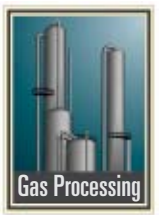
2. Southwestern Energy Co., June 2007 update, using data from Bloomberg and John S. Herold Inc.

The author

Vello A. Kuuskraa (vkuuskraa@adv-res.com) is president of Advanced Resources International Inc., Arlington, Va. He has more than 30 years of experience in the oil and gas industry, particularly in unconventional oil and gas resources, enhanced oil recovery, and CO_2 sequestration. Kuuskraa holds a BS in applied mathematics from North Carolina State University and an MBA from the Wharton Graduate School, University of Pennsylvania. He serves on the Board of Directors of Southwestern Energy Co.

Model accurately predicts HC solubility in methanol

Alireza Bahadori
National Iranian South Oil Co.
Ahwaz, Iran



A newly developed model accurately predicts solubility of hydrocarbon components in methanol.

Quantifying the absorption of hydrocarbons, primarily methane and ethane, in methanol is critical in minimizing hydrocarbon losses or optimizing hydrocarbon recovery, depending on the objective of the process.

This article presents model results for an accurate prediction of solubility of light alkanes in methanol, in which the obtained results of the proposed method have been compared with experimental data showing good agreement between reported experimental data with the model results.

The average absolute deviation is 1.5289%.

HC solubility

In gas processing, methanol is commonly injected into gas streams to inhibit hydrate formation. After chilling and separation from the hydrocarbon phases, the aqueous methanol phase is usually stored in atmospheric pressure tanks for disposal.

Because the atmospheric storage tanks are at less than the separator pressure, hydrocarbons absorbed by the injected methanol may flash.

This article examines the influence of temperature and pressure on hydrocarbon solubility, which is a major factor in any consideration of using a physical solvent.

Also, for environmental reasons, a great amount of work has gone into determining the solubility of hydrocarbons in water and hydrate inhibitors at various temperatures. These solubility data have been compiled and correlated.

Equations

$$x_i = a + bP_{ri} + cP_{ri}^2 + dP_{ri}^3 \quad (1)$$

$$a = A_l + B_l T_{ri} + C_l T_{ri}^2 + D_l T_{ri}^3 \quad (2)$$

$$b = A_2 + B_2 T_{ri} + C_2 T_{ri}^2 + D_2 T_{ri}^3 \quad (3)$$

$$c = A_3 + B_3 T_{ri} + C_3 T_{ri}^2 + D_3 T_{ri}^3 \quad (4)$$

$$d = A_4 + B_4 T_{ri} + C_4 T_{ri}^2 + D_4 T_{ri}^3 \quad (5)$$

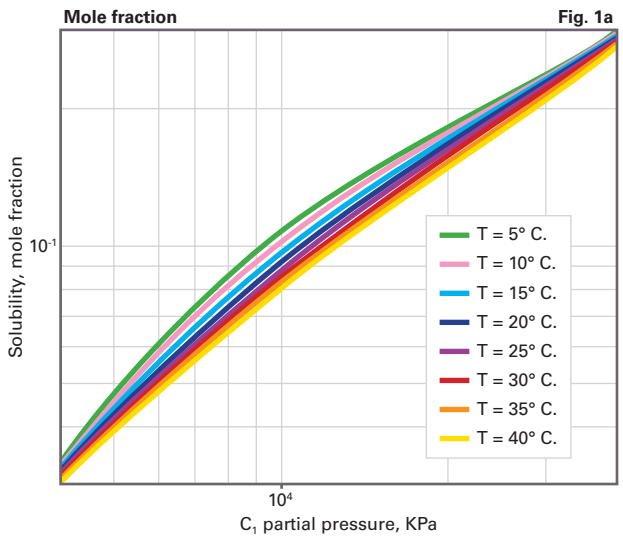
$$v = \frac{23,645 x_i}{M x_i + S_M (1 - x_i)} \quad (6)$$

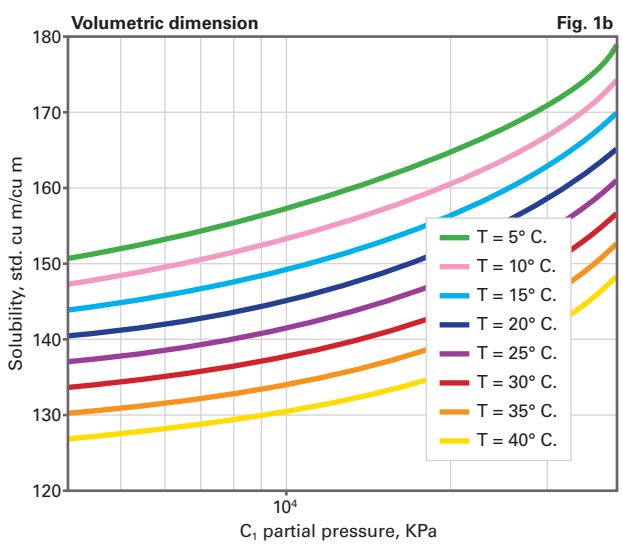
$$v_s = \frac{1 - \frac{M x_i}{M x_i + S_M (1 - x_i)}}{S_g} \quad (7)$$

Nomenclature

A	=	coefficient
B	=	coefficient
C	=	coefficient
D	=	coefficient
a	=	coefficient
b	=	coefficient
c	=	coefficient
d	=	coefficient
P_r, T_r	=	reduced partial pressure (P_r) and reduced temperature (T_r) are dimensionless
M	=	solute molecular weight
x_i	=	mole fraction of solute components (i) in physical solvent
SM	=	solvent molecular weight
Sg	=	solvent specific gravity
V	=	solute volume, std. cu m
V_s	=	solvent volume, cu m
i	=	component index

PROPOSED MODEL: PREDICTING C_1 SOLUBILITY IN METHANOL Fig. 1





Model results with experimental data*

Table 1

Pressure, KPa (abs)	Temperature, °K.	Component	Experimental, mole fraction	Model results, mole fraction
5,050	283.2	CH_4	0.04595	0.04681
10,050	283.2	CH_4	0.1038	0.10306
15,050	283.2	CH_4	0.1489	0.14617
20,040	283.2	CH_4	0.1774	0.1797
25,040	283.2	CH_4	0.2046	0.2073
30,060	283.2	CH_4	0.2342	0.2327
35,060	283.2	CH_4	0.2614	0.2593
40,050	283.2	CH_4	0.2894	0.2907
5,050	293.2	CH_4	0.04464	0.04347
10,050	293.2	CH_4	0.0897	0.09318
15,050	293.2	CH_4	0.1377	0.1347
20,040	293.2	CH_4	0.1709	0.1698
25,040	293.2	CH_4	0.1992	0.2003
30,060	293.2	CH_4	0.2261	0.2282
35,060	293.2	CH_4	0.2571	0.25484
40,050	293.2	CH_4	0.2816	0.2822
5,050	303.2	CH_4	0.04231	0.04118
10,050	303.2	CH_4	0.08313	0.08599
15,050	303.2	CH_4	0.126	0.1251
20,040	303.2	CH_4	0.162	0.1596
25,040	303.2	CH_4	0.19	0.19096
30,060	303.2	CH_4	0.219	0.2203
35,060	303.2	CH_4	0.2495	0.2488
40,050	303.2	CH_4	0.2775	0.27749
500	283.2	C_2H_6	0.03568	0.03595
1,000	283.2	C_2H_6	0.07748	0.0765
1,500	283.2	C_2H_6	0.1146	0.1158
2,000	283.2	C_2H_6	0.1572	0.1567
2,500	283.2	C_2H_6	0.2019	0.2018
3,000	283.2	C_2H_6	0.2537	0.2538
500	293.2	C_2H_6	0.02841	0.02967
1,000	293.2	C_2H_6	0.06326	0.05944
2,000	293.2	C_2H_6	0.1373	0.1389
2,500	293.2	C_2H_6	0.1878	0.1847
3,000	293.2	C_2H_6	0.2307	0.2318
500	303.2	C_2H_6	0.02703	0.02867
1,000	303.2	C_2H_6	0.05099	0.04775
1,500	303.2	C_2H_6	0.07574	0.0752
2,000	303.2	C_2H_6	0.1065	0.1093
2,500	303.2	C_2H_6	0.1465	0.1485
3,000	303.2	C_2H_6	0.1943	0.1913
3,500	303.2	C_2H_6	0.2365	0.236
4,000	303.2	C_2H_6	0.2801	0.2809

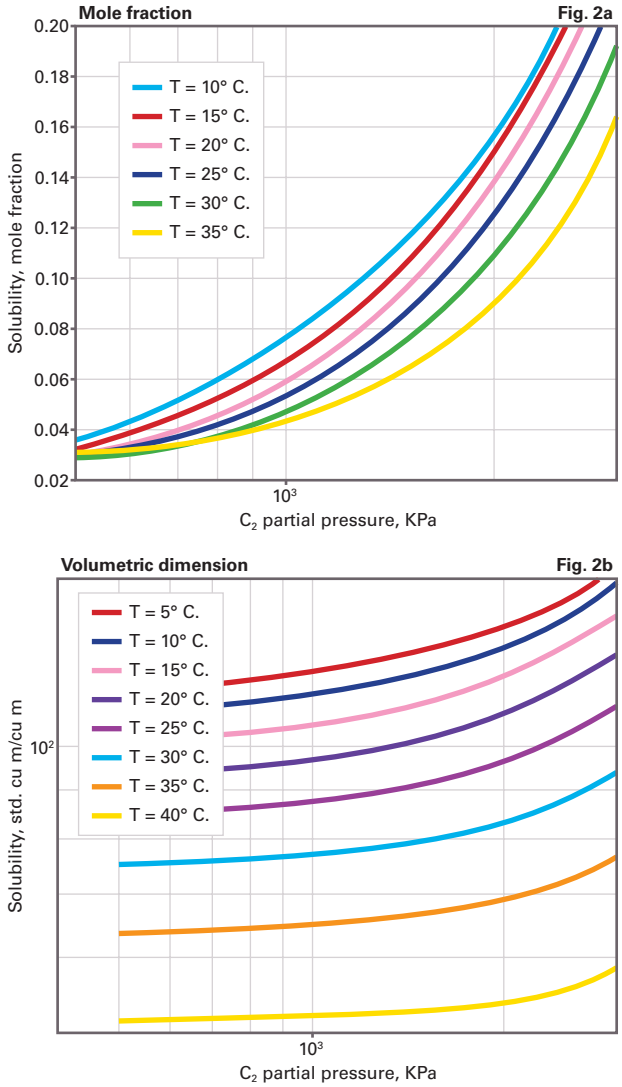
Average of absolute deviation =1.5289%

$$\%AADP = \frac{100}{NOP}\sum_{i}^{NOP}\left|\left(\frac{\text{Calculated value}}{\text{Experimental value}}\right)_i - 1\right| = 1.5289\%$$

*Reported in Reference 1.

Proposed model: predicting C_2 solubility in methanol

Fig. 2



The prediction of light alkanes' solubility in methanol is usually based on use of the pure component solubilities and the mole fraction of the components in the mixture. In most cases, however, the current models may be insufficient.

The goal of the work presented here is to contribute to the modeling and understanding of methanol solubility behavior of light alkanes. Using this simple model, we explain the observed solubility behavior and compare results with experimental data.[1]

Model

An easy-to-use model predicts the solubility of methane and ethane components in methanol.[2] Equation 1 (see accompanying box on p. 40) presents the correlation for predicting the solubility of solutes in which four coefficients correlate the mole fraction of individual components and reduced partial pressure of the component.

Equations 2-4 calculate the required coefficients for Equation 1; Equations 6 and 7 convert solute and solvent mole fraction to volumetric dimensions.

This model only needs data to tune the coefficients and accurately predict a wide range of data.

Results

Table 1 presents the obtained results of the model for determining the solubility of methane and ethane components in methanol with the experimental data. As can be seen, the average absolute deviation for model is 1.5289%. The proposed method is therefore accurate in predicting the solubility of light alkanes in methanol.

Figs. 1a and 1b illustrate the solubility trends of methane components in methanol at different temperatures and pressures, applying the model from Reference 2 and in molar and volumetric dimensions.

Figs. 2a and 2b show the solubility of ethane in methanol at different

temperatures and pressures applying the same model and in molar and volumetric dimensions. ✦

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1. Wang, L.K., et al., "Experimental Study on the Solubility of Natural Gas Components in Water with or without Hydrate Inhibitor," Fluid Phase Equilibria, No. 207 (2003), pp. 143–154.

2. Bahadori, A., "New model predicts solubility in glycols," OGJ, Feb. 26, 2007, p. 50.

The author

Alireza Bahadori (bahadori.a@nisoc.ir) is a senior process engineer in the petroleum engineering department of National Iranian South Oil Co., Ahwaz, Iran. Previously he worked 4 years as a CIS technologist for Aghajari Oil and Gas Co. He has a technical diploma (1991) in control instrument services from NIOC Technical School in Aghajari. He also holds a BSc in chemical engineering (1998) from Petroleum University of Technology (Abadan Institute of Technology) Abadan, Iran, and an MSc (2000) in chemical engineering from the University of Shiraz, Iran. Bahadori is a member of Iranian Association of Chemical Engineers.

Nelson-Farrar cost indexes

Refinery construction (1946 Basis)

(Explained on p.145 of the Dec. 30, 1985, issue)

	1962	1980	2004	2005	2006	May 2006	Apr. 2007	May 2007
Pumps, compressors, etc.	222.5	777.3	1,581.5	1,685.5	1,758.2	1,747.3	1,841.8	1,840.8
Electrical machinery	189.5	394.7	516.9	513.6	520.2	514.6	517.7	515.0
Internal-comb. engines	183.4	512.6	919.4	931.1	959.7	956.9	969.5	973.9
Instruments	214.8	587.3	1,087.6	1,108.0	1,166.0	1,148.5	1,261.4	1,261.3
Heat exchangers	183.6	618.7	863.8	1,072.3	1,162.7	1,179.4	1,374.7	1,374.7
Misc. equip. average	198.8	578.1	993.8	1,062.1	1,113.3	1,109.3	1,193.0	1,193.1
Materials component	205.9	629.2	1,112.7	1,179.8	1,273.5	1,262.8	1,409.7	1,385.5
Labor component	258.8	951.9	2,314.2	2,411.6	2,497.8	2,478.6	2,560.7	2,576.2
Refinery (Inflation) Index	237.6	822.8	1,833.6	1,918.8	2,008.1	1,992.3	2,100.3	2,099.9

Refinery operating (1956 Basis)

(Explained on p.145 of the Dec. 30, 1985, issue)

	1962	1980	2004	2005	2006	May 2006	Apr. 2007	May 2007
Fuel cost	100.9	810.5	971.9	1,360.2	1,569.0	1,670.2	1,526.4	1,627.5
Labor cost	93.9	200.5	191.8	201.9	204.2	200.6	223.8	216.5
Wages	123.9	439.9	984.0	1,007.4	1,015.4	1,017.5	1,078.8	1,047.3
Productivity	131.8	226.3	513.3	501.1	497.5	507.2	482.0	483.7
Invest., maint., etc.	121.7	324.8	686.7	716.0	743.7	737.9	775.0	774.9
Chemical costs	96.7	229.2	268.2	310.5	365.4	363.8	371.6	380.9
Operating indexes								
Refinery	103.7	312.7	486.7	542.1	579.0	584.0	596.9	604.0
*Process units**	103.6	457.5	638.1	787.2	870.7	903.0	872.6	905.8

**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.

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PennWell

US oil carriers' 2006 net incomes rebound; labor increases push up construction costs

Christopher E. Smith
Pipeline Editor

US oil pipeline operators saw their net profits rebound in 2006, the more than $3.7 billion earned marking an increase of almost 18%, following a more than 7% dip in 2005. Oil pipeline operators' profits equaled nearly 44% of revenue.

Natural gas pipeline operators, meanwhile, saw their net profits continue to grow, rising almost 4% to top $4 billion for the first time.

Operators also continued to use these profits to expand capacity. The number of formal construction plans brought before the US Federal Energy Regulatory Commission for new or expanded pipeline and compression fell for the 12 months ending June 30, 2006, but planned expenditures grew, tracking both the increased size of the proposed projects and increased expenses.

All of the proposed pipeline plans were for projects using pipe of 24-in. OD or greater, with 9 of 25 calling for 42-in. OD pipe. Proposed mileage also increased by more than 40%. Compression plans followed a similar pattern, with 16 of 32 projects calling for new or additional compression of 20,000 hp or greater and 4 calling for more than 40,000 hp.

The increased scale of the proposed projects had the anticipated effect on unit costs, with estimated $/mile pipeline costs jumping nearly 45% to more than $2.75 million, while $/hp cost estimates slipped 11.5%.

More than scale alone, however, drove the changes in cost estimates, surging labor prices passing material and miscellaneous costs as the

IN THIS REPORT . . .

- Pipeline revenues, incomes—2006
- US pipeline costs—land and offshore
- US pipeline costs: estimated vs. actual
- US compressor construction costs
- US compressor costs: estimated vs. actual
- US interstate mileage
- Investment in US oil pipelines
- 10 years of land construction costs
- Top 10 interstate oil lines
- Top 10 interstate gas lines
- Oil pipeline companies
- Gas pipeline companies

single most expensive per-mile item.

Higher-cost labor also affected the balance between estimated and actual costs for both pipeline and compressor projects completed in the 12 months ending June 30, 2007. Actual pipeline costs were very close to estimated costs in aggregate, but higher than anticipated labor costs more than equaled lower than expected expenditures in every other category.

Higher than anticipated labor costs also contributed almost the entire difference between estimated and actual compressor costs, with projects completed by June 30, 2007, running more than $100/hp more expensive than had been predicted.

US pipeline data

At the end of this article, two large tables (beginning on p. 59) offer a variety of data for US oil and gas pipeline companies: revenue, income, volumes transported, miles operated, and investments in physical plants. These data are gathered from annual reports filed with FERC by regulated oil and natural gas pipeline companies for the previous calendar year.

Data are also gathered from periodic filings with FERC by those regulated natural gas pipeline companies seeking FERC approval to expand capacity. OGJ keeps a record of these filings for each 12-month period ending June 30.

Combined, these data enable an analysis of the US regulated interstate pipeline system.

• Annual reports. Companies that FERC determines to be involved in interstate movement of oil or natural gas for a fee are jurisdictional to FERC, must apply to FERC for approval of transportation rates, and therefore must file a FERC annual report: Form 2 or 2A for major or nonmajor, respectively, natural gas pipelines; Form 6 for oil (crude or product) pipelines.

The distinction between "major" and "nonmajor" is defined by FERC and appears as a note at the end of the table listing all FERC-regulated natural gas pipeline companies for 2006 at the end of this article (p. 64).

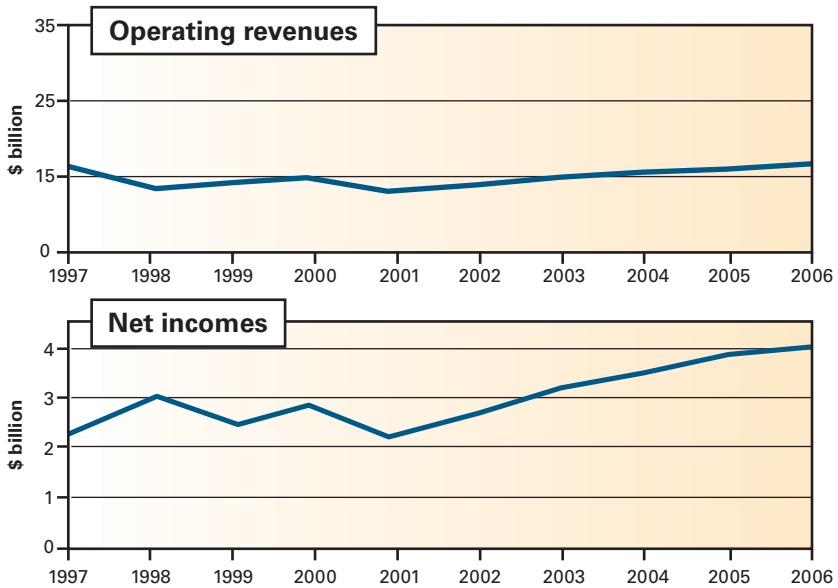
The deadline to file these reports each year is Apr. 1. For a variety of reasons, a number of companies miss that deadline and apply for extensions, but eventually file an annual report. That deadline and the numerous delayed filings explain why publication of this OGJ report on pipeline economics occurs as late as the third quarter of each year. Earlier publication would exclude many companies' information.

• Periodic reports. When a FERC-regulated natural gas pipeline company wants to modify its system, it must apply for a "certificate of public convenience and necessity." This filing must explain in detail the planned construction, justify it, and—except in certain instances—specify what the company estimates construction will cost.

Not all applications are approved. Not all that are approved are built. But, assuming a company receives its

NATURAL GAS PIPELINE PERFORMANCE TRENDS

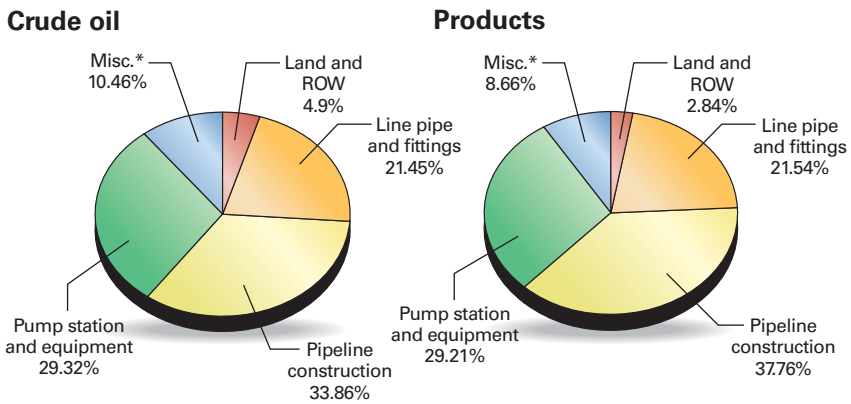
Fig. 1



Source: US FERC Forms 2 and 2A, gas pipeline company reports.

OIL PIPELINE INVESTMENT

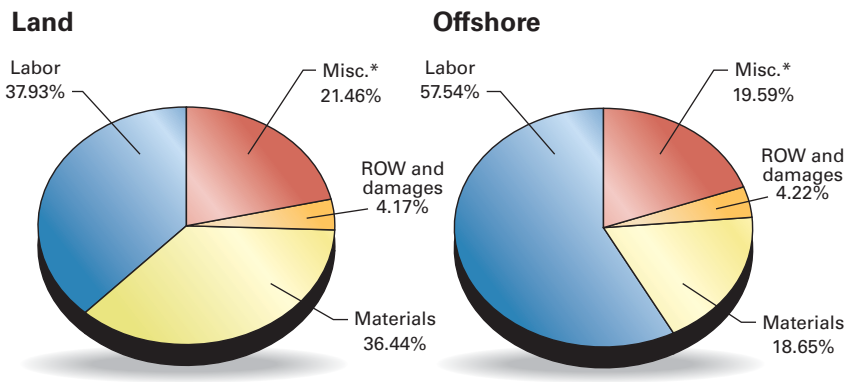
Fig. 2



*Generally includes delivery systems, communications, office furniture and equipment, vehicles and other work equipment, and other property.
Source: US oil pipeline company annual reports (Form 6) to FERC for 2006.

PIPELINE CONSTRUCTION COSTS— ESTIMATED

Fig. 3



*Generally includes surveying, engineering, supervision, administration and overhead, interest, contingencies and allowances for funds used during construction (AFUDC), and regulatory filing fees.
Source: US FERC construction-permit filings July 1, 2006, to June 30, 2007.

US INTERSTATE PIPELINE MILEAGE

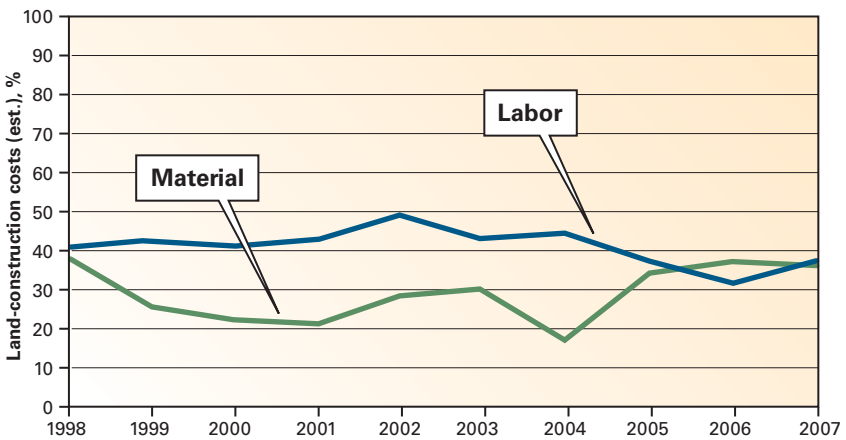
Table 1

Year	Miles Gas[1,2]	Miles Oil	Miles Total[1]
1997	178,469	160,176	338,645
1998	190,250	157,234	347,484
1999	180,489	155,904	336,393
2000	186,151	152,823	338,974
2001	180,961	154,877	335,838
2002	190,899	149,619	340,518
2003	188,178	139,901	328,079
2004	190,117	142,200	332,317
2005	188,847	131,334	320,181
2006	189,012	140,407	329,419

[1]FERC-defined major gas pipelines only; transmission mileage. See GAS COMPANIES table for definition of major and nonmajor companies and details of companies reporting mileage for 2006. [2]Totals revised from initial publication.
Source: US FERC annual reports: Form 6, oil pipelines; Forms 2 & 2A, gas pipelines.

MAJOR COST COMPONENTS—10 YEARS

Fig. 4



Source: US FERC.

certificate and builds its facilities, it must—again, with some exceptions—report back to FERC how its original cost estimates compared with what it actually spent.

OGJ spends the year July 1 to June 30 monitoring these filings, collecting them, and analyzing their numbers.

For 2001, OGJ began reporting what natural gas companies spent during the year on operations and maintenance (OGJ, Sept. 16, 2002, p. 52).

The table on natural gas companies has tracked how the US gas transmission industry has changed under reduced regulation.

OGJ's exclusive, annual Pipeline Economics Report began tracking volumes of gas transported for a fee by major interstate pipelines for 1987 (OGJ, Nov. 28, 1988, p. 33) as pipelines moved gradually after 1984 from owning the gas they moved to mostly providing

TOP 10 INTERSTATE OIL PIPELINE COMPANIES—2006

	Company	Mileage	Company	Trunkline traffic, million bbl-miles	Company	Income, $1,000
1	Magellan Pipeline Co. LP	8,563	Colonial Pipeline Co.	706,277	Kinder Morgan Operating LP "A"	463,747
2	Plains Pipeline LP	8,387	Enbridge Energy LP	399,814	ExxonMobil Pipeline Co.	258,260
3	Mid-America Pipeline Co.	7,447	Marathon Pipeline LLC	175,399	Shell Pipeline Co. LP	256,693
4	ConocoPhillips Pipe Line Co.	7,352	Explorer Pipeline Co.	148,518	BP Pipelines North America Inc.	251,936
5	BP Pipelines North America Inc.	6,344	Plantation Pipe Line Co.	118,914	Colonial Pipeline Co.	193,013
6	Colonial Pipeline Co.	5,589	TE Products Pipeline Co. LP	117,772	Marathon Pipeline LLC	164,293
7	TE Products Pipeline Co. LP	4,676	Plains Pipeline LP	84,574	Magellan Pipeline Co. LP	151,967
8	ExxonMobil Pipeline Co.	4,557	Mid-America Pipeline Co.	84,447	SFPP LP	144,725
9	TEPPCO Crude Pipeline LP	3,967	ConocoPhillips Transportation Alaska Inc.	83,528	Enbridge Energy LP	113,526
10	Chevron Pipe Line Co.	3,565	Magellan Pipeline Co. LP	82,308	Whiting Oil & Gas Corp.	89,665
	Top 10 total—2006	**60,447**		**2,001,551**		**$2,087,825**
	Part of all companies	**43.05%**		**56.60%**		**55.78%**
	Top 10 total—2005	59,288		2,001,636		$1,870,784

Source: US FERC Form 6: Annual Report of Oil Pipeline Companies, Dec. 31, 2006

TOP 10 US INTERSTATE GAS PIPELINE COMPANIES—2006

	Company	Transmission mileage	Company	Volumes moved for fee, MMcf	Company	Net income, $1,000
1	Northern Natural Gas Co.	15,744	Transcontinental Gas Pipe Line Corp.	2,750,531	Natural Gas Pipeline Co. of America	280,187
2	Tennessee Gas Pipeline Co.	13,996	ANR Pipeline Co.	2,057,960	Texas Eastern Transmission Corp.	228,153
3	Transcontinental Gas Pipe Line Corp.	10,413	Columbia Gas Transmission Corp.	1,792,016	Dominion Transmission Inc.	202,104
4	Columbia Gas Transmission Corp.	10,318	Natural Gas Pipeline Co. of America	1,709,368	Distrigas of Massachusetts LLC	193,607
5	El Paso Natural Gas Co.	10,295	Tennessee Gas Pipeline Co.	1,674,476	Columbia Gas Transmission Corp.	187,561
6	ANR Pipeline Co.	9,600	El Paso Natural Gas Co.	1,636,246	Southern Natural Gas Co.	183,704
7	Natural Gas Pipeline Co. of America	9,297	Texas Eastern Transmission Corp.	1,240,518	El Paso Natural Gas Co.	151,938
8	Texas Eastern Transmission LP	9,176	Columbia Gulf Tranmission Co.	1,041,611	Tennessee Gas Pipeline Co.	147,591
9	Southern Natural Gas Co.	7,439	Northern Natural Gas Co.	949,838	Kern River Gas Tranmission Co.	144,320
10	Gulf South Pipeline Co. LP	6,532	Northern Border Pipeline Co.	857,761	Transcontinental Gas Pipe Line Co.	142,927
	Total—2006	**102,810**		**15,710,325**		**$1,862,092**
	Part of majors	**54.39%**		**46.96%**		**47.77%**
	Part of all companies	**52.59%**		**45.79%**		**46.38%**
	Total–2005 top 10	104,237		15,362,733		$1,729,255

*All FERC-classified as "major."
Source: US FERC Forms 2 & 2A: annual reports for natural gas companies, Dec. 31, 2006

transportation services.

Volumes of natural gas sold by pipelines have been steadily declining, so that, beginning with 2001 data in the 2002 report, the table only lists volumes transported for others.

The company tables have also reflected the recent asset consolidation and merger activity among companies in their efforts to improve transportation efficiencies and improve bottom lines.

Reporting changes

The number of companies required to file annual reports with FERC may change from year-to-year, with some companies becoming jurisdictional, others nonjurisdictional, and still others

INVESTMENT IN OIL PIPELINES—2006

Table 2

	Company and investment, $						
	A	B	C	D	E	Total, $	%
CRUDE PIPELINES							
Land	5,604,735	141,938	292,544	1,046,795	5,203,260	12,289,272	0.39
Right of way	119,691,919	955,277	316,592	8,124,118	13,764,171	142,852,077	4.51
Line pipe	461,767,104	23,386,168	11,353,060	36,050,141	67,641,947	600,198,420	18.96
Line pipe fittings	32,340,387	1,237,355	5,604,453	20,132,197	19,635,616	78,950,008	2.49
Pipeline construction	709,641,391	29,670,794	20,591,873	91,595,969	220,677,512	1,072,177,539	33.86
Buildings	81,710,383	4,002,647	3,619,895	6,199,227	12,575,775	108,107,927	3.41
Boilers	—	—	—	—	—	—	0.00
Pumping equipment	62,017,405	4,808,565	10,011,613	18,149,951	21,323,343	116,310,877	3.67
Machine tools and machinery	—	—	—	32,353	9,128	41,481	0.00
Other station equipment	381,202,490	22,337,327	11,529,089	93,532,969	43,611,479	552,213,354	17.44
Oil tanks	80,823,272	5,317,491	8,249,726	19,482,391	38,186,880	152,059,760	4.80
Delivery facilities	—	14,454	21,641,591	334,329	—	21,990,374	0.69
Communication systems	5,540,619	1,756,825	92,702	1,816,033	1,903,808	11,109,987	0.35
Office furniture and equipment	16,141,131	643,522	1,349,857	670,924	481,571	19,287,005	0.61
Vehicles and other work equip.	22,642,868	785,854	566,672	1,866,663	—	25,862,057	0.82
Other property	9,935,048	2,156,025	—	237,105,718	3,762,644	252,959,435	7.99
Total investment—2006	**$1,989,058,752**	**$97,214,242**	**$95,219,667**	**$536,139,778**	**$448,777,134**	**$3,166,409,573**	**100.00**
Total carrier property—2006	**$2,152,427,462**	**$97,698,787**	**$97,131,166**	**$550,052,251**	**$582,131,919**		
Total investment—2005	**$1,948,459,883**	**$94,882,067**	**$89,329,029**	**$516,295,337**	**$479,000,241**	**$3,127,966,557**	
PRODUCT PIPELINES							
Land	5,889,973	2,365,483	834,766	4,374,305	8,083,162	21,547,689	0.39
Right of way	—	13,109,315	27,679,012	11,701,291	83,248,614	135,738,232	2.45
Line pipe	398,276,479	75,014,977	191,043,830	92,662,535	205,319,121	962,316,942	17.34
Line pipe fittings	120,303,516	50,203,020	32,490,603	4,237,021	25,603,982	232,838,142	4.20
Pipeline construction	1,008,891,354	139,429,195	380,511,015	127,282,348	439,324,149	2,095,438,061	37.76
Buildings	37,379,753	14,479,810	7,695,898	19,690,078	35,606,580	114,852,119	2.07
Boilers	—	—	—	—	—	—	0.00
Pumping equipment	79,923,167	36,323,398	59,887,453	41,458,276	52,294,046	269,886,340	4.86
Machine tools and machinery	—	—	—	—	—	—	0.00
Other station equipment	272,893,401	102,501,763	101,057,804	102,172,992	244,413,283	823,039,243	14.83
Oil tanks	167,551,245	26,986,755	7,725,875	36,100,453	174,901,953	413,266,281	7.45
Delivery facilities	—	—	10,497,306	32,856,158	121,187,959	164,541,423	2.96
Communication systems	8,975,354	740,282	3,400,029	15,650,570	14,976,180	43,742,415	0.79
Office furniture and equipment	45,983,139	407,984	34,062,969	7,102,199	3,761,626	91,317,917	1.65
Vehicles and other work equip.	19,050,077	3,231,492	8,840,332	15,568,388	3,779,717	50,470,006	0.91
Other property	100,277,363	—	29,155,751	—	1,237,013	130,670,127	2.35
Total investment—2006	**$2,265,394,821**	**$464,793,474**	**$894,882,643**	**$510,856,614**	**$1,413,737,385**	**$5,549,664,937**	**100.00**
Total carrier property—2006	**$2,290,977,062**	**$483,461,451**	**$1,107,254,777**	**$515,548,061**	**$1,442,695,200**		
Total investment—2005	$2,160,731,072	$458,775,861	$865,541,350	$505,329,967	$1,377,235,956	$5,367,614,206	

Sources: US FERC Forms 6, Annual Report of Oil Pipeline Companies, Dec. 31, 2005, and 2006

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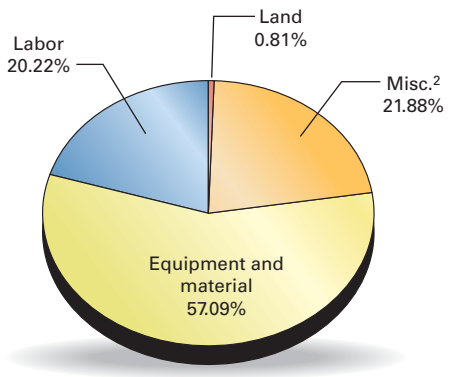
COMPRESSOR CONSTRUCTION COSTS—ESTIMATED[1]

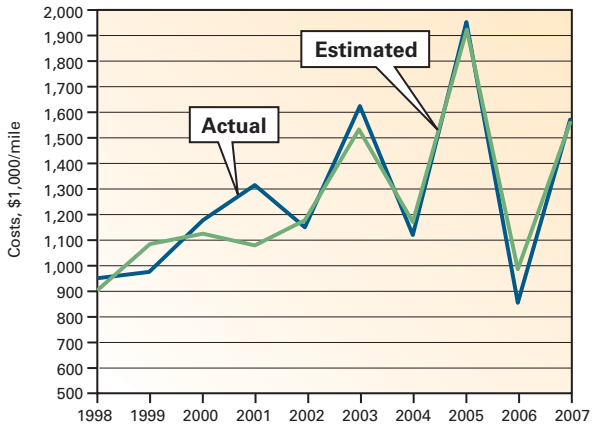
Fig. 5



[1]Land only. [2]Generally includes surveying, engineering, supervision, administration and overhead, interest, contingencies, allowances for funds used during construction (AFUDC), and regulatory filing fees.
Source: US FERC construction-permit filings, July 1, 2006, to June 30, 2007.

ESTIMATED, ACTUAL COST TRENDS—10 YEARS*

Fig. 6



*Land and offshore gas pipeline construction as of June 30 of each year for the previous 12 months.
Source: US FERC.

PIPELINE COMPANY REVENUES, INCOMES

Table 3

	Gas		Oil	
	Operating revenues, $1,000	Net income, $1,000	Operating revenues, $1,000	Net income, $1,000
1997	16,142,675	2,264,577	7,214,705	2,254,587
1998	13,584,783	3,010,821	6,890,083	2,050,982
1999	14,616,949	2,545,043	7,219,500	2,928,460
2000	14,980,925	2,910,835	7,483,100	2,705,463
2001	14,407,467	2,246,109	7,729,972	3,006,898
2002	14,015,308	2,734,182	7,811,951	3,408,753
2003	15,082,011	3,260,797	7,703,998	3,469,996
2004	15,781,445	3,588,344	8,019,554	3,322,738
2005	16,375,921	3,863,331	7,917,176	3,076,476
2006	$17,122,586	$4,015,253	$8,516,563	$3,743,115

Source: US FERC annual reports (Forms 2, 2A, and 6) by regulated interstate natural gas and oil pipeline companies

merging or being consolidated out of existence.

Such changes require that care be taken in comparing annual US petroleum and natural gas pipeline statistics.

Institution by FERC of the two-tiered (2 and 2A) classification system for natural gas pipeline companies after 1984 further complicated comparisons (OGJ, Nov. 25, 1985, p. 55).

Only major gas pipelines are required to file miles operated in a given year. The other companies may indicate miles operated but are not specifically required to do so.

For several years after 1984, many non-majors did not describe their systems. But filing descriptions of their systems has become standard, and most provide miles operated.

Reports for 2006 show an increase in FERC-defined major gas pipeline companies: 73 companies of 118 filing for 2006, from 71 of 112 for 2005.

The FERC made an additional change to reporting requirements for 1995 for both crude oil and petroleum products pipelines.

Exempt from requirements to prepare and file a Form 6 were those pipelines with operating revenues at or less than $350,000 for each of the 3 preceding calendar years.

These companies must now file only an "Annual Cost of Service Based Analysis Schedule," which provides only total annual cost of service, actual operating revenues, and total throughput in both deliveries and barrel-miles.

In 1996 major natural gas pipeline companies were no longer required to report miles of gathering and storage systems separately from transmission.

Thus, total miles operated for gas pipelines consist almost entirely of transmission mileage. To continue to convey a 10-year trend, Table 1 has been adjusted to reflect only transmission mileage operated since 1995.

FERC-regulated natural gas and oil pipeline mileage increased in 2006 after having decreased in 2005 (Table 1). Final data show an increase of more than 9,000 miles, or nearly 3%.

This increase in majors-operated transmission pipeline mileage came largely on the back of a 13.73% increase in products mileage.

Rankings; activity

Major natural gas pipeline companies in 2006 saw operating revenues increase by more than $778 million or nearly 5% from 2005. The results were roughly similar when both major and nonmajor pipelines are considered, and in both cases grew in comparison to the $613 million move, more than 4%, seen for majors in 2005 from 2004.

This jump in revenues once again translated into the highest net incomes yet seen for either majors or all companies combined. Income for majors improved by more than 4%, or more than $160.5 million; with increases seen

for all companies in 2006 of nearly the same 4%.

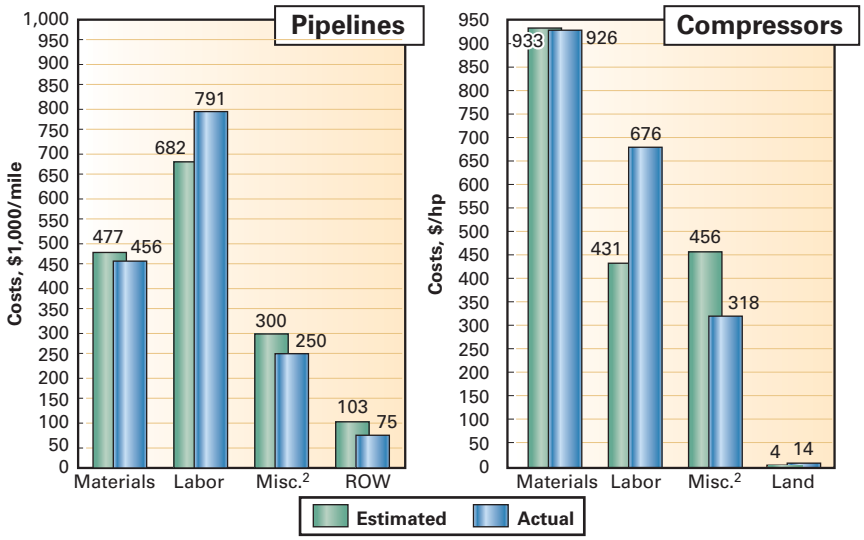
Income as a percent of revenues for natural gas pipeline companies, however, slipped to 23.45% in 2006 from 23.59% in 2005, breaking a string of five straight annual increases.

Oil pipelines saw even healthier gains in both revenues and income. Revenues increased by nearly $600 million or 7.6%, more than reversing the declines seen in 2005, while incomes rose more than $666.6 million or 21.7%, wiping out both the 7.4% decline seen in 2005 and the 4.2% decline of 2004.

Products deliveries for 2006 via pipeline rose 43.7 million bbl or 0.7%, only partially offsetting the losses seen in 2005. Crude oil deliveries, in contrast, were relatively flat. Throughput

COMPONENT COSTS: ESTIMATED VS. ACTUAL[1]

Fig. 7



[1]Land only. For construction cost filings made before July 1, 2007. [2]Generally includes surveying, engineering, supervision, administration and overhead, interest, contingencies, allowances for funds used during construction (AFUDC), and regulatory filing fees.
Source: US FERC.

US PIPELINE COSTS, ESTIMATED

Table 4

Size, in.	Location[1]	Length, miles	$ Material	Labor	Misc.[2]	ROW & damages	Total	$/mile
LAND PIPELINES								
24	New Mexico	0.31	515,000	15,000	225,000	15,000	770,000	2,483,871
24	Louisiana (lat.)	2.30	1,111,280	2,035,903	860,547	183,411	4,191,141	1,822,235
24	Illinois	3.10	2,335,881	3,907,192	6,844,915	248,000	13,335,988	4,301,932
24	Colorado	6.10	2,571,589	5,519,600	2,786,755	1,160,000	12,037,944	1,973,433
24	Alabama (L, R)	6.83	2,762,915	85,348	7,439,164	80,000	10,367,427	1,517,925
24	Colorado	58.00	18,219,425	16,504,700	11,796,077	1,670,400	48,190,602	830,872
24	Utah	59.00	21,476,000	3,422,000	72,727,000	1,028,000	98,653,000	1,672,085
24	Wyoming (lat.)	125.00	42,701,834	52,963,723	15,582,569	2,252,800	113,500,926	908,007
30	Texas	9.00	10,392,460	3,618,591	4,127,947	662,500	18,801,498	2,089,055
30	Colorado	15.00	10,822,673	7,044,300	4,903,522	432,000	23,202,495	1,546,833
30	Texas	20.00	23,840,013	8,596,818	7,928,928	1,537,500	41,903,259	2,095,163
30	Maryland-Pennsylvania	88.00	136,025,000	156,146,000	104,829,000	18,000,000	415,000,000	4,715,909
36	Louisiana	1.00	1,784,942	1,215,780	891,353	164,294	4,056,369	4,056,369
36	New Mexico (L, lat.)	25.00	15,455,202	27,783,001	15,840,139	3,299,520	62,377,862	2,495,114
36	Texas-Louisiana	45.00	52,290,118	59,531,465	37,237,799	9,888,623	158,948,005	3,532,178
36	Wyoming	77.00	59,229,045	4,444,000	78,238,000	1,114,000	143,025,045	1,857,468
42	Mississippi (L)	18.00	21,560,519	28,253,948	12,680,624	1,669,422	64,164,513	3,564,695
42	Missouri	43.00	44,939,832	47,981,429	23,959,826	6,772,052	123,653,139	2,875,654
42	Mississippi-Alabama	111.00	121,763,900	114,180,700	50,543,400	11,078,400	297,566,400	2,680,778
42	Louisiana	132.00	176,429,261	146,359,508	96,234,557	26,404,617	445,427,943	3,374,454
42	Indiana	166.00	171,417,828	183,019,651	91,392,001	25,831,213	471,660,693	2,841,329
42	Illinois	195.00	203,324,066	217,085,352	108,402,922	30,639,212	559,451,552	2,868,982
42	Ohio	234.00	242,737,654	259,166,513	129,416,411	36,578,506	667,899,084	2,854,270
42	Louisiana-Mississippi	239.00	241,145,000	226,127,000	99,512,000	21,939,000	588,723,000	2,463,276
42	Texas-Louisiana	353.00	430,094,000	563,615,000	225,546,887	32,329,067	1,251,584,954	3,545,566
Total projects—land		**2,031.64**	**$2,054,945,437**	**$2,138,622,522**	**$1,209,947,343**	**$234,977,537**	**$5,638,492,839**	**$2,775,341**
Total land—2006 report		1,450.55	$1,056,274,890	$902,121,525	$691,465,787	$134,485,703	$2,784,347,905	$1,919,512
OFFSHORE PIPELINES								
20	Florida	17.74	10,489,616	32,364,339	11,020,308	2,374,760	56,249,023	3,170,745
Total projects—offshore		**17.74**	**$10,489,616**	**$32,364,339**	**$11,020,308**	**$2,374,760**	**$56,249,023**	**$3,170,745**
TOTAL—ALL PROJECTS		**2,049.38**	**$2,065,435,053**	**$2,170,986,861**	**$1,220,967,651**	**$237,352,297**	**$5,694,741,862**	**$2,778,763**
2006—report total, all projects		1,456.78	$1,063,450,722	$911,030,583	$697,344,497	$134,485,703	$2,806,311,505	$1,926,380

[1]L = loop; lat. = lateral; R = replacement. [2]Generally includes surveys, engineering, supervision, interest, administration, overheads, contingencies, allowances for funds used during construction (AFUDC), and FERC fees.
Source: US FERC construction-permit applications, July 1, 2006, to June 30, 2007

US COMPRESSOR-CONSTRUCTION COSTS, ESTIMATED

Table 5

Location	Horsepower	$ Equipment material	Labor	Land	Misc.[1]	Total	$/hp
Wyoming	2,370	2,622,500	250,000	40,000	949,900	3,862,400	1,630
Colorado	3,550	7,109,414	354,389	10,000	3,684,447	11,158,250	3,143
New Mexico	4,740	12,146,815	363,230	10,000	5,765,915	18,285,960	3,858
Nebraska[2]	4,083	979,277	2,484,037	–	1,856,150	5,319,464	1,303
Colorado	7,100	14,313,817	527,463	40,000	6,602,405	21,483,685	3,026
Mississippi	7,100	10,424,500	2,966,700	185,800	3,565,100	17,142,100	2,414
Colorado	10,310	7,585,200	7,206,800	–	5,502,200	20,294,200	1,968
Texas	12,552	15,090,597	6,873,995	624,748	5,095,080	27,684,420	2,206
Wyoming	15,000	11,680,000	1,145,000	35,000	9,340,000	22,200,000	1,480
Texas	15,000	8,273,557	3,636,250	167,000	4,344,588	16,421,395	1,095
Louisiana	15,000	11,453,135	5,400,250	317,000	5,308,088	22,478,473	1,499
Alabama[2]	15,000	11,714,440	2,826,940	–	6,505,620	21,047,000	1,403
Mississippi	18,940	22,786,600	6,484,800	406,200	7,792,800	37,470,400	1,978
Louisiana	18,940	22,786,600	6,484,800	406,200	7,792,800	37,470,400	1,978
Ohio	20,450	22,487,701	8,512,933	125,000	6,899,064	38,024,698	1,859
Louisiana	20,604	22,517,551	7,672,034	854,024	5,552,529	36,596,138	1,776
Wyoming	20,620	11,570,919	5,222,199	10,000	5,417,457	22,220,575	1,078
Wyoming	24,540	22,487,701	8,417,933	165,000	7,033,682	38,104,316	1,553
Wyoming[2]	24,930	18,174,300	7,298,400	125,000	6,475,800	32,073,500	1,287
Louisiana	25,339	26,748,970	11,900,066	1,153,163	7,646,723	47,448,922	1,873
Mississippi	30,000	30,351,088	13,872,951	188,878	10,646,566	55,059,483	1,835
Florida	30,000	21,083,000	5,002,500	–	9,121,500	35,207,000	1,174
Wyoming	30,000	16,000,000	1,300,000	35,000	15,265,000	32,600,000	1,087
Louisiana	30,000	30,461,000	7,519,000	616,000	9,332,000	47,928,000	1,598
Ohio	35,000	18,288,317	14,718,740	150,000	6,576,362	39,733,419	1,135
Texas	35,641	40,433,179	15,836,332	1,689,369	12,919,606	70,878,486	1,989
Nebraska	36,810	30,250,094	13,135,395	121,000	9,266,809	52,773,298	1,434
Illinois	36,810	30,250,094	13,161,470	150,000	9,205,966	52,767,530	1,434
Louisiana	40,302	34,555,000	9,834,000	616,000	12,070,000	57,075,000	1,416
Texas	40,302	32,156,000	9,353,000	75,000	11,550,000	53,134,000	1,318
Indiana	41,000	20,684,299	7,822,064	150,000	6,374,047	35,030,410	854
Missouri	41,000	20,684,299	7,847,605	128,000	7,635,856	36,295,760	885
Total, land projects	**713,033**	**$608,149,964**	**$215,431,276**	**$8,593,382**	**$233,094,060**	**$1,065,268,682**	**$1,494**
2006—report total, land projects	583,212	$454,924,377	$257,962,346	$17,989,090	$255,344,048	$985,219,861	$1,689
TOTAL, ALL PROJECTS	**713,033**	**$608,149,964**	**$215,431,276**	**$8,593,382**	**$233,094,060**	**$1,065,268,682**	**$1,494**
2006—report total, all projects	583,212	$454,924,377	$257,962,346	$17,989,090	$255,344,048	$985,219,861	$1,689

[1]Generally includes surveys, engineering, supervision, interest, administration, freight, taxes, overheads, contingencies, allowances for funds used during construction (AFUDC), and FERC fees. [2]Addition.
Source: US FERC construction-permit applications, July 1, 2006, to June 30, 2007

measured in million bbl-miles (bbl-mile: 1 bbl moving 1 mile) increased roughly 1.5%, by more than 51 billion bbl-miles, led by product throughput rising by more than 43.5 billion bbl-miles, or 2.3%

OGJ uses the FERC annual report data to rank the top 10 pipeline companies in three categories (miles operated, trunkline traffic, and operating income) for oil-pipeline companies and three categories (miles operated, gas transported for others, and net income) for natural gas pipeline companies.

Positions in these rankings shift year to year, reflecting normal fluctuations in companies' activities and fortunes. But also, because these companies comprise such a large portion of their respective groups, the listings provide snapshots of overall industry trends and events.

Company financial data for all companies, not just the majors in both types of pipeline service, provide a view of the ongoing condition of these industries (Fig. 1; Table 3).

For all natural gas pipeline companies, for example, net income as a portion of operating revenues fell in 2006 to 23.45%, after having risen for 5 straight years to reach 23.59% in 2005. Income as a portion of operating revenues stood at 15.59% in 2001.

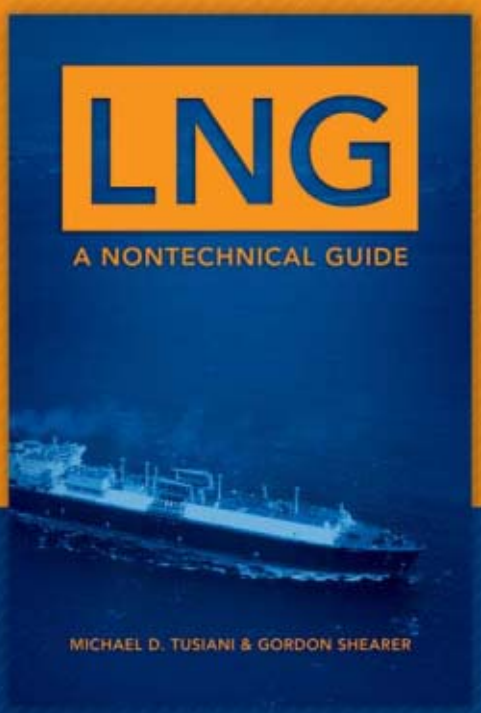
The percentage of income in operating revenues for oil pipelines had been hovering in the mid-20s for the first 5 years of the 1990s; for the last 10 years, however, it pushed first into the 30s, reaching almost 39% in 2001, and was in the 40s from 2002-04 (43%, 45%, and 41%, respectively).

Income as a percent of revenues retreated from these highs in 2005, dropping to 39%, but rebounded strongly in 2006, reaching nearly 44%.

Another measure of company performance and health is provided by a calculation of return on investment: net income as a portion of gas-plant investment. This traced the slight decline seen in income as a portion of revenue, moving to 4.55% following 4 consecutive years of gains that saw it top out at 4.6%. Even so, it remains close to the 4.7% levels last seen in 1998.

For oil pipelines, net income as a portion of investment in carrier property in 2006 resumed an upward trend begun in 1999, rising to 11.5% after having dipped to 10.4% in 2005. Income as part of investment in carrier property in 2004 stood at 11.4%, having risen steadily toward that level from 6.8% in 1998.

Major and nonmajor natural gas pipelines in 2006 reported an industry gas-plant investment of more than $88.3 billion, the highest level ever, up from nearly $84 billion in 2005,



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10 YEARS OF LAND CONSTRUCTION COSTS[1]

Table 6

Size	Year	Average cost, $/mile ROW	Material	Labor	Misc.	Total	Range, $/mile Low	High
8 in.	2007	—	—	—	—	—	—	—
	2006	—	—	—	—	—	—	—
	2005	—	—	—	—	—	—	—
	2004	239,860	84,651	599,280	591,276	1,515,068	1,507,694	1,518,017
	2003	206,313	72,270	280,847	207,362	766,793	390,870	10,712,500
	2002	25,302	31,809	88,400	81,165	[2]206,675	—	—
	2001	21,910	39,548	59,400	47,676	[2]168,533	—	—
	2000	20,099	51,065	385,845	137,789	594,797	909,727	4,003,300
	1999	—	—	—	—	—	—	—
	1998	19,484	337,559	763,099	569,718	[2]1,689,859	—	—
12 in.	2007	—	—	—	—	—	—	—
	2006	45,944	160,618	243,104	174,207	623,873	515,091	1,159,683
	2005	—	—	—	—	—	—	—
	2004	559,684	212,495	1,740,003	691,419	3,203,601	222,012	4,628,800
	2003	10,941	119,813	196,100	75,363	402,217	158,194	646,240
	2002	15,470	88,398	180,110	39,168	323,146	160,116	524,417
	2001	88,592	83,940	481,060	267,073	920,665	820,179	925,452
	2000	30,721	83,069	264,461	163,653	541,894	190,731	885,051
	1999	28,786	380,886	1,331,040	827,938	2,568,651	2,280,685	[3]3,639,364
	1998	—	—	—	—	—	—	—
16 in.	2007	—	—	—	—	—	—	—
	2006	181,184	192,998	398,048	111,888	884,118	601,274	948,857
	2005	88,312	144,768	238,056	181,419	652,555	396,660	1,728,247
	2004	246,628	141,315	849,567	386,050	1,623,560	353,528	2,529,399
	2003	24,549	93,299	172,599	73,049	363,497	210,023	1,377,297
	2002	11,756	88,358	135,606	71,383	307,104	201,614	1,796,507
	2001	30,964	146,191	592,557	464,233	1,233,953	822,866	3,619,607
	2000	132,500	121,675	374,154	359,815	988,143	241,877	3,612,208
	1999	127,078	237,824	442,903	275,440	1,083,245	325,082	4,373,200
	1998	38,093	455,896	324,772	232,192	[2]1,059,952	—	—
20 in.	2007	—	—	—	—	—	—	—
	2006	99,125	233,125	796,688	478,406	[2]1,607,344	—	—
	2005	28,999	191,553	385,889	187,486	793,927	502,795	1,254,420
	2004	17,254	134,986	999,273	295,479	1,446,991	1,016,598	1,942,989
	2003	68,940	215,322	448,600	193,029	925,890	626,622	4,077,000
	2002	129,877	177,985	460,622	348,899	1,117,383	537,001	1,701,544
	2001	71,108	169,648	509,417	183,938	934,111	371,817	1,492,528
	2000	175,788	227,202	506,423	318,035	1,227,447	548,727	1,928,926
	1999	13,043	159,411	247,845	131,931	552,230	441,634	658,440
	1998	22,950	168,795	700,998	365,312	1,258,055	1,133,345	58,416,667
24 in.	2007	25,467	351,083	324,023	453,737	1,155,030	830,872	4,301,932
	2006	126,822	263,200	584,428	577,136	1,551,586	1,248,916	4,883,022
	2005	99,492	324,099	553,603	289,991	1,267,185	701,664	8,153,531
	2004	1,554,828	409,165	2,913,257	1,165,957	[2]6,043,208	—	—
	2003	197,476	323,116	1,124,623	728,855	2,374,070	923,400	9,236,061
	2002	43,494	233,583	641,094	305,899	1,224,069	754,046	7,021,087
	2001	130,504	241,517	540,604	281,141	1,193,767	532,645	5,029,640
	2000	119,147	238,555	461,141	327,696	1,146,538	402,515	2,168,000
	1999	27,662	187,217	239,619	109,016	563,515	457,266	1,145,345
	1998	28,232	252,140	1,069,049	514,710	1,864,131	1,475,621	4,389,362
30 in.	2007	156,303	1,371,819	1,328,831	922,647	3,779,600	1,546,833	4,715,909
	2006	135,337	589,703	960,760	650,255	2,336,055	1,131,419	6,791,954
	2005	108,418	580,031	1,296,166	639,103	2,623,718	1,333,438	4,082,365
	2004	150,549	448,125	634,490	371,734	1,604,899	1,447,235	2,264,492
	2003	40,472	389,806	476,194	205,405	1,111,877	732,468	[3]36,333,333
	2002	51,157	385,485	613,322	298,134	1,348,098	952,210	2,559,292
	2001	203,491	354,127	797,432	565,989	1,921,040	1,360,178	5,008,770
	2000	138,324	389,249	639,270	463,670	1,630,514	985,036	4,457,536
	1999	81,542	330,925	553,334	377,925	1,343,726	[3]646,407	3,990,476
	1998	88,779	352,877	652,808	397,338	1,491,801	979,167	2,021,347
36 in.	2007	97,746	869,995	628,204	893,293	2,489,238	1,857,468	4,056,369
	2006	233,258	844,583	1,141,388	1,349,079	3,568,308	1,900,376	8,066,157
	2005	161,665	819,178	929,436	633,630	2,543,909	1,424,610	4,798,806
	2004	150,070	426,999	352,594	565,474	[2]1,495,137	—	—
	2003	137,857	716,743	696,259	547,675	[2]2,098,532	—	—
	2002	53,571	475,832	762,214	212,008	1,503,625	1,127,089	3,616,470
	2001	58,344	420,420	491,155	323,870	1,293,789	966,841	3,217,182
	2000	195,848	454,764	779,527	442,122	1,874,260	1,256,079	10,708,278
	1999	177,714	458,936	831,128	441,646	1,909,424	1,348,224	2,530,873
	1998	19,905	432,953	435,414	169,861	1,058,134	595,428	2,681,859

[1]Estimates; based on FERC and construction-permit applications for a 12-month period ending June 30 of each year. [2]Only one project proposed during this period for this diameter. [3]Involves river, stream, or channel crossing.

more than $83 billion in 2004, nearly $78 billion in 2003, $74.2 billion in 2002, almost $71 billion in 2001, $68 billion in 2000, and nearly $66 billion in 1999.

Investment in oil pipeline carrier property in 2006 rebounded from the lowest level seen since at least 1997, reaching almost $32.7 billion, after

US PIPELINE COSTS: ESTIMATED VS. ACTUAL, 2006-07[1]

Table 7

Size, in.	Location[1]	Length, miles	$ Materials	Labor	Misc.[2]	ROW & damages	Total	$/mile
Land pipelines								
16	Wisconsin (L)	3.00						
	Estimated		971,000	2,269,000	1,640,000	446,000	5,326,000	1,775,333
	Actual		1,070,688	2,996,064	1,385,228	522,279	5,974,259	1,991,420
16	Wyoming (lat.)	5.30						
	Estimated		636,300	704,600	432,800	100,000	1,873,700	353,528
	Actual		693,437	674,184	489,178	44,596	1,901,395	358,754
24	Virginia	33.00						
	Estimated		4,692,080	700,206	802,714	5,000	6,200,000	187,879
	Actual		4,401,579	1,822,829	833,184	8,376	7,065,968	214,120
24	Colorado-Wyoming	143.00						
	Estimated		40,362,100	43,225,800	15,773,000	4,759,000	104,119,900	728,111
	Actual		43,338,341	51,445,757	24,049,356	2,599,220	121,432,674	849,180
30	Alabama (C)	0.14						
	Estimated		185,113	362,010	307,088	15,820	870,031	6,214,507
	Actual		163,522	513,110	196,624	2,000	875,256	6,251,829
30	Wisconsin (lat., L)	4.00						
	Estimated		2,251,000	3,023,000	2,214,000	562,000	8,050,000	2,012,500
	Actual		1,943,681	2,789,592	1,445,414	502,646	6,681,333	1,670,333
36	Louisiana	22.80						
	Estimated		16,441,300	14,216,700	9,386,757	3,874,600	43,919,357	1,926,288
	Actual		13,410,646	11,123,000	13,052,777	3,258,717	40,845,140	1,791,454
36	Wyoming	27.10						
	Estimated		20,200,000	1,831,000	28,933,200	336,000	51,300,200	1,892,996
	Actual		19,205,000	866,069	30,264,980	305,000	50,641,049	1,868,673
36	Washington (L)	79.50						
	Estimated		65,992,000	150,370,000	35,722,000	22,503,000	274,587,000	3,453,925
	Actual		60,647,000	181,763,000	7,732,000	16,658,000	266,800,000	3,355,975
Total, miles		**317.84**						
Estimated			**$151,730,893**	**$216,702,316**	**$95,211,559**	**$32,601,420**	**$496,246,188**	**$1,561,308**
Actual			**$144,873,894**	**$253,993,605**	**$79,448,741**	**$23,900,834**	**$502,217,074**	**$1,580,094**

[1]Actual cost data must be filed within 6 months following final hydrostatic test of pipeline. Not all projects proposed (estimated costs) are built (actual costs). L = loop; lat. = lateral; C = crossing. [2]Generally includes surveys, engr., supervision, interest, administration and overheads, contingencies, allowances for funds used during construction (AFUDC), and regulatory fees.
Source: US FERC; for completed-project costs filed between July 1, 2006, and June 30, 2007, under CFR Section 157.20(c)(4).

spending 2005 and 2004 relatively flat near $29.5 billion. This plateau followed a steep drop of nearly 8% between 2003 and 2004.

OGJ for several years has tracked carrier-property investment by five crude oil pipeline and five products pipeline companies chosen as representative in terms of physical systems and expenditures (Table 2). Starting in 2003, we added the base carrier-property investment to allow for comparisons among the anonymous companies.

The five crude oil pipeline companies in 2006 increased their overall investment in carrier property by more than $38.4 million, or 1.2%; the same grouping of companies increased overall investment in carrier property by nearly $108 million, or 3.6%, in 2005. One of the five companies has lowered its investment in carrier property for the past 2 years, despite the increases made by the group overall. A similar group of companies decreased investment in carrier property by 2.4% in 2004.

The five products pipeline companies increased overall investment in carrier property in 2006 by $182 million, or 3.39%, following a more modest $127 million, or 2.4%, increase in 2005 and a $509 million (nearly 11%) increase in 2004.

Comparisons of data in Table 2 with previous years' must be done with caution: In 1998, a major crude oil pipeline company listed there merged with two other large pipeline companies. More transactions have followed, including the 2004 sale of significant assets by a major crude line also listed on the table, making comparisons with previous years' data difficult.

Investment by the five product pipeline companies in 2006 was more than $5.5 billion and continued a return to growth that started in 2003 when investment of more than $4.7 billion was up from 2002's $4.5 billion level.

Fig. 2 illustrates the investment split in the crude oil and products pipeline companies.

Construction stays strong

Applications to FERC by regulated interstate natural gas pipeline companies to modify certain systems must, except in certain instances, provide estimated costs of these modifications in varying degrees of details.

Tracking the mileage and compression horsepower applied for and the

US COMPRESSOR-STATION COSTS: ESTIMATED VS. ACTUAL, 2006-07[1]

Table 8

Location		Size, hp	Cost, $ Materials	Labor	Misc.[2]	Land	Total	$/hp
Colorado		1,650						
	Estimated		5,619,600	2,997,000	2,801,200	—	11,417,800	6,920
	Actual		5,567,392	2,712,455	2,058,878	—	10,338,725	6,266
Wisconsin		2,370						
	Estimated		3,182,000	1,619,000	2,014,000	14,000	6,829,000	2,881
	Actual		3,419,084	2,520,923	1,858,118	12,736	7,810,861	3,296
Wyoming		2,370						
	Estimated		3,790,100	2,515,400	2,714,700	75,000	9,095,200	3,838
	Actual		3,409,977	1,942,315	1,275,646	35,800	6,663,738	2,812
New Jersey[3]		2,400						
	Estimated		3,462,297	95,096	1,318,607	—	4,876,000	2,032
	Actual		2,794,096	1,852,951	1,169,863	6,948	5,823,858	2,427
Texas[3]		5,325						
	Estimated		5,016,714	2,221,561	3,172,827	—	10,411,102	1,955
	Actual		4,570,501	3,573,826	1,943,003	922	10,088,252	1,895
Louisiana[3]		5,488						
	Estimated		5,164,700	2,745,500	2,538,900	—	10,449,100	1,904
	Actual		5,030,135	2,844,776	1,789,953	2,884	9,667,748	1,762
Oklahoma[3]		5,920						
	Estimated		5,584,020	2,077,244	3,003,885	—	10,665,149	1,802
	Actual		5,541,778	3,462,495	2,244,848	922	11,250,043	1,900
Wisconsin		6,000						
	Estimated		5,392,320	4,098,110	3,958,430	70,450	13,519,310	2,253
	Actual		5,225,795	3,741,824	2,294,935	79,865	11,342,419	1,890
Texas		7,000						
	Estimated		4,143,846	2,341,055	3,762,989	—	10,247,890	1,464
	Actual		5,059,200	3,318,148	1,856,136	—	10,233,484	1,462
Louisiana[3]		10,310						
	Estimated		8,189,300	3,649,840	4,691,200	—	16,530,340	1,603
	Actual		7,863,554	6,709,497	3,646,284	—	18,219,335	1,767
Washington[3]		10,760						
	Estimated		14,719,000	6,740,000	3,310,000	—	24,769,000	2,302
	Actual		13,161,000	18,896,000	2,482,000	1,024,000	35,563,000	3,305
Illinois		16,000						
	Estimated		10,846,000	5,402,000	4,408,000	1,000	20,657,000	1,291
	Actual		11,652,000	6,620,000	2,969,000	3,000	21,244,000	1,328
Wisconsin		20,600						
	Estimated		14,643,000	4,928,000	6,173,000	184,000	25,928,000	1,259
	Actual		15,794,267	6,864,066	4,987,673	220,065	27,866,071	1,353
Total		**96,193**						
	Estimated		**$89,752,897**	**$41,429,806**	**$43,867,738**	**$344,450**	**$175,394,891**	**$1,823**
	Actual		**$89,088,779**	**$65,059,276**	**$30,576,337**	**$1,387,142**	**$186,111,534**	**$1,935**

[1]Actual cost data must be filed within 6 months following commissioning of installed compression equipment. Not all projects proposed (estimated costs) are built (actual costs). [2]Generally includes surveys, engr., supervision, interest, administration and overheads, contingencies, allowances for funds used during construction (afudc), and FERC fees. [3]Addition.
Source: US FERC; for completed-project costs filed between July 1, 2006, and June 30, 2007, under CFR Section 157.20(c)(4)

estimated costs can indicate levels of construction activity over 2-4 years. OGJ has been doing that since this report began almost 50 years ago.

Tables 4 and 5 show companies' estimates during the period July 1, 2006, to June 30, 2007, for what it will cost to construct a pipeline or install new or additional compression.

These tables cover a variety of locations, pipeline sizes, and compressor-horsepower ratings.

Not all projects that are proposed are approved. And not all projects that are approved are eventually built.

Applications filled in the 12 months ending June 30, 2007, remained strong following a marked rebound in the construction of future gas pipelines along the US interstate system in 2005 and similar levels in 2006:

- More than 2,000 miles of pipeline were proposed for land construction, and 17.7 miles for offshore work. The land level is up from both the more than 1,450 miles proposed in 2006 and the 1,700 miles proposed in 2005. The offshore proposals were up from the 6.23 miles proposed in 2006, but still well below the 2005 total of 92 miles.
- New or additional compression proposed by the end of June 2007 reached more than 713,000 hp, continuing the upward momentum seen in 2006 when proposed horsepower more than tripled, reaching in excess of 583,000 hp from the nearly 175,000 hp envisioned by the pipelines in 2005 (Table 5).

Putting the continued rebound in US gas pipeline construction in some perspective, Table 4 lists 25 land-pipeline construction "spreads," or mileage segments, and 1 marine project, compared with:

- 42 land and 1 marine project (OGJ, Sept. 11, 2006, p. 46).
- 56 land and 4 marine projects (OGJ, Sept. 12, 2005, p. 50).
- 15 land and 0 marine projects (OGJ, Aug. 23, 2004, p. 60).
- 37 land and 3 marine projects (OGJ, Sept. 8, 2003, p. 60).
- 83 land and 3 marine projects (OGJ, Sept. 16, 2002, p. 52).
- 49 land and 2 marine projects (OGJ, Sept. 3, 2001, p. 66).
- 115 land and 6 marine projects (OGJ, Sept. 4, 2000, p. 68).

Further, of the 25 land pipeline projects applied for, 22 are for new pipeline as opposed to looping or replacement mileage. And of these 22, 12 are for pipeline of 50 miles or more in length, with 8 of these being for projects over 100 miles long (and 7 of the 8 of 42-in. OD).

For the 12 months ending June 30, 2007, the 25 land projects would cost more than $5.6 billion, more than twice the estimated cost of the 42 projects proposed in 2006.

The number and nature of these filings, pending actual progress on the projects themselves, continue progress in addressing the infrastructural needs associated with anticipated US natural gas demand growth.

Projects' cost projections indicate much about where companies believe unit construction costs ($/mile) are headed. It is telling that the number and scale of projects remain strong despite high costs.

For proposed US gas pipeline projects 2006-07, the average land cost was $2.775 million/mile; in 2005-06, the average land cost was $1.92 million/mile; for 2004-05 the average land cost was $2.2 million/mile; for 2003-04 the average land cost was $1.7 million/mile; and for the 2002-03 period the average land cost was $1.28 million/mile.

Offshore costs per mile continued to slip. Projects proposed in 2006-07 cost $3.17 million/mile. Projects proposed in 2005-06 cost $3.5 million/mile. No offshore projects applied for in 2003-04. Those proposed in 2004-05 cost $6.07 million/mile, more than double the 2002-03 figure of $3 million.

Cost components

Variations over time in the four major categories of pipeline construction costs—material, labor, miscellaneous, and right-of-way (ROW)—can also suggest trends within each group.

Materials can include line pipe, pipe coating, and cathodic protection.

"Miscellaneous" costs generally cover surveying, engineering, supervision, contingencies, telecommunications equipment, freight, taxes, allowances for funds used during construction (AFUDC), administration and overheads, and regulatory filing fees.

ROW costs include obtaining rights-of-way and allowing for damages.

For the 25 land spreads filed for in 2006-07, costs-per-mile projections for the four categories all showed increases, with material and labor showing particularly sharp jumps, rebounding from the declines seen the previous year:

- Material—$1,011,471/mile, up from $728.189/mile for 2005-06.
- Labor—$1,052,658/mile, up from $621,917/mile for 2005-06.
- Miscellaneous—$595,552/mile, up from $476,692/mile for 2005-06.
- ROW and damages—$115,659/mile, up from $92,714/mile for 2005-06.

Table 4 lists proposed pipeline in order or increasing size (OD) and increasing lengths within each size.

The average cost-per-mile for the projects rarely shows clear-cut trends related to either length or geographic area. In general, however, the cost-per-mile within a given diameter indicates that the longer the pipeline, the lower the unit (per-mile) cost for construction. And, lines built nearer populated areas tend to have higher unit costs.

Additionally, road, highway, river, or channel crossings and marshy or rocky terrain each strongly effects pipeline construction costs.

Fig. 3, derived from Table 4, shows the major cost-component splits for land and offshore pipeline construction costs.

Material and labor's combined portion of the cost for constructing land and offshore pipelines rose to nearly 75% of the cost. Labor rose most rapidly, passing material to return to the single largest portion of land construction costs. Labor's portion of estimated costs for land pipelines moved to 37.93% in 2007 from 32.35% in 2006. Material costs for land pipelines also continued to rise, but slipped as a percentage of total costs in 2007 to 36.44% from 38.17% in 2006.

Fig. 4 plots a 10-year comparison of land-construction unit costs for the two major components, material and labor.

Fig. 5 shows the cost split for land compressor stations based on data in Table 5.

Table 6 lists 10 years of unit land-construction costs for natural gas pipeline with diameters ranging from 8 to 36 in. The table's data consist of estimated costs filed under CP dockets with FERC, the same data shown in Tables 4 and 5.

Table 6 shows that the average cost per mile for any given diameter may fluctuate year to year as projects' costs are affected by geographic location, terrain, population density, or other factors.

Completed projects' costs

In most instances, a natural gas pipeline company must file with FERC what it has actually spent on an approved and built project. This filing must occur within 6 months after the pipeline's successful hydrostatic testing or the compressor's being put in service.

Fig. 6 shows 10 years of estimated vs. actual costs on cost-per-mile bases for project totals.

Tables 7 and 8 show such actual costs for pipeline and compressor projects reported to FERC during the 12 months

ending June 30, 2007. Fig. 7, for the same period, depicts how total actual costs ($/mile) for each category compare with estimated costs.

Per-mile pipeline construction costs for completed projects jumped by more than 86%, led by higher than estimated labor costs. It cost roughly the same amount to build a total of 317.84 miles of pipeline in the 12 months ending June 30, 2007, as it did to build 594 miles of pipeline in the year-earlier period. Material costs were lower, in line with the smaller mileage constructed, with both miscellaneous and ROW categories relatively flat.

Actual costs were only 1.2% higher than projected costs for the 12 months ending June 30, 2007, as some increase in the price of labor had been anticipated, just not the amount that occurred.

Some of these projects may have been proposed and even approved much earlier than the 1-year survey period. Others may have been filed for, approved, and built during the survey period. If a project was reported in construction spreads in its initial filing, that's how it is broken out in Table 4. Completed projects' cost data, however, are usually reported to FERC for an entire filing, usually but not always separating pipeline from compressor-station (or metering site) costs and lumping several diameters together.

The 12 months ending June 30 saw more than 96,000 hp of new or additional compression completed, continuing recent declines that saw nearly 106,000 hp completed in 2006, and 153,000 hp of new or additional compression were reported in 2005 vs. 468,000 hp in 2004.

More than a fifth of the 2006-07 horsepower was from a single project.

Overall, actual land gas pipeline construction costs came in less than $40,000/mile above estimated costs. Table 8 shows a similar trend between installed and estimated compression costs, with actual costs higher than estimated and the largest discrepancy seen in labor costs ($431/hp estimated vs. $676/hp actual). ✦

Oil pipelines

Company	Miles of pipeline: Gathering	Trunk: Crude	Trunk: Products	Trunk: Total	Deliveries, 1,000 bbl: Crude	Deliveries, 1,000 bbl: Products	Deliveries, 1,000 bbl: Total	Total trunkline traffic, million bbl-miles: Crude	Total trunkline traffic, million bbl-miles: Products	Total trunkline traffic, million bbl-miles: Total	Fiscal data, $1,000: Carrier property	Fiscal data, $1,000: Property change	Fiscal data, $1,000: Operating revenue	Fiscal data, $1,000: Income
Alon Petroleum Pipe Line Co. (final)	—	527	—	527	—	—	—	—	—	—	—	—	—	32,771
Alpine Transportation Co.	—	—	—	—	44,269	—	44,269	1,521	—	1,521	107,181	1,736	30,483	14,661
Amoco Capline Pipeline Co.	—	667	—	667	29,991	—	29,991	18,513	—	18,513	26,786	—	19,576	8,402
Apache GOM Pipeline Inc.	NR	NR	NR	—	NR	NR	—	NR	NR	—	NR	NR	NR	NR
Baton Rouge Pipeline LLC	30	—	—	30	—	17,472	17,472	—	524	524	14,900	—	1,834	507
Belle Fourche Pipeline Co.	595	161	80	836	22,321	802	23,123	—	—	—	37,451	–918	8,571	2,505
Belle Rose NGL Pipeline LLC	—	—	48	48	—	3,984	3,984	—	187	187	29,835	947	920	–582
Bengal Pipeline Co. (new)	—	—	158	158	—	117,435	117,435	—	6,686	6,686	152,936	152,936	24,516	15,746
Black Lake Pipeline Co.	—	—	312	312	-	4,134	4,134	—	920	920	32,093	1,360	3,876	–453
Blue Dolphin Pipe Line Co.	—	NR	—	—	NR	—	—	—	—	—	NR	NR	NR	NR
BP Oil Pipeline Co.	—	311	—	311	50,728	—	50,728	10,936	—	10,936	16,041	–20,340	16,591	87,547
BP Pipelines (Alaska) Inc.*	—	2,065	—	2,065	93,295	—	93,295	74,311	—	74,311	NR	NR	363,520	3,090
BP Pipelines North America Inc.	1,473	3,600	1,271	6,344	175,325	57,248	232,573	56,971	4,176	61,147	582,132	–33,040	147,755	251,936
BP Transportation (Alaska) Inc.	—	42	—	42	19,356	—	19,356	335	—	335	144,428	—	27,670	16,743
Bridger Pipeline LLC	263	271	—	534	14,548	—	14,548	NR	—	—	35,126	965	8,396	3,520
Buckeye NGL Pipe Lines LLC (new)	71	—	369		—	7,211	7,211	—	2,647	2,647	86,835	86,835	10,821	2,821
Buckeye Pipe Line Co. LP	—	—	2,649	2,649	34,841	296,379	331,220	—	39,651	39,651	671,015	31,973	216,567	65,007
Buckeye Pipe Line Transportation LLC	—	—	571	571	—	27,370	27,370	—	3,843	3,843	155,574	1,792	16,863	2,889
Burlington Resources Trading Inc.	—	NR	—	—	NR	—	—	NR	—	—	1,104	NR	NR	NR
Butte Pipe Line Co.	—	373	—	373	30,368	—	30,368	8,693	—	8,693	25,038	436	15,985	6,285
Calnev Pipe Line Co.	—	—	558	558	—	49,804	49,804	—	11,047	11,047	287,767	6,918	55,965	34,529
CCPS Transportation LLC	—	658	—	658	24,953	—	24,953	16,206	—	16,206	191,017	5,094	34,143	9,807
Cenex Pipeline LLC	—	—	703	703	—	15,522	15,522	—	4,157	4,157	64,818	99	21,421	10,989
Centennial Pipeline LLC	—	—	797	797	—	29,342	29,342	—	21,895	21,895	299,684	2,273	38,323	–13,874
Centurion Pipeline LP	814	863	—	1,677	48,886	—	48,886	2,483	—	2,483	174,935	16,835	33,473	6,935
Chaparral Pipeline Co. LP	—	—	845	845	—	47,023	47,023	—	18,321	18,321	116,546	724	29,102	8,090
Chevron Pipe Line Co.	157	1,932	1,476	3,565	178,935	56,011	234,946	8,270	9,351	17,621	640,609	70,128	142,690	–67,408
Chicap Pipe Line Co.	—	234	—	234	53,953	—	53,953	10,609	—	10,609	55,658	2,964	11,301	2,216
Chisholm Pipeline Co.	—	—	185	185	—	7,086	7,086	—	1,308	1,308	21,091	109	3,042	514
Chunchula Pipeline Co. LLC	—	—	144	144	—	1,341	1,341	—	193	193	17,983	550	1,538	-717
Citgo Pipeline Co.	5	137	—	142	138,542	6,773	145,315	1,927	7	1,934	32,715	429	15,510	4,979
Citgo Products Pipeline Co.	—	—	1,017	1,017	—	36,989	36,989	—	7,409	7,409	64,112	187	27,224	5,267
Clear Fork Pipeline Co.	—	—	—	—	NR	—	—	—	—	—	—	—	—	—
Cochin Pipeline System (US Dome Pipeline Corp., oper.)	—	—	NR	—	—	7,095	7,095	—	12,867	12,867	327,466	—	27,380	27,287
Coffeyville Resources Crude Transportation LLC.	102	334	—	436	—	—	—	823	—	823	13,157	166	7,760	-418
Collins Pipeline Co.	—	—	124	124	—	47,061	47,061	—	5,860	5,860	20,937	–144	10,072	1,673
Colonial Pipeline Co.	—	—	5,589	5,589	—	863,719	863,719	—	706,277	706,277	2,290,977	30,872	764,100	193,013
Conoco Offshore Pipe Line Co.	184	—	—	184	4,521	—	4,521	461	—	461	—	—	2,706	1,605
ConocoPhillips Pipe Line Co.	1,046	2,646	3,660	7,352	300,063	235,496	535,559	26,177	39,400	65,577	968,900	36,650	266,822	75,473
ConocoPhillips Transportation Alaska Inc.*	—	818	—	818	106,534	—	106,534	83,528	—	83,528	3,100,592	–31,158	371,087	25,028
Cook Inlet Pipe Line Co.	—	53	—	53	4,907	—	4,907	126	—	126	73,101	716	21,524	6,166
Cypress Pipe Line Co. LLC.	—	57	—	57	10,997	—	10,997	627	—	627	11,636	416	5,952	1,989
Devon Energy Offshore Pipeline Co.	—	NR	—	—	NR	—	—	NR	—	—	NR	—	—	NR
Devon Energy Petroleum Pipeline Co.	—	NR	—	—	NR	—	—	NR	—	—	NR	—	NR	NR
Dixie Pipeline Co.	—	—	1,404	1,404	—	35,348	35,348	—	18,446	18,446	132,373	8,269	52,243	16,008
Dome Pipeline Corp.	—	—	NR	—	—	6,128	6,128	—	—	—	28,073	—	3,718	3,718
DryTrails Midstream Energy LLC (new) + A26.	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Ellwood Pipeline Inc.	11	26	—	37	3,379	—	3,379	—	—	—	1,256	–158	4,648	4,364
Enbridge Energy LP	—	3,340	—	3,340	538,528	—	538,528	399,814	—	399,814	2,152,427	196,429	421,738	113,526
Enbridge Pipelines (North Dakota) LLC	307	623	—	930	31,236	—	31,236	11,796	—	11,796	87,545	15,380	31,120	11,230
Enbridge Pipelines (Ozark) LLC	—	480	—	480	89,007	—	89,007	30,723	—	30,723	148,501	13,797	39,895	23,673
Enbridge Pipelines (Toledo) Inc.	—	98	—	98	28,234	—	28,234	2,356	—	2,356	54,472	1,501	15,569	1,694
Endicott Pipeline Co.	—	26	—	26	8,843	—	8,843	183	—	183	57,738	—	3,238	–1,583
Energy Development Corp. (HIPS) Inc. (new)	NR	NR	NR	—	NR	NR	—	NR	NR	—	NR	NR	NR	NR
Enterprise Lou-Tex NGL Pipeline LP	—	—	204	204	—	11,165	11,165	—	2,278	2,278	94,970	2,379	15,361	7,225
Explorer Pipeline Co.	—	—	1,411	1,411	—	202,803	202,803	—	148,518	148,518	483,461	18,433	247,236	65,412
Express Pipeline LLC.	—	513	—	513	82,752	—	82,752	39,847	—	39,847	404,337	1,793	80,572	25,575
ExxonMobil Pipeline Co.*	605	1,051	2,901	4,557	403,916	319,142	723,058	68,753	9,298	78,051	572,545	–7,440	386,628	258,260
Frontier Pipeline Co.	—	290	—	290	16,726	—	16,726	4,851	—	4,851	65,986	4,524	11,253	5,719
Genesis Pipeline USA LP	131	228	—	359	11,053	—	11,053	650	—	650	52,453	782	16,473	4,838
Heartland Pipeline Co.	—	—	36	36	—	8,226	8,226	—	2,674	2,674	12,040	47	6,771	3,714
Holly Energy Partners-Operating LP	—	—	1,481	1,481	—	44,593	44,593	—	9,628	9,628	31,017	5,463	29,204	38,140
Inland Corp.	—	—	616	616	—	50,673	50,673	—	3,501	3,501	34,213	658	22,618	6,250
Interstate Storage & Pipe Line Corp.	—	—	—	—	—	—	—	—	—	—	5,023	—	2,270	272
IMTT-Pipeline	—	—	10	10	—	21,346	21,346	—	154	154	21,158	34	1,374	–1,691

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Oil pipelines (continued)

Company	Miles of pipeline: Gathering	Trunk: Crude	Trunk: Products	Trunk: Total	Deliveries, 1,000 bbl: Crude	Deliveries, 1,000 bbl: Products	Deliveries, 1,000 bbl: Total	Total trunkline traffic, million bbl-miles: Crude	Total trunkline traffic, million bbl-miles: Products	Total trunkline traffic, million bbl-miles: Total	Fiscal data, $1,000: Carrier property	Fiscal data, $1,000: Property change	Fiscal data, $1,000: Operating revenue	Fiscal data, $1,000: Income
Jayhawk Pipeline LLC	4	724	—	728	34,369	—	34,369	2,896	—	2,896	58,129	3,337	18,524	3,237
Kaneb Pipe Line Operating Partnership LP	—	—	2,329	2,329	—	67,574	67,574	—	18,585	18,585	530,410	8,936	89,374	76,317
Kenai Pipe Line Co.	—	—	23	23	12,628	11,937	24,565	290	275	565	28,538	4,213	8,492	103
Keystone Pipeline Co. LLC	—	—	—	—	2,930	—	2,930	680	—	680	—	—	2,820	39
Kiantone Pipeline Corp.	—	78	—	78	23,847	—	23,847	—	—	—	11,492	44	5,008	1,156
Kinder Morgan Operating LP "A"	—	—	1,734	1,734	—	29,143	29,143	—	9,357	9,357	231,219	10,155	43,451	463,747
Kinder Morgan Wink Pipeline LP	9	425	—	434	42,405	NR	42,405	10,411	—	10,411	89,692	1,016	28,584	16,646
Koch Alaska Pipeline Co. LLC*	—	819	—	819	11,574	—	11,574	5,903	—	5,903	324,662	—	18,990	–6,544
Koch Pipeline Co. LP	—	591	11	602	18,584	1,526	20,110	10,452	16,569	27,021	190,596	1,411	31,315	28,130
Kuparuk Transportation Co.	—	—	—	—	119,627	—	119,627	3,922	—	3,922	136,805	346	23,923	9,748
Laclede Pipeline Co.	—	—	40	40	—	2,035	2,035	—	44,955	44,955	6,043	507	1,013	245
LOCAP LLC	—	114	—	114	367,674	—	367,674	20,982	—	20,982	149,460	1,178	29,378	8,945
Longhorn Partners Pipeline LP	—	—	761	761	—	7,663	7,663	—	4,818	4,818	503,190	7,249	21,573	11,412
Magellan Pipeline Co. LP	—	—	8,583	8,583	—	311,118	311,118	—	82,308	82,308	1,442,695	58,862	366,595	151,967
Marathon Offshore Pipeline LLC	—	296	—	296	7,675	—	7,675	604	—	604	30,134	6	7,365	2,999
Marathon Pipe Line LLC	—	1,813	1,272	3,085	457,156	264,568	721,724	152,117	23,282	175,399	550,052	30,025	313,517	164,293
MarkWest Michigan Pipeline Co. LLC	85	152	—	237	—	—	—	—	—	—	22,134	661	4,899	25
Mars Oil Pipeline Co.	—	121	—	121	NR	—	—	NR	—	—	147,471	980	94,007	43,487
Mid-America Pipeline Co. LLC	2,252	—	5,195	7,447	—	252,894	252,894	—	84,447	84,447	1,107,255	246,440	229,397	61,151
Mid-Valley Pipeline Co.	—	1,087	—	1,087	109,899	—	109,899	68,384	—	68,384	97,699	3,658	54,424	12,936
Milne Point Pipeline LLC	—	11	10	21	13,291	—	13,291	146	—	146	51,293	—	7,974	–227
Minnesota Pipe Line Co.	—	675	—	675	100,884	—	100,884	25,826	—	25,826	149,758	19,710	43,822	17,659
Mobil Eugene Island Pipeline Co.	—	NR	—	—	3,488	—	3,488	318	—	318	21,005	6,599	5,844	–1,835
Mobil Pipe Line Co.	94	999	689	1,782	126,792	77,797	204,589	11,885	7,279	19,164	178,398	9,621	46,962	28,254
MOEM Pipeline LLC	—	56	—	56	25,858	—	25,858	1,460	—	1,460	16,966	535	6,623	2,786
Muskegon Pipeline LLC	—	—	170	170	—	10,388	10,388	—	2,141	2,141	28,050	50	6,300	2,351
Mustang Pipe Line LLC	—	211	—	211	33,452	—	33,452	6,471	—	6,471	58,509	406	23,780	13,753
Navajo Pipeline Co.	—	—	826	826	28,641	—	28,641	516	—	516	18,389	5,072	6,445	4,469
NORCO Pipe Line Co. LLC	—	—	423	423	—	14,795	14,795	—	1,334	1,334	71,788	6,603	8,963	–1,230
Nova Chemicals Inc.	—	—	—	—	—	—	—	—	—	—	—	—	—	—
NW Pipeline Inc.	NR	NR	NR	—	—	—	—	123	—	123	6,358	1	964	364
Ohio Oil Gathering Corp. II	137	—	—	137	1,551	—	1,551	—	—	—	10,097	640	4,233	–585
Ohio River Pipe Line LLC	—	—	549	549	—	29,712	29,712	—	3,500	3,500	190,064	1,231	37,522	19,586
Olympic Pipe Line Co.	—	—	408	408	—	104,885	104,885	—	18,319	18,319	207,111	9,392	66,443	11,305
ONEOK NGL Pipeline LP (formerly part of Koch Pipeline Co. LP)	—	—	2,415	2,415	—	95,042	95,042	—	27,492	27,492	441,387	13,245	66,492	25,439
Osage Pipe Line Co. LLC	—	135	—	135	45,035	—	45,035	6,080	—	6,080	19,929	32	12,032	7,970
Phillips Texas Pipeline Co. Ltd.	492	612	216	1,320	62,320	103,524	165,844	11,336	8,392	19,728	195,731	11,734	95,743	63,186
Pioneer Natural Resources USA Inc.	—	—	NR	—	—	NR	—	—	NR	—	NR	NR	NR	NR
Pioneer Pipe Line Co.	—	—	346	346	—	27,045	27,045	—	5,894	5,894	89,875	1,293	26,344	9,262
Plains Pipeline LP	2,047	6,084	256	8,387	478,998	5,796	484,794	83,935	639	84,574	936,264	219,097	249,606	86,824
Plantation Pipe Line Co.	—	—	3,128	3,128		202,598	202,598	—	118,914	118,914	515,548	9,233	173,774	15,411
Platte Pipe Line Co.	—	936	—	936	80,015	—	80,015	46,191	—	46,191	246,332	2,292	57,763	5,565
Point Arguello Pipeline Co.	—	28	—	28	3,354	—	3,354	—	—	—	287,797	1,327	7,155	–6,021
Point Arguello Terminal Co.	—	—	—	—	—	—	—	—	—	—	—	—	—	-595
Pogo Offshore Pipeline Co.	—	—	—	—	—	—	—	—	—	—	—	—	—	—
Portland Pipe Line Corp.	37	332	—	369	136,441	—	136,441	22,649	—	22,649	97,131	8,309	65,942	13,996
Premcor Pipeline Co. (Valero Energy Corp., oper.)	—	124	128	252	72,705	83,798	156,503	2,031	801	2,832	46,813	5,163	26,397	–12,065
Razorback LLC (new)	67	—	—	67	—	—	—	—	5	5	15,715	—	2,547	3,640
Red Butte Pipe Line Co.	67	736	—	803	15,173	—	15,173	1,454	—	1,454	17,586	660	13,411	1,374
Regency Liquids Pipeline LLC	—	—	40	40	—	—	—	—	50	50	5,528	9	918	78
Rio Grande Pipeline Co. (Holly Energy Partners - Operating LP, oper.)	—	—	223	223	—	5,512	5,512	—	1,232	1,232	44,795	219	8,400	2,267
Rocky Mountain Pipeline System LLC	328	1,698	545	2,571	62,715	30,601	93,316	12,196	2,302	14,498	343,327	42,458	68,668	19,200
Salmon Resources Ltd.	—	NR	—	—	NR	—	—	—	—	—	NR	—	NR	NR
Sanders Pipeline Co.	—	—	9	9	—	3,117	3,117	—	—	—	1,934	—	2,437	4
San Pedro Bay Pipeline Co.	—	18	—	18	832	—	832	15	—	15	10,438	112	863	209
Seaway Crude Pipeline Co.	—	NR	—	—	176,935	—	176,935	46,353	—	46,353	299,446	4,513	64,575	34,250
Seaway Products Pipeline Co.	—	—	520	520	—	3,588	3,588	—	1,887	1,887	68,694	228	1,996	-7,860
Seminole Pipeline Co.	97	—	1,229	1,326	—	100,377	100,377	—	54,076	54,076	400,108	10,935	80,665	14,021
SemPipe LP	—	—	—	—	NR	—	—	NR	—	—	NR	NR	NR	NR
SFPP LP	—	—	2,605	2,605	—	429,985	429,985	—	66,971	66,971	1,731,392	121,448	266,614	144,725
Shamrock Pipe Line Corp.	198	25	—	223	9,609	—	9,609	—	—	—	3,222	74	1,807	29,225
Shell Pipeline Co. LP	10	1,600	414	2,024	554,407	196,817	751,224	34,066	2,868	36,934	561,950	–64,547	248,316	256,693
Ship Shoal Pipeline Co.	—	121	—	121	96,276	—	96,276	4,282	—	4,282	42,403	101	17,437	11,033
Sinclair Pipeline Co. LLC	—	—	491	491	—	9,872	9,872	—	—	—	3,701	—	6,149	1,613

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Oil pipelines (continued)

Company	Miles of pipeline — Gathering	Trunk — Crude	Trunk — Products	Trunk — Total	Deliveries, 1,000 bbl — Crude	Deliveries, 1,000 bbl — Products	Deliveries, 1,000 bbl — Total	Total trunkline traffic, million bbl-miles — Crude	Total trunkline traffic, million bbl-miles — Products	Total trunkline traffic, million bbl-miles — Total	Fiscal data, $1,000 — Carrier property	Fiscal data, $1,000 — Property change	Fiscal data, $1,000 — Operating revenue	Fiscal data, $1,000 — Income
Skelly-Belvieu Pipeline Co. LLC	—	—	571	571	—	7,852	7,852	—	4,491	4,491	68,117	1,101	9,282	1,596
Sorrento Pipeline Co LLC	—	—	220	220	—	15,303	15,303	—	442	442	114,709	3,851	10,107	6,622
Southcap Pipe Line Co.	—	638	—	638	42,495	—	42,495	20,718	—	20,718	NR	NR	25,187	8,273
SouthTex 66 Pipeline Co. Ltd.	—	—	738	738	—	77,229	77,229	—	14,282	14,282	166,081	1,307	71,403	47,353
St. Louis Pipeline Corp.	—	—	22	22	—	—	—	—	NR	—	4,327	—	—	—
Suburban Pipeline LLC.	—	—	62	62	—	50	50	—	NR	—	4,073	—	641	–539
Suncor Energy (USA) Pipeline Co.	—	313	—	313	31,719	—	31,719	4,225	—	4,225	22,939	5,626	19,270	6,940
Sunoco Pipeline LP	—	123	1,680	1,803	225,666	216,823	442,489	21,335	17,449	38,784	868,591	192,927	180,986	60,742
Targa NGL Pipeline Co. LLC	—	—	155	155	—	—	—	—	1,062	1,062	28,932	60	5,534	1,201
TE Products Pipeline Co. LP	—	—	4,676	4,676	—	97,376	97,376	—	117,772	117,772	1,085,105	94,655	267,029	49,339
TEPPCO Crude Pipeline LP	—	3,967	—	3,967	139,288	—	139,288	8,242	—	8,242	209,451	56,062	31,335	20,736
Terasen Pipelines (Puget Sound) Corp.	—	64	—	64	33,996	—	33,996	1,098	—	1,098	16,951	792	10,199	5,221
Tesoro High Plains Pipeline Co.	228	547	—	775	19,943	—	19,943	4,449	—	4,449	93,228	773	20,238	3,333
Total Petrochemicals Pipeline USA Inc.	—	14	—	—	NR	NR	—	NR	NR	—	361	—	1,677	1,195
Tri-States NGL Pipeline LLC	—	—	165	165	—	22,070	22,070	—	3,328	3,328	89,331	236	15,975	7,154
Unocal Pipeline Co.*	93	1,179	—	1,272	6,594	—	6,594	3,594	—	3,594	19,309	55	14,117	–25,922
Valero Logistics Operations LP	36	404	2,324	2,764	83,420	82,071	165,491	4,454	15,273	19,727	557,753	37,250	164,104	81,542
Valero Terminaling and Distribution Co.	—	—	113	113	—	1,689	1,689	—	148	148	1,409	199	618	-2,651
West Shore Pipe Line Co.	—	3	649	652	31,947	133,711	165,658	110	13,425	13,535	83,739	2,683	48,988	11,908
WestTex 66 Pipeline Co.	—	—	640	640	—	10,952	10,952	—	3,002	3,002	24,784	1,318	6,019	22,130
West Texas Gulf Pipe Line Co.	—	579	—	579	113,170	—	113,170	32,946	—	32,946	54,867	1,893	23,023	7,825
West Texas LPG Pipeline LP	—	—	2,504	2,504	—	73,551	73,551	—	32,971	32,971	134,056	8,989	49,772	11,323
Whiting Oil & Gas Corp. (new)	66	13	—	79	1,354	—	1,354	1,768	—	1,768	5,306	5,306	1,004	89,665
WILPRISE Pipeline Co. LLC	—	—	30	30	—	14,752	14,752	—	442	442	24,468	55	3,567	2,261
Wolverine Pipe Line Co.	—	—	742	742	—	110,635	110,635	—	12,527	12,527	151,416	–1,953	52,532	8,873
Wood River Pipe Lines LLC	—	—	915	915	—	79,654	79,654	—	13,789	13,789	371,730	11,681	39,975	13,344
Yellowstone Pipe Line Co.	—	—	690	690	—	38,369	38,369	—	7,487	7,487	60,721	1,520	22,398	4,636
2006 total	**12,141**	**47,617**	**81,103**	**140,407**	**6,667,739**	**6,100,515**	**12,768,254**	**1,578,403**	**1,957,805**	**3,536,208**	**$32,686,026**	**$1,883,606**	**$8,516,563**	**$3,743,115**
2005 total	13,804	46,234	71,310	131,348	6,675,445	6,056,820	12,732,265	1,570,684	1,914,270	3,484,954	$29,525,611	$1,531,103	$7,917,176	$3,076,476

*Crude and total mileages represent 818 miles of Trans-Alaska Pipeline, operated by Alyeska Pipeline Service Co., Anchorage. This figure is included in column total only once to avoid duplication. NR = not reported.
Source: US FERC Form No. 6: Annual Report of Oil Pipelines, Dec. 31, 2006

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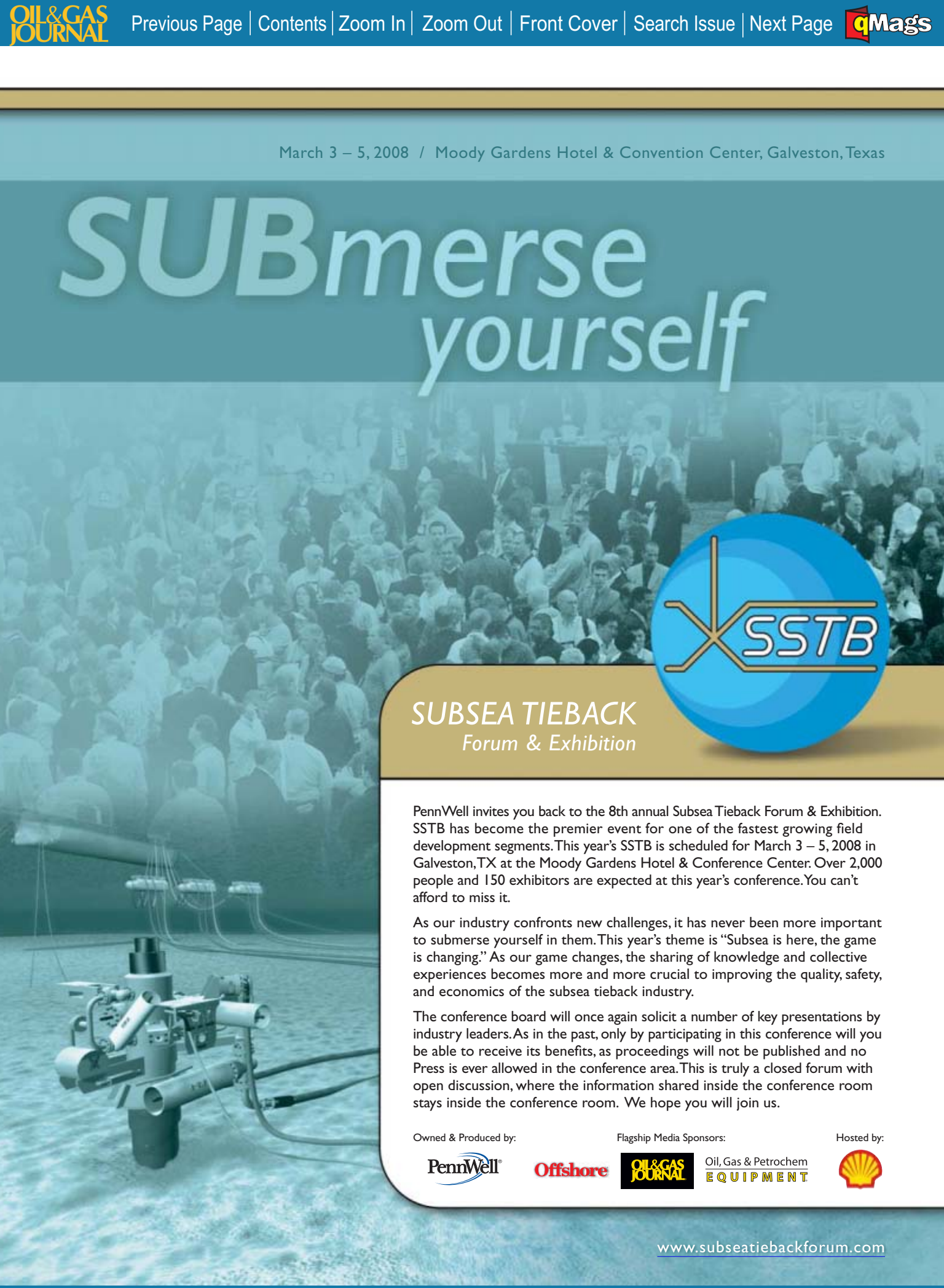

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GAS PIPELINES

Company	Transmission system, miles	Total compression stations — Transmission	Other	Total	Volumes trans. for others, MMcf	Fiscal data, $1,000 — Gas plant	Additions	Operating & maintenance expenses	Operating revenue	Net income
Algonquin Gas Transmission LLC*	1,103	6	—	6	330,163	1,241,998	12,677	51,674	160,910	30,776
Alliance Pipeline LP*	886	7	—	7	634,451	1,851,556	13,469	38,936	286,163	85,257
ANR Pipeline Co.*	9,600	47	24	71	2,057,960	3,594,304	178,165	225,169	539,615	126,767
ANR Storage Co.*	24	—	3	3	—	140,877	1,759	4,494	26,221	24,165
Auxier Road Gas Co. Inc.*	—	—	—	0	—	1,224	18	1,348	1,531	65
Bear Creek Storage Co.*	—	—	1	1	—	160,567	1,543	5,340	39,093	18,341
Black Marlin Pipeline Co.	67	—	—	0	4,163	26,444	11	2,024	444	–2,386
Blue Lake Gas Storage Co.	—	—	1	1	—	103,088	77	3,922	23,472	7,731
Canyon Creek Compression Co.	—	1	—	1	15,226	23,046	109	1,906	2,876	157
Carolina Gas Transmission Corp.*	1,485	3	—	3	19,790	269,620	1,317	3,601	7,982	950
CenterPoint Energy Gas Transmissiion Co.*	6,170	52	3	55	657,514	1,331,720	59,121	117,015	310,919	88,182
CenterPoint Energy Mississippi River Transmission Corp.*	1,644	13	2	15	335,478	534,664	10,120	58,889	89,780	6,316
Centra Pipelines Minnesota Inc.	66	—	—	0	12,503	4,754	5	853	895	–136
Central Kentucky Transmission (new)	29	—	—	0	2,566	742	742	43	100	24
Chandeleur Pipe Line Co.*	117	—	—	0	40,761	50,941	9,736	3,605	2,795	–1,054
Cheyenne Plains Gas Pipeline Co. LLC*	419	2	—	2	212,890	402,940	23,386	9,511	89,480	26,694
Clear Creek Storage Co. LLC	15	—	2	2	—	20,184	1,176	884	1,068	–441
Colorado Interstate Gas Co.*	3,979	32	6	38	733,070	1,246,949	49,876	121,762	308,589	135,699
Columbia Gas Transmission Corp.*	10,318	71	25	96	1,792,016	3,720,179	168,809	269,460	714,753	187,561
Columbia Gulf Transmission Co.*	4,124	15	—	15	1,041,611	1,376,630	14,702	61,996	123,259	18,336
Crossroads Pipeline Co.	202	1	—	1	38,484	37,602	52	3,020	4,556	–207
Dauphin Island Gathering Partners*	120	—	—	0	—	111,199	—	6,486	10,454	–26,059
Destin Pipeline Co. LLC*	271	2	—	2	338,972	505,234	689	18,488	78,820	21,492
Discovery Gas Transmission LLC*	142	—	—	0	205,578	209,517	945	8,060	18,503	–10,481
Distrigas of Massachusetts LLC*	—	—	—	0	—	292,175	14,041	1,277,767	1,424,015	193,607
Dominion Cove Point LNG LP	90	2	—	2	150,779	381,112	28,458	26,407	81,311	16,636
Dominion South Pipeline Co. LP	—	—	—	0	12,886	2,113	105	70	761	308
Dominion Transmission Inc.*	3,393	59	46	105	585,285	2,858,490	182,723	311,907	797,865	202,114
Duke Energy Kentucky Inc.*	—	—	—	0	4,589	297,891	24,657	114,076	399,881	10,723
East Tennessee Natural Gas LLC*	1,431	22		22	147,370	783,875	108,024	24,184	82,609	20,601
Eastern Shore Natural Gas Co.	308	—	—	0	19,858	116,650	33,810	5,590	18,067	4,432
El Paso Natural Gas Co.*	10,295	56	1	57	1,636,246	3,026,289	158,638	194,530	572,650	151,938
Enbridge Offshore Pipelines (UTOS) LLC*	30	—	—	0	66,464	63,210	876	3,990	2,261	–1,907
Enbridge Pipelines (AlaTenn) LLC	295	2	—	2	14,970	27,950	685	2,871	2,701	–564
Enbridge Pipelines (KPC)	1,121	3	—	3	10,535	79,122	725	8,296	19,561	4,243
Enbridge Pipelines (MidLa) LLC	412	1	—	1	40,467	43,262	1,625	6,955	5,727	–1,706
Energy West Development	46	—	1	1	—	756	7	55	337	127
Equitrans LP*	2,391	4	26	30	53,151	368,129	16,678	29,247	74,475	18,385
Florida Gas Transmission Co. LLC*	4,869	26	1	27	736,739	2,851,398	50,773	107,407	505,575	141,966
Garden Banks Gas Pipeline LLC*	50	—	—	0	134,746	100,468	—	3,639	12,975	1,656
Gas Transmission Northwest Corp.*	1,356	13	—	13	804,834	1,690,025	15,442	68,681	211,993	54,028
Granite State Gas Transmission Inc.	87	—	—	0	26,919	33,684	3,696	17,347	18,672	91
Great Lakes Gas Transmission LP*	2,115	14	—	14	819,100	2,030,742	21,129	34,083	272,257	78,274
Guardian Pipeline LLC*	143	1	—	1	40,557	287,469	1,706	7,016	35,403	5,643
Gulf South Pipeline Co. LP*	6,532	31	—	31	628,268	1,376,607	93,794	109,421	295,016	95,809
Gulf States Transmission Corp.	10	—	—	0	30,625	1,916	25	162	729	345
Gulfstream Natural Gas System LLC*	690	1	—	1	259,540	1,706,923	8,623	15,227	180,249	43,712
Hampshire Gas Co.	18	—	1	1	—	23,202	5,003	1,402	3,569	550
High Island Offshore System LLC*	212	1	—	1	185,878	388,949	1,728	20,613	22,912	302
Honeoye Storage Corp.	11	—	1	1	—	12,202	144	1,614	4,046	1,494
Horizon Pipeline Co. LLC	28	1	—	1	63,649	91,781	59	3,229	12,747	2,194
Iroquois Gas Transmission Systems LP (IPOC agent)*	414	5	—	5	389,396	1,101,379	7,327	26,202	158,684	29,947
Jackson Prairie Underground Storage Project	—	—	—	0	—	57,879	336	1,979	—	–1,979
Jupiter Energy Corp.	—	—	—	0	—	—	—	156	156	–410
Kern River Gas Transmission Co.*	1,680	12	—	12	755,958	2,348,558	16,388	33,093	325,165	144,320
KeySpan LNG LP	—	—	—	0	—	47,190	207	3,117	7,948	2,972
Kinder Morgan Interstate Gas Transmission LLC*	5,138	25	2	27	189,382	697,205	17,428	77,814	183,637	58,993
KO Transmission Co.	92	—	—	0	35,598	16,587	1,789	541	1,641	596
Maritimes & Northeast Pipeline LLC*	341	2	—	2	152,747	871,491	1,001	19,792	107,689	18,361
MarkWest New Mexico LP*	5	NR	NR	0	NR	2,938	652	141	717	265
Midwest Energy Inc.*	53	—	—	0	6,883	56,564	1,788	39,340	147,457	9,290
Midwestern Gas Transmission Co.*	366	7	—	7	164,430	132,279	5,804	9,907	27,599	9,471

GAS PIPELINES (CONTINUED)

Company	Transmission system, miles	Total compression stations — Transmission	Other	Total	Volumes trans. for others, MMcf	Fiscal data, $1,000 — Gas plant	Additions	Operating & maintenance expenses	Operating revenue	Net income
MIGC Inc.	264	10	0	10	44,725	45,607	1,014	3,861	17,233	8,493
Mississippi Canyon Gas Pipeline LLC*	45	—	—	0	158,162	56,862	—	3,177	15,439	5,028
Mojave Pipeline Co.*	362	1	—	1	168,441	246,665	1,373	11,451	41,672	16,097
National Fuel Gas Supply Corp.*	1,502	15	3	18	279,086	759,064	21,458	58,835	173,019	42,801
Natural Gas Pipeline Co. of America*	9,297	49	13	62	1,709,368	3,332,087	130,321	529,598	1,110,942	280,187
Nautilus Pipeline Co. LLC*	101	—	—	0	73,735	120,505	—	2,631	5,739	–2,619
NGO Transmission Inc.	—	—	—	0	9,547	19,595	515	2,035	3,712	–127
Nornew Energy Supply Inc.	26	—	—	0	153	5,167	—	102	678	16
North Baja Pipeline LLC*	80	1	—	1	99,414	156,065	117	3,121	22,127	3,095
Northern Border Pipeline Co.*	1,399	17	—	17	857,761	2,483,887	31,017	50,338	310,900	80,144
Northern Natural Gas Co.*	15,744	82	6	88	949,838	2,926,353	157,901	270,516	645,040	142,371
Northwest Pipeline Corp.*	3,865	43	1	44	675,510	2,600,023	511,800	122,226	323,959	58,813
Oktex Pipeline Co.	109	1	—	1	48,153	7,573	125	439	1,656	571
Ozark Gas Transmission LLC	530	2	—	2	92,811	215,851	1,148	7,920	30,902	18,025
Paiute Pipeline Co.	856	6	—	6	39,825	159,209	2,264	12,038	30,061	6,934
Panhandle Eastern Pipe Line Co. LP*	6,376	24	—	24	579,446	1,224,740	59,718	159,717	310,488	123,303
Panther Interstate Pipeline Energy LLC	56	1	—	1	12,410	23,012	60	478	1,140	567
Petal Gas Storage LLC*	59	1	2	3	91,277	212,540	2,244	5,941	42,111	16,594
Pine Needle LNG Co. LLC	—	—	—	0	—	108,725	122	3,164	19,097	6,018
Point Arguello Natural Gas Line Co.	—	—	—	0	493	141,654	276	1,707	14,753	12,635
Portland Natural Gas Transmission System*	296	—	—	0	51,476	492,663	554	18,489	65,730	21,099
Questar Overthrust Pipeline Co.*	116	—	—	0	140,085	114,713	49,951	1,156	7,796	2,582
Questar Pipeline Co.*	1,722	38	12	50	376,875	730,368	12,369	47,091	154,934	42,409
Questar Southern Trails Pipeline Co.	488	4	—	4	28,343	115,313	6	6,884	13,164	–3,446
Raton Gas Transmission Co. Inc.	23	—	—	0	1,079	991	25	1,178	1,220	21
Rocky Mountain Natural Gas Co.*	561	4	2	6	24,780	102,806	13,750	62,220	79,047	8,647
Sabine Pipe Line LLC*	152	4	—	4	253,741	53,423	125	9,323	15,417	3,770
Saltville Gas Storage Co. LLC.	7	—	1	1	—	99,527	25,461	2,287	11,765	4,238
SCG Pipeline Inc. (final)	18	—	—	0	14,703	31,331	7	756	5,988	2,369
Sea Robin Pipeline Co. LLC*	477	2	—	2	114,655	305,760	16,618	9,571	9,310	–2,232
Southern LNG Inc.*	—	—	—	0	—	386,284	157,832	21,929	65,759	23,207
Southern Natural Gas Co.*	7,439	42	0	42	805,359	2,924,033	120,445	169,489	464,628	183,704
Southern Star Central Gas Pipeline Inc.*	5,725	33	7	40	301,774	1,050,420	32,653	75,672	187,248	37,587
Southwest Gas Storage Co.	—	—	4	4	—	152,832	3,160	5,097	46,015	19,154
Southwest Gas Transmission Co. LP	8	—	—	0	30,900	1,795	—	106	458	143
Steuben Gas Storage Co.	15	—	1	1	—	31,583	—	2,932	6,714	807
Stingray Pipeline Co.LLC*	379	—	2	2	155,090	311,250	—	14,933	16,178	–379
Tennessee Gas Pipeline Co.*	13,996	70	1	71	1,674,476	5,971,999	295,816	397,482	878,636	147,591
Texas Eastern Transmission LP*	9,176	71	—	71	1,240,518	5,323,327	110,663	398,088	943,999	228,153
Texas Gas Transmission LLC.*	5,643	26	7	33	718,142	1,589,436	—	94,914	194,404	43,108
Trailblazer Pipeline Co.*	439	3	—	3	309,245	332,635	78	12,427	62,331	24,674
TransColorado Gas Transmission Co.*	326	6	—	6	314,421	353,267	15,479	3,926	47,858	23,316
Transcontinental Gas Pipe Line Corp.*	10,413	47	18	65	2,750,531	7,040,017	375,476	550,608	1,032,784	142,927
Transwestern Pipeline Co. LLC*	2,518	31	—	31	589,362	1,138,689	154,554	62,734	236,359	62,958
Trunkline Gas Co. LLC*	3,558	19	1	20	486,107	1,295,185	62,761	59,969	143,994	34,275
Tuscarora Gas Transmission Co.	240	2	1	3	28,619	181,132	302	3,518	29,492	8,822
Valero Natural Gas Pipeline Co.	3	—	—	0	6,795	1,157	—	265	341	–9
Vector Pipeline LP*	333	2	—	2	382,494	723,474	1,329	10,158	84,947	17,297
Venice Gathering System LLC*	247	—	—	0	—	73,052	83	7,872	4,425	–4,571
Viking Gas Transmission Co.*	671	8	—	8	135,307	175,619	7,271	12,482	30,088	5,687
West Texas Gas Inc.	650	—	—	0	7,016	93,839	3,501	91,406	94,736	–5,999
Western Gas Interstate Co.	264	—	—	0	3,511	13,206	82	769	1,926	1,685
WestGas InterState Inc.	12	—	—	0	3,011	667	15	53	178	75
Williston Basin Interstate Pipeline Co.*	3,364	19	8	27	130,889	379,723	10,667	36,680	96,542	24,332
Wyoming Interstate Co. Ltd.*	725	8	—	8	698,735	610,508	138,149	27,239	97,806	42,076
Young Gas Storage Co. Ltd.	11	1	—	1	—	46,222	744	2,400	8,366	1,785
2006 total—majors (73)	**189,012**	**1,195**	**223**	**1,418**	**33,457,917**	**$85,680,615**	**$3,788,124**	**$6,855,914**	**$16,571,607**	**$3,898,405**
2005 total—majors (71)	188,847	1,188	190	1,378	31,836,617	$81,265,489	$2,954,306	$6,838,551	$15,793,499	$3,737,882
2006 total—all	**195,489**	**1,233**	**236**	**1,469**	**34,309,239**	**$88,327,869**	**$3,905,797**	**$7,097,752**	**$17,122,586**	**$4,015,253**
2005 total—all	195,001	1,216	204	1,420	32,664,198	$83,915,753	$3,054,063	$7,064,523	$16,375,921	$3,863,331

*Major natural gas pipeline companies as defined below (and in FERC Accounting and Reporting Requirements for Natural Gas Companies, para. 20-011, effective Feb. 2, 1985, beginning with 1984 reporting year). Beginning with 1996, major companies were required to file mileage for transmission systems only.

Source: FERC Forms 2 and 2A for major and nonmajor natural gas pipeline companies. Under criteria established for the 1984 reporting year (OGJ, Nov. 25, 1985, p. 80), major pipeline companies are those whose combined gas sold for resale and gas transported for a fee exceeded 50 bcf at 14.73 psi (60° F.) in each of the 3 previous calendar years. Nonmajors are natural gas pipeline companies not classified as majors and whose total gas sales of volume transactions exceeded 200 MMcf at 14.73 psi (60° F.) in each of the 3 previous calendar years.

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Fleet of nitrogen converter pumps adds three units

An expanded fleet of nitrogen converter pump units is available in Aberdeen.

The three new diesel-driven 180k split skid units are designed to carry out commissioning services for operators in the UK continental shelf and Norwegian sectors of the North Sea.

These three nitrogen generator units increase the firm's fleet in the UK and Norway to 37 units. Equipment meets requirements set by the UK and Norwegian oil and gas industries. A main feature is the reduced lifting load possible when the system is moved in two lighter lifts, as opposed to one heavy lift that may be difficult or impossible in many installations, the firm points out. The power pack and liquid N2 converter each weigh 7,500 kg.

The soundproof units comply with ATEX 94/9/EC and are manufactured to CE Standard. Every system features Pyroban exhaust gas cooling systems, inlet and exhaust flame traps, overspeed and overpressure shutdowns, and a gas detection system.

Certified for use in Zone II areas, the units feature a split skid. The engine cooling system and Zone II components are situated in one skid, while the other skid contains the hydraulic system and cryogenic components.

Source: **BJ Services Co.,** Box 4442, Houston, TX 77210-4442.

Database of offshore oil seeps now covers Arctic frontier

Mapping of offshore oil slicks in the Arctic area covering more than 2 million sq km has been completed by this firm.

The area includes the Chukchi Sea, Beaufort Sea, Mackenzie Delta, Hudson Strait, Greenland, and Outer Rockall areas.

The Global Seeps database, covering more than 60 million sq km of offshore basins, has been constructed by interpreting radar satellite data and screening offshore basins worldwide to a water depth of about 3,000 m. The database is made up of more than 12,300 ERS satellite equivalent scenes. Mapping covers rigs, platforms, and ship traffic for a more complete picture of the controls on oil slick distribution, the company notes.

Source: **Infoterra Ltd.,** Atlas House, 41 Wembley Rd., Leicester LE3 1UT, UK.

Petrofac Ltd.


Methven

London, has announced the appointment of John Methven as director of group HSSE and integrity assurance. Methven, a petroleum production engineer and 10-year veteran of Petrofac, previously was UK managing director for Petrofac Facilities Management.

Petrofac Ltd. is a leading international provider of facilities solutions to the oil and gas production and processing industry. The company has three divisions: engineering and construction, operations services, and energy developments.

Knight Fishing Services

Houston, has named Mike Foster as Mid-Continent regional manager. Foster, who will be based at Knight's Houston facility, has more than 27 years of management experience in the oil industry.

Knight Fishing Services, a division of Knight Oil Tools, operates from 22 locations across nine oil-producing states in the US.

Performance Pulsation Control Inc. (PPC)

Plano, Tex., has announced its acquisition of Odessa, Tex.-based Status Flow.

Status Flow offers a full line of gas-charged, pulsation control products, providing a good fit with the maintenance free pulsation control products of PPC.

Superior Manufacturing & Hydraulics Inc.

Broussard, La., has announced that it has been purchased by Canadian McCoy Corp. The transaction includes McCoy's acquisition of Precision Die Technologies LLC, a provider of dies and inserts for oil field tools also headquartered in Broussard.

By acquiring Superior, McCoy has brought together two of the world's leading tong manufacturers. Farr Canada, a McCoy company based in Edmonton, and Superior together have a significant global presence in most types and size ranges of power tongs.

The new acquisitions will be part of McCoy Corp.'s Energy Products & Services Group, joining Inotec Coatings & Hydraulics Inc., Farr Canada, and Rebel Metal Fabricators Ltd.

Roxar

Stavanger, has announced the opening of an office in Cairo, Egypt, in response to increasing demand in the region for the company's integrated reservoir and production management solutions.

Roxar is a leading technology solutions provider to the global upstream oil and gas industry. The company was acquired in July 2007 by CorrOcean ASA, Trondheim.

Imports of crude and products

	Districts 1-4		District 5		Total US		
	8-17 2007	8-10 2007	8-17 2007	8-10 2007	8-17 2007	8-10 2007	*8-18 2006
	1,000 b/d						
Total motor gasoline	828	1,154	99	59	927	1,213	1,324
Mo. gas. blending comp.	589	796	12	52	601	848	952
Distillate	394	218	34	14	428	232	521
Residual	218	173	29	0	247	173	219
Jet fuel-kerosine	180	84	103	147	283	231	399
Propane-propylene	186	121	0	1	186	122	145
Other	376	416	135	13	511	429	817
Total products	**2,771**	**2,962**	**412**	**286**	**3,183**	**3,248**	**4,377**
Total crude	**9,657**	**8,509**	**1,158**	**1,364**	**10,815**	**9,873**	**10,197**
Total imports	**12,428**	**11,471**	**1,570**	**1,650**	**13,998**	**13,121**	**14,574**

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

Purvin & Gertz LNG netbacks—Aug. 24, 2007

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	6.73	4.70	5.93	4.60	5.28	5.90
Everett	4.61	2.80	4.24	2.90	3.32	4.89
Isle of Grain	3.33	2.14	2.89	2.05	2.36	2.89
Lake Charles	3.37	1.79	3.19	1.96	2.20	3.87
Sodegaura	5.35	7.06	5.55	7.18	6.52	4.81
Zeebrugge	5.92	4.35	5.40	4.21	4.68	5.41

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

Crude and product stocks

	Crude oil	Motor gasoline		Jet fuel, kerosine	Fuel oils		Propane-propylene
		Total	Blending comp.[1]		Distillate	Residual	
	1,000 bbl						
PADD 1	15,604	52,155	25,182	10,611	51,792	13,411	4,006
PADD 2	67,151	46,431	14,450	7,263	27,887	1,325	21,458
PADD 3	184,739	62,087	25,346	13,547	34,376	16,217	25,647
PADD 4	13,333	6,102	2,087	566	3,058	366	[1]2,172
PADD 5	56,291	29,456	21,098	9,931	11,912	5,157	—
Aug. 17, 2007	**337,118**	**196,231**	**88,163**	**41,918**	**129,025**	**36,476**	**53,283**
Aug. 10, 2007	**335,228**	**201,940**	**91,964**	**41,400**	**127,669**	**36,977**	**51,719**
Aug. 18, 2006[2]	**330,359**	**205,795**	**90,083**	**41,451**	**135,481**	**41,533**	**62,722**

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

Refinery report—Aug. 17, 2007

District	Refinery operations		Refinery output				
	Gross inputs	Crude oil inputs	Total motor gasoline	Jet fuel, kerosine	Fuel oils		Propane-propylene
					Distillate	Residual	
	1,000 b/d						
PADD 1	1,499	1,492	1,911	91	474	135	49
PADD 2	3,355	3,342	2,023	225	921	42	186
PADD 3	7,685	7,533	3,409	730	2,061	358	652
PADD 4	599	599	326	28	200	16	[1]157
PADD 5	2,849	2,761	1,618	383	550	115	—
Aug. 17, 2007	**15,987**	**15,727**	**9,287**	**1,457**	**4,206**	**666**	**1,044**
Aug. 10, 2007	**16,021**	**15,783**	**9,271**	**1,423**	**4,100**	**654**	**1,058**
Aug. 18, 2006[2]	**16,134**	**15,747**	**9,269**	**1,506**	**4,058**	**575**	**1,028**
	17,447 operable capacity		**91.6% utilization rate**				

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

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

OGJ crack spread

	*8-24-07	*8-25-06	Change $/bbl	Change, %
SPOT PRICES				
Product value	81.25	81.17	0.08	0.1
Brent crude	68.05	71.74	–3.69	–5.1
Crack spread	13.19	9.44	3.75	39.8
FUTURES MARKET PRICES				
One month				
Product value	81.41	82.48	–1.07	–1.3
Light sweet crude	70.01	72.34	–2.33	–3.2
Crack spread	11.40	10.14	1.26	12.4
Six month				
Product value	81.05	82.48	–1.43	–1.7
Light sweet crude	68.83	72.34	–3.51	–4.8
Crack spread	12.22	10.14	2.08	20.5

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

OGJ GASOLINE PRICES

	Price ex tax 8-22-07	Pump price* 8-22-07	Pump price 8-23-06
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	237.8	277.5	288.2
Baltimore	226.7	268.6	294.1
Boston	223.8	265.7	293.9
Buffalo	221.6	281.7	302.1
Miami	236.3	286.6	307.1
Newark	230.5	263.4	290.4
New York	221.6	281.7	313.2
Norfolk	223.9	261.5	275.7
Philadelphia	229.9	280.6	309.9
Pittsburgh	226.6	277.3	290.0
Wash., DC	242.1	280.5	312.5
PAD I avg.	229.2	275.0	297.9
Chicago	243.0	293.9	341.7
Cleveland	229.5	275.0	272.3
Des Moines	242.9	283.3	261.5
Detroit	235.6	284.8	284.3
Indianapolis	239.8	284.8	273.2
Kansas City	238.8	274.8	278.0
Louisville	255.3	292.2	274.8
Memphis	248.1	287.9	277.1
Milwaukee	235.4	286.7	301.5
Minn.-St. Paul	230.2	270.6	285.8
Oklahoma City	227.9	263.3	270.8
Omaha	235.3	281.7	278.4
St. Louis	253.7	289.7	279.0
Tulsa	226.4	261.8	271.6
Wichita	238.9	282.3	274.3
PAD II avg.	238.7	280.9	281.6
Albuquerque	238.9	275.3	292.1
Birmingham	227.7	266.4	278.8
Dallas-Fort Worth	226.0	264.4	282.3
Houston	231.8	270.2	280.5
Little Rock	226.1	266.3	278.6
New Orleans	231.8	270.2	288.3
San Antonio	226.0	264.4	275.7
PAD III avg.	229.8	268.2	282.3
Cheyenne	244.9	277.3	286.9
Denver	246.3	286.7	295.8
Salt Lake City	245.6	288.5	294.7
PAD IV avg.	245.6	284.2	292.5
Los Angeles	222.6	281.1	316.9
Phoenix	245.2	282.6	279.8
Portland	237.7	281.0	301.8
San Diego	235.5	294.0	322.4
San Francisco	232.5	291.0	323.9
Seattle	224.4	276.8	313.3
PAD V avg.	233.0	284.4	309.7
Week's avg.	**234.4**	**278.0**	**290.8**
July avg.	**251.6**	**295.2**	**295.2**
June avg.	**265.9**	**309.4**	**288.4**
2007 to date	**228.5**	**272.1**	—
2006 to date	**223.1**	**266.5**	—

*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

	8-17-07 ¢/gal		8-17-07 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	209.65	New York Harbor	199.80
Gulf Coast	204.65	Gulf Coast	198.55
Los Angeles	200.50	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	186.26	ARA	199.77
Singapore	183.33	Singapore	197.38
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	210.40	New York Harbor	126.12
Gulf Coast	211.50	Gulf Coast	137.50
Los Angeles	209.50	Los Angeles	154.53
		ARA	133.05
		Singapore	135.34

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

BAKER HUGHES RIG COUNT

	8-24-07	8-25-06
Alabama	4	5
Alaska	4	6
Arkansas	50	30
California	37	30
Land	35	27
Offshore	2	3
Colorado	118	95
Florida	1	0
Illinois	1	0
Indiana	4	0
Kansas	13	16
Kentucky	8	7
Louisiana	173	209
N. Land	58	58
S. Inland waters	22	21
S. Land	31	45
Offshore	62	85
Maryland	1	0
Michigan	3	3
Mississippi	13	12
Montana	18	21
Nebraska	0	0
New Mexico	89	93
New York	6	6
North Dakota	41	34
Ohio	14	6
Oklahoma	194	195
Pennsylvania	17	11
South Dakota	1	2
Texas	851	790
Offshore	6	11
Inland waters	1	4
Dist. 1	25	23
Dist. 2	32	22
Dist. 3	55	59
Dist. 4	85	96
Dist. 5	190	147
Dist. 6	135	111
Dist. 7B	35	48
Dist. 7C	58	39
Dist. 8	115	103
Dist. 8A	19	19
Dist. 9	31	31
Dist. 10	64	77
Utah	39	45
West Virginia	33	26
Wyoming	73	109
Others—NV-2; TN-5; VA-2; WA-1	10	5
Total US	**1,816**	**1,756**
Total Canada	**319**	**489**
Grand total	**2,135**	**2,245**
Oil rigs	316	315
Gas rigs	1,494	1,436
Total offshore	71	100
Total cum. avg. YTD	**1,755**	**1,609**

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	8-24-07 Rig count	8-24-07 Percent footage*	8-25-06 Rig count	8-25-06 Percent footage*
0-2,500	57	10.5	42	2.3
2,501-5,000	109	53.2	85	35.2
5,001-7,500	230	23.9	240	20.4
7,501-10,000	432	4.1	377	5.3
10,001-12,500	447	0.8	414	2.1
12,501-15,000	274	0.3	297	—
15,001-17,500	108	—	105	—
17,501-20,000	72	—	75	—
20,001-over	32	—	31	—
Total	**1,761**	**8.0**	**1,666**	**6.5**
INLAND	42		39	
LAND	1,655		1,560	
OFFSHORE	64		67	

*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]8-24-07	[2]8-25-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	19	20
Alaska	754	621
California	666	676
Colorado	51	59
Florida	7	7
Illinois	31	28
Kansas	96	99
Louisiana	1,356	1,405
Michigan	14	14
Mississippi	50	48
Montana	94	100
New Mexico	166	163
North Dakota	105	112
Oklahoma	167	174
Texas	1,352	1,366
Utah	44	49
Wyoming	144	143
All others	61	71
Total	**5,177**	**5,155**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	8-24-07
Alaska-North Slope 27°	62.00
South Louisiana Sweet	76.00
California-Kern River 13°	61.40
Lost Hills 30°	69.25
Southwest Wyoming Sweet	65.09
East Texas Sweet	67.25
West Texas Sour 34°	61.95
West Texas Intermediate	67.75
Oklahoma Sweet	67.75
Texas Upper Gulf Coast	64.50
Michigan Sour	60.75
Kansas Common	66.75
North Dakota Sweet	62.50

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

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

WORLD CRUDE PRICES

$/bbl[1]	8-17-07
United Kingdom-Brent 38°	69.79
Russia-Urals 32°	67.64
Saudi Light 34°	67.19
Dubai Fateh 32°	66.46
Algeria Saharan 44°	72.25
Nigeria-Bonny Light 37°	73.47
Indonesia-Minas 34°	72.66
Venezuela-Tia Juana Light 31°	66.06
Mexico-Isthmus 33°	65.95
OPEC basket	69.15
Total OPEC[2]	68.50
Total non-OPEC[2]	67.73
Total world[2]	68.15
US imports[3]	66.29

[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]

	8-17-07	8-10-07	Change
	bcf		
Producing region	904	919	–15
Consuming region east	1,613	1,573	40
Consuming region west	409	411	–2
Total US	**2,926**	**2,903**	**23**
	May 07	**May 06**	**Change, %**
Total US[2]	**2,179**	**2,310**	**–5.7**

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

PACE REFINING MARGINS

	June 2007	July 2007	Aug. 2007	Aug 2006	Change 2007 vs. 2006	Change, % 2007 vs. 2006
	$/bbl					
US Gulf Coast						
West Texas Sour	21.60	16.61	13.70	14.84	–1.14	–7.7
Composite US Gulf Refinery	20.91	16.24	14.45	16.11	–1.67	–10.4
Arabian Light	21.51	14.35	10.96	15.10	–4.14	–27.4
Bonny Light	13.76	8.32	7.85	8.62	–0.77	–8.9
US PADD II						
Chicago (WTI)	25.07	21.33	18.93	18.75	0.18	1.0
US East Coast						
NY Harbor (Arab Med)	18.40	14.70	11.80	14.46	–2.65	–18.4
East Coast Comp-RFG	21.60	16.88	14.69	18.56	–3.98	–21.4
US West Coast						
Los Angeles (ANS)	20.46	13.79	8.24	15.64	–7.40	–47.3
NW Europe						
Rotterdam (Brent)	6.52	1.62	4.26	2.03	2.23	109.4
Mediterranean						
Italy (Urals)	9.68	8.82	7.82	9.78	–1.96	–20.3
Far East						
Singapore (Dubai)	8.47	8.05	6.62	0.23	6.39	2,777.4

Source: Jacobs Consultancy Inc.
Data available in OGJ Online Research Center.

US NATURAL GAS BALANCE DEMAND/SUPPLY SCOREBOARD

	May 2007	Apr. 2007	May 2006	May 2007-2006 change	Total YTD 2007	Total YTD 2006	YTD 2007-2006 change
	bcf						
DEMAND							
Consumption	1,541	1,798	1,543	–2	10,454	9,683	771
Addition to storage	498	274	420	78	1,100	1,046	54
Exports	79	68	63	16	351	292	59
Canada	43	32	21	22	204	139	65
Mexico	32	32	36	–4	125	125	0
LNG	4	4	6	–2	22	28	–6
Total demand	**2,118**	**2,140**	**2,026**	**92**	**11,905**	**11,021**	**884**
SUPPLY							
Production (dry gas)	1,605	1,549	1,554	51	7,757	7,601	156
Supplemental gas	3	4	3	0	25	25	0
Storage withdrawal	39	154	52	–13	1,984	1,373	611
Imports	345	378	350	–5	1,888	1,713	175
Canada	251	279	283	–32	1,493	1,473	20
Mexico	0	0	0	0	18	3	15
LNG	94	99	67	27	377	237	140
Total supply	**1,992**	**2,085**	**1,959**	**33**	**11,654**	**10,712**	**942**

NATURAL GAS IN UNDERGROUND STORAGE

	May 2007	Apr. 2007	Mar. 2007	May 2006	Change
	bcf				
Base gas	4,251	4,246	4,242	4,202	49
Working gas	2,179	1,720	1,603	2,310	–131
Total gas	**6,430**	**5,966**	**5,845**	**6,512**	**–82**

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

WORLDWIDE NGL PRODUCTION

	May 2007	Apr. 2007	5 month average Production 2007	5 month average Production 2006	Change vs. previous year Volume	Change vs. previous year %
	1,000 b/d					
Brazil	78	83	84	84	—	0.6
Canada	685	697	715	701	15	2.1
Mexico	413	420	413	438	–25	–5.6
United States	1,787	1,749	1,736	1,706	30	1.7
Venezuela	200	200	200	200	—	—
Other Western Hemisphere	162	162	162	170	–9	–5.0
Western Hemisphere	**3,325**	**3,311**	**3,309**	**3,298**	**11**	**0.3**
Norway	281	317	300	291	9	3.2
United Kingdom	152	164	161	162	–2	–0.9
Other Western Europe	19	19	19	20	–1	–2.7
Western Europe	**452**	**500**	**480**	**473**	**7**	**1.5**
Russia	423	422	424	412	12	3.0
Other FSU	160	160	160	160	—	—
Other Eastern Europe	14	15	15	18	–3	–14.9
Eastern Europe	**597**	**597**	**600**	**590**	**9**	**1.6**
Algeria	340	340	340	295	45	15.3
Egypt	65	65	65	65	—	—
Libya	60	60	60	60	—	—
Other Africa	196	198	196	187	9	4.7
Africa	**661**	**663**	**661**	**607**	**54**	**8.9**
Saudi Arabia	1,439	1,439	1,439	1,439	—	—
United Arab Emirates	400	400	400	400	—	—
Other Middle East	680	680	680	670	10	1.5
Middle East	**2,519**	**2,519**	**2,519**	**2,509**	**10**	**0.4**
Australia	62	82	73	77	–4	–5.2
China	180	180	180	180	—	—
India	—	—	8	43	–36	–82.5
Other Asia-Pacific	217	219	219	220	–1	–0.6
Asia-Pacific	**459**	**481**	**479**	**520**	**–41**	**–7.9**
TOTAL WORLD	**8,014**	**8,071**	**8,049**	**7,998**	**51**	**0.6**

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

OXYGENATES

	May 2007	Apr. 2007	Change	YTD 2007	YTD 2006	Change
	1,000 bbl					
Fuel ethanol						
Production	12,573	11,716	857	58,597	44,481	14,116
Stocks	8,950	8,791	159	8,950	7,848	1,102
MTBE						
Production	2,003	1,959	44	9,857	14,973	–34,624
Stocks	1,353	2,324	–971	1,353	2,314	–961

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

US COOLING DEGREE DAYS

	July 2007	July 2006	Normal	2007 % change from normal	Total degree days Jan. 1 through July 31 2007	2006	Normal	% change from normal
New England	183	265	175	4.6	300	389	248	21.0
Middle Atlantic	245	325	245	—	450	500	396	13.6
East North Central	214	307	245	–12.7	462	479	454	1.8
West North Central	309	383	309	—	609	698	582	4.6
South Atlantic	414	454	425	–2.6	1,148	1,181	1,114	3.1
East South Central	384	452	412	–6.8	987	1,016	910	8.5
West South Central	464	562	547	–15.2	1,319	1,636	1,417	–6.9
Mountain	428	424	351	21.9	878	905	751	16.9
Pacific	256	343	196	30.6	392	560	377	4.0
US average*	**319**	**390**	**323**	**–1.2**	**734**	**826**	**710**	**3.4**

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

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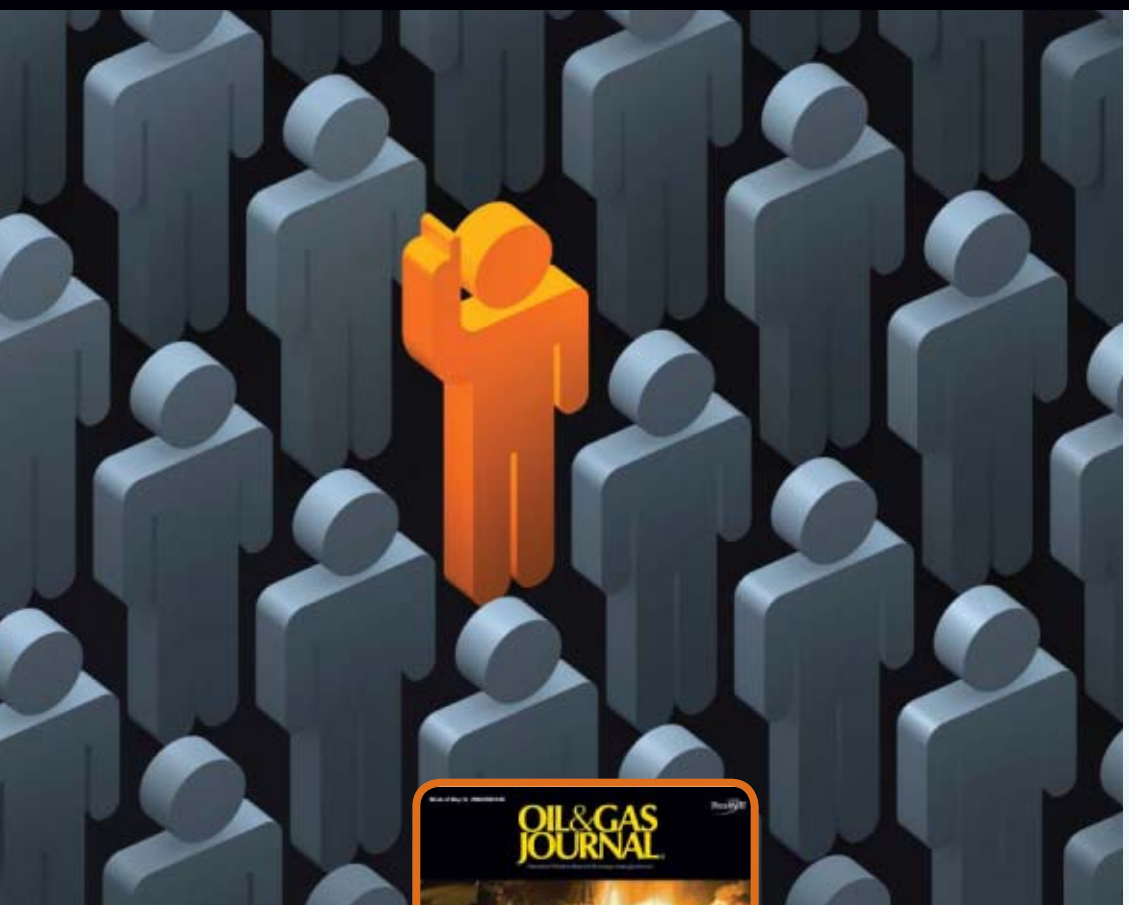

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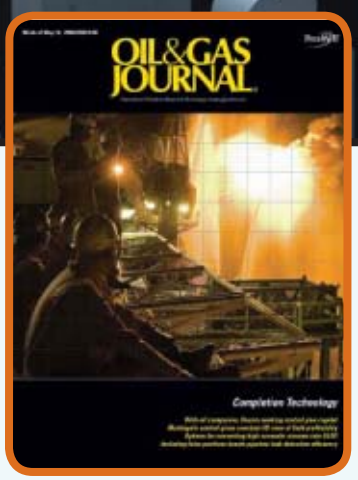

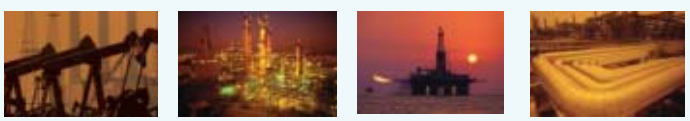

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[1] *Signet Readership Survey (February 2007)*

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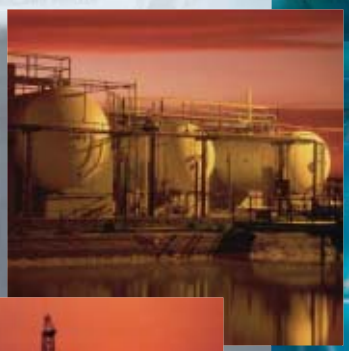

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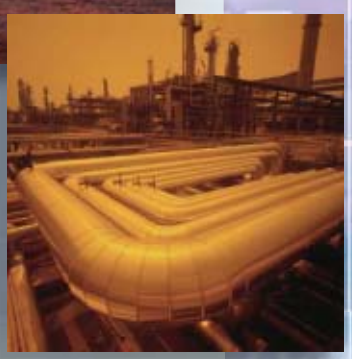

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All-powerful oil lobby a juvenile Obama fantasy

There's a reason Hillary Clinton, in her race for the Democratic presidential nomination, is making Barak Obama look juvenile. He acts that way.

Obama, a US senator from Illinois, has been disparaging the oil lobby lately.

"The reason that we're not getting things done is not because we don't have good plans or good policy prescriptions," Obama told an audience in Cedar Rapids, Iowa.

The Editor's Perspective

by Bob Tippee, Editor

"The reason is because it's not our agenda that's being moved forward in Washington. It's the agenda of the oil companies, the insurance companies, the drug companies, the special interests who dominate on a day-to-day basis in terms of legislative activity."

In Waverly, Iowa, the Illinois senator called cutting oil demand "an urgent moral challenge" and blamed oil companies for a lack of government action.

"Americans can't come and sit at the table because oil and gas companies have bought every chair," he said.

This kind of blather appeals to people who reflexively assume the most sinister possible interpretation about any event but who generally ignore facts.

To such people, the existence of a potent, evil oil lobby seems not only plausible but likely. Facts, however, indicate otherwise.

If an all-powerful oil lobby manipulated events in Washington, DC, the worst energy legislation in decades would not now await action in a House-Senate conference.

If an all-powerful oil lobby had existed in years past, drilling would be under way on the coastal plain of the Arctic National Wildlife Refuge in Alaska, off the East and West Coasts, in the eastern Gulf of Mexico, and on inaccessible federal land in the US West. By now, some or all of these areas might be producing oil and gas.

If an all-powerful oil lobby controlled events in Washington, DC, several modern refineries might be under construction or on stream where none exist now, and existing refineries wouldn't be under stress.

The fact is that no such lobby exists. Yes, the oil and gas industry has a lobby. All industries have lobbies. But the suggestion that the oil lobby accomplishes more than occasionally keeping the government from acting on its worst impulses is laughable.

(Online Aug. 27, 2007; author's e-mail: bobt@ogjonline.com)

Market Journal

by Sam Fletcher, Senior Writer

Facilities escape damage from Dean

For all of the initial fears it generated among traders and Gulf Coast residents, Hurricane Dean inflicted apparently little damage to or disruptions of oil and gas operations in the Gulf of Mexico.

It wasn't for want of effort. When Dean hit the Yucatan Peninsula on Aug. 21 with 165 mph winds gusting to 200 mph, it was a rare Category 5 hurricane and the third-most powerful Atlantic hurricane to make landfall since record-keeping began in the 1850s. But as usually happens when hurricanes move across land, Dean weakened to a Category 1 storm before it reached the Bay of Campeche, where Petroleos Mexicanos has 66% of its oil production. Its projected path was through the productive Cantarell oil field, and Pemex evacuated more than 14,000 workers from 140 offshore facilities and shut in production of 2.65 million b/d of oil and 2.63 bcfd of gas.

Further north, the Minerals Management Service reported 24 of 101 drilling rigs and 34 of 834 manned production platforms in the US sector of the Gulf of Mexico were evacuated. Shut-in production topped out Aug. 21 at 43,881 b/d of oil, or 3.4% of total crude production from federal leases in the gulf; and 140 MMcfd—1.83% of total gas production. By that date, Shell Oil Co. was already returning workers offshore and bringing shut in production on stream. By Aug. 24, MMS reported only one production platform was still without a crew, while 2,600 b/d of oil and 1.3 MMcfd of gas remained shut in.

Olivier Jakob, managing director of Petromatrix GMBH, Zug, Switzerland, said, "The precautionary closing of the Mexican fields and ports will cause delays in crude supply to US Gulf refineries, but the system is accustomed to having weather delays in Mexico, and this will not cause a state of emergency, especially when crude stocks in the US Gulf are at multiyear high for this time of the year."

Shell also reduced production rates at the 340,000 b/d Deer Park refinery outside Houston in anticipation of interrupted crude supplies due to Hurricane Dean. "There is the potential for delayed oil shipments due to the weather so we are monitoring the situation to determine its potential impact on our operations," said Shell officials Aug. 22.

US inventories

Energy prices fell Aug. 20-21 when it became evident that Hurricane Dean was going to miss the US sector and strike the Mexican sector of the Gulf of Mexico. Prices continued to fall Aug. 22 after the Energy Information Administration reported a surprise build in commercial US crude inventories and a continued decline in gasoline stocks during the week ended Aug. 17. Crude stocks increased 1.9 million bbl to 337.1 million bbl while gasoline inventories dropped 5.7 million bbl to 196.2 million bbl. Distillate fuel inventories increased 1.3 million bbl to 129 million bbl (OGJ Online, Aug. 22, 2007). The new front-month crude contract closed at the lowest price level in 2 months, while natural gas dropped 10% to a 10-month low in anticipation of increased storage.

Jakob said, "With higher than expected crude oil imports and lower than expected gasoline stocks, the US weekly statistics provided two surprises with opposing directional influences. Products cracks have improved, but on crude oil the West Texas Intermediate long-dated time spreads have weakened, and the WTI premium to [North Sea] Brent is weakening on the slight increase in Cushing, Okla., stocks. The natural gas flat price [for the September contract] has now lost 20.4% in 3 days."

Jakob said, "The weekly change [in gasoline stocks was] so large that there could have been an early rush from retailers to fill in before the expected storm in order to not be caught short into the Labor Day weekend. High imports of crude oil (the highest since mid-May) have stopped the crude stock hemorrhage and are maintaining them at multiyear high for the season."

Paul Horsnell at Barclays Capital Inc., London, said, "Despite market fears about demand, US gasoline demand has hit a new all-time record in the latest weekly data. Demand for August as a whole is neck-and-neck with July's all-time monthly record, with gasoline inventories remaining very tight."

On Aug. 23, EIA reported the injection of 23 bcf of natural gas into US underground storage for the week ended Aug. 17, compared with injections of 21 bcf the prior week and 57 bcf during the same period a year ago. US gas storage now exceeds 2.9 tcf, up 77 bcf from last year and 333 bcf more than the 5-year average.

(Online Aug. 27, 2007; author's e-mail: samf@ogjonline.com)

Wasting money for CP?

What kind of question is this?

Most in the pipeline industry agree that cathodic protection (CP) is the smart way to provide backup corrosion protection on underground pipelines.

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

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

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

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

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

NACE Standard RP0169-2002 states: *"Materials....that create electrical shielding should not be used on the pipeline"* [1].

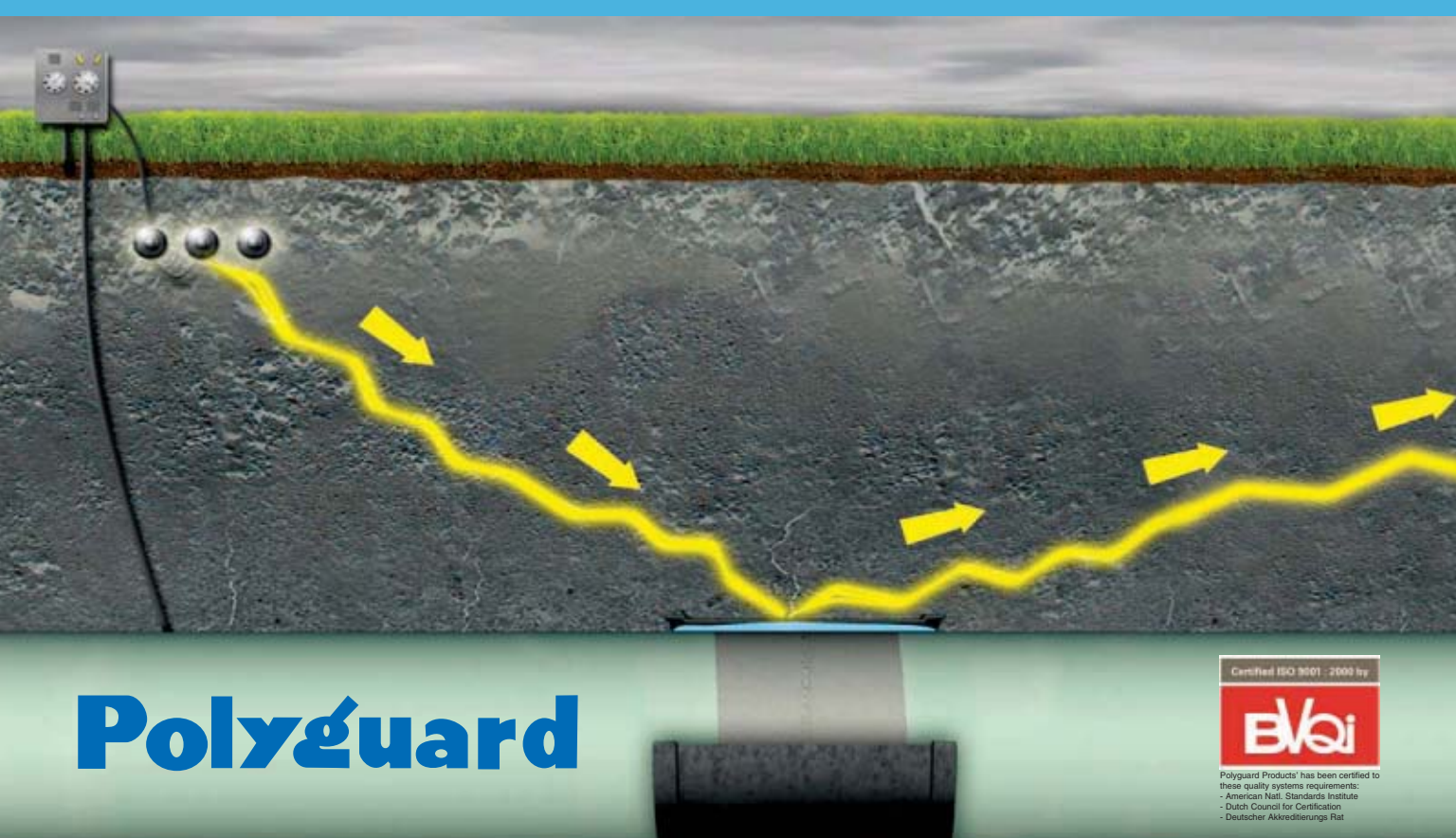
49 CFR §192.461 states: *"External protective coating...must...have properties compatible with any supplemental cathodic protection."* [2]

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

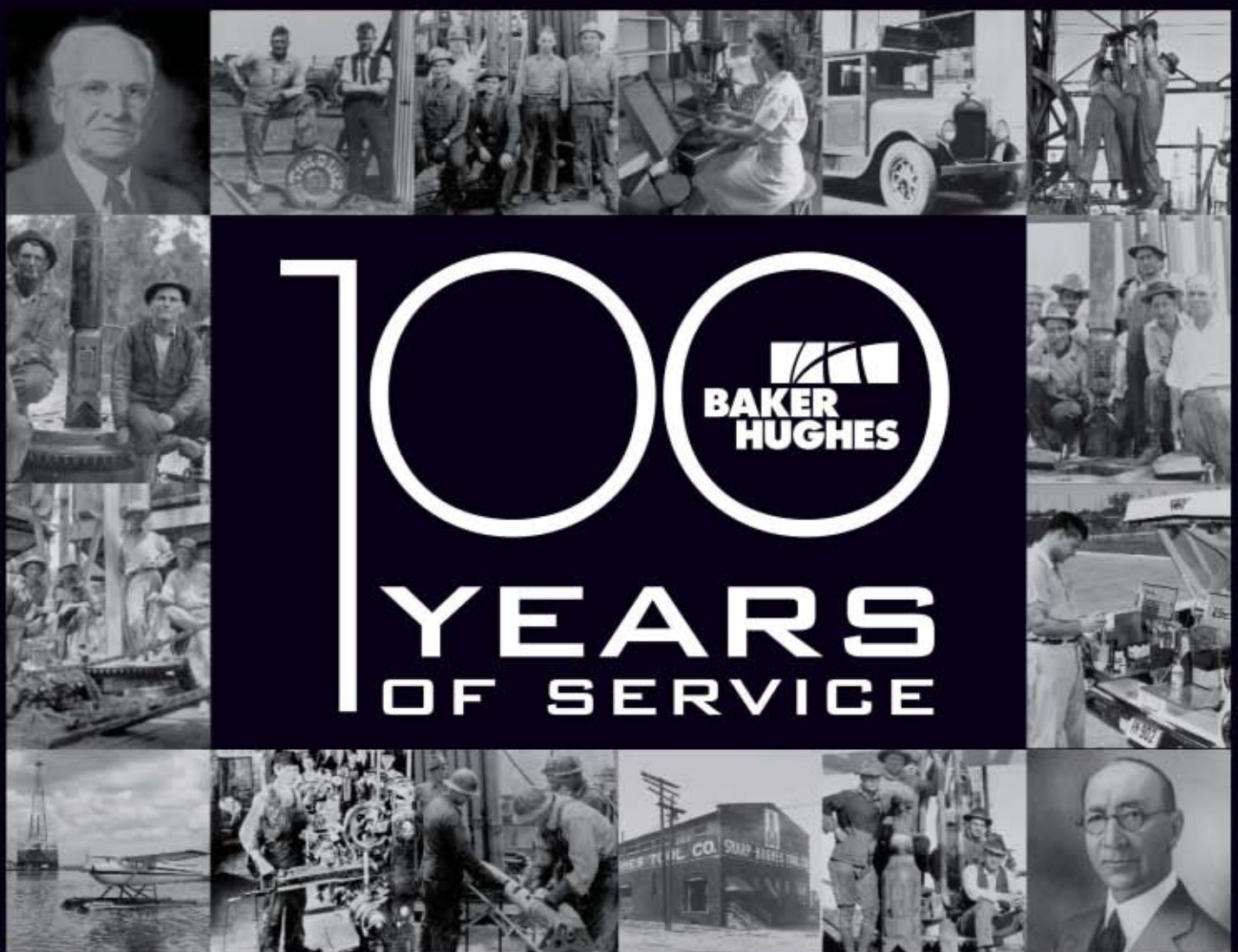
- Visit *polyguardproducts.com/failsafecoating.htm.* and review the large body of information about shielding problems.
- Talk to operators who have used Polyguard's RD-6 system. *(There are many)* Ask them if they know of any serious corrosion or SCC ever found under RD-6. *(We don't, even after 19 years and thousands of installations).*

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

1. NACE Standard RP0169-2002 *"Control of External Corrosion on Underground or Submergeed Metallic Piping Systems".*
2. 49 CFR Ch.1 (§192.461 see also §195.559) *w.xj.11 ad text 08227*



A Century of Innovation



In 2007, Baker Hughes is celebrating a century of innovation and service in the oil and gas industry. Since 1907, when R.C. Baker invented a casing shoe that increased efficiency and reliability for early wildcatters, our engineers and scientists have served the industry by solving problems for customers. Today's Baker Hughes carries on the tradition of Mr. Baker, Howard Hughes, Sr. and many other oil service pioneers whose creativity delivered technology innovations that have helped our customers find, develop and produce oil and gas around the world on land and offshore.

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