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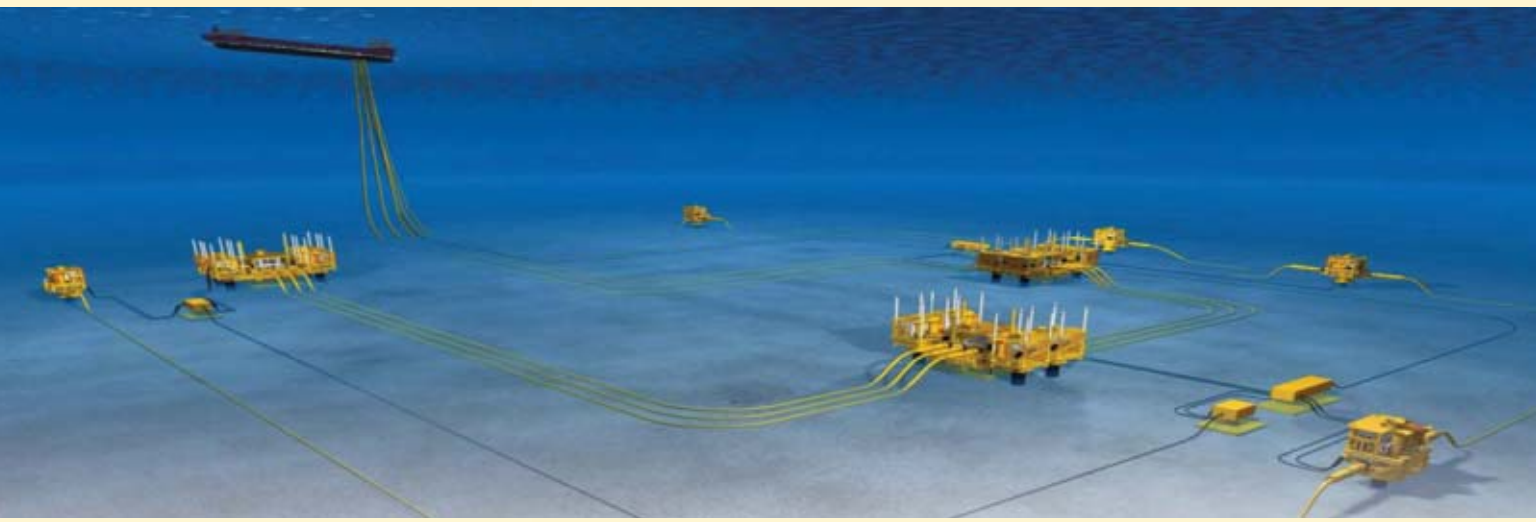
Dec. 18, 2006
Volume 104.47

WORLDWIDE REPORT



REGULAR FEATURES

COVER

Woodside Petroleum Ltd. operates Chinguetti field off Mauritania. With peak oil production capacity of 75,000 b/d, production from the field began Feb. 24, 2006, through wells on the seabed connected by flowlines to an FPSO. Berge Helene is a converted tanker, permanently moored over the field, as illustrated on p. 20. Oil stored in the FPSO is periodically offloaded to trading tankers for transport to markets in the US, Europe, and Asia. Images courtesy Woodside. Also, a distillate hydrotreater produces ultralow-sulfur diesel at Countrymark Cooperative Inc.'s Mount Vernon, Ind., refinery. This grassroots 11,000-b/sd hydrotreater will reduce the sulfur content in diesel fuels manufactured and processed by Countrymark to meet the regulated lower sulfur-content levels mandated by the US Environmental Protection Agency. Mustang Engineering LP provided the front-end engineering, detailed engineering, procurement, and construction management services for the hydrotreater. Photo from Countrymark Cooperative.

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General Interest — Quick Takes

Gazprom may buy half of Shell's Sakhalin-2 stake

Royal Dutch Shell PLC, under stepped-up pressure from the Russian government, is close to making a deal that would allow Russia's OAO Gazprom a stake in the Sakhalin-2 oil and natural gas project.

Dmitry Medvedev, who serves as chairman of Gazprom chairman as well as Russia's deputy prime minister, Dec. 12 said talks with Shell were going quickly and that the Russian side hoped to reach a deal soon.

Reports suggested that Shell's share in the project would drop from 55% to 25%, while its Japanese partners Mitsui (25%) and Mitsubishi (20%) would each sell 10% of their shares to Gazprom. However, it was expected that Shell would remain as operator of the project since Gazprom has never before run an LNG project.

Medvedev did not confirm those reports, saying only, "as far as the size of the stake is concerned, it is important but not critically important." He told a press conference in Moscow, "We are looking at all options ranging from cash to an exchange of assets." The announcement of a deal coincided with further threats by the Russian government to undertake legal action against the Shell-led project for alleged violations of the country's environmental laws.

Oleg Mitvol, deputy head of natural resources watchdog Rosprirodnadzor, Dec. 12 claimed that damages inflicted by the operator of the Sakhalin-2 hydrocarbons project are estimated at $10 billion, according to preliminary calculations.

Mitvol said the agency would come up with a more-precise figure by the end of next summer, but that the estimated amount included damage to the environment, lost revenue, and compensation for lawyers that Rosprirodnadzor would hire for litigation.

He said Rosprirodnadzor plans to start court proceedings in March over violations at the Sakhalin-2 project, and that it would file Sakhalin-2 suits in several court jurisdictions, including in Russia and in the Stockholm Arbitration Court.

The announcements followed earlier pressure from the Russian government which last week withdrew key environmental permits from Shell and its Japanese partners. As a result of the withdrawn permits, construction on the project has effectively come to a halt (OGJ Online, Dec. 7, 2006). Japan's Economy, Trade and Industry Minister Akira Amari Dec. 12 underscored the urgency of reaching an agreement, urging the operators of the Sakhalin-2 project to abide by a plan to supply LNG to Japan beginning in 2008.

"It is important that the resource is properly delivered to the final user," such as Japanese electric power and gas companies, Amari told a news conference in Tokyo.

Kazakhstan to decide on mineral rights

Kazakhstan's Energy and Natural Resource Minister Baktykozha Izmukhambetov said the Kazakh government will decide by Dec. 30 whether to seek oil and natural gas rights in that country now held by Canada's Nations Energy Co.

Commenting on the pending sale of Nations Energy and its Kazakh assets to China's state-owned Citic Group, Izmukhambetov said, "In principle, we have the right to bid for any offer, for any deal, or stake that is being sold."

Izmukhambetov said the Kazakh government has 45 days to reach a decision according to the law on subsurface operations and that the deadline for it to decide on the Citic-Nations deal expires on Dec 30. "By Dec. 30 we should reach a decision," he said.

At the end of October, Nations Energy said Citic would acquire its assets in Kazakhstan in December under an agreement that includes its interests in Karazhanbas field, where Nations produces 50,000 b/d of oil equivalent and has an estimated 340 million bbl in reserves. In early December, however, the government of Kazakhstan was reportedly planning to block the Citic-Nations agreement in order to acquire the Karazhanbas development for itself (OGJ Online, Dec. 11, 2006). ✦

Exploration & Development — Quick Takes

Sakhalin-2 water-use licenses suspended

Russia's Ministry of Natural Resources has suspended 12 water-use licenses for the Sakhalin-2 oil and gas project after discovering what it called major violations of environmental law (OGJ, Nov. 6, 2006, Newsletter). Natural Resources Minister Yuriy Trutnev said a comprehensive inspection of the project showed that "in the course of implementing the Sakhalin-2 project major violations of Russian environmental law have been committed."

As a result of the inspection, Trutnev's ministry said it has suspended 12 licenses for water use granted to Starstroi, a Russian-Italian joint venture building natural gas and oil export pipelines as a subcontractor of the Sakhalin Energy consortium.

The ministry said Russia's environmental watchdog, Rosprirodnadzor, had uncovered violations of water law requirements by the company during the laying of pipelines in the Piltun-Astokhskoye and Lunskoye regions.

It gave the company 2 months to remove the designated violations; otherwise, it will annul the licenses, which are mandatory for any construction affecting rivers and other water resources.

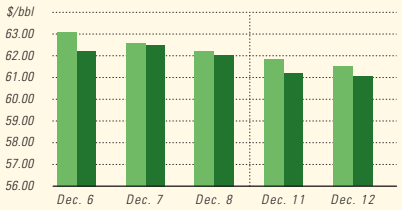
Royal Dutch Shell owns a 55% stake in Sakhalin Energy, Mitsui 25%, and Mitsubishi 20%.

ONGC Videsh to bid for Sakhalin-3 stake

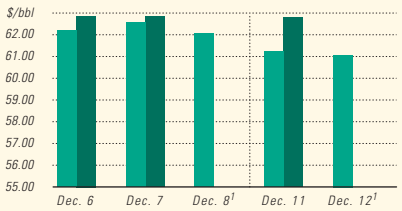
India wants to obtain a stake in the Sakhalin-3 project in its

Industry Scoreboard

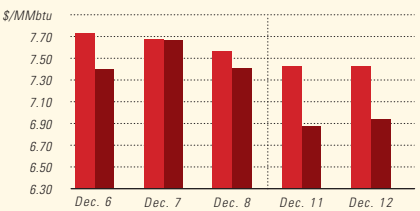
IPE BRENT / NYMEX LIGHT SWEET CRUDE



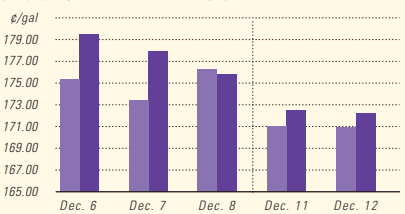
WTI CUSHING / BRENT SPOT



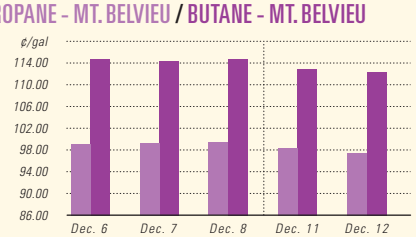
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



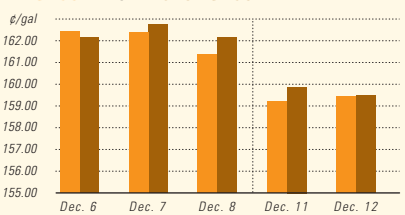
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



NYMEX GASOLINE / NY SPOT GASOLINE[2]



[1]Not available.
[2]Nonoxygenated regular unleaded.

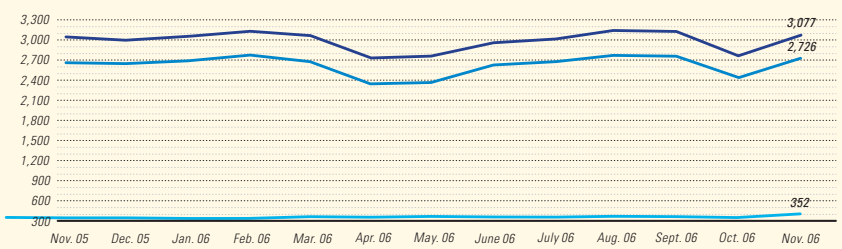
US INDUSTRY SCOREBOARD — 12/18

Latest week 12/8	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	9,827	9,167	7.2	9,832	9,157	7.4
Distillate	4,268	4,140	3.1	4,164	4,118	1.1
Jet fuel	1,625	1,658	–2.0	1,605	1,679	–4.4
Residual	556	991	–43.8	715	920	–22.3
Other products	5,025	4,916	2.2	4,960	4,925	0.7
TOTAL DEMAND	21,301	20,873	2.1	21,276	20,799	2.3
Supply, 1,000 b/d						
Crude production	5,269	4,879	8.0	5,132	5,179	–0.9
NGL production	2,264	1,575	43.8	2,237	1,717	30.3
Crude imports	9,962	10,159	–1.9	10,223	10,074	1.5
Product imports	3,020	3,754	–19.5	3,414	3,588	–4.9
Other supply[2]	1,178	1,154	2.1	1,098	1,162	–5.5
TOTAL SUPPLY	21,693	21,520	0.8	22,105	21,720	1.8
Refining, 1,000 b/d						
Crude runs to stills	15,019	15,036	–0.1	15,146	15,220	–0.5
Input to crude stills	15,351	15,243	0.7	15,569	15,479	0.6
% utilization	88.6	89.0	—	90.4	90.4	—

Latest week 12/8	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	325,799	334,102	–8,303	322,033	3,766	1.2
Motor gasoline	200,121	201,206	–1,085	206,439	–6,318	–3.1
Distillate	136,630	139,309	–2,679	132,701	3,929	3.0
Jet fuel	39,021	37,900	1,121	42,850	–3,829	–8.9
Residual	43,764	45,015	–1,251	38,471	5,293	13.8
Futures prices[3]						
Light sweet crude, $/bbl	62.29	62.50	–0.21	59.82	2.47	4.1
Natural gas, $/MMbtu	7.69	8.49	–0.80	14.03	–6.34	–45.2

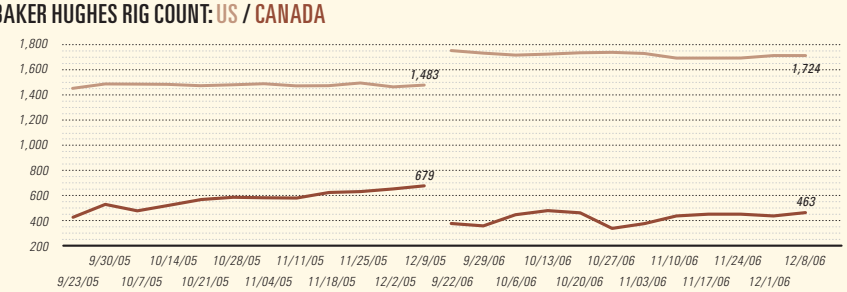
[1]Based on revised figures. [2]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil.
[3]Weekly average of daily closing futures prices.

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



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

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strategy to invest heavily in Russian oil and gas work, said R.S. Butola, managing director of ONGC Videsh Ltd. (OVL).

OVL, the overseas subsidiary of state-owned Oil & Natural Gas Corp., initiated discussions with OAO Rosneft and OAO Gazprom for compiling a joint bid to buy into Sakhalin-3.

Butola's comments came during a formal function to receive the first consignment of crude from Russia's Sakhalin-1 project, in which OVL holds 20% interest. Russian oil tanker MK Viktortitov, an OVL charter, delivered 92,055 tonnes (672,000 bbl) of Sokol crude. A second shipment is expected by Dec. 31.

ExxonMobil Corp. holds 30% interest in Sakhalin-1, Japan's Sakhalin Oil & Gas Development Co. holds 30%, and Rosneft and OVL each hold 20%.

Anadarko makes gulf find at Mission Deep

Anadarko Petroleum Corp. has made an oil discovery at its Mission Deep prospect on Green Canyon Block 955 in the Gulf of Mexico. The discovery well found more than 250 ft of net oil pay in the primary middle Miocene objective.

The well, in 7,300 ft of water, was drilled to TD 25,000 ft. Future plans include deepening the well to a secondary lower Tertiary objective and drilling a sidetrack well to further delineate the extent of the reservoir, the company said.

The discovery at Mission Deep is the company's ninth out of 12 tests so far this year in the deepwater gulf. Anadarko is one of the top three leaseholders in the deepwater gulf with an inventory of about 150 prospects and leads, representing an estimated 13-18 billion bbl of gross, unrisked resource potential, the company said. Anadarko said it plans to drill 10-15 exploration tests over the next 2 years to evaluate this potential within its position in the Miocene and emerging lower Tertiary plays.

Anadarko, Mission Deep operator, holds a 50% working interest; Devon Energy Corp. has a 50% working interest.

ConocoPhillips, Santos test new Timor Sea well

A joint venture of ConocoPhillips and Santos Ltd. has confirmed the presence of natural gas in another field in the eastern Timor Sea during its aggressive search for reserves to feed a second LNG train at its Darwin liquefaction plant.

The JV recorded a strong flow from the Barossa-1 well. It is on an old Royal Dutch Shell discovery, Lyndoch, on Permit NT/P69 about 295 km northeast of Darwin and near the maritime boundary with Indonesia.

The main test, on a high quality reservoir interval, flowed gas at 30 MMcfd through a $^{5}/_{64}$-in. choke accompanied by condensate at 7-9 bbl/MMcf of gas. The flow rates were constrained by limitations of the rig equipment.

An earlier test of a lesser-quality reservoir flowed at 0.8 MMcfd of gas through a 1-in. choke.

Barossa-1 is the third well on the structure following Shell's Lyndoch-1, drilled in 1973, and Lyndoch-2, drilled in 1998. Shell abandoned the prospect as uneconomic at the time.

The reservoir lies about 4,250 m subsea in 233 m of water.

The one drawback, in common with other finds in this eastern Timor Sea region, is the relatively high levels of carbon dioxide—in Barossa's case 16%.

The JV's earlier Caldita discovery immediately to the south in an adjoining permit has similar CO_2 content, as does Santos' Evans Shoal field to the southwest.

Nevertheless, the Barossa-1 result is encouraging. It builds on the group's resources in this region and may result in a development that links all the fields in this general area via a trunk line to Darwin.

Japanese company Inpex Corp. also has a major discovery in Abadi field in Indonesian waters near the Australian offshore border. Because of its isolation from Indonesian infrastructure, Inpex is considering a development option to send Adabi gas via pipeline to Darwin. Like ConocoPhillips and Santos, Inpex holds an interest in the Darwin LNG plant.

Barossa-1 will now be plugged and abandoned and the rig moved south to drill a Caldita-2 appraisal.

ConocoPhillips has 60% of Barossa and Caldita while Santos holds 40%.

BHP to drill Ruby appraisal off Trinidad

A month after reporting an oil discovery with the Ruby-1 well on Block 3(a) off the northeast coast of Trinidad and Tobago, BHP Billiton and its partners are preparing to drill an appraisal well (OGJ, Dec. 11, 2006, Newsletter).

BHP Billiton confirmed it will spud the Ruby-2 well soon and finish drilling in 5-7 weeks. Ruby-2 is being drilled in 200 ft of water on Block 3(a) by Nabors Offshore's Nabors 657 jack up rig.

Block 3(a) is operated by BHP Billiton, which has a 25.5% interest. Partners are Talisman (Trinidad Block 3a) Ltd., and Anadarko Petroleum Corp., each with 25.5% interest; Petrotrin, 15%; and Total SA, 8.5%.

Engineering approved for Kipper gas field

A group comprising ExxonMobil Corp., BHP Billiton, and Santos Ltd. has agreed to begin engineering and design on the Kipper gas field development in the offshore Gippsland basin of southeast Victoria.

The field, operated by ExxonMobil's Australian subsidiary, is in 100 m of water about 45 km off the coast. It holds about 620 bcf of gas and 30 million bbl of condensate. Discovered in 1986, it is the largest undeveloped gas field in the region.

The intention is to bring Kipper gas and condensate ashore for treatment in the ExxonMobil-BHP Bass Strait production facilities at Longford in Victoria. Entry into the system would be via the West Tuna platform. Kipper straddles the boundary between two permits, so the field has been unitized for development. ExxonMobil and BHP each has 32.5%, while Santos, which bought Woodside's interest in May, has 35%.

ExxonMobil says a final investment decision is expected in 2007. Production could then begin by the end of the decade.

Gas flow up at Greater Natural Buttes, Utah

The giant Greater Natural Buttes area in the Uinta basin reached a milestone in September, averaging a gross 225 MMcfd of gas, said operator Anadarko Petroleum Corp.

Anadarko has more than 1,400 wells and owns and operates a 700-mile gathering system in the basin. The 2006 program called

for the drilling of 270 wells, and 4,900 drillsites are in inventory.

The company, which holds 237,000 net acres in the heart of the field, is exploiting tight gas formations with 12 rigs, including 8 operated rigs. Anadarko has drilled 3 pilot wells on 20-acre spacing to evaluate recovery potential in the field's more developed areas drilled on 40-acre units.

A slick-water completion pilot program begun in the first quarter of 2006 has grown to 61 wells and resulted in an average frac cost reduction of $100,000/well with no material effect on well performance, the company said.

Eight Trinidad and Tobago blocks draw bids

Nine companies entered bids for 8 of the 11 onshore and nearshore blocks offered by the government of Trinidad and Tobago.

The bid round was completed after more than a year's delay caused by the introduction of a new production-sharing contract.

Many large oil and gas companies did not bid for the small nearshore and onshore blocks but are expected to bid in the Atlantic Deep bid round, which concluded Dec. 15.

Of the 11 blocks on offer there were no bids for the Herrera shallow and deep horizon blocks as well as NCMA 3 (OGJ Online, Mar. 24, 2006).

Among companies bidding for blocks were Australia's Hardman Oil & Gas Pty. Ltd. and the Indian partnership of Oil & Natural Gas Corp. and Mittal. ✦

Drilling & Production — *Quick Takes*

Petrobras gets OK for FPSO in Gulf of Mexico

Petroleo Brasileiro SA (Petrobras) has received approval from the US Minerals Management Service for the conceptual subsea development plan of Cascade and Chinook oil fields in the Gulf of Mexico.

This is the first time the agency approved a plan that includes the deployment of a floating, production, storage, and offloading vessel in the gulf.

Oil production from the project is scheduled to start in 2009, since field operator Petrobras intends to use its new technologies to allow a fast-tracked development approach.

Petrobras proposes to use six technologies, which are new to the US gulf, including a disconnectable turret buoy allowing the FPSO to move offsite during hurricanes and severe weather, crude transportation via shuttle tanker, free-standing hybrid risers, subsea electric submersible pumps, torpedo pile vertical-loaded anchors, and polyester mooring systems.

The development plan consists of the installation and operation of a FPSO in about 8,200 ft of water. It provides for at least two subsea wells in Cascade and one subsea well in Chinook, each drilled to about 27,000 ft and to be tied back to the FPSO. Based on reservoir performance, the development plan could be expanded to include additional wells on each unit.

More detailed engineering studies will now be carried out, including the preparation of the Deepwater Operations Plan which will include all technical details demonstrating that these technologies will meet or exceed the current requirements for operations in the gulf.

Petrobras holds 50% and 66.67% interests respectively in the Cascade and Chinook units. Devon Energy Corp. owns the remaining 50% of Cascade unit and Total E&P USA Inc. owns 33.33% of Chinook unit.

E&P firms compete to drill wells in UKCS

Oil and gas exploration and production firms operating in the UK Continental Shelf (UKCS) are planning to drill about 180 wells in 2006-08, according to a report published by UK based North Sea consultancy Hannon Westwood. Around $2 billion/year of investment will be required to boost production from the mature province.

Companies will compete intensely for drilling rigs, the consultancy added, noting that there is a rig utilization rate of 93-100% of Europe's 72-rig offshore fleet. There are 143 companies with UKCS interests, many of which are small independent North Sea companies and listed on the Alternative Investment Market in London. The wells are expected to add 500 million boe/year of reserves.

A key problem for small companies is accessing finance for their drilling operations, but this has been particularly exacerbated recently because of the growth of small companies looking for oil and gas in the UKCS, delegates told OGJ at the Prospects Fair in London. The event, organized by the UK government's Department for Trade and Industry, and the Petroleum Exploration Society of Great Britain, which brings small companies together to seek partners in developing their prospects.

"With more opportunity than available funds over the next few years, we can expect a wave of mergers or acquisitions among those 80 companies who have exploration licenses but do not have North Sea production," said Charles Westwood, Hannon Westwood founding partner. "Perhaps 30 of these 80 new-start companies will survive in the long run."

The strong competition for exploration opportunities has been demonstrated by the record number of applications for acreage under the UK's 24th licensing round. The results have not yet been announced although they are meant to be reported in the fall. About 141 companies have applied for licenses. DTI said the results have been delayed because it is carrying out additional environmental checks against the applications to comply with the European Union's Habitat Directive.

The report added that the ownership of licenses and acreage has dramatically changed also: "We have gone from a license system where acreage could be held with little effective challenge for up to 40 years, to a system where a three year lull in activity will now place the property on the ramps for either third-party investment or relinquishment."

The UKCS has entered into a dynamic period "when value is no longer measured simply by traditional production, but is also much more a function of exploration acreage and secured drilling activity", the report concluded.

Fort Hills files plan for heavy oil upgrader

Petro-Canada Oil Sands Inc., on behalf of Fort Hills Energy LP, filed an application with the Alberta Energy and Utilities Board for the construction and operation of a heavy oil upgrader in Sturgeon County, about 40 km northeast of Edmonton (OGJ, Feb. 13, 2006, Newsletter).

The upgrader is expected eventually to process as much as 340,000 b/d of bitumen from the Fort Hills mine and other production sources into as much as 280,000 b/d of synthetic crude oil. The Fort Hills mine, which obtained regulatory approval in 2002 for as much as 190,000 b/d of bitumen production, is about 90 km north of Fort McMurray, Alta. Production is planned to start in 2011.

Fort Hills Energy partners are Petro-Canada, Calgary, 55%; UTS Energy Corp., Calgary, 30%; and mining company Teck Cominco Ltd., Vancouver, BC, 15%. Petro-Canada Oil Sands serves as the project's contract operator. ✦

Processing — *Quick Takes*

HPCL seeks partners for Vizag plant expansion

State-run refiner Hindustan Petroleum Corp. Ltd. (HPCL) is seeking partners for investments, oil procurement, and product marketing as part of its proposed Visakhapatnam (Vizag) refinery expansion.

HPCL plans to expand the Vizag refinery's capacity to 16.5 million tonnes/year from 7.5 million tonnes/year. Project consultant Engineers India Ltd. estimates the expansion cost at $2 billion.

Once the proposed expansion is completed, HPCL plans to dismantle an uneconomical plant having a capacity of 1.5 million tonnes/year. The effective net refining capacity of the Vizag plant then would be 15 million tonnes/year.

Ecopetrol plans Barrancabermeja upgrade

State-owned Ecopetrol has let a project management consulting contract to Technip for an upgrade of its 205,000 b/cd refinery in Barrancabermeja, Colombia.

The $50 million contract covers front-end design, detailed engineering, and procurement services for process units, as well as supervision of contractors' activities for engineering, procurement, and construction.

The project includes a 19,000 b/sd gasoline hydrodesulfurization (HDS) unit and a 57,000 b/sd diesel HDS unit (both based on Axens technology); a 19,000 MMscfd hydrogen production unit; a 55 ton/day sulfur recovery unit, a 110 ton/day tail gas treatment unit; a 500 gpm sour water stripper; and a 30 gpm diesel-gasoline amine regeneration unit.

The project is slated for completion in fourth quarter 2009.

Grupa Lotos lets contract for Gdansk HDS unit

Grupa Lotos SA, Poland's second largest refiner, let a contract to ABB of Zurich for the engineering, procurement, and construction of a diesel hydrodesulfurization (HDS) unit at its 90,000-b/cd refinery in Gdansk, Poland.

The $130 million award is part of Grupa Lotos's $1.3 billion residue-upgrade project.

The HDS unit will enable Grupa Lotos to meet European Union requirements that diesel contain less than 10 ppm of sulfur, which will come into force in 2009.

ABB Lummus Global's business in Wiesbaden, Germany, will handle the work. Project start is planned for early 2009.

The unit will use Chevron-Lummus Global technology. It help Grupa Lotos increase production of ultralow-sulfur diesel to about 2.3 million tonnes/year. ✦

Transportation — *Quick Takes*

Canaport LNG lets contract for St. John terminal

Canaport LNG LP, a partnership of Repsol YPF SA and Irving Oil Ltd., has let a contract to Foster Wheeler Canada Ltd. for project management consultancy services for an LNG regasification terminal with 1 bcfd of gas capacity planned in St. John, NB (OGJ Online, May 18, 2006).

Terms of the award were not disclosed.

Foster Wheeler also will provide technical advisory services during the detailed engineering, procurement, construction, commissioning, and start-up phases of the project. Services will be performed in cooperation with Foster Wheeler USA Corp. in Houston. The Canaport terminal is slated for completion in late 2008.

Pertamina, partners plan LNG plant on Sulawesi

Indonesia's state-owned PT Pertamina, PT Medco Energi Internasional, and Japan's Mitsubishi Corp. plan to build a 2 million tonne/year LNG plant at Senoro on the island of Sulawesi. Construction is projected to begin in 2007, with completion targeted for 2009.

Senoro gas field, which has proved reserves of 2.3 tcf of gas, will provide gas to the plant, which will cost some $1 billion, with $600-800 million to be invested by Mitsubishi.

Pertamina Vice-Pres. Iin Arifin Takhyan said Mitsubishi will be an offtaker of LNG from the project, while Medco Pres. Hilmi Panigoro said the Indonesian government already has approved plans to export LNG from the plant to Japan.

In late November, Pertamina and Medco announced they were still in the process of selecting a Japanese partner for the 2 million tonne/year liquefaction plant they planned to build in Senoro (OGJ Online, Nov. 27, 2006).

The decision over Mitsubishi comes within a framework of wider cooperation on energy between Japan and Indonesia signed in November.

The agreement calls for cooperation in ensuring stable supplies of energy and mineral resources, including LNG, from Indonesia to Japan. ✦

Jostein Jaasund, Tenaris logistics manager in Norway, coordinates pipe and accessory deliveries for the offshore operations.

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2007

JANUARY

Petrotech India Conference and Exhibition, New Delhi, +44 (0) 20 8439 8890, +44 (0) 20 8439 8897 (fax), e-mail: adam.evan-cook@reedexpo.co.uk, website: www.petrotech2007.com. 15-19.

Offshore Asia Conference & Exhibition, Kuala Lumpur, (918) 831-9160, (918) 831-9161 (fax), e-mail: oaconference@pennwell.com, website: www.offshoreas-iaevent.com. 16-18.

Power-Gen Middle East Conference, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.pennwell.com. 22-24.

API Exploration and Production Winter Standards Meeting, Scottsdale, Ariz., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org. 22-26.

Deepwater Operations Conference & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepwater-operations.com. 23-25.

SPE Hydraulic Fracturing Technology Conference, College Station, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 29-31.

Underwater Intervention Conference, New Orleans, (281) 893-8539, (281) 893-5118 (fax), website: www.underwaterintervention.com. Jan. 30-Feb.1.

FEBRUARY

NAPE Expo, Houston, (817) 847-7700, (817) 847-7704 (fax), e-mail: nape@landman.org, website: www.napeonline.com. 1-2.

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

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

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

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

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

International Petrochemicals & Gas Technology Conference & Exhibition, London, +44 (0) 20 7357 8394, e-mail: Conference@EuroPetro.com,

website: www.europetro.com. 12-13.

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

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

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

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

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

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

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

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

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

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

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

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

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

MARCH

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

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

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

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

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

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

Annual Fuels & Lubes Asia Conference, Bangkok, +632 772 4731, +632

Calendar

772 4735 (fax), e-mail: conference@flasia.info, website: www.flasia.info. 7-9.

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

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

NACE Annual Conference & Exposition, Nashville, (281) 228-6200, (281) 228-6300, website: www.nace.org. 11-15.

NPRA Security Conference, The Woodlands, Tex., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 12-14.

China Offshore Expo, Tianjin, 84 8 9634388, 84 8 9635112 (fax), e-mail: cp-info@hcm.vnn.vn, website: www.cpexhibition.com. 15-17.

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

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

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

Offshore West Africa Conference & Exhibition, Abuja, (918) 831-9160, (918) 831-9161 (fax), e-mail: owaconference@pennwell.com, website: www.offshorewestafrica.com. 20-22.

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

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

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

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

IADC/SPE Managed Pressure Drilling & Underbalanced Operations Conference, Galveston, Tex., (713) 292-1945, (713) 292-1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 28-29.

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

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

APRIL

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

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

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

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

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Settle for a slowdown

Marilyn Radler
Senior Editor-Economics

Elevated exploration and production activity has driven up costs for operators. This was bound to lead to a slowdown in companies' ability to continue to drill and profit at the accelerated pace of the past couple of years, which originally was spurred by rising worldwide demand for oil and gas amid limited excess production capacity.

Earlier this month Devon Energy Corp. announced that it was reducing its 2007 capital budget projections from its 2006 E&P spending. In addition, the Oklahoma City oil and gas producer forecast that its production volumes next year and through 2009 will be lower than originally projected.

The reasons behind the reduced projections include rising costs of services and equipment in Canada, where the development of heavy oil demands abundant resources, human and otherwise.

Devon said it had cut activity levels on conventional gas projects in Canada until business conditions improve.

"Competitive pressures for equipment, services, and supplies in Canada have created a highly inflationary cost environment. In addition, the strengthening of the Canadian dollar relative to the US dollar has negatively impacted profit margins on these projects," the company said. This curtailment of drilling activity in Canada is the largest factor contributing to the revisions from Devon's previous estimates of production over the next 3 years.

Also, Devon said this year's higher-than-expected oil prices and higher forecast prices for 2007-09 have reduced its expected production from areas where the company operates under production-sharing agreements. Under the terms of PSAs, higher oil prices increase revenues and profitability, but higher prices also reduce reported production volumes.

Devon is not the only company to forecast a slowdown in its investments for 2007. E&P spending in Canada this year will decline 8% following a 19% increase last year, according to the newest Lehman Bros. E&P spending survey.

In addition to reduced spending, there will be a decline in E&P of conventional oil and gas and a rise in the development of oil sands and coalbed methane in Canada. And a growing amount of natural gas will be required for oil sands development.

How high, how fast?

Oil sands now account for 39% of Canada's total oil production at approximately 1 million b/d, according to the Canadian Association of Petroleum Producers (CAPP). By 2020, production will grow to 4 million b/d, CAPP says.

The association's latest figures show that in 2005, capital spending on oil sands projects grew to $10.4 billion (Can.) from $6.2 billion (Can.) a year earlier. Over the same period, capital spending on conventional oil and gas projects in Canada grew 30% to $34.8 billion (Can.).

Growth in the number of wells drilled was not as pronounced as in 2005, though. The number of gas wells drilled in Canada grew 5%, while the number of oil wells drilled there last year climbed 21%.

A presentation by CAPP's Greg Stringham to the 2006 annual meeting of the Independent Petroleum Association of America in October showed that the association expects the total number of wells drilled in Canada to decline 6% in 2007. The number of conventional gas wells drilled in western Canada is expected to decline next year, while the number of coalbed methane wells in that part of the country, especially in Alberta, is forecast to increase.

Finding and development costs for natural gas in Canada have risen dramatically since 1987. Stringham's figures showed that the 5-year rolling average had soared to nearly $2.50/Mcf (Can.) in 2004 from less than 50¢/Mcf (Can.) in the late 1980s.

Stringham predicted that in 2007 lower commodity prices and reduced capital investment will be realities in Canada, as drilling and land sales decline. But he said costs will continue to rise. Globally, the cost of steel and other materials will rise next year but will begin to plateau.

In addition, the cost of labor will remain tight in Canada, as demand for workers to mine and upgrade oil sands stays strong. CAPP projects that capital expenditures for oil sands in 2007 will be the one growth area, with outlays up $1.5 billion (Can.) from this year. The good news is that the overall decrease in E&P activity should mean that land and drilling costs will begin to moderate. ✦

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Energy to Trade

Editorial

Cynicism and corruption

The first foe in any fight against corruption is cynicism. Corruption thrives where people consider it part of the natural order. And where corruption thrives, economies struggle, political systems decay, and people suffer. Any program to combat poverty must address corruption. Any effort to improve political systems must address corruption. Any oil company seeking rights to make money developing resources must address corruption.

Apparently, cynicism about corruption remains high. Transparency International (TI) this month released its annual Global Corruption Barometer, a public opinion survey indicating that people around the world lack confidence in anticorruption efforts by governments. According to the barometer, conducted for TI by Gallup International, 69% of nearly 60,000 people surveyed in 62 countries believe their governments are ineffective in fighting corruption or worse. At least some of this failure of confidence must flow from the belief that corruption is an incorrigible part of life.

Global cynicism

The cynicism is global. Shares of respondents calling government anticorruption efforts ineffective were 42% in Europe and 50% in North America. What's more, 19% of North Americans, 15% of Asians, and 23% of Latin Americans believe their governments encourage corruption. The concern in North America and Western Europe is about widespread corruption, the survey showed; direct involvement in bribe-paying is lower in those regions than in developing countries. "In spite of the lack of day-to-day experience with bribe-paying," TI said, "respondents in North America think that the business environment (85%) and political life (89%) are affected to a moderate or large extent by corruption."

Changing the cynicism that fosters corruption requires leadership.

At the World Bank, Pres. Paul D. Wolfowitz has tried to make resistance to corruption in poor countries a priority. Under his administration, the bank has withheld financing of several projects because of suspected corruption. Lately, however, the institution has undermined his effort. In September, shareholder governments on the bank's development committee took over management of the anticorruption program. Comments quoted in the New York Times by a former World Bank senior vice-president revealed a troubling attitude. Saluting anticorruption efforts as "an essential part of development finance," the former official nevertheless said, "The bank should not overemphasize its anticorruption agenda at the expense of other policies required for development." In other words, acknowledge that corruption is a problem, but don't let concern about it stop the money flow. No wonder people are cynical.

On Dec. 11, outgoing United Nations Sec. Gen. Koffi Annan, in a speech at the Truman Presidential Museum and Library in Independence, Mo., described five lessons he's learned in his decade of UN leadership: collective responsibility, global solidarity, the rule of law, mutual accountability, and multilateralism. He didn't mention corruption. Since the multibillion-dollar Oil-for-Food scandal, of course, corruption has been an especially touchy subject at the UN. While Annan wasn't personally implicated in that mess, it's hard to imagine how lessons on the subject failed to make his top-five lessons list. The omission relegates corruption to the nether realms of UN concerns and makes the Conference of States Parties of the UN Convention Against Corruption, which was meeting in Jordan as Annan spoke, look like a forgettable sideshow. It deserves more support than that from the UN boss.

An example?

Annan's speech irked some commentators because of the backhanded scolding it gave the US on subjects such as human rights, the use of military force, and unilateralism in foreign affairs. Some commentators saw a rebuke of the Bush administration in Annan's appeal for "far-sighted American leadership." Maybe. Or maybe Annan was just recognizing US stature and the obligations that come with it. One of those obligations must be to set a standard of zero toleration for corruption in any form at any time. As recent scandals in Congress show, this area needs work.

With words and action, the oil and gas industry must respond to any lapse it sees into popular or official cynicism on corruption. Its right to work depends greatly on economic and social benefits associated with resource development. Corruption dissipates those benefits. It's not inevitable. It's intolerable. ✦

Oil production, reserves increase slightly in 2006

Marilyn Radler
Senior Editor-Economics

Worldwide oil and gas reserves rose in 2006 as oil production posted a small increase from a year earlier, according to Oil & Gas Journal's annual worldwide survey of production and reserves. Remaining oil reserves still exceed estimated cumulative production.

Reserves estimates for oil are up 2% from the previous survey, while gas reserves estimates are 1% greater (OGJ, Dec. 19, 2005, p. 20). Total proved crude and condensate reserves stand at 1.317 trillion bbl, and proved natural gas reserves are 6.18 quadrillion cu ft.

The volume of oil reserves held by members of the Organization of Petroleum Exporting Countries moved up slightly from the previous survey, but OPEC's estimated gas reserves were down a bit. The organization controls 68.5% of the world's proved oil reserves and 51% of total proved gas reserves.

OGJ's estimates of proved reserves are compiled from a survey of official sources. Since most countries don't reassess resources annually, many estimates are unchanged from the previous report.

Reserves changes

Most changes to reserves estimates are small due to a combination of this year's production and recent discoveries. In addition, higher oil prices have resulted in reevaluations due to economics.

Canada and the US this year reported higher oil and gas reserves, but Mexico's newest estimates are declines. Oil reserves in Brazil and Argentina are higher, while gas reserves in those countries moved lower. Collectively, oil and gas reserves for countries in the Western Hemisphere changed negligibly from the previous report.

The Canadian reserves estimate is predominantly oil sands.

The country's conventional oil reserves are estimated at 5.2 billion bbl, up 20% from a year ago, according to the Canadian Association of Petroleum Producers (CAPP). The increase is due in large part to revisions to the three producing projects off Newfoundland, CAPP said.

The Alberta Energy and Utilities Board estimates Canadian oil sands reserves at 174 billion bbl.

Reported reserves in the UK declined for both oil and gas. The changes are due to this year's production as well as reserves revisions in established fields and reserves additions from new field developments, including those resulting from recent exploration success, the UK Department of Trade and Industry reported.

OGJ reports gains for a few countries' reserves based on new data. For example, oil reserves in Kazakhstan, Sudan, and Equatorial Guinea are up sharply from the previous report as a result of better information from operators in those countries.

Due to the change in Kazakhstan's reserves, collective oil reserves in Eastern Europe and the former Soviet Union are up 26%, leading all other regions in combined changes.

Propelled by increases for Australia and China, gas reserves estimates in the Asia-Pacific region are up 7%, while Western Europe's gas reserves declined

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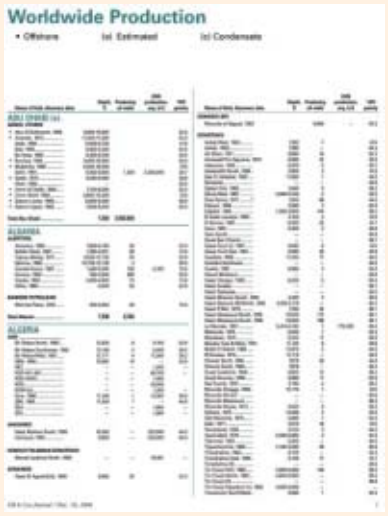

10% from a year ago. The other regions collectively show little or no change to gas reserves.

OPEC countries' reserves are little changed from a year earlier. Oil reserves are reported slightly higher for Iran, Algeria, Libya, and Nigeria but a bit lower for Saudi Arabia. OPEC marginally adjusted its gas reserves in a handful of its member countries.

US reserves

The latest estimates from the US Energy Information Administration show increases for both oil and gas reserves during 2005.

Proved reserves of dry natural gas in the US increased 6% during 2005, the largest annual increase since 1970. Last year's was the seventh increase in a row for gas reserves. Recording a 2% increase, US crude oil reserves moved up for the first time in 3 years.

EIA reported that gas reserves additions onshore in the Lower 48 states were large enough to overcome a 10% decline in gas reserves for federal areas of the Gulf of Mexico. Texas and Colorado led reserves additions with increases in Newark East field of the Barnett Shale and tight sands and coalbeds of Ignacio-Blanco field.

Most gas reserves additions were from extensions of existing fields rather than new field or reservoir discoveries. Field extensions totaled 21.05 tcf last year, while new field discoveries were 942 bcf. New reservoir discoveries in old fields were 1.21 tcf.

Coalbed methane reserves increased 8% and accounted for 10% of dry gas reserves in the US last year, as production climbed less than 1% from 2004.

EIA also reported that while several large deepwater discoveries made recently have not yet been booked as proved reserves, reserves additions of crude oil replaced 122% of 2005 production. Texas reported the largest oil reserves additions, mostly in the Permian basin. Wyoming and Montana posted the second and third largest increases.

Total 2005 discoveries of crude oil in the US were 1.05 billion bbl, with new field discoveries of 205 million bbl, mostly from the federal Gulf of Mexico. New reservoir discoveries in old fields amounted to 41 million bbl.

In addition, EIA reported that proved reserves of natural gas liquids in the US increased 3% last year as operators replaced 130% of production. Total NGL reserves stood at 8.165 billion bbl at the end of 2005.

Oil production

Cumulative worldwide crude oil production surpassed 1 trillion bbl during 2006, according to calculations based on DeGolyer and MacNaughton figures indicating cumulative output of 986.5 billion bbl through 2005 (OGJ, Nov. 27, 2006, p. 20).

Worldwide crude and condensate production this year averaged 72.39 million b/d, according to OGJ estimates. This is up from 72.26 million b/d last year.

The region with the largest gain in crude output this year is Eastern Europe and the former Soviet Union. This increase was led by oil production in Kazakhstan, Russia, and Azerbaijan.

Some regions saw a collective decline in oil production this year. Output in Western Europe declined almost 10% from a year earlier, as Norway, Denmark, and the UK reported lower oil production.

Combined oil production in North America and Latin America was just 0.4% lower than during 2005. While Canada and Brazil recorded increases, Mexico and the US posted declines for this year. OGJ estimates that US oil production averaged 5.135 million b/d, down from 5.178 million b/d last year.

OPEC oil production this year averaged an estimated 29.66 million b/d vs. 29.77 million b/d last year. Indonesia, Saudi Arabia, Venezuela, and Nigeria posted declines, while production in Kuwait and Qatar is estimated to have increased. ✦

A DECADE OF RESERVES CHANGES

Table 1

Jan. 1	World	OPEC	World gas, bcf
	1,000 bbl		
2007	1,317,447,415	902,343,000	6,182,692
2006	1,293,344,534	901,659,000	6,101,158
2005	1,277,701,992	885,188,000	6,040,208
2004	1,265,811,583	869,521,000	6,068,302
2003	1,212,880,852	819,007,000	5,501,424
2002	1,031,100,681	818,842,000	5,451,332
2001	1,028,457,585	814,398,710	5,278,484
2000	1,016,041,221	802,479,710	5,146,207
1999	1,034,264,678	800,479,710	5,144,753
1998	1,019,545,664	797,134,589	5,086,469

Source: OGJ Worldwide Production Reports

RUSSIAN PRODUCTION

Table 2

	1,000 b/d
2005	9,190
2004	8,887
2003	8,216
2002	7,405
2001	6,781
2000	6,325
1999	5,930
1998	5,919
1997	5,914
1996	5,844

WORLDWIDE LOOK AT RESERVES AND PRODUCTION

	ESTIMATED PROVED RESERVES				OIL PRODUCTION			
	Jan. 1, 2007		Jan. 1, 2006					
COUNTRY	Oil (1,000 bbl)	Gas (bcf)	Oil (1,000 bbl)	Gas (bcf)	Producing oil wells* Dec. 31, 2005	Estimated 2006 (1,000 b/d)	Change from 2005 (%)	Actual 2005 (1,000 b/d)
ASIA-PACIFIC								
Afghanistan	—	1,750	—	1,750	—	—	—	—
Australia	1,591,790	30,370	1,437,000	27,640	1,325	450.0	–5.3	471.5
Bangladesh	28,000	5,000	28,000	5,000	41	4.0	0.0	4.0
Brunei	1,100,000	13,800	1,350,000	13,800	779	197.0	5.6	186.5
China	16,000,000	80,000	18,250,000	53,325	71,542	3,700.0	2.0	3,627.1
China, Taiwan	2,380	297	2,380	297	71	1.0	—	1.0
India	5,624,640	37,960	5,847,840	38,880	3,674	682.0	3.5	659.1
Indonesia	4,300,000	97,780	4,301,000	97,786	8,331	892.0	–5.6	945.0
Japan	58,500	1,400	58,500	1,400	145	15.0	–4.0	15.6
Malaysia	3,000,000	75,000	3,000,000	75,000	788	737.0	–4.3	770.0
Myanmar	50,000	10,000	50,000	10,000	450	13.0	0.0	13.0
New Zealand	53,000	900	53,000	900	72	14.0	0.7	13.9
Pakistan	289,202	28,000	289,202	28,153	204	63.5	–1.6	64.5
Papua New Guinea	240,000	12,200	240,000	12,200	44	56.5	22.8	46.0
Philippines	138,500	3,480	138,500	3,960	11	16.0	4.6	15.3
Thailand	290,000	14,750	291,000	14,754	905	212.0	14.0	186.0
Vietnam	600,000	6,800	600,000	6,800	28	350.0	2.9	340.0
Total Asia-Pacific	**33,366,012**	**419,487**	**35,936,422**	**391,645**	**88,410**	**7,403.0**	**0.6**	**7,358.5**
WESTERN EUROPE								
Austria	50,000	570	62,000	530	905	17.4	0.6	17.3
Denmark	1,277,000	2,542	1,328,000	2,786	217	342.0	–9.4	377.3
France	121,500	341	158,400	378	463	21.5	–0.8	21.7
Germany	367,000	9,000	367,200	9,076	1,006	69.0	–3.4	71.5
Greece	5,000	35	7,000	35	12	1.8	—	1.8
Ireland	—	350	—	350	—	—	—	—
Italy	600,000	5,800	621,700	8,000	207	105.0	–8.7	115.0
Netherlands	100,000	50,000	106,000	62,000	203	23.0	–20.7	29.0
Norway	7,849,300	82,320	7,705,000	84,260	801	2,465.0	–8.6	2,697.6
Spain	150,000	90	157,626	90	3,300	3.0	–9.9	3.3
Turkey	300,000	300	300,000	300	852	42.0	—	42.0
United Kingdom	3,875,000	17,000	4,029,480	18,750	1,360	1,480.0	–11.8	1,678.0
Total Western Europe	**14,694,800**	**168,349**	**14,842,406**	**186,555**	**9,326**	**4,569.7**	**–9.6**	**5,054.5**
EASTERN EUROPE and FSU								
Albania	198,130	30	198,130	30	1,338	7.0	15.3	6.1
Azerbaijan	7,000,000	30,000	7,000,000	30,000	130	625.0	41.0	443.3
Belarus	198,000	100	198,000	100	—	35.0	–1.4	35.5
Bulgaria	15,000	200	15,000	210	100	1.0	—	1.0
Croatia	74,320	1,052	69,144	1,000	864	16.8	–4.0	17.5
Czech Republic	15,000	140	15,000	140	—	4.7	–2.1	4.8
Georgia	35,000	300	35,000	300	281	2.0	—	2.0
Hungary	20,180	286	102,480	1,210	875	16.5	–13.2	19.0
Kazakhstan	30,000,000	100,000	9,000,000	65,000	705	1,060.0	6.6	994.2
Kyrgyzstan	40,000	200	40,000	200	—	1.0	—	1.0
Lithuania	12,000	—	12,000	—	—	3.6	–16.3	4.3
Poland	96,375	5,820	96,375	5,820	512	17.0	–14.6	19.9
Romania	600,000	2,225	955,620	3,550	6,000	98.4	–1.6	100.0
Russia	60,000,000	1,680,000	60,000,000	1,680,000	38,173	9,475.0	3.1	9,190.0
Serbia	77,500	1,700	77,500	1,700	646	15.0	—	15.0
Slovakia	9,000	500	9,000	530	—	1.0	—	1.0
Tajikistan	12,000	200	12,000	200	—	—	—	—
Turkmenistan	600,000	100,000	546,000	71,000	2,460	165.0	–15.4	195.0
Ukraine	395,000	39,000	395,000	39,600	1,353	97.0	–1.0	98.0
Uzbekistan	594,000	65,000	594,000	66,200	2,190	105.0	–7.1	113.0
Total Eastern Europe and FSU	**99,991,505**	**2,026,753**	**79,370,249**	**1,966,790**	**55,627**	**11,746.0**	**4.3**	**11,260.6**
MIDDLE EAST								
Abu Dhabi	92,200,000	198,500	92,200,000	198,500	1,200	2,450.0	6.5	2,300.0
Bahrain	124,560	3,250	124,560	3,250	496	172.0	–1.4	174.4
Dubai	4,000,000	4,000	4,000,000	4,000	200	90.0	–11.8	102.0
Iran	136,270,000	974,000	132,460,000	971,150	1,120	3,850.0	–1.0	3,890.8
Iraq	115,000,000	112,000	115,000,000	111,950	1,685	1,915.0	5.8	1,810.0
Israel	1,960	1,275	2,000	1,375	6	0.1	0.0	0.1
Jordan	1,000	213	1,000	220	4	—	—	—
Kuwait	99,000,000	54,500	101,500,000	55,515	790	2,200.0	3.3	2,130.0

COUNTRY	ESTIMATED PROVED RESERVES Jan. 1, 2007 Oil (1,000 bbl)	Gas (bcf)	Jan. 1, 2006 Oil (1,000 bbl)	Gas (bcf)	OIL PRODUCTION Producing oil wells* Dec. 31, 2005	Estimated 2006 (1,000 b/d)	Change from 2005 (%)	Actual 2005 (1,000 b/d)
Neutral Zone	5,000,000	1,000	5,000,000	1,000	578	575.0	–0.9	580.0
Oman	5,500,000	30,000	5,506,000	29,280	2,298	738.0	–2.6	757.5
Qatar	15,207,000	910,500	15,207,000	910,520	421	820.0	2.7	798.3
Ras al Khaimah	100,000	1,200	100,000	1,200	7	0.7	–30.0	1.0
Saudi Arabia	259,800,000	239,500	264,310,000	241,340	1,560	8,990.0	–0.8	9,060.0
Sharjah	1,500,000	10,700	1,500,000	10,700	49	50.0	—	50.0
Syria	2,500,000	8,500	2,500,000	8,500	132	422.5	–8.2	460.0
Yemen	3,000,000	16,900	4,000,000	16,900	1,402	415.0	0.9	412.8
Total Middle East	**739,204,520**	**2,566,038**	**743,410,560**	**2,565,400**	**11,948**	**22,688.3**	**0.7**	**22,526.9**
AFRICA								
Algeria	12,270,000	161,740	11,350,000	160,505	1,285	1,345.0	–0.5	1,351.7
Angola	8,000,000	2,000	5,412,000	1,620	1,068	1,385.0	11.9	1,238.1
Benin	8,000	40	8,210	40	8	—	—	—
Cameroon	400,000	3,900	400,000	3,900	255	87.5	6.1	82.5
Chad	1,500,000	—	1,500,000	—	250	180.0	—	180.0
Congo (former Zaire)	180,000	35	187,000	35	150	20.0	—	20.0
Congo Brazzaville	1,600,000	3,200	1,505,900	3,200	460	240.0	—	240.0
Egypt	3,700,000	58,500	3,700,000	58,500	1,267	667.5	–4.0	695.0
Equatorial Guinea	1,100,000	1,300	12,000	1,300	38	320.0	–8.6	350.0
Ethiopia	428	880	428	880	—	—	—	—
Gabon	2,000,000	1,000	2,499,000	1,200	393	232.0	–0.9	234.2
Ghana	15,000	800	16,500	840	3	6.0	—	6.0
Ivory Coast	100,000	1,000	100,000	1,000	9	30.0	—	30.0
Libya	41,464,000	52,650	39,126,000	52,650	1,472	1,700.0	3.7	1,640.0
Mauritania	100,000	1,000	—	—	—	32.0	—	—
Morocco	988	58	1,069	60	7	0.2	32.5	0.2
Mozambique	—	4,500	—	4,500	—	—	—	—
Namibia	—	2,200	—	2,200	—	—	—	—
Nigeria	36,220,000	181,900	35,876,000	184,660	2,379	2,220.0	–7.8	2,406.7
Rwanda	—	2,000	—	2,000	—	—	—	—
Somalia	—	200	—	200	—	—	—	—
South Africa	15,000	—	15,680	1	28	20.0	–16.6	24.0
Sudan	5,000,000	3,000	563,000	3,000	9	295.0	1.7	290.0
Tanzania	—	230	—	800	—	—	—	—
Tunisia	400,000	2,300	307,560	2,750	239	65.0	–8.6	71.1
Total Africa	**114,073,416**	**484,433**	**102,580,347**	**485,841**	**9,320**	**8,845.2**	**–0.2**	**8,859.4**
WESTERN HEMISPHERE								
Argentina	2,468,000	16,090	2,320,450	18,866	15,874	635.0	–1.6	645.4
Barbados	2,852	6	2,500	5	77	1.0	5.3	1.0
Belize	6,700	—	—	—	—	1.0	—	—
Bolivia	440,000	24,000	440,500	24,000	346	45.0	8.2	41.6
Brazil	11,772,640	10,820	11,243,300	11,515	11,995	1,710.0	4.7	1,634.0
Canada	179,210,000	57,946	178,792,400	56,577	58,966	2,500.0	5.5	2,368.8
Chile	150,000	3,460	150,000	3,460	315	10.0	—	10.0
Colombia	1,453,000	3,996	1,542,000	4,040	7,644	530.0	0.7	526.1
Cuba	124,000	2,500	750,000	2,500	251	39.0	1.0	38.6
Ecuador	4,517,000	—	4,629,600	345	1,044	500.0	–6.0	532.0
Guatemala	83,070	—	526,000	109	20	16.5	–10.6	18.5
Mexico	12,352,000	14,557	12,882,200	15,985	3,052	3,273.0	–1.8	3,334.2
Peru	929,600	8,723	929,600	8,723	4,660	113.0	1.6	111.2
Suriname	111,000	—	111,000	—	523	12.8	6.7	12.0
Trinidad and Tobago	728,300	18,770	990,000	25,880	3,821	150.0	3.8	144.5
United States	21,757,000	204,385	21,371,000	192,513	507,928	5,135.0	–0.8	5,178.4
Venezuela	80,012,000	152,380	79,729,000	151,395	15,669	2,563.0	–5.3	2,705.8
Total Western Hemisphere	**316,117,162**	**517,633**	**316,409,550**	**515,913**	**632,541**	**17,234.3**	**–0.4**	**17,301.8**
TOTAL WORLD	**1,317,447,415**	**6,182,692**	**1,292,549,534**	**6,112,144**	**807,172**	**72,486.5**	**0.2**	**72,361.6**
Total OPEC	**902,343,000**	**3,152,350**	**901,659,000**	**3,152,871**	**36,746**	**29,660.7**	**–0.4**	**29,771.3**

*Does not include shut in, injection, or service wells.

E&P activity, refining drive third-quarter earnings

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Although most companies in a sample of US-based oil and gas firms posted moderate third-quarter 2006 profits or losses, big earnings gains by a handful of large operators propelled the group toward an increase in net income as compared with third-quarter earnings a year earlier.

Downstream results, led by strong refining and marketing margins, drove profits for refiners and integrated companies. Product demand, especially that for transportation fuels, was strong during the quarter as well as in the first 9 months of this year, pushing refining throughputs higher. Refinery utilization in the US held above 93% during the third quarter, according to the American Petroleum Institute.

On average oil prices in the recent quarter were higher year-on-year, but natural gas prices declined. The average price at the wellhead for oil during the third quarter of 2006 was up 14% from a year earlier to $65.07/bbl. The spot price for gas at Henry Hub averaged $6.314/MMbtu in the recent quarter vs. $9.531/MMbtu a year earlier.

A sample of service and supply companies reported a spike in earnings for the quarter and for the first half of this year, as nearly all of them recorded improved earnings from a year earlier. These firms continued to experience high demand for oil-field services and equipment and strong day rates during 2006.

A sample group of Canadian firms posted a jump in earnings for the quarter, while their combined net income for the first 9 months of this year more than doubled from the comparable 2005 period.

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

Table 1

	Revenues		Net income		Revenues		Net income	
	3rd quarter				Nine months			
	2006	2005	2006	2005	2006	2005	2006	2005
	Million $ (US)							
Abraxas Petroleum Corp.	13.2	14.2	0.6	3.8	39.8	31.6	2.8	2.8
Alon USA Energy Inc.	1,020.9	648.1	38.1	24.4	2,277.9	1,646.5	135.4	74.3
Anadarko Petroleum Corp.	3,498.0	1,525.0	1,461.0	598.0	7,008.0	4,270.0	2,937.0	1,596.0
Apache Corp.	2,261.5	2,061.1	647.1	687.0	6,322.1	5,482.6	2,031.6	1,835.5
Arena Resources Inc.	18.3	7.9	8.0	3.4	43.3	16.5	18.0	6.4
Aurora Oil & Gas Corp.	5.6	2.0	(2.1)	0.2	17.2	3.7	(4.0)	(0.6)
Berry Petroleum Co.	129.4	110.0	31.4	34.2	370.1	290.7	88.8	82.0
Bill Barrett Corp.	105.1	71.6	20.7	13.3	286.7	179.0	51.0	0.5
Brigham Exploration Co.	26.1	25.2	5.2	7.7	78.1	60.5	14.8	15.5
Cabot Oil & Gas Corp.	184.7	161.8	189.0	33.8	590.3	457.7	289.0	89.9
Carrizo Oil & Gas Inc.	20.5	18.9	4.8	(7.9)	59.6	50.6	14.0	(2.9)
Cheniere Energy Inc.	0.7	0.7	(33.1)	8.0	1.6	2.2	(52.5)	(11.2)
Chesapeake Energy Corp.	1,929.4	1,082.8	548.3	177.0	5,458.0	2,914.3	1,532.0	495.8
Chevron Corp.	54,212.0	54,456.0	5,017.0	3,594.0	162,372.0	144,406.0	13,366.0	9,955.0
Clayton Williams Energy Inc.	66.4	85.1	5.3	(2.0)	200.1	217.2	26.7	(1.1)
CMS Energy Corp.	1,462.0	1,307.0	(101.0)	(263.0)	4,890.0	4,382.0	(50.0)	(81.0)
Comstock Resources Inc.	129.5	71.9	17.3	14.1	385.2	211.4	62.3	19.1
ConocoPhillips	49,585.0	49,659.0	3,876.0	3,800.0	145,988.0	131,191.0	12,353.0	9,850.0
Delta Petroleum Corp.	45.9	25.9	4.2	1.4	86.8	50.3	18.0	6.3
Devon Energy Corp.	2,722.0	2,704.0	705.0	744.0	8,056.0	7,523.0	2,264.0	1,960.0
Edge Petroleum Corp.	35.9	29.6	(56.9)	8.1	104.8	78.7	(44.2)	20.1
EnDevCo Inc.	0.6	—	(0.9)	(0.3)	1.6	0.7	(1.9)	(0.7)
EOG Resources Inc.	968.2	934.4	299.1	343.8	2,971.9	2,406.5	1,057.3	795.9
Equitable Supply	160.6	163.4	31.8	46.5	547.0	530.2	148.1	187.2
ExxonMobil Corp.	99,593.0	100,717.0	10,490.0	9,920.0	287,607.0	271,336.0	29,250.0	25,420.0
FieldPoint Petroleum Corp.	1.1	1.0	0.4	0.2	3.2	2.8	1.1	0.8
Forest Oil Corp.	202.8	268.2	76.9	3.3	636.1	799.6	137.7	94.3
Frontier Oil Corp.	13,811.1	1,185.9	120.9	109.2	3,708.7	2,850.9	321.8	209.6
FX Energy Inc.	1.8	2.5	(1.7)	(1.4)	5.1	4.4	(8.0)	(4.8)
Gasco Energy Inc.	6.1	4.7	(0.8)	0.6	19.1	8.5	(54.0)	(2.1)
GeoResources Inc.	2.5	2.4	0.5	0.6	7.2	6.1	1.9	1.7
GMX Resources Inc.	4.4	8.5	2.1	2.9	10.4	21.7	3.6	6.6
Goodrich Petroleum Corp.	29.4	17.5	8.2	(19.5)	85.3	43.9	24.1	(26.1)
Harken Energy Corp.	11.0	7.4	32.8	1.4	29.9	22.9	42.3	(0.9)
Harvest Natural Resources Inc.	0.0	61.2	(13.6)	8.1	59.5	178.6	(50.0)	40.3
Hess Corp.	7,130.0	5,956.0	297.0	272.0	21,511.0	16,108.0	1,557.0	790.0
Holly Corp.	1,172.7	880.5	79.0	61.7	3,085.1	2,233.9	218.9	127.8
Houston Exploration Co.	131.3	125.4	34.0	8.1	454.9	467.0	87.1	85.3
Lucas Energy Inc.*	0.4	0.1	0.1	0.0	0.5	0.1	0.2	0.0
Marathon Oil Corp.	16,634.0	17,151.0	1,623.0	770.0	51,463.0	46,130.0	4,155.0	1,767.0
McMoRan Exploration Co.	60.4	44.3	(18.6)	7.1	153.5	92.9	(17.2)	(14.0)
Murphy Oil Corp.	4,153.4	3,316.9	222.8	230.9	10,943.6	8,681.7	550.7	691.9
Newfield Exploration Inc.	425.0	460.0	266.0	0.0	1,246.0	1,319.0	509.0	164.0
Noble Energy Inc.	741.3	632.1	318.1	177.0	2,225.9	1,485.7	513.4	423.8
Occidental Petroleum Corp.	4,603.0	4,634.0	1,168.0	1,747.0	13,745.0	11,405.0	3,254.0	4,129.0

OLOKOLA GAS SUPPLY PROJECT (OKGS)

Gas Production Platform Complexes and Wellhead Platforms

CHEVRON NIGERIA LIMITED

(Operator of the NNPC/CNL Joint Venture)

Invitation to pre-qualify for inclusion on the bid list for the lump sum contract covering Engineering, Procurement, Installation (Fabrication + Offshore Installation), and Commissioning (EPIC) of two Gas Production Complexes and five Wellhead Platforms (NWPs) in association with the Olokola Gas Supply Facilities; offshore Delta and Bayelsa states, Federal Republic of Nigeria.

Note: CNL will allow either single awards or a combined contract award (GPP Complexes and/or NWPs) against this Invitation.

INTRODUCTION

Chevron Nigeria Limited (CNL), the operator of the Joint Venture between itself and the Nigerian National Petroleum Corporation (NNPC), intends, on behalf of the Joint Venture, to install two (2) Gas Production Complexes comprised of a Gas Production Platform (GPP) with associated Living Quarters Platforms (LQPs), flare tripods with interconnecting bridges and five (5) Wellhead Platforms as part of the Olokola Gas Supply Project (OKGS) Facilities. The platforms are to be located offshore Delta and Bayelsa states in Nigeria.

The NNPC/CNL Joint Venture is committed to providing opportunities for Nigerian companies and Nigerian labor to participate and develop their expertise in line with the Federal Government Policy on Local Content Development and consistent with the project objectives of safety, schedule, cost and quality. Accordingly, the NWPs (jackets and topsides), the LQP jackets, decks and LQ modules, GPP jackets, FPs, and interconnecting bridges will all be fabricated in Nigeria. In addition, all the pressure vessels and the decks that are on both Okan and Funiwa GPPs must be fabricated in Nigeria.

SCOPE OF WORK

Capable national engineering and construction firms and International EPCI contractors who are committed to including local Nigerian firms in their execution strategy are hereby invited to submit pre-qualification documentation for the OKGS GPPs, NWPs, LQPs, and FPs lump sum tender for Engineering, Procurement, Construction and Installation (EPCI) of the following preliminary scope of work as summarized below:

1. ***Okan / Funiwa Gas Production Complexes (GPPs/LQPs/FPs) - two each as described herein***
   - ***Okan GPP Platform:*** *One (1) new 1400 MMSCFD capacity gas production platform containing gas separation, dehydration, export gas compression, and various utilities with an integrated topsides module weight of approximately 22,400 short tons (20,000 tonnes), in a water depth of 57 feet (17 meters). The current design philosophy is trending to a "Float Over" installation of the integrated topsides module due to the water depth and overall weight. The facility complex also contains a remote flare tripod platform, intermediate flare bridge tripod support platform, and two (2) bridges to connect the remote flare to the Okan GPP (bridges are approximately 255 feet, 78 meters in length each).*
   - ***Funiwa GPP Platform:*** *One (1) new 700 MMSCFD capacity non-associated gas production platform containing gas separation, dehydration, export gas compression, and various utilities with an integrated topsides module weight of approximately 18,700 short tons (17,000 tonnes), in a water depth of 57 feet (17 meters). The current design philosophy is trending to a "Float Over" installation of the integrated topsides module due to the water depth and overall weight. The facility complex also contains a remote flare tripod platform and one (1) bridge to connect the remote flare to the Funiwa GPP (bridge is approximately 350 feet, 107 meters in length).*
   - ***Living Quarters Platforms (2):*** *One for each GPP Complex consisting of new Living Quarters Platforms each containing one (1) 87 person 1,122 short tons (1,020 tonnes) Living Quarters Module, LQP deck, associated utility equipment and systems, and a single bridge (approx. 164 feet, 50 meters in length) for connection to the Okan and Funiwa GPP Platforms. The lift weight of each of the LQP deck supporting the Living Quarters Module is approximately 550 short tons (500 tonnes) with the current design philosophy to lift the LQP decks separately from their associated LQ Modules.*
2. ***Wellhead Platforms:*** *Five (5) new wellhead platforms - Okan NWP-2 (23 feet, 7 meters water depth), Okan NWP-3 (33 feet, 10 meters water depth), Okan NWP-4 (23 feet, 7 meters water depth), Sonam NWP-1 (210 feet, 64 meters water depth), Sonam NWP-2 (210 feet, 64 meters water depth). The approximate topsides weights for each of the wellhead platforms range from 1000 – 1200 tons (900 – 1100 metric tonnes), and each facility contains 9 well slots, associated manifolds, test separation equipment, and misc. utilities. The current design philosophy is to lift the topsides in a single lift.*

PRE-QUALIFICATION CRITERIA

Only qualified contractors and/or consortiums that have recent, relevant, and demonstrated experience in successfully managing EPIC offshore platform contracts with values of at least US$750,000,000 for a combined effort of GPP Complexes and Wellhead Platforms (NWPs) or at least US$150,000,000 for the Wellhead Platforms only will be considered to competitively tender for the scope of work described above. In addition, interested contractors are also required to submit information to establish their qualifications in areas including but not limited to the following:

- **Company Profile:** Provide full details of company profile (including but not limited to organizational structure, copy of certificate of incorporation, business locations, fabrication yards and/or installation equipment, holdings, Insurance Agencies, contacts and resumes of key management personnel).
- **Business Registration and Documentation:** Provide copies of the current Nigerian Department of Petroleum Resources (DPR) certificate of registration, income Tax Clearance Certificate and VAT Registration Number.
- **Company Financial Status:** Submit copies of Certified Audited financial statement for the last three years, income Tax Clearance Certificate with minimum annual turnover of US$750 million for the combined effort of GPPs Complexes and NWPs or $150 million for the NWPs, Bankers, funding information, and evidence of credit limit that can be available within a year.
- **Previous work experience:** Evidence of relevant, verifiable and completed experience on similar work on a turnkey basis. Attach list of references with description, the Scope, Value, Man-hours, Responsibility, Service in Nigeria and other locations worldwide, Name of the Client, Contact Representative with Telephone Numbers and E-mail Addresses of each for reference purposes. Evidence of Equipment own or plans to lease.
- **HES Policies:** Submit detail summary of existing and proposed Health, Environment and Safety Policy, Program and Management System. Evidence exemplary work site Safety Performance.
- **QA/QC Policies:** Submit Company existing Quality Assurance and Quality Control Policies and Program with ISO Certification. This document shall be used as a primary tool for evaluation.
- **Subcontractors:** Provide list of any specific portions of the work which are intended to be subcontracted.
- **Community Relations:** Evidence of Community Affairs Policy, Records and Program, including interfaces, social responsibilities and liabilities.
- **Local Content Policy:** Evidence of existing and/or proposed local content policy and program, including all aspects of the work to be executed in Nigeria, utilizing Nigerian personnel and expatriate, Facilities and Services, Demonstrate Commitment to Optimizing Nigerian Content in the Execution of the Work to the Extent of Meeting and/or Surpassing Nigerian Content Target.
- **Power of Attorney:** Provide a signed Power of Attorney for an officer that will lead and communicate with Chevron JV during the bid period.
- **Joint Venture Arrangement:** In the case of a Joint Venture or consortium arrangement, evidence of signed agreement of interest and memorandum of understanding (MOU) by the Partners will be required including each partner's legal status, country of incorporation and residence for tax purposes. The Joint Venture shall provide evidence of joint and several liabilities among the Ventures or Consortium.
- **NOTE:** Preference will be given major companies which possess adequate experience in the Oil and Gas production facilities Engineering Design, Procurement, Installation and Commissioning (EPIC) and are committed to including Nigerian/Local firms in their execution strategy. Companies that are structured as agencies will not be considered and foreign companies that are interested in the project must identify and indicate its local affiliate or partners showing the aspect of the work that will be executed in Nigeria.

Any incomplete information may disqualify a respondent. CNL may also disqualify any contractor which is delinquent in its payment of Nigerian taxes.

NIGERIAN CONTENT

In line with the Federal Government of Nigeria directives on Nigerian content of targets of 45% and 70% by year end 2006 and 2010, interested Contractors and/or Consortiums are to include in their Prequalification Data Package submittal, a statement that if qualified and selected to submit a technical and/or commercial bid, their Nigerian content plan submission will comply with this directive. In addition, this statement shall confirm that if qualified and selected to submit a technical and commercial bid, then their bid submission will identify the Nigerian work scope and this identification will be in the form of a percentage of the overall work scope in monetary terms (commercial submission) of the value that will be created "in-country" and use of Nigerian resources (material and labor) on this project.

Any Interested Contractor and/or Consortium must include in the statement submitted in response to this Advertisement and "Prequalification Data Package Submittal" an acknowledgement and willingness to comply with the following:

- Domiciliation of 100% engineering activities Nigeria.
- Location of Project Management personnel and a procurement center in Nigeria.
- All pressure vessels associated with all facilities must be fabricated in Nigeria.
- All fabrication works (all decks, jackets, piles, bridges, living quarters modules, and wellhead platform topsides) will be executed in Nigerian fabrication yards.
- For Okan and Funiwa GPP integrated topsides modules, all the pressure vessels and the decks that are on the GPPs must be fabricated in-country.
- Binding MOUs indicating both the scope of work and their corresponding values in man-hours and tonnages must be provided. The MOUs must be signed by CEOs of the companies.
- Commitment to comply with Nigerian content directives along with plans for optimizing Nigerian content in the execution of this work.
- Acknowledge that, if qualified and selected to submit a technical and commercial bid, then the technical and/or commercial bid submission will contain the following information:
  - List of Nigerian subcontractors that will participate in the execution of the project.
  - Identify local equipment, materials and goods that will be sourced on this project.
- Non-compliance with Nigerian Content Directives may disqualify a bid submission.

PRE-QUALIFICATION DATA PACKAGE

To be considered, responses must be submitted in the format and level of detail required in the CNL OKGS EPIC Pre-Qualification Data Package. This package may be obtained, between the hours 08:00 and 15:00 (Monday through Thursday), by calling at either of the following locations:

Chevron Nigeria Limited
Manager of Internal Controls
2 Chevron Drive, Lekki Peninsula
P.M.B. 12825, Lagos, Nigeria
Tel: +234 1 2600600

Chevron International Exploration and Production
CNL Gas Projects Contracts Advisor
25062C 1500 Louisiana Street
Houston, TX 77002 USA
Tel: 832.854.3553

The OKGS GGP Complexes and NWPs EPIC Contract Pre-Qualification Data Package will be available until January 3, 2007 at the locations specified above. Failure to obtain the pre-qualification package and provide all requested data within the specified time frame will automatically disqualify the applicant.

RESPONSES

Responses must be submitted in accordance with and demonstrate fulfillment of the requirements set forth in the CNL OKGS GPP Complexes and NWP EPIC Contract Pre-Qualification Data Package. Responses to this invitation shall be sealed and submitted in accordance with the pre-qualification data package instructions. Each response shall be marked "CONFIDENTIAL – OKGS GPP Complexes and NWPs EPIC Invitation for Pre-Qualification." The full name and address of the responding company or entity must be clearly marked on the submittals. Responses must reach the address given below not later than 14:00 hours on January 9, 2007.

Chevron Nigeria Limited
Manager of Internal Controls
2 Chevron Drive, Lekki Peninsula
P.M.B. 12825, Lagos, Nigeria
Tel: +234 1 2600600

This invitation does not obligate CNL to consider a responding company for prequalification, to include a responding company on a bid list, to award them a contract, or to inform them of any resultant action. CNL reserves the right to either accept or reject any submittal in part or in whole, at its sole discretion. All costs incurred as a result of this pre-qualification and any subsequent request for information shall be to the responding companies' accounts.

US OIL AND GAS FIRMS' THIRD QUARTER 2006 REVENUES, EARNINGS (CONTINUED FROM P. 24)

Table 1

	Revenues		Net income		Revenues		Net income	
	3rd quarter				Nine months			
	2006	2005	2006	2005	2006	2005	2006	2005
	Million $ (US)							
Panhandle Royalty Co.	7.4	9.4	2.1	3.4	28.4	24.3	9.6	7.4
PetroQuest Energy Inc.	55.1	31.9	6.5	5.0	154.9	83.9	23.7	13.1
Pioneer Natural Resources Co.	432.6	397.9	80.8	123.6	1,243.0	1,058.4	712.0	393.8
Plains Exploration & Production Co.	280.9	262.6	272.7	(31.8)	810.9	670.0	213.9	(284.8)
Pogo Producing Co.	353.8	275.8	33.3	473.5	1,401.9	806.1	462.7	636.2
PRB Energy Inc.	1.1	0.7	(1.8)	(2.9)	2.6	2.3	(5.1)	(3.7)
PrimeEnergy Corp.	24.8	19.3	6.6	14.6	71.2	53.0	15.9	19.1
Quest Resource Inc.	16.7	13.5	(10.1)	(4.3)	42.5	38.6	(7.1)	(7.3)
Questar Corp.	555.1	582.9	95.1	65.8	2,062.7	1,783.4	322.6	221.7
Quicksilver Resources Inc.	99.2	83.8	22.9	24.8	288.3	207.6	74.0	52.7
Range Resources Corp.	228.9	141.8	51.3	24.7	595.6	369.4	158.3	68.3
Royale Energy Inc.	4.6	6.5	(0.8)	0.2	16.6	18.1	(0.1)	0.3
Southwestern Energy Co.	168.4	162.1	33.5	39.5	549.1	455.6	128.9	98.9
Stone Energy Corp.	182.2	159.3	21.8	33.0	509.8	500.7	44.3	110.4
Sunoco Inc.	10,496.0	9,295.0	351.0	329.0	29,679.0	24,494.0	856.0	687.0
Swift Energy Co.	173.5	100.9	50.8	27.5	456.8	300.8	126.3	81.1
Tengasco Inc.	2.3	1.9	0.5	0.7	6.7	4.9	1.6	0.1
Teton Energy Co.	0.7	0.0	(1.5)	(1.7)	0.9	0.0	(2.8)	(2.3)
The Williams Cos.	3,300.0	3,082.3	106.2	4.4	9,042.6	8,907.5	162.1	246.8
Toreador Resources Corp.	10.7	8.8	2.1	1.0	30.8	22.3	7.6	3.9
Transmeridian Exploration Inc.	7.8	3.9	(14.2)	(2.5)	15.7	7.0	(40.1)	(6.0)
Ultra Petroleum Corp.	145.4	134.4	52.5	60.9	426.5	334.4	170.6	146.1
Unit Corp.	299.9	231.0	81.3	57.6	863.1	592.5	231.0	128.0
VAALCO Energy Inc.	25.6	26.2	13.6	11.9	82.5	66.0	35.1	24.2
Valero Energy Corp.	24,319.0	23,283.0	1,603.0	862.0	72,041.0	56,268.0	4,349.0	2,243.0
W&T Offshore Inc.	213.4	153.4	66.7	53.1	536.1	432.3	161.0	138.2
Warren Resource Inc.	10.2	10.0	2.2	(1.1)	29.8	26.1	4.1	(4.2)
Whiting Petroleum Corp.	207.6	139.8	49.5	33.3	592.2	354.5	128.4	83.6
XTO Energy Inc.	1,096.0	964.0	367.0	313.0	3,377.0	2,342.0	1,431.0	699.0
Total	**310,035.4**	**290,224.5**	**30,765.7**	**25,686.7**	**870,114.6**	**769,825.0**	**86,530.3**	**66,593.8**

*Second quarter.

US-based operators

The group of oil and gas producers and refiners based in the US recorded a combined 20% jump in net income for the recent quarter, and for the first 9 months of this year, their earnings climbed 30% from the prior year (Table 1). Leading these gains were large increases in the earnings of Anadarko Petroleum Corp., Chevron Corp., Marathon Oil Corp., and Valero Energy Corp. Meanwhile, 14 of the 74 companies in this group posted a net loss for the third quarter.

For Anadarko, the 144% quarterly earnings gain to $1.46 billion was partially due to the inclusion of the results of Kerr-McGee Corp. and Western Gas Resources, beginning on their respective Aug. 10 and Aug. 23 acquisition dates.

Downstream earnings drove Chevron's 40% earnings increase for the third quarter. The company reported that its downstream earnings increased nearly $900 million to $1.4 billion on improved product margins and refinery utilization. Meanwhile, upstream profits of $3.5 billion were up 5% on greater production volumes and higher oil prices.

Solid refining and marketing margins also were key to the Marathon and Valero earnings increases.

Marathon's downstream segment income was $1 billion in the third quarter of 2006, compared to $473 million in the third quarter of 2005. The main driver behind this increase was the company's refining and wholesale marketing gross margin, which averaged 32.7¢/gal in the recent quarter vs. 17.7¢/gal a year earlier.

Valero's Chief Executive Officer Bill Klesse said, "We had the highest third-quarter earnings in the company's history despite the drop in gasoline margins that began in early August. Throughout the third quarter, though, distillate margins and sour crude oil discounts were very favorable."

Klesse said, "Gulf Coast conventional gasoline margins averaged $12/bbl for the quarter, and (US) Gulf Coast off-road diesel margins averaged around $9/bbl throughout the quarter. More importantly, Gulf Coast on-road diesel margins averaged almost $17/bbl."

Klesse added, "We continue to believe that the combination of slower-than-anticipated growth in global refining capacity, cleaner fuel specifications, and continued demand growth should keep the supply and demand balance for refined products tight."

One of the firms in the sample that posted a net loss for the quarter is McMoRan Exploration Co. Increased exploration expenses and greater depreciation and amortization outweighed higher revenues from increased production volumes and higher oil price realizations for the company, resulting in a loss of $18.6 million for the third quarter vs. earnings of $7.1 million in the comparable year-earlier period.

Service, supply companies

OGJ's sample of service and supply firms (Table 2) outperformed the US operators and Canadian companies for the third quarter. For the period the

SERVICE-SUPPLY COMPANIES' THIRD QUARTER 2006 REVENUES, EARNINGS

Table 2

	Revenues — 3rd quarter		Net income — 3rd quarter		Revenues — Nine months		Net income — Nine months	
	2006	2005	2006	2005	2006	2005	2006	2005
	Million $ (US)							
Allis-Chalmers Energy Inc.	85.7	28.9	11.3	1.3	193.2	71.8	25.3	4.6
Baker Hughes Inc.	2,309.4	1,784.8	358.6	221.9	6,574.7	5,196.1	2,092.8	620.5
BJ Services Inc.	1,116.9	817.3	212.9	114.2	3,151.9	2,350.9	576.0	318.8
Bronco Drilling Co. Inc.	79.8	18.6	17.4	(5.1)	203.4	38.9	43.5	(1.7)
Cameron Corp.	978.8	636.6	89.3	49.2	2,666.2	1,779.3	221.3	116.4
Diamond Offshore Drilling Inc.	514.5	310.5	164.5	82.0	1,474.4	852.7	485.5	153.4
Dril-Quip Inc.	117.8	95.3	23.4	9.8	324.4	245.9	62.0	20.9
Foster Wheeler Ltd.	910.6	532.4	75.8	(16.7)	2,301.7	1,581.4	198.9	12.4
GlobalSantaFe Corp.	989.2	596.6	36.1	18.3	2,362.0	1,660.0	91.6	39.5
Grant Prideco	471.3	352.2	126.5	48.1	1,317.6	961.3	324.5	110.6
Grey Wolf Inc.	242.7	181.5	55.3	31.8	705.2	492.8	167.4	82.5
Halliburton Co.	5,831.0	4,912.0	611.0	499.0	16,560.0	14,668.0	1,690.0	1,256.0
Horizon Offshore Inc.	143.7	92.8	20.9	3.1	430.6	200.7	53.2	(40.1)
Hornbeck Offshore Services Inc.	77.5	46.5	23.9	9.4	209.3	125.4	59.1	22.4
Hydril Co.	117.3	93.0	19.7	19.6	373.5	263.4	67.3	51.9
Itron Inc.	164.7	141.1	9.2	6.0	484.1	392.7	26.4	16.1
Lone Star Technologies Inc.	336.1	324.1	16.6	50.3	1,042.8	947.6	90.1	152.7
Nabors Industries Inc.	1,287.3	920.5	292.8	178.9	3,613.6	2,504.2	782.9	438.1
Noble Corp.	562.0	367.2	207.2	76.5	1,541.4	1,021.5	532.2	195.4
Oceaneering International Inc.	337.3	263.1	38.5	17.7	937.8	709.8	94.7	43.0
Parker Drilling Co.	146.8	127.9	18.6	18.1	440.1	382.1	43.9	42.2
Patterson-UTI Energy Inc.	673.7	468.7	186.0	106.3	1,908.2	1,209.3	516.2	238.6
Pioneer Drilling Co.*	106.9	67.0	23.5	11.1	200.4	126.8	43.0	18.8
Pride International Inc.	642.8	538.8	89.3	68.9	1,826.2	1,482.3	227.6	88.0
Rowan Cos. Inc.	417.1	284.4	87.0	74.6	1,100.0	751.4	255.8	160.3
RPC Inc.	154.2	115.8	28.8	23.1	436.3	310.1	81.3	44.9
Schlumberger Ltd.	4,954.8	3,698.1	999.8	540.8	13,880.6	10,285.8	2,579.2	1,546.4
Smith International Inc.	1,738.3	1,350.2	118.8	68.1	3,420.4	2,638.4	226.0	134.2
Transocean Inc.	1,025.7	762.6	309.0	170.4	2,696.3	2,120.5	764.2	564.0
Warrior Energy Services Corp.	38.2	17.4	5.6	2.2	98.1	51.6	12.9	6.6
Weatherford International Inc.	1,696.8	1,076.8	234.2	47.8	4,771.3	2,871.8	624.4	223.7
Total	**28,268.9**	**21,022.7**	**4,511.5**	**2,546.7**	**77,245.7**	**58,294.5**	**13,059.2**	**6,681.1**

*Second quarter.

service and suppliers collectively posted a 77% year-on-year surge in earnings.

Offshore drilling contractor GlobalSantaFe Corp. reported net income for the third quarter was up 97% from a year earlier. For the first 9 months of 2006, the company reported its net income grew 132% year-on-year.

"Reflecting the continued strength of international offshore drilling markets, our contract drilling segment improved significantly on a strong second quarter performance with record revenues and operating income in the third quarter," said GlobalSantaFe Pres. and Chief Executive Officer Jon Marshall. "These positive results were diminished by an unusually large loss on one turnkey well in the US Gulf of Mexico and by timing of oil sales in the North Sea."

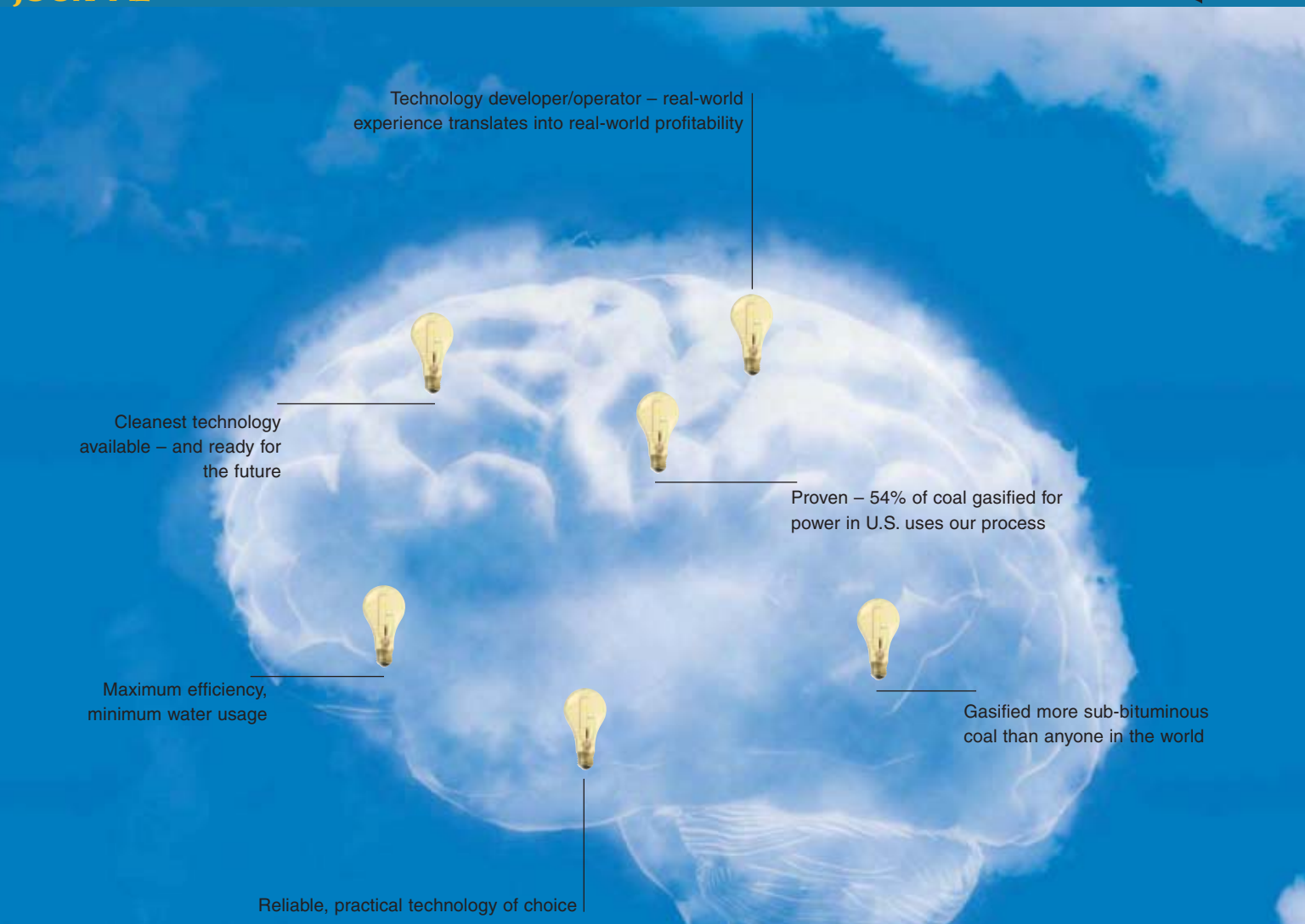
GlobalSantaFe attributes its earnings improvement to higher contract drilling revenues from increased day rates and continued high fleet utilization. But higher labor, insurance, repair and maintenance, and other operating expenses compared with the same 2005 period partially offset those gains, the company said.

In the third quarter of 2006, average

CANADIAN OIL AND GAS FIRMS' THIRD QUARTER 2006 REVENUES, EARNINGS

Table 3

	Revenues — 3rd quarter		Net income — 3rd quarter		Revenues — Nine months		Net income — Nine months	
	2006	2005	2006	2005	2006	2005	2006	2005
	Million $ (Can.)							
Bow Valley Energy Ltd.	11.4	11.8	1.0	0.6	30.9	39.4	2.8	3.3
Canadian Natural Resources Ltd.	2,549.0	2,515.0	1,116.0	151.0	7,020.0	6,130.0	2,211.0	(54.0)
Enbridge Inc.	2,184.9	1,657.1	97.2	69.5	7,858.8	5,785.3	449.4	387.1
EnCana Corp.	4,372.3	3,325.2	1,514.3	296.6	13,821.7	9,373.5	5,563.2	1,182.0
Heritage Oil Corp.	3.0	0.2	(1.9)	0.2	7.5	1.1	(3.2)	(1.0)
Husky Energy Inc.	3,436.0	2,594.0	682.0	556.0	9,580.0	7,038.0	2,184.0	1,334.0
Imperial Oil Ltd.	6,651.0	7,711.0	822.0	652.0	19,157.0	20,471.0	2,250.0	1,584.0
Ivanhoe Energy Inc.	15.6	9.9	(4.9)	(2.3)	41.3	23.8	(15.8)	(5.1)
Nexen Inc.	1,284.0	1,307.0	193.0	615.0	4,105.0	3,381.0	520.0	852.0
Petro-Canada	5,201.0	4,721.0	678.0	614.0	14,119.0	11,941.0	1,356.0	1,077.0
Shell Canada Ltd.	4,028.0	3,956.0	581.0	457.0	11,225.0	10,351.0	1,503.0	1,400.0
Suncor Energy Inc.	4,114.0	3,149.0	682.0	315.0	12,042.0	7,608.0	2,613.0	465.0
Talisman Energy Inc.	1,956.0	2,119.0	524.0	430.0	6,306.0	5,424.0	1,407.0	1,028.0
TransCanada Corp.	1,850.0	1,494.0	293.0	427.0	5,429.0	4,353.0	810.0	859.0
Gentry Resources Ltd.	125.5	14.4	0.1	4.3	40.2	34.6	3.7	7.5
Penn West Energy Trust	582.9	439.9	177.8	209.5	1,296.1	1,122.6	542.7	336.1
Total	**38,364.6**	**35,024.6**	**7,354.6**	**4,795.4**	**112,079.4**	**93,077.3**	**21,396.8**	**10,454.9**



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revenues per day from contract drilling increased to $130,500/rig, up 60% from the third quarter of 2005. The company reported average fleet utilization at 97% in the third quarter of 2006, compared with 98% in the same period of 2005.

Canadian firms

A sample of 16 companies based in Canada recorded a 53% gain in combined earnings for the third quarter vs. the same quarter in 2005 (Table 3). For the first 9 months of this year, their net income climbed 105% year-on-year.

Despite the group's overall gain, the third-quarter results of six of its members declined from the third quarter of last year. One of these is Nexen Inc.

Earlier this year, a court of arbitration concluded that Nexen breached an obligation with respect to Block 51 in Yemen. Nexen announced that while the amount of damages is not yet determined, the company reduced its net income by $93 million to reflect its estimate of this liability. For the recent quarter, Nexen reported net income of $193 million (Can.), down from $615 million (Can.) a year earlier.

Canadian Natural Resources Ltd. (CNRL) reported the largest earnings increase among the firms in this group. Up 639% from a year earlier, CNRL's net income in the third quarter included a pretax gain of $754 million for the unrealized risk management activities relating to oil and gas hedges, the company said.

CNRL's gas production increased 1% from the third quarter of 2005 despite reduced gas drilling activity in the second and third quarters of this year. The company's third quarter 2006 crude oil production volumes declined 4% from a year earlier due to scheduled maintenance turnarounds in the North Sea and sand screen issues on four production wells at Baobab, offshore West Africa, CNRL said. ✦

Senate's OCS bill clears Congress, heads to White House

Nick Snow
Washington Correspondent

Working through the night, the US Senate approved a legislative package including its OCS leasing reform bill early Dec. 9 and sent it to the White House for President George W. Bush's signature. The measure had cleared the House at midafternoon on Dec. 8 after an attempt to amend the Outer Continental Shelf oil and gas leasing provision failed by 2 votes.

Senate passage of a measure including S. 3711 concluded months of maneuvering which moved into high gear during the final week of the 109th Congress.

The bill was one of 16 free-standing measures on the calendar as the House resumed work on Dec. 5 following the Thanksgiving holiday recess, but it was pulled at the last minutes when supporters determined they did not have the necessary two-thirds majority for passage under suspended rules.

Proponents sought that status for the bill to avoid amendments, which Senate energy leaders said would sink S. 3711 and let Congress conclude its second session without passing any bill increasing access to the OCS.

They repeatedly indicated that the Senate's bill, which focuses on the so-called Sale 181 area and adjacent tracts in deeper water in the eastern Gulf of Mexico, stood a much better chance of being adopted than HR 4761—a more ambitious measure that sought to also give states on the US east and west coasts options to initiate offshore leasing and share revenues.

House Resources Committee leaders and members could not get the Senate to attempt to reconcile differences between the two bills. Senators insisted that S. 3711 had to be the vehicle, and that it had to be free of amendments, in part to keep the crucial support of Florida's two US senators.

Part of HR 6111

After S. 3711 was pulled from the floor on Dec. 5, speculation centered on whether it would return as a separate bill or as part of a bigger package. It showed up on Dec. 8 as part of HR 6111, which also included provisions dealing with reimbursement of physicians, extensions of tax credits, and expansion of health savings accounts.

Reps. Edward J. Markey (D-Mass.) offered an amendment that would have required holders of federal deepwater leases in the gulf issued in 1998 and 1999 without price thresholds to renegotiate terms or forfeit the right to bid on future leases in the gulf.

The amendment failed by 207 to 205 votes. But the fact that it came so close to passing signals that a bill to force renegotiation of those deepwater leases will be a top priority when the Democrats take control of the House in January.

The House then passed HR 6111 and the catch-all bill moved to the Senate, where it passed by a 79-9 vote in the early hours of Dec. 9.

Senate Energy and Natural Resources Committee Chairman Pete V. Domenici (R-NM) said the provision dealing with the OCS was the first legislation in several years to open new federal offshore areas to energy development. "It is particularly fitting that the Senate pass the bill just as the cold winter was setting in and as families start seeing a sharp rise in their natural gas bills. The price of natural gas has more than doubled since October. We aim to ease the gas price volatility by increasing supply," he said.

Domenici said the OCS provision, which he expects to bring 1.26 billion bbl of crude oil and 5.8 tcf of gas to US

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WATCHING GOVERNMENT

Nick Snow, Washington Correspondent

Programs aim at gas flares

Critics may consider the idea of environmentally aware oil and gas producers an oxymoron. Others who are willing to take a closer look quickly learn that it's an increasingly vital part of the business.

An example is the worldwide emphasis on using instead of flaring associated gas.

A leader in this effort is Global Gas Flaring Reduction (GGFR), a partnership of government agencies and oil companies led by the World Bank and International Finance Corp. The group was scheduled to hold a forum on flaring reduction and gas utilization Dec. 13-15 in Paris.

In early November it announced that a project in Nigeria, which leads the world in reported flared gas, would be the first in the African nation to put associated gas to work generating electricity. GGFR officials would like to see many similar efforts.

Flaring in US

It's hardly surprising that much flaring involves stranded gas in developing nations. But I was surprised when Rashad Kaldany, director of the IFC and World Bank's oil, gas, mining and chemicals department in Washington, DC, said gas is still being flared in Canada and the US. "Most of the flaring in the US is at small onshore wells regulated by states," he told me.

That led me to the Interstate Oil & Gas Compact Commission, which put me in touch with Lynn D. Helms, director of the industrial commission in North Dakota's Department of Natural Resources.

"We've had a program since 1985, when the state legislature passed an antiflaring law. It said that if a producer is going to flare a well, he has to get an exemption from the industrial commission and still pay royalties on the flared gas," he explained.

Producers flared 20% of their gas in North Dakota before the law took effect more than 20 years ago, he said. Now, the level is 2-4%. "In 20 years, we reduced our gas flaring by 90%. The big reduction happened quickly—within 2 years of the law being passed," said Helms.

Some exceptions

He said that for operators in North Dakota to obtain an exemption, they must demonstrate that they can't get a 10% rate of return from laying a sales line and processing the gas. There are provisions for emergency situations, such as shut-downs when a plant is closed.

Also, when a new well comes on production, the operator is allowed to flare for 2 months while testing.

Helms said North Dakota's flare rate has been around 2% until recently, when several projects have had nitrogen breakthrough problems. One producer is building a $75 million plant, which should be running by the end of January, to separate the gas and nitrogen.

"That should give you an indication how hard our producers are working to not flare gas," said Helms. Or, basically, producing with flair instead of flares. ✦

consumers over several years, was not the only energy element in the bill. It also includes tax credits and provisions covering renewable resources, energy efficient home and building construction, photovoltaic devices, fuel cells, coal gasification and production of methanol and ethanol from coal, and cellulosic biomass ethanol plants.

"I have always believed that increased production of fossil fuels is effective only if we also expand our production and use of renewable energies and make a concerted effort to use less energy," Domenici said. "This package achieves all three goals. It complements last year's energy bill in charting a course for this country toward a future of clean, abundant, and affordable energy."

Earlier compromise

S. 3711 itself was a compromise. The Energy and Natural Resources Committee passed S. 2253 on Mar. 8 to reopen eastern gulf tracts that President Bush withdrew in 2001 at the request of his brother, Florida Gov. Jeb Bush.

But Mary L. Landrieu (D-La.) and seven more senators from Texas, Louisiana, Alabama, and Mississippi objected because it did not contain a provision to share future revenues from the offshore leases with affected coastal states. Florida's two senators, Republican Mel Martinez and Democrat Bill Nelson, also protested that a provision barring leases within 100 miles of the state's coast beyond the Sale 181 area was inadequate.

Domenici withheld the bill until July 12, when Majority Leader William H. Frist (R-Tenn.) announced that compromises had been reached with the 10 Gulf Coast senators. The Floridians won an addition of 25 miles to the no-lease buffer zone, which would be in effect through 2022. The other four Gulf Coast states won a 37.5% share of future federal leases in the area covered by the bill, while another 12.5% would go to the state side of the Land and Water Conservation Fund.

"Today the Senate confirmed its strong support for Louisiana and the entire Gulf Coast by passing the Do-

menici-Landrieu fair-share bill, which after nearly 60 years, provides for Louisiana a significant share of oil and gas revenues produced off our shores. In August, 71 senators agreed to the bill because they recognized that a dedicated stream of revenue is necessary for Louisiana to protect itself from future storms. [Hurricanes] Katrina and Rita showed us what devastation can ensue if our communities remain vulnerable," Landrieu said following the Senate's Dec. 9 vote.

Nelson said that the bill's final passage made it "a huge day for Floridians... [who] can take comfort in the fact that there will be no drilling off the state's shores. This is major protection for our state's $50 billion tourism-driven economy and its unique environment."

Oil and gas and other industry trade associations immediately hailed S. 3711's passage through Congress. National Petrochemical & Refiners Association Pres. Bob Slaughter said that it represents the best opportunity for US energy exploration in 25 years. "Reliable supplies of affordably price natural gas are essential to the operations of both the refining and the petrochemical industries, and to the consumers who rely on the essential products they produce," he said.

Twenty-five-year supply

"While the bill does open as much acreage to exploration as NPRA and others would have liked, we hope that additional action affecting other OCS areas will eventually take place," Slaughter said. "Allowing full access to the OCS could bring as much as 633 tcf to the domestic market, enough to provide the US with 25 years of affordable natural gas."

Independent Petroleum Association of America Pres. Barry Russell said the bill was not a solution, but a necessary first step. "The federal government still maintains its unnecessary moratoria on the East and West coasts as well as the eastern Gulf of Mexico. It's now time as a nation, and as the new Congress convenes in January, to look at frontier areas both onshore and offshore for safe energy development," Russell said.

American Gas Association Pres. David N. Parker said that Congress "has ensured that an increasing share of domestic natural gas supplies will be available for use by all Americans" and said the bill is a step in the right direction. But he added that more work will need to be done to open additional OCS tracts.

Natural Gas Supply Association Pres. Skip Horvath said Dec. 11 the bill "cannot be the final answer when it comes to ensuring access to the most economical supplies, but it has taken strong leadership in both parties in both houses to achieve this initial step, which represents the first congressional expansion of available offshore resources in several decades."

Horvath said, "It is vital that the 110th Congress continue to work together to ensure greater access to even more supplies to meet the resource needs of our country, while letting markets allocate supplies where they are needed most."

National Association of Manufacturers Pres. John Engler said that the legislative package contained several important trade provisions for his group's members, but immediately cited the OCS segment. "Exploring the OCS is an important step toward a more abundant, flexible, and affordable energy supply that is critical to the US economy," he said.

American Chemistry Council Pres. Jack N. Gerard called the bill's passage "an enormous victory in the fight against a 6-year-old natural gas crisis that's been killing American jobs, making the United States less competitive with other nations and costing households across the nation more for home heating and electricity."

He also said there's a relationship between restricting access to gas resources and development of energy alternatives. "One of the biggest sources of rising natural gas demand is for generating electricity, and more natural gas also will be needed to produce ethanol, hydrogen, ultra-low sulfur diesel fuel, solar panels, wind power blades, and energy-efficient materials such as insulation and plastics for light-weight cars," Gerard said. ✦

US Senate follows House, approves pipeline safety bill

Nick Snow
Washington Correspondent

The US Senate passed an amended pipeline safety bill by voice vote on Dec. 7, following House passage of the measure on a similarly expedited basis (OGJ Online, Dec. 7, 2006). HR 5782 now heads to the White House, where President George W. Bush is expected to sign it.

The bill would authorize a 50% increase in the number of federal pipeline inspectors, give additional enforcement authority to the US Office of Pipeline Safety and states to prevent third-party excavation damage, and federally regulate low-stress oil pipelines and local gas distribution systems for the first time, according to Sen. Frank R. Lautenberg (D-NJ), one of the main sponsors earlier this year of the Senate's original pipeline safety bill.

But Lautenberg added that one of the bill's most significant features is its provision establishing the mandatory use of excess flow valves, which he helped to write. "These important safety devices can shut off gas flow when a service line is ruptured, preventing a potential explosion. One lesson we learned after the 1994 gas explosion in Edison, NJ, is that technology must be used to shut

off gas flow after a rupture," he explained.

Lautenberg said excess flow valves would be required in every new single-family residence or replacement line to a single-family residence under HR 5782. He added that Thomas J. Barrett, who heads the Pipeline and Hazardous Materials Safety Administration within the US Department of Transportation, indicated that he intends to exempt operators of master meter and liquefied petroleum gas systems from the requirement, but only because excess flow valves have been shown to be ineffective on such systems.

Passage welcomed

Oil and gas trade associations and citizens' groups both welcomed the bill's passage through Congress.

"This legislation is a significant step in protecting natural gas distribution pipelines from damage by third-party excavators," said David N. Parker, president of the American Gas Association, which represents 200 local distribution companies. Parker said HR 5782 contains provisions and financial incentives to encourage states to adopt excavation damage prevention programs containing the same elements which have been successful in Minnesota and Virginia's programs.

DOT safety statistics show that the number of serious incidents caused by third-party excavators hitting utility lines has more than doubled in the last 4 years, Parker said.

Lois Epstein, a senior engineer with Cook Inletkeeper, an Alaskan citizens' organization dedicated to protecting the region's watershed, human population, and wildlife, called HR 5782 "a strong bill that will move pipeline safety forward."

Referring to leaks in BP Alaska's oil-gathering operations at Prudhoe Bay, which eventually led to shutdowns of several portions of the system this past summer, Epstein added, "Ironically, BP's corrosion problems this past year helped federal regulators improve pipeline safety overall." ✦

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Food costs fuel concern

We never imagined—never for a minute—that Chinese officials would react so swiftly to our comment last week about the increasing use of biofuels and the upward pressure that puts on food costs, particularly grains (OGJ, Dec. 11, 2006, p. 32). But react they did—and very swiftly, too.

On Dec. 12, Zhu Zhigang, China's vice-minister of finance, assured the public of sufficient food supplies amid concerns over the rising cost of food resulting from the use of grains like corn in the development of biofuel.

Zhu made the comments in the face of rising costs for grain—particularly for corn as the main raw material for ethanol used as vehicle fuel. Zhu said biofuel can be developed only if China's food supplies are guaranteed first.

Other Chinese officials chimed in with similar remarks.

Pending disaster

Zhai Huqu, president of the Chinese Academy of Agricultural Sciences, said, "We can do research on using corn and other grains as an energy substitute, but it cannot be industrialized." Even more to the point, Zhai said: "It will be a disaster for us if we depend on a huge amount of corn and other grains for energy."

That should come as no surprise as ethanol has become the main biofuel produced in China, with output hitting 1.02 million tonnes last year—and corn accounting for 76% of the raw material. The others are wheat and sorghum.

For his part, Zhu picked up Zhai's refrain, saying that China would carefully evaluate the grain consumption of the biofuel project and its influence on the food chain. He also said the government would impose strict controls on any biofuel project using grain as the raw material.

In that regard, the Chinese might take a leaf out of Japan's book of ethanol production. Instead of relying on the food chain as a supply source for the production of ethanol, the Japanese are developing a sweet tooth for ethanol produced in Brazil.

Sweet tooth

In fact, Brazil's state-owned Petroleo Brasileiro SA (Petrobras)—in cooperation with Japan's Mitsui & Co.—has concluded a deal to sell Japan ethanol produced from sugarcane for use in electric power plants starting in 2010.

Under the deal, Mitsui will secure sugarcane fields and build a facility to extract ethanol from the crops, while Petrobras will lay pipelines in Brazil and secure tankers for transport to Japan.

Annual shipments of Brazilian ethanol to Japan are expected to total 3 billion l. That amount will include exports for use in automobiles, which are increasingly using the material as a fuel.

Japanese power utilities, including Tokyo Electric Power Co., are reportedly interested in using ethanol to power their stations as using the substance in combination with fuel oil would require minimal equipment changes.

To us, that sounds like a sweet deal, and certainly one that does not go against the grain. ✦

Existing state laws, regulations urged for CO_2 storage

Paula Dittrick
Senior Staff Writer

Existing state gas-storage statutes and regulatory frameworks should govern future carbon capture and storage (CCS) projects, says an Interstate Oil & Gas Compact Commission task force leader.

Lawrence Bengal, chair of the Arkansas Oil and Gas Commission and head of IOGCC's Carbon Capture and Geological Storage Regulatory Task Force, told a Dec. 4-5 carbon management workshop in The Woodlands, Tex., that the oil industry must prepare for carbon regulation.

Others at the event echoed the warning, which relates to concerns about the climate effects of carbon dioxide emissions. The workshop, sponsored by various oil companies, is associated with the CO_2 flooding conference in Midland, Tex.

For more than a year, the IOGCC task force examined technical, policy, and regulatory issues related to CO_2 storage in depleted oil and gas fields, saline formations, and coalbeds.

Protocols developed through CO_2 enhanced oil recovery projects probably will guide early CCS efforts. The main difference will be that EOR CO_2 comes from natural sources, while future CCS projects are expected to capture and store CO_2 from industrial sources.

Proposals

The task force issued an initial report in 2005 and expects next year to release recommended regulatory guidelines. Bengal said the task force believes carbon regulations need to be flexible and responsive to emerging CCS technologies and experience.

"It's a certainty that one size will not fit all projects," he said. "The most

important element will be a positive public presentation of the issues. CCS is part of a solution with economic and environmental benefits and not a waste problem."

Scott Anderson, Environmental Defense energy policy specialist for the organization's Texas office, said carbon management regulations are inevitable. He said the only questions are when and how such regulations might be implemented and administered.

"The political context in which CO_2 sequestration regulations are developed is very important," Anderson said, adding that transparency will be vital.

The US Department of Energy and its National Energy Technology Laboratory provided funding for the IOGCC task force, which included representatives from IOGCC member states and international affiliates, state oil and gas agencies, DOE, DOE-sponsored regional carbon sequestration partnerships, the Association of American State Geologists, and others.

States

Bengal said the task force plans to propose a state-administered CCS regulatory framework under the authorities of states wishing to participate. The US already has more than 3,500 miles of high-pressure CO_2 pipelines.

Texas state officials have 30 years of experience with CO_2 injection for EOR, Bengal said. Many states regulate EOR under the Underground Injection Control Program of the Safe Drinking Water Act.

"States have the necessary regulatory analogs in place to facilitate development of a comprehensive CCS regulatory framework," Bengal said. "CO_2 should be regulated as a commodity to allow the application of oil and gas conservation laws that will facilitate development of storage projects."

The task force will propose state oil and gas regulatory agencies are the best vehicles for implementing regulatory CCS frameworks, he said.

In addition, the task force plans to suggest that states administer long-term caretaker responsibility for CCS projects. It believes regulations will be needed to determine long-term liability and also to establish long-term monitoring and verification to confirm that injected CO_2 remains in its intended storage place.

Experience in those areas is limited, Bengal said.

"Given the long timeframes proposed for CO_2 storage projects, innovative solutions to protect against orphaned sites will need to be developed," the 2005 task force report said. "This can be accomplished through state and provincial government administration of federally guaranteed, industry-funded abandonment programs." ✦

DOE: 'Microhole' coiled tubing drilling holds promise

Nick Snow
Washington Correspondent

A federally funded technology that could change the way oil and gas wells are drilled was successfully demonstrated in the US Midcontinent, the US Department of Energy said.

A specially designed hybrid "microhole" coiled tubing rig recently drilled 25 test wells to penetrate the Niobrara, a particularly intractable gas formation in western Kansas and eastern Colorado. The effort delivered cost savings of 25-35%/well drilled compared with conventional drilling equipment, DOE's Fossil Energy office said.

It said about 1 tcf of shallow gas that had been bypassed by conventional drilling has become economic as a result. The volume equates to about 5% of the country's annual gas consumption, it indicated.

The commercial Niobrara drilling program—in which 3,000-ft wells were drilled in as little as 19 hr, from rig move-in to move-out—followed a DOE-funded research project undertaken by Gas Technology Institute (GTI) of Des Plaines, Ill. In that effort, GTI partnered with two small firms, Advanced Drilling Technology LLC of Yuma, Colo., and Rosewood Resources Inc. of Dallas, to adapt a conventional coiled tubing rig for drilling exploratory and development wells with ultrasmall diameters.

Normally, coiled tubing rigs are used to service or stimulate production in problematic oil and gas wells, according to DOE. Producers have only recently begun to use them in grassroots exploratory and development areas, largely in Alaska, Canada, and other higher-cost operating areas, it said.

Technology's purpose

GTI's project received funding from DOE's Microhole Technology Initiative. Managed by the Office of Fossil Energy's National Energy Technology Laboratory, the initiative seeks to develop the tools and techniques for drilling ultrasmall boreholes (generally, with diameters of 1¾ to 4½ in.) and related downhole microinstrumentation, using coiled tubing drilling rigs that are small and easily transportable.

These rigs—some small enough to mount on a trailer pulled by a standard pickup truck—employ solid tubing coiled around a spool on the trailer to drill boreholes with well casing diameters of less than 4½ in. Such rigs can drill shallow wells very quickly, saving substantially on daily rig costs and dramatically improving the economics of drilling, according to DOE.

GTI's microhole project was meant to pioneer the use of an experimental, "built-for-purpose" coiled tubing rig designed to drill exploratory and development wells with ultrasmall diameters in the Lower 48 states. ADT and its predecessor Coiled Tubing Solutions Inc. designed and fabricated the rig

specifically for microhole coiled tubing drilling to depths as great as 5,000 ft. Earlier DOE research had proven this capability to only a few hundred feet, the federal agency said.

GTI and its partners field tested this state-of-the-art hybrid coiled tubing rig by drilling a few inexpensive microbore wells to about 1,200-1,400 ft in the Niobrara chalk formation along the Kansas-Colorado border. The results far exceeded expectations, with drilling cost savings averaging 38%, DOE said.

It said the project's initial success and strong commercial follow-up also demonstrated the potential for coiled tubing drilling of exploration and development wells in the Lower 48 states. For the first time, a Canadian coiled tubing drilling company, Xtreme Coil Drilling Corp. of Calgary, is drilling grassroots wells in the Lower 48 for Anadarko Petroleum Corp. Xtreme Coil is using its newly patented coiled tubing design to drill wells in the aging, marginally economic, shallow oil fields of Colorado's Denver-Julesburg basin.

By the end of this year, said DOE, Xtreme Coil also is expected to deploy its coiled tubing drilling at depths as great as 10,000-12,000 ft in deep gas fields such as Pinedale and Jonah in Colorado's Green River basin for another operator, EnCana Oil & Gas (USA) Inc.

DOE said that microhole coiled tubing drilling technology has the kind of game-changing potential that could be applied to bypassed resources in thousands of oil and gas reservoirs across the US, particularly for shallow reservoirs in mature or even apparently depleted fields.

DOE estimates the volume of bypassed oil in US oil fields at less than 5,000 ft subsurface at more than 218 billion bbl. Recovering just 10% of this targeted untapped resource equates to an amount equal to 10 years of oil imports from the Organization of Petroleum Exporting Countries, at current rates. ✦

Gazprom seeks role in US LNG market

Angel White
Associate Editor

Russia's OAO Gazprom hopes to become a "serious player" in the US LNG market, said Deputy Chairman Alexander Medvedev.

With the anticipated amount of LNG to be produced in Russia after 2015, the company can "play a substantial role in the North American market," Medvedev said at a Dec. 1 press conference.

These statements follow Gazprom's recent decision to develop giant Shtokman gas-condensate field in the Barents Sea without foreign partners and to pipe the gas to Europe rather than liquefy it for North America as had been planned. "Before the first LNG train will begin producing LNG in Russia," Medvedev said, "[Gazprom] will require experience in handling LNG cargoes from different parts of the world."

Medvedev said, "Ownership of infrastructure is a key to the market" in North America, adding, "[Gazprom], as a responsible supplier, wishes not just to produce or to leave product somewhere in the middle between producer and consumer but to be as close to the consumers to meet the need of the consumers."

Gazprom has been applying the strategy in Europe. On Nov. 24 it launched Gazprom Marketing & Trading France in Paris to develop an upstream-to-downstream gas export strategy. Describing France as "a strategic market," the company said it intends to sell gas directly to consumers rather than through wholesalers. GM&T France seeks access to transport networks and infrastructure to deliver gas directly to endusers. Medvedev said Gazprom would acquire local companies and set up joint ventures for this purpose. ✦

SEISMIC EMISSION TOMOGRAPHY—2

Seismic used to map permeability fields

Peter Geiser
Jan Vermilye
STRM LLC
Boulder, Colo.

Rob Scammell
Burlington Resources Canada
Calgary

Steve Roecker
Rennselaer Polytechnic Institute
Troy, NY

This is the second of two parts on the use of seismic emission tomography (SET) to directly map reservoir permeability fields. The first part appeared last week (OGJ, Dec. 11, 2006, p. 37).

Burlington Resources Inc., now part of ConocoPhillips, in conjunction with STRM LLC, has conducted a series of field studies to test the validity of the fluid pressure (P_f) wave geomechanical model using SET for direct mapping of the reservoir scale permeability field.

Two studies were done: a tight gas sand discovery well in northern British Columbia and a frac in the Barnett shale in North Texas. Data for both studies were acquired and processed by MicroSeismic Inc., Houston, with further processing of the raw SET data and analysis by STRM. The following criteria were used to determine the success of the technology.

1. Acoustic energy (AE) emission trends should parallel known tectonic trends of folds, faults, and jointing.
2. A change in fluid pressure at the well should produce AE patterns consistent with known tectonic trends, e.g., jointing, faulting, etc.
3. The AE patterns produced by the ΔP_f should statistically parallel directions of maximum shear stress for Mohr Coulomb failure criteria consistent with the ambient Sh_{max}.
4. The AE emissions must be demonstrably related to crack failure.
5. It should be possible to acquire data in a production environment.

Field study 1

The British Columbia study was conducted on a tight gas sand discovery well in the Canadian Rockies Foothills belt.

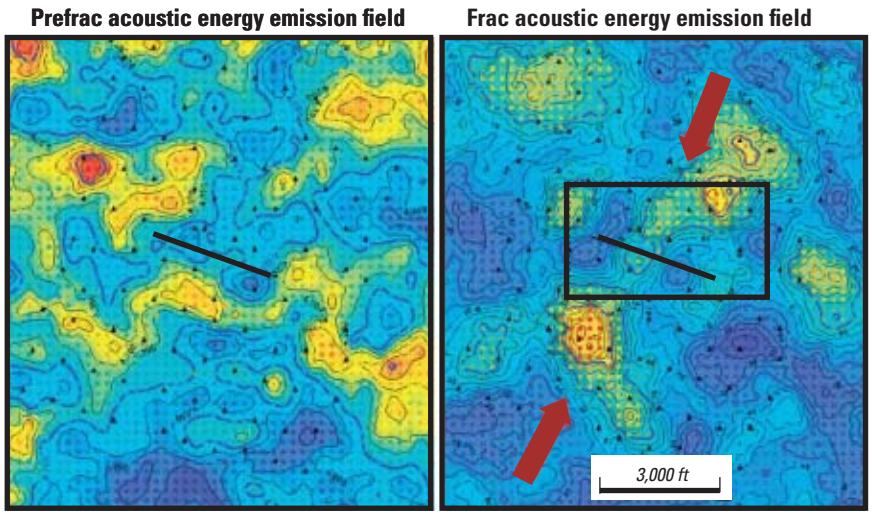
An initial network of nine 6-channel Kinemetric K2 portable seismic stations was established to monitor a cube with an 8x8 km map area and a 4-km depth. Each station consisted of one 3C and three 1C Sercel geophones for a total of 54 channels for the entire network.

Three stratigraphic intervals were monitored during the study period, which extended over a month. The lowest two intervals were flow tests, and the third was a frac.

Various adverse field conditions caused the successive loss of stations from nine for the first test to seven

REORGANIZATION OF AE FIELD INDUCED BY FRAC OPERATIONS

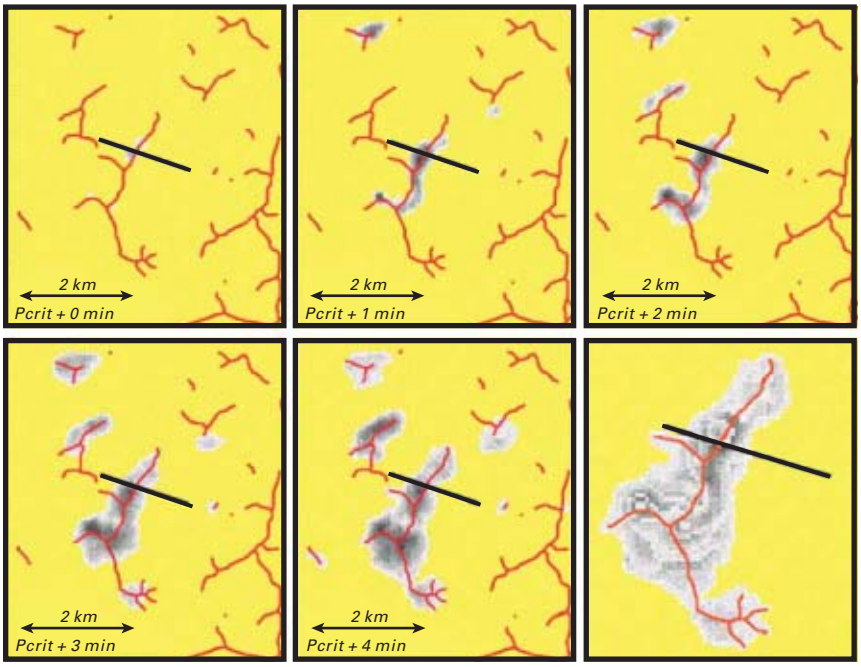
Fig. 4



Two contoured map slices of 1-min SET data stacks at 7,800-8,000 ft KB. Triangles locate surface geophone network. Treatment well is diagonal WNW line and is located at 7,800 ft TVD. Arrows indicate orientation of Sh_{max}. Blues are low AE values, orange and yellows are higher. Voxel size is 180 ft. NB: These data are from an early version of the processing software in which AE values for each SET volume are normalized only against the given volume, thus only the relative AE values are comparable from one volume to another. E_{max}, which can be compared, is highest for the frac state. Dotted rectangle is location of map images of Fig. 6. Vertical component data.

ENERGY MIGRATION ALONG FRACTURE NETWORK

Fig. 5



Sequence of 1-min stacks at the 7,400-7,600 ft interval showing migration of the top 5% of the energy along fracture network. These data are concatenated to form the region shown in the lower right corner panel. The "skeleton" of the concatenated high AE areas is found (lower right hand panel. NB: Scale is larger than the sequential ones) and used as a proxy for the location of the zone of maximum fracturing. Treatment well is WNW trending line. Vertical component data.

for the second and five for the third. Although all tests showed the predicted AE patterns, the two latter tests monitored by less than 54 channels resulted in significant aliasing and antenna effects that degraded resolution.

Fig. 3 (see Part 1, OGJ, Dec. 11, 2006, p. 37) shows the results of the first flow test. In the preflow state (unperturbed stress field) a set of NW-trending bands of high AE is most prominent. These trends parallel the major tectonic trends defined by folding and faulting. The band that passes through the well is coincident with the faulted anticline into which the well has been drilled.

A second NE-trending set of directions is present as a rippling effect superposed on the NW-trending bands. This trend parallels the dominant NE-trending joint sets. A NNW set of AE trends parallels a second set of known joint directions. The high AE bands are geographically stable; however, the locations of individual AE highs on the bands vary on a second by second basis.

Fig. 3 shows a dramatic contrast between the unperturbed (ambient) stress state and the perturbed state. As the P_f wave geomechanical model predicts, the AE emissions shift to those directions favorably oriented for Mohr Coulomb shear failure (NE and NNW trends) while AE emissions for those directions unfavorably oriented (NW trends) are suppressed relative to the favorable ones.

All the remaining tests showed results consistent with the model predictions. In addition to the reorganization of the AE field in response to the flow test, the variation in the maximum energy value (E_{max} in volts) for each of the SET cubes is consistent with energy changes expected during flow tests (E_{max} decrease) and fracs (E_{max} increase). Energy changes were two orders of magnitude.

Field study 2

The second field study, a frac in the Barnett shale, was focused on using SET in a production environment and comparing the results with those acquired by downhole monitoring.

The latter goal was meant to confirm that the primary AE emissions being recorded and processed were the product of rock failure.

For this study a much denser geophone network was used. The network, a Sercel 408 system consisting of 97 3C geophones, was distributed over a 2.5 sq mile area around the horizontal treatment well. The frac was monitored over a 3-day period consisting of a day before and a day during and after the frac. Pinnacle Technologies handled the downhole monitoring.

Fig. 4 shows the effects of changing fluid pressure on the organization of the AE field. Although the prefrac slice AE field shows some degree of organization as reflected in the NE and NW trends of the AE bands, the field is relatively disorganized compared to that induced by the frac.

The frac state stack shows the condition of the field at the time when wellhead pressure first reached the critical value at which fracturing began. Although the general organization of the field and the location of high AE bands remain stable for as much as 30 min, as with the ambient field the high AE loci on the bands change location but do so systematically.

The regions of high AE are observed to migrate outwards from the treatment well at about 60 fps in a manner con-

sistent with crack propagation. The systematic migration of the energy also provides a means of more precisely locating the potential zones of highest permeability.

Earthquake and crack theory predict that the principal fracture should occupy the region of highest AE emission. This region is found by clamping out all but the top 5% of the energy values over a sequence of stacks revealing a set of regions of high AE systematically migrating along some path.

The sets of regions are concatenated and the center or "skeleton" of the summed high AE areas found. The "skeleton" is inferred to locate the fracture/fault fairway. The results of this process are shown in Fig. 5.

According to the P_f geomechanical model, the hydraulically linked fracture systems should statistically parallel directions for maximum shear stress. To test this we have broken the "skeleton" into segments and measured the orientation of skeleton segments for both the ambient and perturbed state. The results are shown in Fig. 6.

As is well known, fractures formed during fracs utilize preexisting joint sets. In this region of the Barnett there are two dominant joint sets; NE and WNW. New fracture networks are formed by a "laddering" of the two joints sets to form an "average" direction for the fracture itself.

In both the prefrac and frac states the WNW and NE sets combine to form "average" trends for the combined sets. In the prefrac state the dominant average trend is west while in the frac state two additional dominant average trends are formed consistent with maximum shear stress directions.

The comparison of the SET results to those obtained using downhole seismometers is shown in Fig. 7. These figures show a set of consecutive 1-min stacks of SET data. Hypocenter data (diamonds) recorded by the downhole instruments for the 1-min time interval of each stack, are superposed on the AE field map slice for the same 200-ft interval as the hypocenters.

The observation well location is given by the purple hexagon in the NE corner. The sequence starts 7 min before Pcrit (time number 2397) and extends 4 min beyond it. There are several caveats with respect to the data:

1. The SET data show the sum of all AE energy released by the entire crack spectrum for the given time interval, whereas the hypocenters represent discrete events lasting on the order of a few seconds as opposed to the 60-sec SET stack time.

2. The AE values are relative, not absolute, values. For each stack the values are normalized relative only to the AE values of that SET volume.

3. The hypocenter data are filtered by distance from the observation well, thus the greater the distance from the well, the fewer resolvable events.

Given that the amount of AE measured by SET is a function of the total fracture energy emitted during the stack interval irrespective of fracture size and that there is a distance filtering bias in the hypocenter data, there is very reasonable agreement between the hypocenter data and the AE emission field. Note that the distribution of the hypocenter data generally reflects the shape of the higher AE values.

These results are interpreted to strongly support the conclusion that the SET data are the product of rock failure induced by a fluid pressure wave.

What is learned

Geometry and behavior of SET energy field images are consistent with of fracture/fault systems.

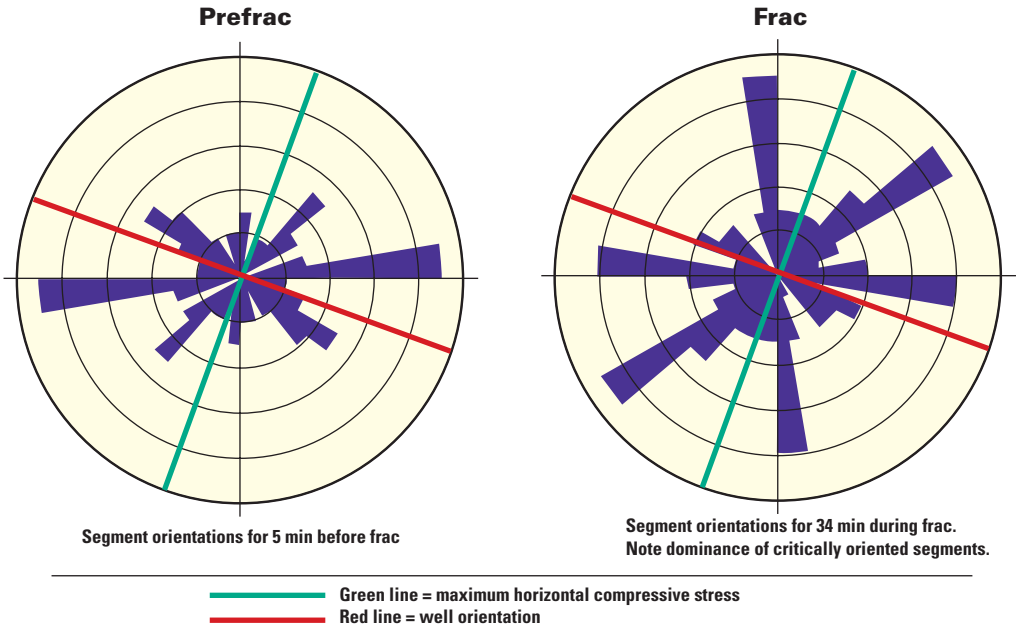
Dynamic behavior of SET energy fields is consistent with crack theory and P_f geomechanical model.

Time/space distribution of SET high AE energy agrees with hypocenter data.

All observations are consistent with

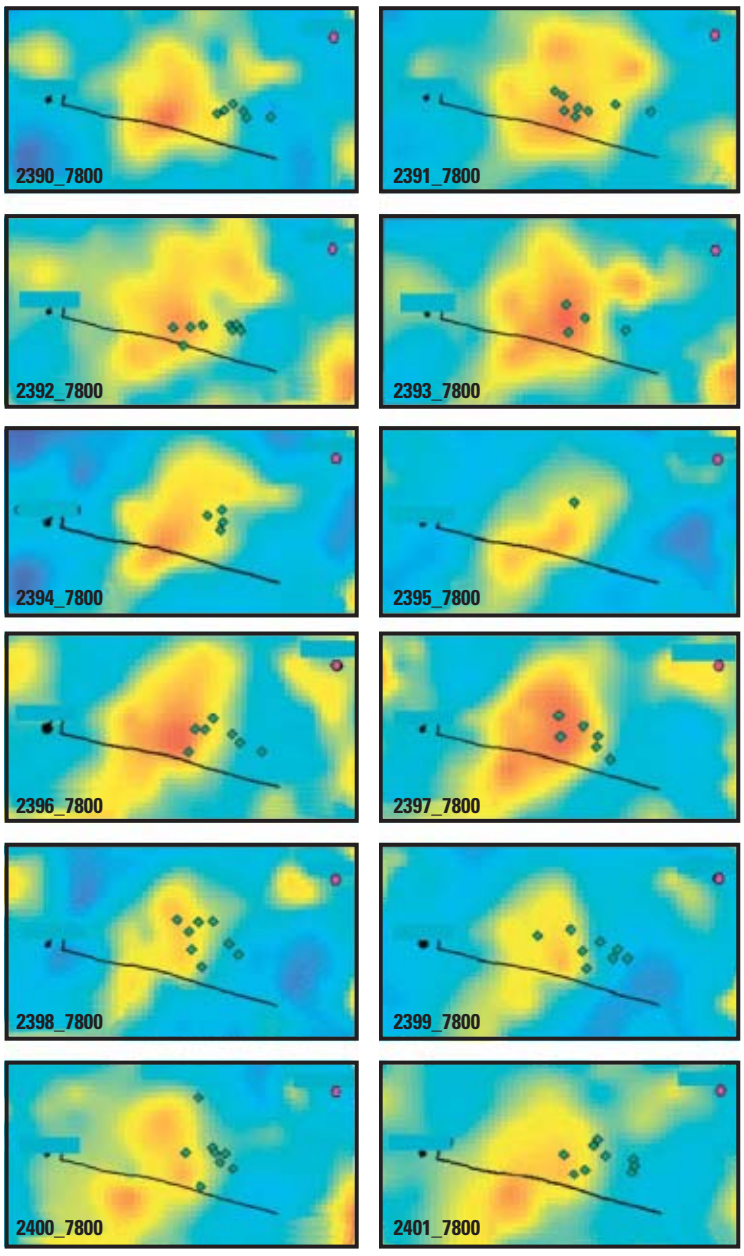
ORIENTATION OF 'SKELETON' SEGMENTS

Fig. 6



S-E-T STACKS AND SUPERPOSED HYPOCENTERS

Fig. 7



Consecutive sequence of 12 map slices of 1-min SET stacks with superposed hypocenters recorded at observation well (red circle). First number on images is time in minutes; second number is KB depth of slice. See Fig. 4 for location of map slice.

the claim that our analysis of the SET-generated AE fields can image both the ambient fracture/fault network and the reservoir-scale permeability field geometry.

This imaging can be done using only a surface based seismic network in which the size of the mapped volume is limited only by the size of the network deployed.

We conclude that the set of studies we have conducted demonstrates that it should now be possible to use surface-based seismic networks to directly map the reservoir scale permeability field of fluid reservoirs. This capability promises to remove one of the major impediments to significantly increasing the efficiency of hydrocarbon production.

Acknowledgment

Burlington Resources provided the major funding for this work. ✦

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Australia

Oil production began Nov. 18 from Callawonga-1, which operator Beach Petroleum NL, Adelaide, describes as the most westerly output achieved in the Cooper/Eromanga region.

Beach assesses P50 reserves to be 1.5

million bbl at Callawonga field, on PEL 92 about 7 km north of Christies oil field and 90 km northwest of Moomba.

Callawonga-1, drilled in July 2006 when it cut 8 m of net oil pay in Jurassic Namur sandstone, was producing on free-flow at 2,100 b/d on Nov. 20.

Beach Petroleum 75% and Cooper Energy Ltd. 25% are continuing to explore PEL 92 using a recently acquired 3D seismic survey.

The Northern Territory government granted exploration permits 103 and 104 totaling 5.5 million acres in the nonproducing Georgina basin.

Texalta Petroleum Ltd., Calgary, purchased the 50% of the acreage held by its Australian partners, giving Texalta 100% working interest.

The permits took effect Nov. 21, 2006, for 5 years. The work program includes seismic reprocessing, more seismic surveys, and the drilling of structural test wells. Texalta began preliminary seismic reprocessing in Calgary.

Oman

TGS-NOPEC Geophysical Co. ASA, Asker, Norway, began acquiring 6,000 km of multiclient 2D seismic data in the Arabian Sea off southernmost Oman.

With strong industry prefunding, the survey also involves gravity and magnetic data.

The survey area is considered highly prospective yet underexplored and lacks any previous data in the deepwater areas, the company said.

Petroleum systems of interest include a subophiolite play and extensions of the prolific hydrocarbon producing Mesozoic rift basins in Yemen as well as postulated overlying Tertiary basins.

Venezuela

Chevron Corp. let a contract to SCAN Geophysical ASA, Oslo, for a 3D seismic survey off Venezuela.

The survey covers two nonadjacent areas and will take several months using the M/V SCAN Resolution, recently arrived in Venezuela.

Chevron has two gas discoveries in the Plataforma Deltana area south of Trinidad and Tobago and recently won a gas-prospective block in the Caribbean on the north side of the Paraguana Peninsula.

Ontario

Greentree Gas & Oil Ltd., London, Ont., said an exploratory well in Haldimand County near Nanticoke is preparing to drill through the Ordovician Trenton-Black River and Cambrian intervals.

The GGOL-67 well cut 8.5 m of sandstone in the Silurian Thorold and Grimsby formations, of which 2.5 m had more than 8% porosity.

Primary target is the Trenton-Black River hydrothermal dolomite play.

Greentree Gas & Oil spudded a light oil prospect in Tilbury West Township, Essex County, south of Detroit, Mich.

The GGOL-71 well, being drilled with cable tools, offsets a Talisman Energy Inc. horizontal oil producer along a seismically defined Ordovician Trenton-Black River anomaly, Greentree said.

Results are not expected until the first quarter of 2007.

Louisiana

Goodrich Petroleum Corp., Houston, took a farmout on 16,000 acres in 33 sq miles in Alabama Bend oil and gas field along the Cotton Valley oil and gas trend in western Bienville Parish from an undisclosed farmor.

Objectives are primarily Cotton Valley and secondarily Hosston and Bossier.

Goodrich will own a 100% interest in the first well drilled in each of the 33 sq miles. The farmor has the right to participate for up to 50% on subsequent wells in each section or unit. Goodrich must drill one well every 90 days from the completion date of the previous well.

The agreement provides for no upfront cost to Goodrich. The farmor reserved an overriding royalty interest equal to the difference in lease burdens and 25%, leaving Goodrich with a 75% net revenue interest.

The deal expands Goodrich's position in the trend by 11% to 103,000 net acres, the equivalent of 400 vertical well locations on 40-acre spacing.

Alabama Bend field was discovered in 1950.

Montana

Gold Point Energy Corp., Vancouver, BC, was spudding a wildcat on the 1,840-acre Woody Creek Dome prospect in 3s-31e, Big Horn County, on the Crow Indian Reservation.

GP Energy, operator with 70% interest in the prospect, seeks oil in Pennsylvanian Tensleep at 2,250 ft and Amsden at 2,370 ft. The area is 35 miles east-southeast of Billings.

Soap Creek, Soap Creek East, and Marcus Snyder fields within 15 miles of the prospect have combined cumulative production of more than 4 million bbl of oil from the same horizons.

Texas

Gulf Coast

PYR Energy Corp., Denver, is attempting to interest industry partners in drilling the 338-acre West Westbury Prospect, which targets Eocene Yegua sand reservoirs in Jefferson County.

The prospect, based on 3D seismic amplitude, is 1.5 miles southwest of an analog well in which PYR has no interest. That well, completed in October 2004 on the same fault block but subject to different seismic attributes, produced 21.9 bcfe through April 2006. The current flow rate is 35 MMcfd of gas and 1,700 b/d of condensate.

A second well in which PYR Energy has no interest, the Paggi Broussard-2, is producing 28 MMcfd and 1,500 b/d. It is in the same fault block with different seismic attributes. PYR Energy holds 100% interest in the prospect.

DRILLING MARKET FOCUS

Industry stable in North America

Nina M. Rach
Drilling Editor

The drilling industry appears to be on the upside of a supercycle, keeping most rigs busy in North America.

Both oil and gas prices have stopped their rapid upward climb, but rigs are still working. The total number of US oil rigs is up slightly but relatively flat over the last 5 years. The bigger story is in the number of rigs drilling for gas in the US, which has doubled in only the last 3 years.

December contracts on the New York market for US crude oil benchmarks expired Nov. 17 at the lowest closing price in 17 months (OGJ Online, Nov. 20, 2006). In some areas, reduced natural gas prices have caused operators to scale back development drilling. Yet operators are proceeding with major exploration projects and leaving few rigs idle, on or offshore.

Day rates in the Gulf of Mexico are depressed only relative to other international markets; rig profitability in the gulf has increased 223% over the last 5 years. Yet the local day rates have caused a steady flow of rigs out of the gulf, while overall worldwide utilization has remained high.

Land rigs in North America are susceptible to fluctuations in gas price, yet rig construction and refurbishment continues at a rapid pace, with most new rigs anchored by term contracts.

Modest softening in gas drilling has caused some companies to shift assets to oil-oriented regions such as the Permian basin and California's San Joaquin basin.

Outlook

Marshall Adkins, managing director of Raymond James & Assoc. expects the global drilling market to be "pretty healthy" for the next 5 years," and said that the US land fleet will continue to grow at 10-12% (net) for "at least the next year, and probably the next 3 years."[1]

Richard Mason uses three indicators (drilling permits, trailing 6-month oil prices, trailing 12-month gas prices) to forecast US drilling activity 60, 180, and 270 days out, for The Land Rig Newsletter's "drilling activity oscillator." He was unusually pessimistic in October, publishing the most negative report yet. Based on his indicators, he forecast reduced drilling over the next 2, 6, and 9 months.

The last few times Mason came close to issuing such a negative prognosis were in July 2003 and July 2002, when he forecast 60-day drilling outlook down and 180-day and 270-day outlooks flat.

In the October 2006 issue, however, Mason reasoned that some of the indicators might be unreliable, and said the latest forecast might be a "false negative."

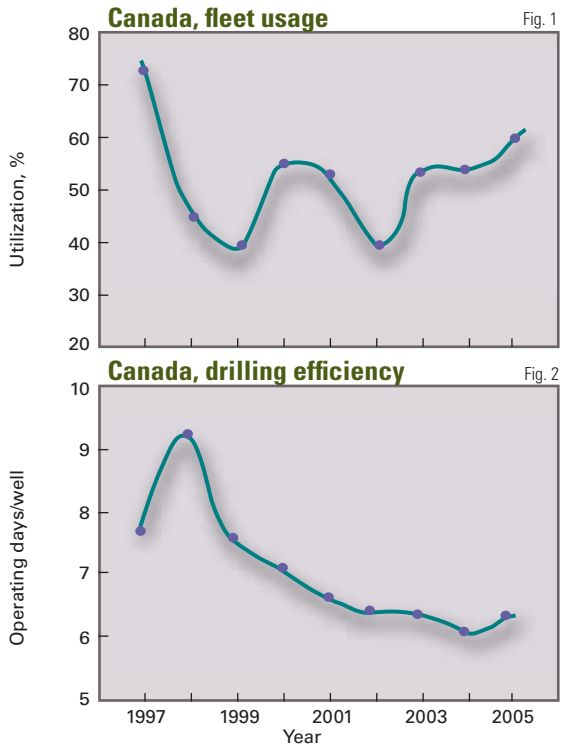
"The industry can't survive $4[/Mcf] gas, though it doesn't need $12 either...why fret with gas in the $7s?"

US drilling

Baker Hughes Inc. reported 1,717 rotary rigs working in the US the week of Dec. 1, 2006, up 18% (257 rigs) from a year earlier. This includes 1,608 land rigs (up 18% from a year ago), 86 offshore rigs (up 10% from a year ago), and 23 rigs working in inland waters.

Regionally, Texas led the states with 771 rigs drilling, followed by Louisiana with 193 rigs, and Oklahoma with 183 rigs. Drilling is also strong in the Rocky Mountain area, with 87 "oil-directed" rigs drilling in Colorado and 90 rigs

CANADIAN DRILLING*



*Data from the Canadian Assoc. of Oilwell Drilling Contractors.

drilling in Wyoming.

Most of the rigs working in the US were drilling vertical holes (1,028 rigs; 60%), while 374 rigs were drilling directionally (22%), and 315 rigs were drilling horizontally (18%).

Most rigs (1,423; 83%) were drilling for gas, up 19% from a year ago. Another 289 rigs were drilling for oil, up 9% from a year ago.

The Land Rig Newsletter composite rig count tracks the fleets of the five largest drilling contractors (Nabors Drilling US LP, Patterson-UTI Energy Inc., Grey Wolf Inc., Unit Drilling Co., and Helmerich & Payne Inc.) and accounts for nearly half of the US rig fleet.

The composite counts all rigs working under contract, including those mobilized, not just rigs turning to the right. The composite count showed 761 active rigs on Nov. 10, down 37 rigs from Oct. 27. Patterson-UTI had 20 fewer rigs; Unit was down 11; Nabors and Grey Wolf each lost 4 rigs. Only H&P added rigs (2) for the week.

H&P

In November, Oklahoma's Helmerich & Payne Inc. announced results of its fiscal year, ended Sept. 30. Hans Helmerich , president and CEO, said the company's "earnings for the current year more than doubled our previous all-time high of 1 year ago."

H&P has been buying back its stock; about 2 million shares since July 2006.

The company owns 117 US land rigs, 11 US platform rigs, and 27 international rigs.

For the US land rigs, H&P reported average revenue/day of $24,343/rig ($13,288/day net) for this fiscal year's fourth quarter, compared with $23,503/day ($12,938/day net) for the previous quarter.

H&P's US land rig utilization averaged 99% in fourth (fiscal) quarter, up from 95% a year earlier.

Since March 2005, the H&P has announced plans to build 73 new FlexRigs, all with minimum work commitments of 3 years. By the end of 2007, all will be completed; 28 have been finished to date.

"The industry can't survive $4 gas, though it doesn't need $12 either...why fret with gas in the $7s?"

—Richard J. Mason, The Land Rig Newsletter

Barnett shale

One of the largest gas resource plays and largest growth areas in the US, the Barnett shale has attracted drilling by Devon Energy Corp., XTO Energy Inc., EnCana Oil & Gas, Chesapeake Energy Corp., EOG Resources Inc., Denbury Resources Inc., Quicksilver Resources Inc., Southern California Public Power Authority, Royal Dutch Shell, and DTE Gas Resources, a subsidiary of DTE Energy Co., among others.

The Barnett play is attracting tremendous growth. So far this year, 2,322 drilling permits have been issued for wells in the Barnett, a 16% increase over the 2,006 permits issued in 2005, and 67% increase over the 1,387 permits issued in 2004.

There are about 165 active rigs, and about 200 are likely to be working the play in 2007.[3] The wells are predominantly (80%) horizontal, enhanced with slickwater fracs (OGJ, Mar. 7, 2005, p. 41).

Houston-based newcomer, Mountain Drilling, is also providing new, Italian-built Drillmec HH300 hydraulic rigs to the Barnett market.

In late October, however, Calgary's EnCana announced plans to cut 4 of its 12 Barnett shale drilling rigs, due to "rising expenses," saying that rigs now cost $20,000-22,000/day. The company had previously announced plans to drill at least 100 wells in the Barnett in 2007, primarily in Denton and Tarrant counties, Texas. The company also plans to cut rigs in Colorado and Wyoming.

Mason observed in his recent newsletter that operators are "pushing hard for rollbacks in rig rates, typically by threatening to let rigs go." But he also noted that a lot of E&P firms are still looking for rigs, and to give one up voluntarily means risking delay in getting a replacement. "Demand for drilling services has risen in tandem with commodity prices."[1]

Gulf of Mexico

The offshore fleet working in the Gulf of Mexico is about 112 rigs: 70 jack ups, 29 semisubmersibles, and 6 drillships. Overall utilization at the end of November was about 80%, according to ODS-Petrodata Group. Although the drillships were 100% engaged and the semisubs 94.5%, only 73% of the jack ups were working.

The Rowan Paris jack up is the latest rig to leave the gulf, after finishing a $160,000/day contract. It will spend 3½ months in a Qatar shipyard before starting a 2-year contract with Maersk Oil at $190,000/day.

GlobalSantaFe Corp.'s monthly summary of current offshore rig economics (SCORE) was about 111 for the Gulf of Mexico in October, down nearly 6% from the previous month but up 16% from a year earlier and up 223% from 5 years earlier.

Regionally, the gulf has the lowest SCORE for any of the regions tracked worldwide, suggesting that prices are locally depressed for jack ups and floaters. This is borne out by a continuing exodus of rigs from the gulf into other areas.

Service rigs

The Weatherford-AESC well-service rig count increased to 2,440 rigs for October 2006, up 2.5% (60 rigs) from the previous month and up 5% from a year earlier. Rig utilization was at 74%. Weatherford took over the count from Halliburton in July 2001.

Houston's Key Energy Services Inc. (www.keyenergy.com) provides well

services, pressure-pumping, fishing, and rental services worldwide, with more than 7,500 employees. CEO Dick Alario reported at the Bank of America Energy Conference on Nov. 16 that revenue in its second fiscal-year quarter (ending Sept. 30, 2006) had beaten the forecasts. The company attributed the positive result to higher pricing, expanded capacity, and increased rig hours due to additional working days. Key Energy had 677,271 well-service rig-hr, up 2% from the previous quarter and a corresponding profit margin expansion to 43% from 39%.

The company is moving some assets out of the San Juan basin and Midcontinent areas and plans to set "new pricing initiatives" across all regions in first-quarter 2007.

PROVINCIAL DRILLING[1]

Table 1

	2007, predicted no. of wells	Change, %	2006, expected no. of wells
British Columbia	1,050	–28	1,450
Alberta	16,010	–12	18,000
Saskatchewan	3,695	flat	3,650
Manitoba	650	+8	600
Ontario	70	+11	63
Eastern Canada[2]	20	–26	27
Northern Canada	5	–50	10
Total	**21,500**	**–10**	**23,900**

[1]Petroleum Services Assoc. of Canada (PSAC). [2]Quebec, New Brunswick, Nova Scotia, Prince Edward Island, Newfoundland & Labrador.

Canada, 2006

Baker Hughes reported 442 rigs drilling (turning to the right) in Canada during the week of Dec. 1, down 32%, or 211 rigs, from a year earlier (653 rigs). Land drilling dominates with 438 rigs, with only 4 rigs working offshore (3 off Newfoundland, 1 off Ontario). Alberta led land drilling with 319 rigs, followed by Saskatchewan (67 rigs), and British Columbia (49 rigs). Manitoba had two and Newfoundland had one land rig working.

The rig count reached a record high of 715 during the last high season (February 2006), but gas well drilling has dropped precipitously since last winter. Still, most (301) rigs were drilling for gas during the week of Dec. 1 (68%), compared with only 141 rigs drilling for oil.

The Canadian Assoc. of Oilwell Drilling Contractors reported 495 rigs working under contract in Western Canada for the week ending Dec. 5, with 347 rigs down, a 59% utilization rate.

Historically, CAODC reported 749 rigs working, on average, in 2005, at about 60% utilization (Fig. 1).

Drilling efficiency has increased in the last decade in Canada, according to data from the CAODC. Wells now require an average of 6.3 days to drill,

down from a high of 9.3 in 1998 (Fig. 2).

From Ottawa on Oct. 31, Canada's Harper government announced plans to end the tax-free status of trusts in 2011, raising the possibility that the E&P industry would be affected by the flight of capital from energy trusts. Dow Jones reported on Nov. 2 that six of top 10 funds on the Toronto Stock Exchange were Calgary-based oil and gas trusts and all had dropped in value.[3]

"It's going to be harder for larger companies to take their mature properties and sell those to energy trusts, then take the cash for that and go do exploration," said Bill Schulz, at Calgary's Haskayne School of Business.[3]

In response to the government's action, 40 different energy trusts formed the Coalition of Energy Trusts, which claims that the sector plays a "vital role in developing lower production fields that are avoided by larger oil and gas companies." The Coalition said the energy trusts have invested $10 billion (Can.) into the oil patch in the last 5 years and are responsible for 20% of Canada's crude oil and natural gas production.[4]

Canada, 2007

On Nov. 1, the Petroleum Services Association of Canada issued its 2007 Canadian drilling activity forecast, predicting "the first slowdown in petroleum industry field activity since 2002" (www.psac.ca).

PSAC expects 21,500 wells to be drilled across Canada in 2007, about 10% fewer than the final tally expected for 2006—23,900 wells (Table 1). The expected well count for 2006 is about 5% lower than the number predicted by PSAC in October, largely due to reduced gas drilling in Alberta.

In 2007, PSAC expects industry to drill about 1,300 more oil wells than in 2006. Estimates are based on $60/bbl (US, WTI) and $6.25/Mcf (Can.).

East Canada

Expect more drilling off Eastern Canada over the next few years. Companies bid $32.4 million (Can.) for licenses off Newfoundland in the 2006 land sale on Nov. 16, under Call for Bids NL06-1 and Call for Bids NL06-3, according to the Canada-Newfoundland and Labrador Offshore Petroleum Board (C-NLOPB; www.cnlopb.nl.ca).

Most of the bidding ($31.4 million Can.) was for commitments to drill in the Jeanne d'Arc basin, followed by $956,008 (Can.) committed to drill off western Newfoundland.

Calgary's Husky Energy Corp. bid $15.5 million (Can.) on their own, as Husky Oil Operations Ltd., for 24,800 hectares near the southern border of the Terra Nova oilfield. Norsk Hydro Canada Oil & Gas Inc. joined Husky as equal partner in $5.5 million and $10.4 million bids for two parcels lying south of the White Rose field.

Husky announced on Nov. 20 that

it would drill two more wells off Newfoundland at North Ben Nevis and Fortune in the Jeanne d'Arc basin. Husky's partners at North Ben Nevis are ExxonMobil, Petro-Canada, Norsk Hydro, and Chevron. Partners at Fortune include Petro-Canada, Norsk Hydro, and Chevron.

In West Newfoundland, NWest Energy Inc. bid $550,008 on two parcels off the Northern peninsula and B.G. Capital Ltd. bid $406,000 on a license for a tract off the Port au Port peninsula.

The 9-year exploration licenses will be issued by C-NLOPB in January 2007. Under a new licensing scheme, parties have 5 years in which to drill with the money committed and then will be assessed rental fees of $20/hectacre (Can.) for any "major finds left fallow."

Mexico

Baker Hughes reported that 82 rigs were drilling in Mexico in October 2006, including 58 land rigs and 24 offshore rigs. This is 11% fewer rigs than a year earlier, when 92 rigs (62 land; 30 offshore) were drilling in Mexico. Most (48) of the rigs were drilling for oil in October 2006; 31 were drilling for gas, and 3 others were listed as having "miscellaneous" objectives. ✦

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Simulation predicts condensate formation in Aghar field

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A compositional program in a dynamic mode simulated multiphase flow through porous media and predicted condensate formation in a gas-condensate reservoir in southern Iran's Aghar field.

The study used the sequential method for treating both thermodynamic and fluid flow so that the pressure-volume-temperature (PVT) condition in each time step determined the fluid flow parameters for the next time step.

The simulation showed the effects of liquid dropout in the near wellbore and the program's flexibility allows for its use in such other processes as gas cycling to clean the wellbore from liquid dropout.

Gas composition

Table 1

Mole, %	Component
5.4535	N_2
1.2975	CO_2
0.007	H_2S
89.7664	C_1
1.453	C_2
0.4301	C_3
0.1145	iC_4
0.1722	nC_4
0.08263	iC_5
0.06471	nC_5
0.12835	nC_6
0.15725	nC_7
0.092575	nC_8
0.072655	nC_9
0.052745	nC_{10}
0.047765	nC_{11}
0.03781	nC_{12}
0.029835	nC_{13}
0.022865	nC_{14}
0.012915	nC_{15}
0.013905	nC_{16}
0.008935	nC_{17}
0.0089375	nC_{18}
0.006948	nC_{19}
0.02278	nC_{20}
0.4422	H_2O
100	**Total**

Gas-condensate reservoirs

Gas-condensate reservoirs are common in the Middle East. These reservoirs exhibit complex phase and flow behaviors because of condensate banking in the near wellbore and dynamic compositional changes of each phase. Accurate forecasts of gas-condensate reservoir performance with a numerical simulator require a good understanding of the gas composition's effect on the flow and phase-behavior properties.

Production rate, fluid properties, and reservoir characteristics such as absolute permeability, relative permeability, wettability, initial reservoir pressure, and temperature influence the behavior of these reservoirs.

Production from these reservoirs causes a decrease in reservoir pressure that leads to liquid dropping out in the reservoir. The phenomenon occurs first in the vicinity of the wellbore and then propagates outward into the reservoir. The most important effect of liquid formation is the reduction of gas relative permeability, which in turn lowers gas production rates.

Evaluation technique

The study investigated gas-composition effects on liquid blockage, relative permeability changes, and hence the decrease in gas production rates.

The analysis used HYSYS, a commercially available simulator that allows user customization for estimating the fluid properties and the PVT calculation for each time step at each node. Besides a rigorous thermodynamic and physical property evaluation, the analysis employed a sequential approach for combining the thermodynamic and fluid flow part of the program.

The field compositional data from a gas-condensate reservoir in the Aghar field confirmed the results.

Literature shows that a single phase, multicomponent system can be used to calculate gas-condensate reservoir

Equations

$$v_{cond} = -\frac{K\,kr_{cond}}{\mu_{cond}}\left(\frac{dP_{cond}}{dx} - \rho_{cond}\,g\right) \quad (1)$$

$$v_g = -\frac{K\,k_{rg}}{\mu_g}\left(\frac{dP_g}{dx} - \rho_g g\right) \quad (2)$$

$$v_{cond} = \frac{K\,kr_{cond}}{\mu_{cond}}(\rho_{cond} - \rho_g)g + \frac{kr_{cond}}{\mu_{cond}}\frac{\mu_g}{kr_g}v_g \quad (3)$$

$$v_{cond} = \frac{kr_{cond}}{\mu_{cond}}\frac{\mu_g}{kr_g}v_g \quad (4)$$

$$Q_t = v_{cond}A = -\frac{K\,kr_{cond}A}{\mu_{cond}}\left(\frac{dP}{dx}\right) \quad (5)$$

$$Q_g = v_g A = -\frac{K\,kr_g A}{\mu_g}\left(\frac{dP}{dx}\right) \quad (6)$$

$$m_g = v_g\rho_g = (S_g\phi\,V_b)\rho_g = (V_s + \Delta t(Q_g^{in} - Q_g^{out}))\rho_g \quad (7)$$

If $S_{cond} \geq S_{critical}$ then

$$m_{cond} = V_{cond}\rho_{cond} = (V_{cond} + \Delta t(Q_{cond}^{in} - Q_{cond}^{out}))\rho_{cond} \quad (8)$$

Otherwise

$$m_{cond} = (V_{cond} + \Delta t(Q_{cond}^{in}))\rho_{cond}$$

Nomenclature:

K	-	Absolute permeability, darcy
v	-	Darcy velocity, cm/sec
kr	-	Relative permeability
μ	-	Viscosity, cp
P	-	Pressure, atm
ρ	-	Density, g/cc
Q	-	Volumetric flow rate, cc/sec
V	-	volume, cc
m	-	mass, g

Subscript

cond	-	Condensate
g	-	Gas
b	-	Bulk

Superscript

in	-	Input
out	-	Output

performance. But because two-phase flow in the near wellbore region plays an important role in the blockage, this approach is not entirely correct.

Another approach is to mimic the gas-condensate reservoirs with a pseudobinary model. Estimating thermodynamic behavior, such as composition changes of the gas and condensate phases, with a binary model is inaccurate.

As a result, two-phase flow in gas-condensate reservoirs could be described better with an equation of state for calculating the thermodynamic properties and phase behavior, for example, flash calculations at each stage.

Prediction of well deliverability and calculation of gas and liquid recovery require a detailed knowledge of the relative permeability and liquid banking. This study uses Corey's correlation for estimating the relative permeability of each phase.[1]

Roussennac documented phase changes during depletion with a numerical simulation procedure.[2] According to Roussennac, during the drawdown period, with the liquid building up in the well grid cell, the overall mixture in that cell becomes richer in heavy components and the fluid behavior changes from the initial gas-condensate reservoir conditions to a volatile oil with a higher critical temperature.

Pressure depletion below the dewpoint pressure causes the formation and buildup of condensate, so that the near wellbore region, which has the largest pressure drop, is expected to be a place where condensate banking forms. This process is not a steady-state condition because of the nature of condensate dropout.

The study described in this article, used a one-dimensional cylindrical core simulation to understand dynamically the condensate banking in the near wellbore region. A novel approach with tank and valve options of HYSYS modeled the formation, accumulation, and movement of condensate through the porous media.

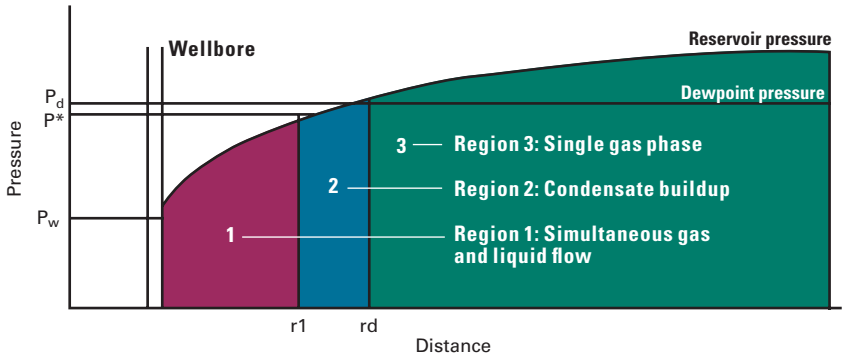
These features allowed for calculating changes in the condensate and gas phase composition near the wellbore. The calculation also considered the slip phenomenon because gas flowing in each node is not necessarily in equilibrium with adjacent liquid in the same node. Valves in the HYSYS model controlled movement of each phase according to the modified Darcy law.

The adherence of condensate to pore walls causes condensate accumulation in the pore space. Because of this, a flash calculation with the original gas composition underestimates the amount of liquid dropout.

The study, therefore, considered connate liquid condensate as the irreducible liquid phase saturation to compensate for this shortcoming.

GAS-CONDENSATE FLOW BEHAVIOR

Fig. 1



NODAL MODEL

Fig. 2

$$S^i_g, K_i, \Phi_i$$

$$k_{rg}\begin{cases} \text{If } S^i_g > S^{i\ \text{critical}}_{g'} & S^{i\ (2+l)/l}_g \\ \text{Otherwise} & 0 \end{cases}$$

Region 2, in the middle, has a reservoir pressure lower than the dewpoint pressure. Liquid starts to dropout in this region, but the condensate is immobile.

The reservoir pressure is much below the dewpoint pressure in Region 1, the part of the reservoir nearest the wellbore. In this region, if accumulated condensate exceeds a threshold saturation or critical condensate saturation, both gas and condensate may flow into the wellbore.

CASE STUDY PARAMETERS

Table 2

Porous media permeability, md	50
Irreducible (connate) oil saturation, %	10
Irreducible (residual) gas saturation, %	10
Core ID, m	2
Core length, m	15
Relative permeability correlation	$K_{r,cond.} = (\text{Cond. saturation})^{\frac{2+l}{l}}$

Condensate buildup behavior

The three-region theory characterizes gas-condensate flow in the near wellbore region (Fig. 1).[3]

The outer part, Region 3, in which the reservoir pressure is greater than the dewpoint pressure, has single-phase gas flow.

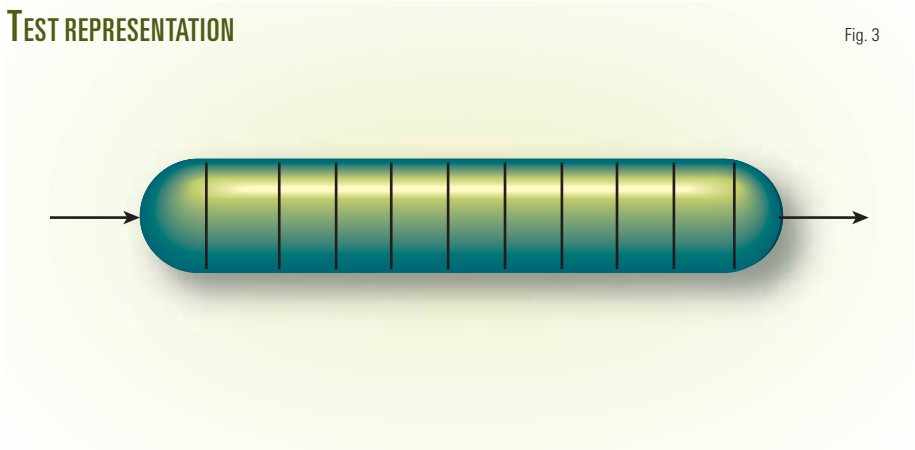
Gas-condensate simulator

The study used Darcy's law and the continuity equation combined with PVT calculations based on the equation of state to simulate gas and liquid flow in the porous media. HYSYS was the core program for the thermodynamic part of the simulator for prediction PVT properties on a dynamic basis.

As previously mentioned, combination of tanks and valves in HYSYS controlled the fluid flow equation based on the modified Darcy equation for

TEST REPRESENTATION

Fig. 3



multiphase flow in porous material.

One can assume that the effect of capillary forces is negligible between oil and gas in the gas-condensate zone because of miscibility conditions and the presence of a thin oil film in the pores and throats invaded by gas. One can then combine Equations 1 and 2 (see the equation box) by neglecting the capillary pressure terms to arrive at Equation 3.

For a horizontal model, Equation 3 becomes the simpler Equation 4.

Corey's expression predicts the relative permeability.[1]

Computer implementation

The study adopted a multistep procedure, known as a quasi-steady method, to predict the gas production history as well as the condensate-saturation profiles.[4] A summary of the simulation steps, based on the combination of the continuity equation, Darcy's law, and the equation of state, are as follows:

1. The selected part of the system for this investigation (Fig. 2) is a cylindrical core divided into a number of segments of equal length, ΔX, and the required input and output data.

2. A time step, Δt, is selected. This time step is shorter than the anticipated time required for a specific gas saturation to move over a distance of length ΔX for reaching to next node.

3. Any segment of length ΔX can be identified by its own characteristics, such as permeability and porosity, as well as the oil relative-permeability correlation (Fig. 2). This enables one to study the gas-condensate system in a heterogeneous medium involving different combinations of layers in series.

4. The gas-saturation profile at the beginning, for example time = 0, is 100% for all nodes. For the next time step, the condensate saturation is set to the previous value at each node in the direction of flow (Step 7). After determining the phase saturation, the simulator calculates the pressure of each node by solving the pressure equation for all nodes with the pressure flow solver in HYSYS software.

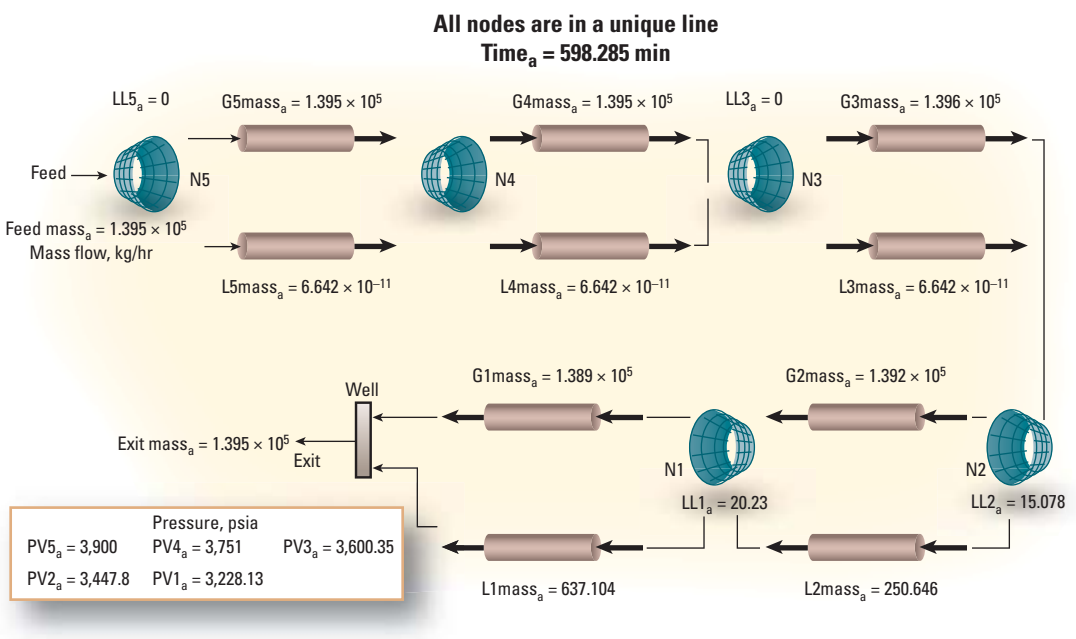
5. After calculating the condensate-saturation profile, the simulator provides the relative permeabilities with Corey's correlation. This facilitates calculation of the volumetric flow for each node with Equations 5 and 6.

6. A mass balance for the gas phase for each segment using the outcomes of Step 5 and 4 calculates the amount of prior accumulated gas in each node in the new time step (Equation 7).

7. If the condensate saturation in each node in the previous time step exceeds the critical value, the amount of previously accumulated condensate in each node for the new time step is found using the continuity equation for

SIMULATION FRAME

Fig. 4

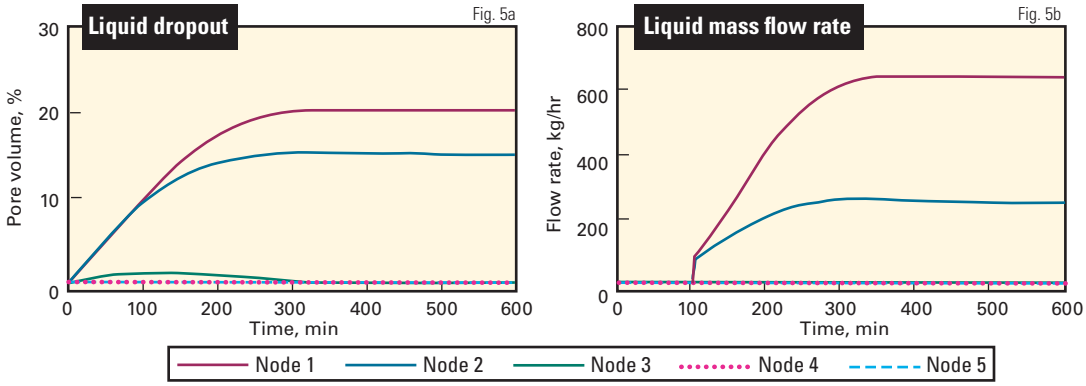


the condensate phase for each segment, as mentioned previously for the gas phase in Step 6. Otherwise the exit volumetric flow rate for the condensate phase is set to zero (Equation 8).

8. After calculating of the thermodynamic properties of each phase in all nodes by flash calculation, the simulation proceeds to the next time step, Δt, until it reaches the required time limit. The production history, oil and gas saturation profiles, as well as the nodal gas pressure are calculated using this procedure.

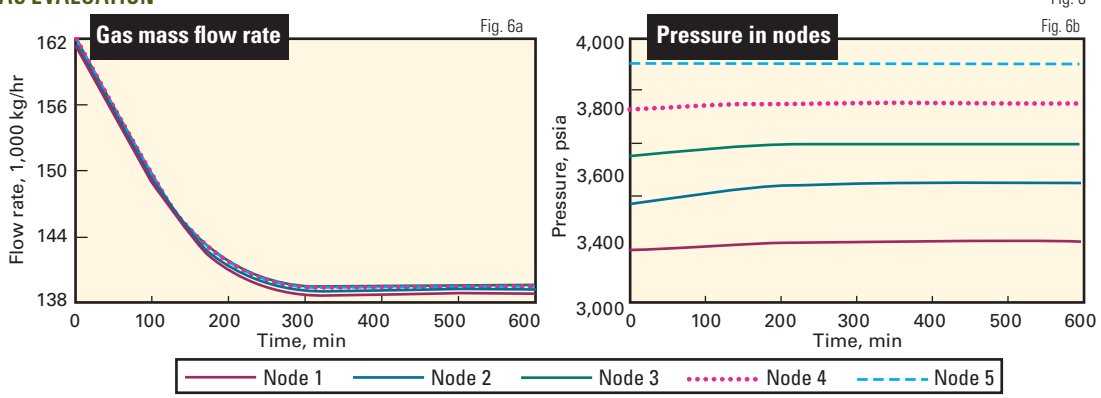
LIQUID EVALUATION

Fig. 5



GAS EVALUATION

Fig. 6



Dynamic simulation of the program requires two boundary conditions either pressure or volumetric gas flow rate. The selection of each of these two parameters as the boundary condition allows for the calculation of appropriate parameters.

The two-phase flow near the wellbore cannot be considered as Darcy laminar flow because of the high gas and liquid flow rates. Although this simulator is based on the Darcy law and laminar two-phase flow, it can handle turbulent conditions by changing the governing equation used in the program.

The program can simulate any other two-phase reservoirs such as oil reservoirs with solution gas. Its application is not restricted to gas-condensate reservoirs.

Result of simulation

Data from the Aghar field, a natural gas field in southern Iran, illustrate the use of the model. The field's estimated reserves are 440 billion cu m of gas and current production is 22 million cu m/day. Table 1 shows the gas composition.

The results of the simulation could be used in any future development plan of this reservoir, such as determining the optimal gas production rate or gas cycling to clean the condensate blocks near the wellbore.

Fig. 3 illustrates the flow conditions.

The pressure drop across the core of the simulator provides the amount of gas passing through the nodes. Besides, the simulator also calculates the condensate saturation profile, pressure, and volumetric flow rate trajectory for each phase. Table 2 summarizes the required parameters.

An animated file (.avi) provides a view of gas and condensate mass flow rates, condensate saturation in each node, and the pressure profile as a function of time. Fig. 4 shows the last frame of this animated file.

Condensate forms in only Nodes 1, 2, and 3 (Fig. 5a). This condensate remains immobile until the critical condensate saturation, which is set at 10% in this calculation. As shown in Fig. 5b, the mass flow rate of the condensate from Node 1 and 2 is zero because the amount of condensate is less than the irreducible saturation.

As a result of condensate formation, the gas mass flow rate decreases by 15% because of the gas relative-permeability reduction in the wellbore (Fig. 6a).

Fig. 6b shows the calculated pressure profiles. Note that the pressure of Node 5 remains constant because of the assigned fixed pressure drop. ✦

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** Photo courtesy of Kvaerner Masa Yards Inc.*

Global refining capacity increases slightly in 2006

David Nakamura
Refining/Petrochemical Editor

The worldwide refining industry added a slight amount of crude distillation capacity in 2006. For the fifth year in a row, worldwide capacity is at a record high. The number of refineries remained relatively stable.

Last year's refining report showed a worldwide capacity of slightly more than 85.1 million b/cd in 662 refineries as of Jan. 1, 2006. This year, OGJ's survey reflects a total capacity of nearly 85.2 million b/cd in 658 refineries, an increase of less than 52,000 b/cd.

The increase is the smallest net gain in refining capacity since 2001, when refining capacity decreased.

Fig. 1 shows the trend in operable refineries and worldwide capacity. The large jump in number of refineries in 1999 was due to improved information from China.

Capacity creep was the main reason for the increases in capacity for the latest survey.

Asia-Pacific showed the largest increase in refining capacity, up 105,000 b/cd or 0.5%, which was also the largest percent increase in capacity.

North America, Eastern Europe, and the Middle East showed smaller changes, increasing 27,000 b/cd, 28,000 b/cd, and 4,300 b/cd, respectively.

US capacity increased more than 146,000 b/cd.

Other regions experienced decreases in capacity. Africa, Western Europe, and South America all lost capacity according to the latest survey numbers, decreasing 18,250 b/cd, 81,500 b/cd, and 8,000 b/cd, respectively.

This year's survey lists four fewer refineries than last year's survey due to corrections and reflections of refineries that had shut down in previous years.

New crude capacity

This year's survey does not list any new refineries. All the increases in refining capacity occurred at existing facilities.

The largest single-facility increase occurred in Formosa Petrochemical Co.'s Mailiao, Taiwan, refinery, which increased capacity by 70,000 b/cd, to 520,000 b/cd from 450,000 b/cd.

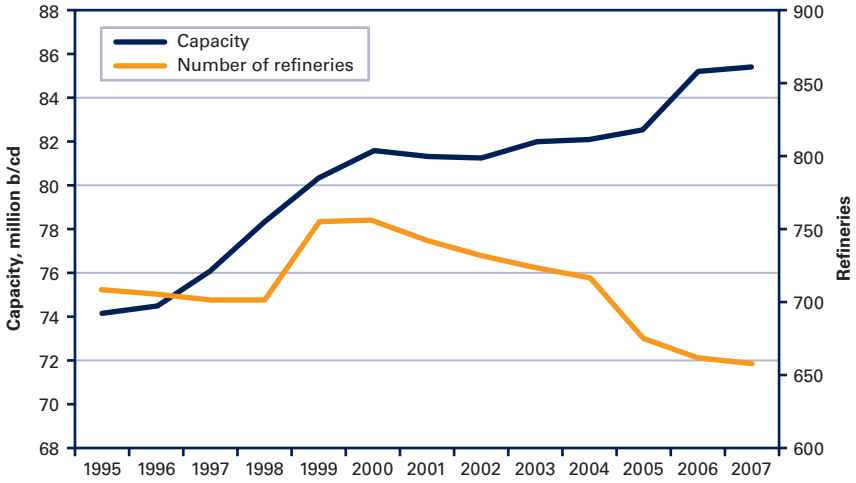
In the US, the largest reported capacity increase occurred in Western Refining Inc.'s El Paso refinery. Western reported a 27,000-b/cd increase, growing to 117,000 b/cd in this year's survey from 90,000 b/cd reported in last year's survey.

Other major increases in reported capacity occurred in Grupa Lotos SA's Gdansk, Poland, refinery, which increased to 120,000 b/cd from 90,000 b/cd; Alliance Refining Co. Ltd.'s Map Ta Phut, Thailand, refinery, which rose to 301,000 b/cd from 275,000 b/cd; and ExxonMobil Corp.'s Antwerp, Belgium, refinery, which went to 298,000 b/cd from 275,000 b/cd.

OGJ subscribers can now download, free of charge, the text version of the OGJ Worldwide Refining Report 2006 tables from www.ogjonline.com by clicking on the Resource Center tab, then the Surveys and OGJ Subscriber Surveys links. This link also features the previous editions of this report as well as a collection of other OGJ Surveys from previous years. Subscribers and nonsubscribers may purchase Excel spreadsheets of the survey data by sending an email to orcinfo@pennwell.com or calling (800) 752-9764. For further information, please email lkoottungal@pennwell.com, or call Leena Koottungal, OGJ Survey Editor (713) 963-6239.

WORLDWIDE REFINING

Fig. 1



HOW THE WORLD'S LARGEST REFINERS RANK

Table 1

Rank Jan. 1, 2007	Rank Jan. 1, 2006	Company	Crude capacity, b/cd[1]
1	1	ExxonMobil Corp.	5,706,000
2	2	Royal Dutch Shell PLC	5,181,000
3	4	Sinopec	3,611,000
4	3	BP PLC	3,474,000
5	8	ConocoPhillips	2,927,000
6	5	Valero Energy Corp.	2,834,000
7	6	Petroleos de Venezuela SA	2,678,000
8	7	Total SA	2,668,000
9	9	China National Petroleum Corp.	2,440,000
10	10	Saudi Aramco	2,369,000
11	11	Chevron Corp.[2]	2,072,000
12	12	Petroleo Brasileiro SA	1,997,000
13	13	Petroleos Mexicanos	1,706,000
14	14	National Iranian Oil Co.	1,451,000
15	17	OAO Lukoil	1,217,000
16	15	OAO Yukos	1,182,000
17	16	Nippon Oil Co. Ltd.	1,157,000
18	18	Repsol YPF SA	1,105,000
19	19	Kuwait National Petroleum Co.	1,085,000
20	20	Pertamina	993,000
21	21	Marathon Oil Corp.	974,000
22	22	Agip Petroli SpA	906,000
23	23	Sunoco Inc.	880,000
24	24	SK Corp.	817,000
25	25	Indian Oil Corp. Ltd.	777,000

[1]Includes partial interests in refineries not wholly owned by the company. [2]Includes holdings in Caltex.

Refinery closures, delistings

Few refinery closures occurred throughout the world in 2006, mainly due to high refining margins that made even the smallest plants profitable.

The only closure reported in this year's survey is the 2,000 b/cd Norilsk, Russia, refinery. Two other refineries were removed from this year's survey.

Petro-Canada's Mississauga, Ont., plant was removed because it feeds no raw crude and produces only lube oil and greases. Removal from the survey, therefore, has no effect on overall crude distillation capacity.

Another refinery in Poland was removed because it has listed zero capacity for the past few years.

Corrections were made to Petroplus International BV's reported capacity. According to the company's website, its Antwerp Processing Facility shut down its atmospheric distillation unit in 2003. The company still runs part of the refinery as diesel hydrodesulfurization.

Largest refining companies

Table 1 lists the top 25 refining companies that own the most worldwide capacity. Table 2 lists companies with more than 200,000 b/cd of capacity in Asia, the US, and Western Europe. Capacities from Tables 1 and 2 include partial interests in refineries that the companies do not wholly own.

Significant changes from last year involve BP PLC, ConocoPhillips, Formosa, Petroleos de Venezuela SA, Saudi Aramco, Petroleos Mexicanos (Pemex), and Petroplus.

On Dec. 16, 2005, Ineos completed the purchase of two refineries from BP's

COMPANIES WITH 200,000+ B/CD REFINING CAPACITY IN ASIA, THE US, WESTERN EUROPE

Table 2

Rank	Company	No. of refineries	Crude capacity, b/cd[1]
Asia[2]			
1	Sinopec	26	3,611,000
2	China National Petroleum Corp.	24	2,425,000
3	Royal Dutch Shell PLC	13	1,375,463
4	ExxonMobil Corp.	10	1,332,469
5	Nippon Oil Co. Ltd.	6	1,157,000
6	Pertamina	8	992,745
7	SK Corp.	1	817,000
8	Indian Oil Co. Ltd.	10	787,290
9	Chinese Petroleum Corp.	3	770,000
10	Reliance Petroleum Ltd.	1	660,000
11	LG-Caltex Corp.	1	[3]650,000
12	Chevron Corp.	6	648,093
13	Tonen/General Sekiyu Seisei KK	4	[4]629,375
14	Idemitsu Kosan Co. Ltd.	4	608,000
15	Hyundai Oil Refinery Co.	3	589,500
16	Cosmo Oil Co. Ltd.	4	565,250
17	S-Oil Corp.	1	[5]520,000
17	Formosa Petrochemical Co.	1	520,000
19	BP PLC	4	332,338
20	Hindustan Petroleum Corp. Ltd.	2	296,250
21	Saudi Aramco	2	254,000
22	Showa Yokkaichi Sekiyu Co. Ltd.	1	[6]222,000
US			
1	Valero Energy Corp.	15	2,320,160
2	ConocoPhillips	13	2,222,200
3	ExxonMobil Corp.	7	1,956,000
4	BP PLC	6	1,475,150
5	Royal Dutch Shell PLC	9	[7]1,084,550
6	Marathon Oil Corp.	7	974,000
7	Chevron Corp.	5	909,000
8	Sunoco Inc.	5	880,000
9	Petroleos de Venezuela SA	4	[8]849,400
10	Flint Hills Resources (Koch Industries)	3	773,775
11	Motiva Enterprises LLC[9]	3	730,000
12	Tesoro Corp.	6	558,000
13	Saudi Aramco	3	[10]372,500
14	Lyondell Chemical Co.	1	282,600
15	Total SA	1	231,452
Western Europe[11]			
1	Total SA	16	2,329,145
2	Royal Dutch Shell PLC	14	1,902,275
3	ExxonMobil Corp.	10	1,724,856
4	BP PLC	10	978,124
5	AgipPetroli SPA	10	876,210
6	Repsol YPF SA	5	709,200
7	ConocoPhillips	4	616,625
8	Turkish Petroleum Refineries Corp.	4	613,275
9	Compania Espanola de Petroles SA (CEPSA)	3	427,000
10	Ineos Group Holdings Inc.	2	402,800
11	OMV AG	3	398,635
12	ERG Group	4	396,214
13	Chevron Corp.	2	327,800
14	Preem Raffinaderi AB	2	316,000
15	Hellenic Petroleum SA	3	313,000
16	Galp Energia SA	2	304,172
17	Statoil AS	3	303,000
18	Neste Oil	6	[12]302,300
19	Saras SPA	1	300,000
19	Petroplus International NV	3	300,000
21	Petroleos de Venezuela SA	8	294,528

[1]Includes partial interest in refineries not wholly owned by the company. [2]Asia includes Australia, Bangladesh, Brunei, China (and Taiwan), India, Indonesia, Japan, Malaysia, Myanmar, New Zealand, North Korea, Pakistan, Papua New Guinea, the Philippines, Singapore, South Korea, Sri Lanka, and Thailand. [3]Includes Caltex's 50% stake. [4]Includes ExxonMobil Corp.'s 50% stake. [5]Includes Saudi Aramco's 35% stake. [6]Includes Royal Dutch Shell's 50% stake. [7]Includes Shell's stakes in Motiva and its 50% stake in the Deer Park, Tex., refinery. [8]Consists of PDVSA's ownership of Citgo and its 50% stake in the ExxonMobil Chalmette, La., refinery. [9]50/50 joint venture between Shell and Saudi Aramco. [10]Consists of 50% stake in Motiva. [11]Western Europe includes Austria, Belgium, Denmark, Finland, France, Germany, Greece, Ireland, Italy, the Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, and the UK. [12]Includes 50% stake in AB Nynas refineries.

LNG Observer begins another year

With the Jan. 1, 2007, issue of Oil & Gas Journal, more than 60,000 subscribers will also receive the first-quarter 2007 installment of OGJ's ***LNG Observer***, a quarterly magazine produced with the widely respected GTI, Des Plaines, Ill. This publication aims at anyone interested or involved in the natural gas and LNG businesses.

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subsidiary, Innovene. Ineos acquired the 195,700-b/cd Grangemouth, Scotland, refinery and the 207,100-b/cd Lavera, France, refinery.

Ineos reportedly acquired the Innovene business from BP for $9 billion. The sale and subsequent loss of refining capacity moved BP down to the fourth largest refiner. Overall, the company reported almost 400,000 b/cd less refining capacity than last year.

ConocoPhillips, on the other hand, added sufficient capacity to become the fifth largest refiner in the world, up from eighth largest last year. The deal was completed too late in 2005 to include it in last year's survey.

On Feb. 28, 2006, ConocoPhillips announced that it had completed a deal, announced in November 2005, to purchase the Wilhelmshaven, Germany, refinery from UK-based Louis Dreyfus Refining & Marketing Ltd. The addition of the 268,000-b/cd refinery increased significantly the company's capacity outside the US.

On Aug. 16, 2006, Lyondell Chemical Co. acquired Citgo Petroleum Corp.'s 41.25% interest in Lyondell-Citgo Refining LP for $2.1 billion, including the refining company's debt. The 282,600-b/cd refinery in Houston processes very heavy high-sulfur crude.

PDVSA, parent company of Citgo, lost a net 114,000 b/cd of refining

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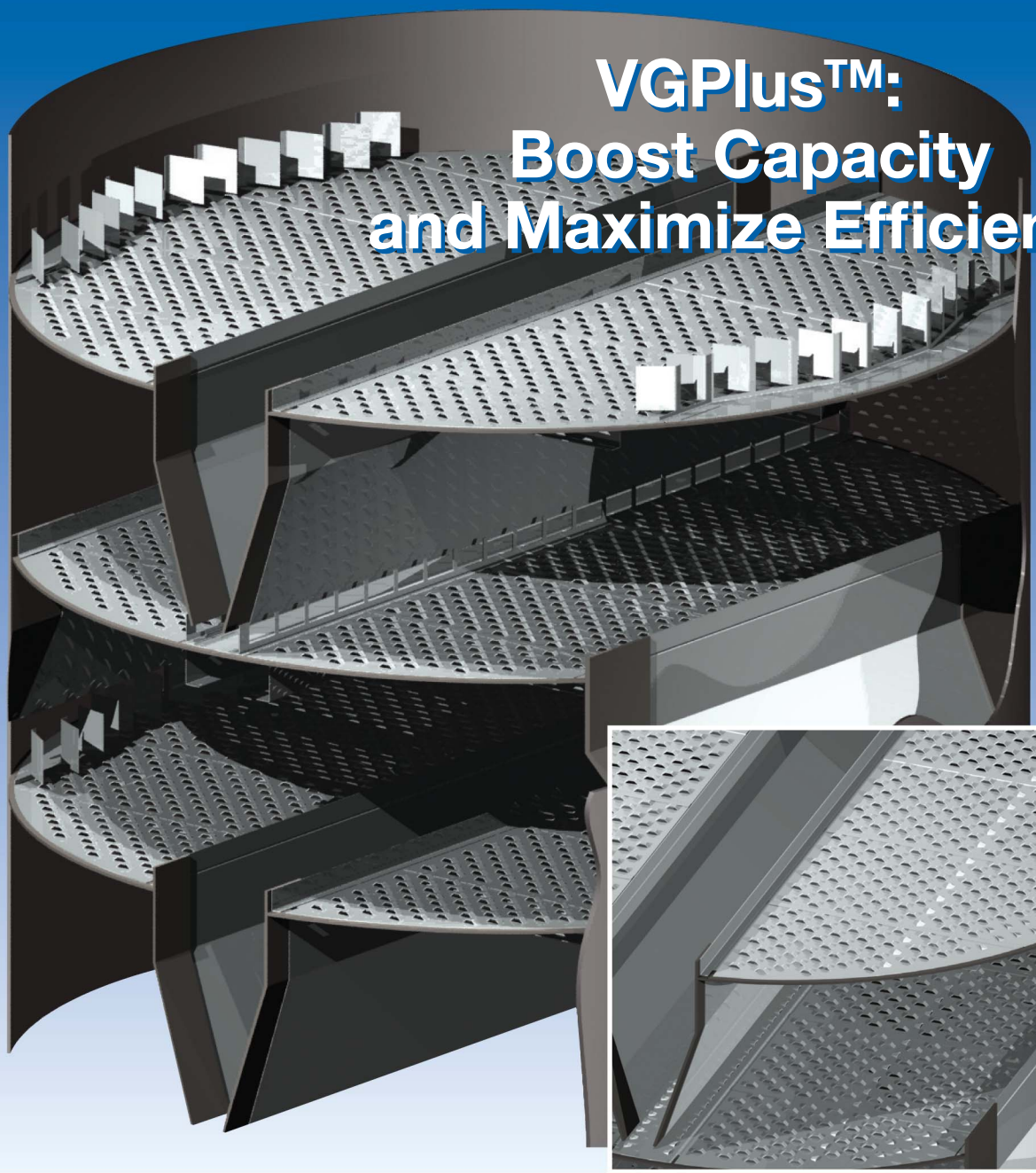

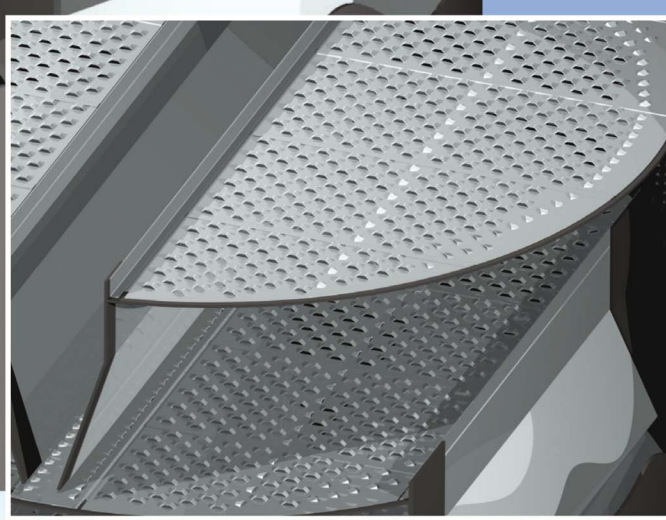

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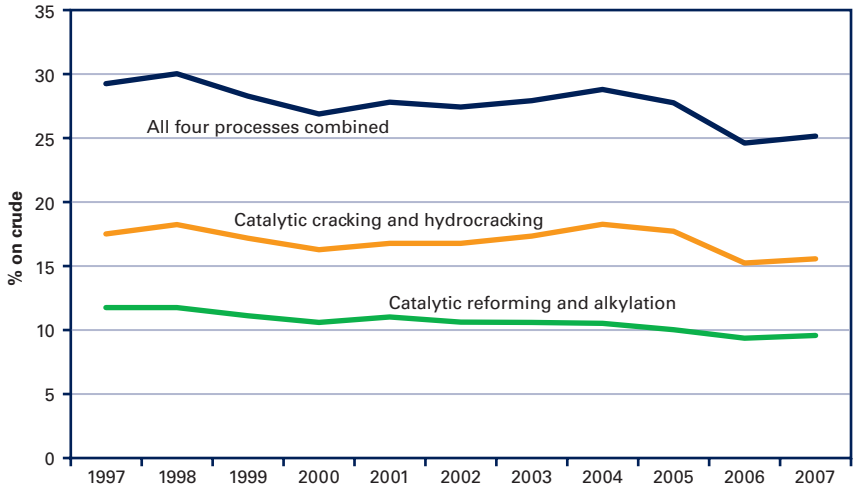
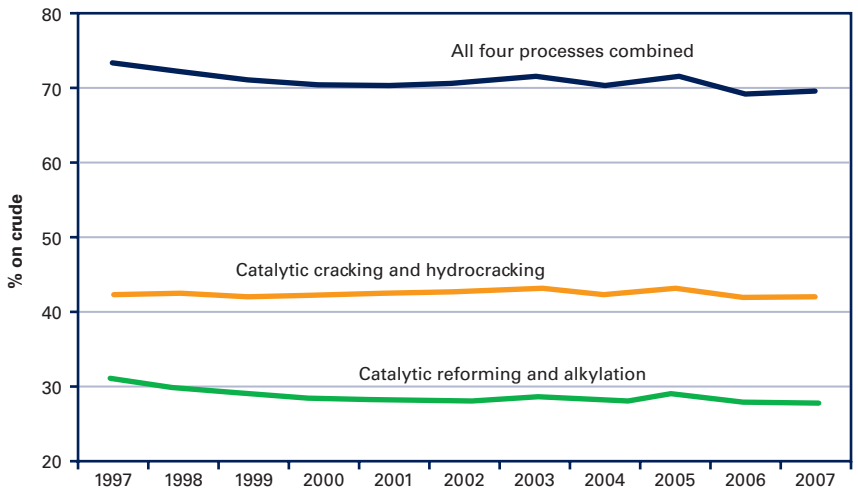
ASIA PROCESSING CAPABILITY

Fig. 2



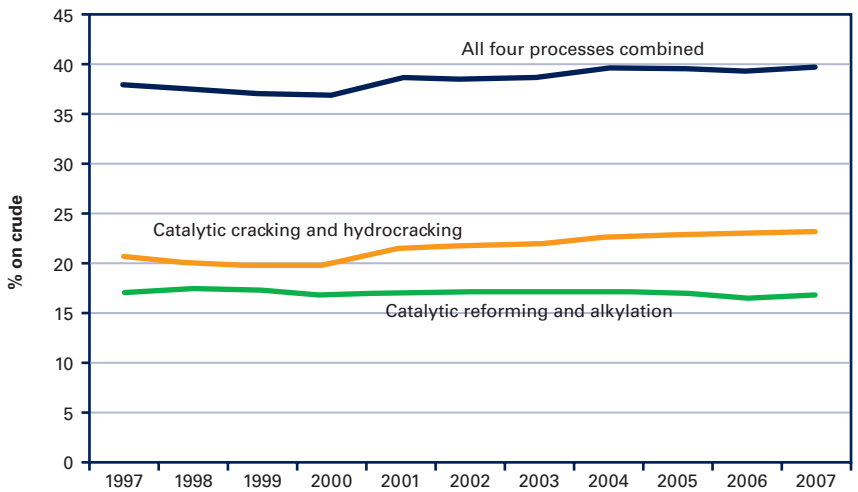
US PROCESSING CAPABILITY

Fig. 3



EU PROCESSING CAPABILITY

Fig. 4



capacity. The company fell to seventh largest global refiner.

Lyondell's acquisition allowed it to meet the minimum 200,000-b/cd requirement for inclusion in Table 2. It is the fourteenth largest refiner in the US.

On Nov. 23, 2005, Aramco Overseas Co., a subsidiary of Saudi Aramco, and Motor Oil Holdings SA, announced that Motor Oil had completed the acquisition of remaining interest in the 100,000-b/cd Corinth refinery in Greece. Previously, the refinery was owned 50/50 by the two companies. For the year, Saudi Aramco decreased refining capacity by 48,000 b/cd.

Pemex also decreased refining capacity in 2006. Last year's survey indicated the company had 1.85 million b/cd of refining capacity, which fell to 1.7 million b/cd in 2006. The loss, however, was not enough to move it in Table 1 in relation to other companies.

One deal that was not included in Table 1 last year was Total AS's trading of refining capacity with Royal Dutch Shell PLC. On July 12, 2005, Total acquired Shell's 20% stake in the 89,000-b/cd Raffineria di Roma in return for Total's 18% interest in the 79,800-b/cd Compagnie Rhénane de Raffinage refinery in France.

Table 2 shows this change—both refiners have ownership stakes in fewer refineries this year.

Newcomers to Table 2 this year include Lyondell in the US and Ineos in Western Europe, both due to deals previously mentioned.

In other deals, Petroleo Brasiliero SA acquired a 50% interest in the 100,000-b/cd Pasadena Refinery System Inc. The refinery was previously 100% owned by Astra Oil Trading NV. Petrobras paid $370 million in the deal.

Petroplus announced on June 1, 2006, that it acquired the Belgian Refining Corp. including the 115,000-b/cd refinery in Antwerp. The acquisition increases Petroplus's total refining capacity to 300,000 b/cd.

The company also announced that it intends to buy ExxonMobil's Ingolstadt, Germany, refinery. The deal for

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WORLD'S LARGEST REFINERIES

Table 3

	Company	Location	Crude capacity, b/cd
1	Paraguana Refining Center	Cardon/Judibana, Falcon, Venezuela	940,000
2	SK Corp.	Ulsan, South Korea	817,000
3	Reliance Industries Ltd.	Jamnagar, India	660,000
4	LG-Caltex	Yosu, South Korea	650,000
5	ExxonMobil Refining & Supply Co.	Jurong/Pulau Ayer Chawan, Singapore	605,000
6	ExxonMobil Refining & Supply Co.	Baytown, Tex.	563,000
7	Saudi Arabian Oil Co. (Saudi Aramco)	Ras Tanura, Saudi Arabia	550,000
8	Formosa Petrochemical Co.	Mailiao, Taiwan	520,000
8	S-Oil Corp.	Onsan, South Korea	520,000
10	ExxonMobil Refining & Supply Co.	Baton Rouge, La.	503,000
11	Hovensa LLC	St. Croix, Virgin Islands	500,000
12	Shell Eastern Petroleum (Pte.) Ltd.	Pulau Bukom, Singapore	458,000
13	BP PLC	Texas City, Tex.	446,500
14	Kuwait National Petroleum Co.	Mina Al-Ahmadi, Kuwait	442,700
15	OAO Yukos	Angarsk, Russia	440,700
16	Citgo Petroleum Corp.	Lake Charles, La.	440,000
17	Shell Nederland Raffinaderij BV	Pernis, Netherlands	406,000
18	Sinopec	Zhenhai, China	403,000
19	Saudi Arabian Oil Co. (Saudi Aramco)	Rabigh, Saudi Arabia	400,000
20	Saudi Aramco-Mobil	Yanbu, Saudi Arabia	400,000

the 106,000-b/cd refinery is to close in early 2007 and will be reflected in next year's survey.

On Oct. 19, 2006, Harvest Energy Trust announced that it closed on the acquisition of North Atlantic Refining Ltd. and related businesses for $1.6 billion (Can.). North Atlantic operates the 109,250-b/cd refinery in Come By Chance, Newf.

Alon USA Energy Inc. announced on Aug. 7, 2006, that it had acquired Paramount Petroleum Corp. Alon paid $314 million cash and $150 in assumed net debt with excess working capital of $50 million. Included in the acquisition is the 52,000-b/cd refinery in Paramount, Calif.

In March 2006, Holly Corp. announced that it had sold its 10,000-b/cd refinery in Great Falls, Mont., to Connacher Oil & Gas Ltd. for $55 million in cash and 1 million shares of Connacher stock.

Not mentioned in last year's report was the fact that Suncor Energy purchased Valero Energy Corp.'s 28,000-b/cd Denver refinery. The purchase price was $30 million plus working capital in a deal that was completed on June 1, 2005. The refinery is next to Suncor's existing 92,000-b/cd refinery, which it acquired in 2003.

Other changes in capacity that appear in Tables 1 and 2 are due to adjustments in declared capacity.

Largest refineries

Table 3 lists the world's largest refineries with a minimum capacity of 400,000 b/cd.

One refinery moved up the list due to an expansion. As previously mentioned, Formosa's refinery increased capacity to 520,000 b/cd, which moved it up four spots in Table 3 from last year.

ExxonMobil reported increased capacity in its Baton Rouge refinery—to 503,000 b/cd from 501,000 b/cd in last year's survey. The Hovensa LLC refinery also reported a slight gain in capacity, to 500,000 b/cd from 495,000 b/cd. The two refineries, however, lost a spot in Table 3 due to Formosa moving up.

The only other change in Table 3 is Shell Nederland Raffinaderij BV revising downward its capacity, to 406,000 b/cd from 416,000 b/cd reported in last year's survey.

Regional crude capacities

Table 4 lists regional process capabilities as of Jan. 1, 2006. As previously mentioned, the largest increase in crude capacity occurred in Asia.

Asia growth was due to large capacity increases in Taiwan and Thailand, and smaller increases in Australia and Japan. For North America, a 146,000-b/cd gain in capacity in the US was offset by a 144,000-b/cd loss in Mexico.

The other regions were flat or had small increases.

Processing capabilities

Figs. 2-4 show the processing capabilities of Asia, the European Union (EU), and the US for the past 10 years. Processing capabilities are defined as conversion capacity (catalytic cracking and hydrocracking) and fuels producing processes (catalytic reforming and alkylation) divided by crude distillation capacity (% on crude).

Countries in the EU include Belgium, Denmark, France, Germany, Greece, Ireland, Italy, the Netherlands, Portugal, Spain, and the UK. ✦

REGIONAL LOOK AT WORLDWIDE REFINING OPERATIONS

Table 4

Region	No. of refineries	Crude distillation	Vacuum distillation	Catalytic cracking	Catalytic reforming	Catalytic hydrocracking	Catalytic hydrotreating	Coke, tonnes/day
		b/cd						
Africa	45	3,212,112	510,144	205,085	462,174	62,208	886,649	1,841
Asia	156	22,310,291	4,179,246	2,682,659	1,984,118	793,468	8,673,206	20,200
Eastern Europe	91	10,272,594	3,759,573	928,944	1,496,038	318,354	4,267,106	12,570
Middle East	42	7,038,115	1,975,715	361,150	651,897	588,621	2,055,363	3,300
North America	156	20,853,787	9,091,606	6,622,194	4,217,628	1,759,180	15,651,468	128,795
South America	66	6,602,703	2,845,795	1,309,337	401,325	132,400	1,899,451	24,640
Western Europe	102	14,889,771	5,915,811	2,259,002	2,155,500	1,033,013	9,851,401	11,494
Total	**658**	**85,179,373**	**28,277,890**	**14,368,371**	**11,368,680**	**4,687,244**	**43,284,644**	**202,840**

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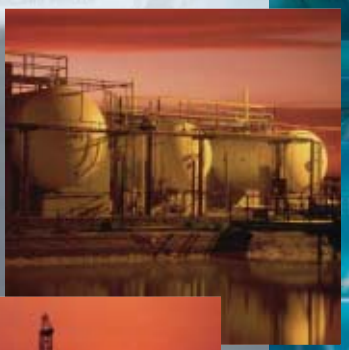

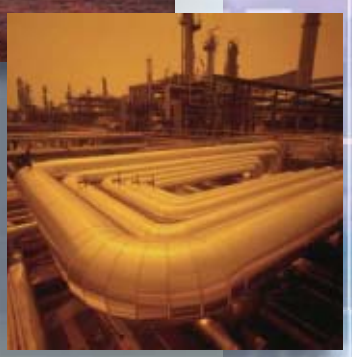

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POINT OF VIEW

TransCanada pipeline president guides course to liquids, TAGP

Christopher E. Smith
Pipeline Editor

"I think one need only look at the Mackenzie Valley to see the impact of the regulatory process if it's not defined as well as it is under the Northern Pipeline Act."
—Russell K. Girling, president, pipelines, TransCanada Corp.

As demand for hydrocarbons continues to rise, it becomes increasingly important not only that new sources of supply are found and developed, but also that the resulting production can be brought to market in a timely and efficient manner.

Transportation solutions are often integrated into the overall development plan for a new field and have direct bearing on the feasibility of developing otherwise marginal resources. Failure to effectively address transportation issues can lead to bottlenecks in development of projects otherwise deemed economically feasible (witness current efforts to move Arctic natural gas south from Alaska and Canada's Mackenzie Valley).

As a more than 20-year veteran of the oil and gas industry and current president, pipelines of TransCanada, Russ Girling holds a front-row seat on such issues, overseeing a 41,000-km pipeline network that transports the majority of Western Canada's natural gas production to Canadian and US markets. Previous experience as TransCanada's executive vice-president, corporate development, and chief financial officer speak to his knowledge of industry finances, risk management, and project evaluation, among other areas for which he has had overall responsibility at TransCanada.

Keystone

Known primarily as a transporter of natural gas, TransCanada's largest and highest-profile current project, the Keystone Oil Pipeline, will carry 435,000 b/d of oil-sands crude 1,830 miles from Alberta to the US Midwest (Fig. 1).

With an in-service target of late 2008-early 2009, the project is currently going through regulatory approval, part of which addresses a request by TransCanada to transfer 530 miles of Canadian line from gas to oil service. With 1,070 miles of the line to be built in the US, the 530-mile converted stretch represents the bulk of the Canadian portion, making approval of the service transfer key to the overall project.

The National Energy Board public hearing considering TransCanada's Section 74 application to transfer a portion of its Canadian Mainline natural gas transmission facilities to the Keystone Oil Pipeline Project for the purposes of transporting crude oil took place Oct. 23., with Girling expecting a decision by late first-quarter 2007.

TransCanada's Section 52 full-facilities application for Keystone has yet to be heard, but the Section 74 application is the key, he says. "Once we know that, the rest of the facilities application will be more akin to what we've done in the past, and we're really comfortable with that process, so we'd become a lot more comfortable with the spending of capital" to meet the in-service target, he says. Even without full approval of Section 52, "we'll start spending money in larger amounts post the Section 74 decision."

Little debate surrounds the need for the additional crude capacity. Instead, concerns regarding TransCanada's transfer request center on its potential effects on the existing gas infrastructure. According to Girling, such concerns are unwarranted; the capacity that would be transferred represents a long-term excess in the Canadian system.

Forecasts in the 1990s which showed continued growth in Canadian natural gas supply prompted approval of the 1.5-bcfd Alliance Pipeline. When Alliance came on in late 2000, Girling says

it removed 1.5 bcfd from TransCanada's system. This capacity has yet to be replaced, even while in-Alberta consumption has grown, and TransCanada now has between 1.5 and 2 bcfd of spare capacity that the company forecasts will not be called on again.

But others wonder what will happen if coalseam gas is larger than currently forecast, or traditional supplies increase faster than is currently forecast. They also wonder what will happen when Mackenzie and Alaskan gas is brought online.

Girling says TransCanada has run several scenarios including each of these variables as well as the possibility that Fort McMurray oil sands operations will become less gas-intensive as technology advances, and all have concluded that the capacity will not be needed for gas transport.

Even TransCanada scenarios involving mid-winter peak days indicate that the capacity will not be needed for gas service again. Others disagree, insisting that the capacity will be needed for short increments in the middle of winter. The industry is divided, with CNRL, Conoco, and Suncor agreeing with TransCanada's figures, while EnCana and Devon foresee the possibility that the capacity will be needed at some point.

Opponents have also raised concerns regarding the fuel-based costs of the increased compression that would be required to move the same quantity of gas through a smaller system. Girling says TransCanada forecasts a negative net present value to gas shippers of about $100 million over a 10 to 15-year period for incremental fuel costs.

This would be balanced, however, by removal of rate-based costs associated with the line of roughly $110 million. These forecasts are based on underlying TransCanada forecasts of gas prices and throughput, with those who disagree with these figures using different underlying price and throughput bases.

Girling believes the NEB will end up adjudicating the issue in the end. He also believes, however, that the transfer proposal serves the greater public interest.

Even those who oppose the change would admit that "at best we're going to need this capacity a few days a year. Our view is that the greater public interest is served by using it every day as a crude oil pipeline, especially with the constraint we see in terms of crude oil capacity requirements in the 2008-09 timeframe, when the industry could face apportionment," Girling says.

"If you take a look at the detrimental impact of not having this pipeline in place at that particular point in time, compared to any kind of scenario you can run on costs on the gas side, the benefit far outweighs the cost," Girling says. The National Energy Board's mandate is to look at the broader public interest; TransCanada's argues that interest is better served by using this pipeline as a crude oil pipeline. "The benefits are substantial."

TransCanada is also considering extending the Keystone project to Cushing and has been gauging consumer interest both in Cushing and on the US Gulf Coast before holding an open season. Potential customers have responded favorably, but only the open season will show if there is commercial interest in the system beyond the current Patoka-Wood River, Ill. terminus.

Not alone

Given the continued upswing in activity in Alberta's oil sands, other companies are also eager to participate in bringing future production to market. Between these competing proposals and Arctic gas projects such as the Trans-Alaska Gas Pipeline and Mackenzie Valley Pipeline, concern has emerged over the availability of material and human resources needed complete them all.

Girling expects that market forces will act effectively to stage the projects, rather than allowing each to proceed independently. He sees the first stage of Enbridge Energy's Southern Access program and Keystone as the first two projects to advance, both having secured commercial underpinning and now able to begin securing pipe and labor.

"The further you move away from Fort McMurray and Alberta, the easier [finding labor] gets," Girling says. "You're still competing for steel and we need to make certain decisions around steel. But what we have is a commercial underpinning that says our project

Career highlights

Russ Girling is president, pipelines, of TransCanada Corp., where he has overall responsibility for the company's regulated businesses, including natural gas and oil pipelines in Canada, the US, and Mexico.

Employment

Prior to his current post, Girling was executive vice-president, corporate development and chief financial officer of TransCanada. He had overall responsibility for finance, accounting, treasury, taxation, risk management, corporate strategy, corporate development, investor relations, and project evaluation. Girling was responsible for TransCanada's $4 billion debt reduction and balance sheet restructuring during 2000.

Through 2001, he was also president of TransCanada Gas Services and was responsible for its ultimate disposition. He earlier served as executive vice-president, power, where he had overall responsibility for the creation and management of subsidiary TransCanada Power. Prior to joining TransCanada in 1994, Girling held marketing and management positions at Suncor Inc., Northridge Petroleum Marketing, and Dome Petroleum.

Education

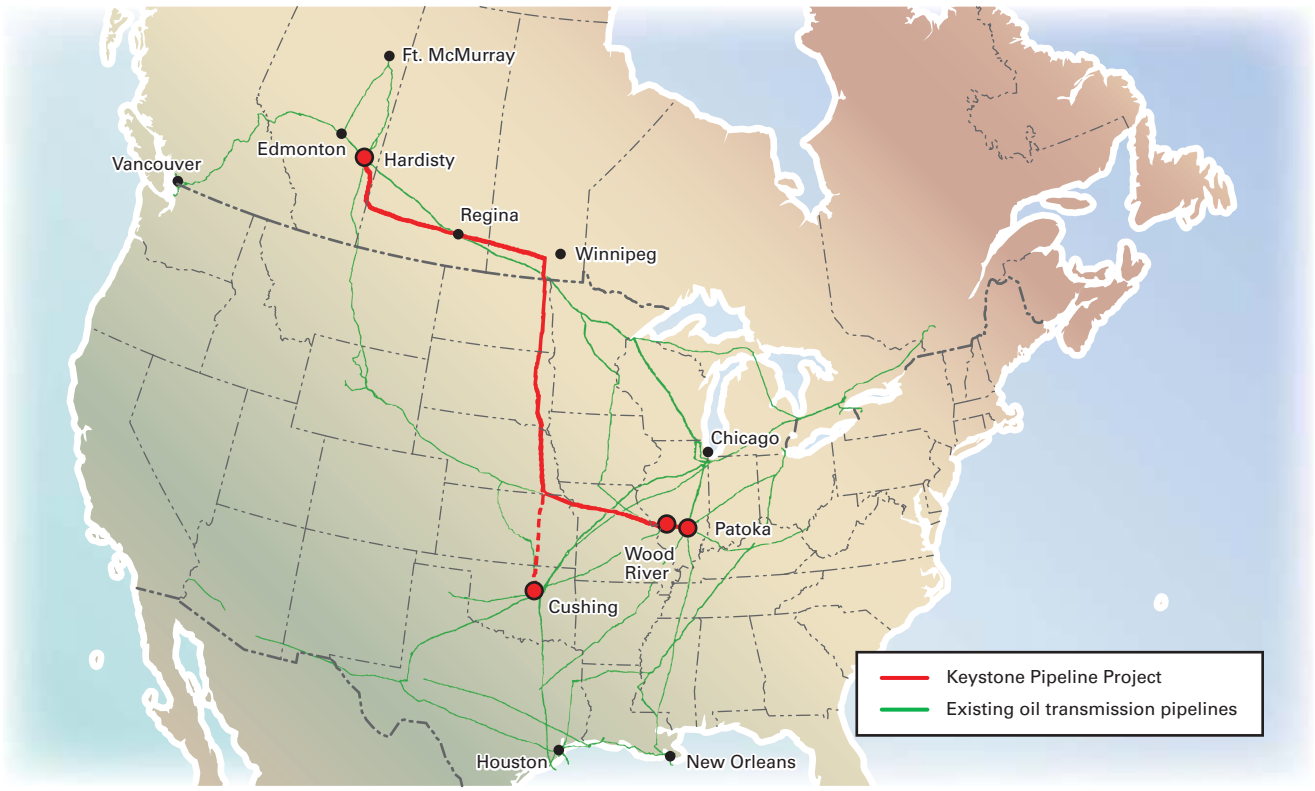
Girling holds a bachelor of commerce degree and an MBA in finance from the University of Calgary.

Affiliations

He is a director of several companies, including Agrium Inc. and Bruce Power Inc. Girling is also director of the Alberta Children's Hospital Fund.

PLANNED KEYSTONE PIPELINE ROUTE

Fig. 1



should go, assuming we get regulatory approval."

Girling expects that similar market forces will guide the direction of resources to other projects further down the road but is hesitant to speculate regarding the sorts of constraints that might be encountered by future projects or the viability of any particular pipeline plan. He describes the securing of long-term commitments from shippers, which TransCanada secured for Keystone in early 2006, as the most difficult part of any large pipeline project and the key to each of them.

Beyond these two projects, there is "going to be need; no question," Girling says. "If the NEB curves are correct, and we would concur generally with those, we'll need another pipeline or expansion, probably a couple years out from ours. What is less clear, according to Girling is the route – south, west, or a different direction altogether – that the next pipeline will follow, and how much of the capital involved in building it will actually get spent in Ft. McMurray.

"The market isn't making those commitments," Girling continues. "The market has committed to the first part of Southern Access and to our pipeline." The next expansion associated with Round 1 would be associated with the Cushing or Gulf Coast extensions, and "right now we're still testing whether people are willing to underpin that or not. They're all still working on their internal plans on how they're going to spend their capital and whether they need that crude to show up and when they need it to show up."

TAGP

As the state of Alaska continues negotiations with ExxonMobil, ConocoPhillips, and BP to establish the terms dictating the southward movement of North Slope natural gas, TransCanada remains on the sidelines as a very interested observer. "We've stepped away from our rights [in Alaska] and said whoever's going to build this project, we'll grant our rights to them in order to expedite the project," Girling says.

"We just want to make sure, once we hit the Canadian border, that our historic rights are recognized in whatever negotiated arrangement we come up with to move that gas further downstream."

The historic rights to which Girling refers are part of 1985's Northern Pipeline Act, which TransCanada sees as giving it rights-of-first-refusal regarding any plans to move Alaskan natural gas through Canada.

"I think one need only look at the Mackenzie Valley to see the impact of the regulatory process if it's not defined as well as it is under the Northern Pipeline Act," Girling says. "It's mired in the joint-review panel process," which incorporates thousands of agencies that have to "opine, grant permits, and approve the project.

"There already was a hearing before the NEB, 30 years ago, and they granted

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the certificates to TransCanada to build this pipeline," Girling continues. "We've been saying that for a number of years, and people say that there could be an alternate way of doing this."

"And maybe there could be, but our view is that you'd have to change the law to do it. But even if you were to change the law, our question would be why you would do that and put yourself just in the position that Mackenzie's in right now."

In addition to its regulatory footing, Girling cites TransCanada's experience in both building and operating Arctic and near-Arctic transportation systems as factors which give it an advantage in the TAGP project, pointing in particular to TransCanada's rights-of-way from the Alaskan border through the Yukon and its already-established Alberta system.

"Once you bring the gas from Alaska to Alberta, rather than having to build from Alberta to a market, dropping all that gas off in one market and spending that capital, you can integrate with TransCanada's system and the ultimate outcome will be something that's far less expensive than [building] downstream," Girling says.

Looking forward

Looking beyond the current projects at the health of the energy industry in general, Girling remains skeptical of those who project a linear pattern of demand growth based on the current rapid expansions of economies such as China's and India's, noting that any sort of economic disruption will lead rapidly to a reduction in demand and with it, price.

"Production comes on in chunks, usually," Girling says, remarking that price will continue to impact field development in both gas and oil and that a low gas price in North America for an extended period will impact producers' willingness to commit capital to moving Arctic gas to market.

Girling sees similar forces at work regarding new facilities in the oil sands. "I've been in this business for more than 20 years," he says, "and I've seen the predictions of $100 oil and I've seen oil at $10. I don't think we're going back to $10. But price volatility still exists [and affects production] decisions for both conventional and nonconventional supplies." ✦

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The hip-mounted unit with a harness design helps make it easy to don and doff quickly. It is lightweight and ergonomic for stability and comfort. The unit is versatile and is used effectively in applications and environments ranging from chemical spills and decontamination operations to routine maintenance tasks.

The new harness and the mask material meets requirements of EN137 heat and flame resistance, which tests the equipment up to 1,742° F. Any flame will self-extinguish within 5 sec. The unit is fully machine washable. The material used is antistatic and is inert to chemicals and oil and impervious to most acids and alkalis.

Source: **Draeger Safety Inc.**, 101 Technology Drive, Pittsburgh, PA 15275-1057.

Encoders offers stainless steel housing option

These H25 and H20 incremental rotary encoders are now available with a stainless steel housing option.

Units offer a 304 series stainless steel encoder body and bearing housing. The maker says this provides resistance to the corrosive agents often found in washdown and chemical and petrochemical plant environments.

The H25 (image below on the right) offers features such as EMI shielding, 40 lb dual, preloaded ABEC 7 bearings,

matched thermal coefficients on critical components, and custom high-efficiency optics. The H20 is a compact encoder that features heavy-duty bearings, shock resistant disk, and conforms to NEMA 4 and 13 requirements.

Source: **BEI Technologies Inc., Industrial Encoder Div.**, 7230 Hollister Ave., Goleta, CA 93117-2891.

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API IMPORTS OF CRUDE AND PRODUCTS

	Districts 1-4		District 5		Total US		
	12-8 2006	[1]12-1 2006	12-8 2006	[1]12-1 2006	12-8 2006	[1]12-1 2006	12-9 2005
	1,000 b/d						
Total motor gasoline	267	354	18	8	285	360	344
Mo. gas. blending comp.	656	427	7	6	663	433	613
Distillate[2]	393	264	19	23	412	287	327
Residual	242	226	42	58	284	284	492
Jet fuel-kerosine	152	66	110	173	262	239	226
LPG	315	370	—	—	315	370	314
Unfinished oils	521	529	79	21	600	550	657
Other	564	396	8	13	573	409	478
Total products	**3,110**	**2,632**	**283**	**300**	**3,393**	**2,932**	**3,451**
Canadian crude	1,682	1,738	303	154	1,985	1,892	1,487
Other foreign	7,621	7,921	809	787	8,430	8,708	8,879
Total crude	**9,303**	**9,659**	**1,112**	**941**	**10,415**	**10,600**	**10,366**
Total imports	**12,413**	**12,291**	**1,395**	**1,241**	**13,808**	**13,532**	**13,817**

[1]Revised. [2]Includes No. 4 fuel oil.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

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

OIL&GAS JOURNAL online research center

OGJ CRACK SPREAD

	*12-8-06	*12-9-05	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	70.69	68.12	2.57	3.8
Brent crude	63.70	56.34	7.36	13.1
Crack spread	6.99	11.78	–4.79	–40.7
FUTURES MARKET PRICES				
One month				
Product value	71.20	69.79	1.41	2.0
Light sweet crude	62.32	59.82	2.50	4.2
Crack spread	8.88	9.97	–1.09	–10.9
Six month				
Product value	78.97	74.30	4.67	6.3
Light sweet crude	66.70	62.28	4.41	7.1
Crack spread	12.27	12.02	0.26	2.1

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

API CRUDE AND PRODUCT STOCKS

	Crude oil	Motor gasoline		Jet fuel	Fuel oils		Unfinished oils
		Total	Blending comp.[1]	Kerosine	Distillate	Residual	
	1,000 bbl						
PAD I	12,511	51,899	24,106	10,473	65,175	18,821	8,245
PAD II	71,828	50,149	15,708	7,374	25,127	1,811	13,497
PAD III	174,227	64,261	26,318	12,008	33,019	17,028	43,141
PAD IV	14,830	6,011	1,993	602	2,650	355	3,719
PAD V	[1]52,403	27,801	20,757	8,564	10,659	5,749	20,286
Dec. 8, 2006	**[1]325,799**	**200,121**	**88,882**	**39,021**	**136,630**	**43,764**	**88,888**
Dec. 1, 2006[3]	**334,102**	**201,206**	**90,532**	**37,900**	**139,309**	**45,015**	**88,290**
Dec. 9, 2005	**322,033**	**206,439**	**68,118**	**42,850**	**132,701**	**38,471**	**91,889**

[1]Included in total motor gasoline. [2]Includes 4.395 million bbl of Alaskan crude in transit by water. [3]Revised.
Source: American Petroleum Institute.
Data available in OGJ Online Research Center.

API REFINERY REPORT—Dec. 8, 2006

	REFINERY OPERATIONS					REFINERY OUTPUT			
District	Total refinery input	Crude runs	Input to crude stills	Operable capacity	Percent operated	Total motor gasoline	Jet fuel, kerosine	Fuel oils: Distillate	Fuel oils: Residual
	1,000 b/d								
East Coast	3,160	1,431	1,441	1,618	89.1	1,737	84	542	124
App. Dist. 1	102	95	95	95	100.0	8	—	25	1
Dist. 1 total	**3,262**	**1,526**	**1,536**	**1,713**	**89.7**	**1,745**	**84**	**567**	**125**
Ind., Ill., Ky.	2,153	2,075	2,098	2,355	89.1	1,234	131	573	28
Minn., Wis., Dak.	435	414	421	442	95.3	337	30	119	14
Okla., Kan., Mo.	844	698	714	786	90.8	492	19	225	6
Dist. 2 total	**3,432**	**3,187**	**3,233**	**3,583**	**90.2**	**2,063**	**180**	**917**	**48**
Inland Texas	932	556	613	647	94.7	412	41	154	7
Texas Gulf Coast	3,882	3,474	3,521	4,031	87.4	1,347	358	796	136
La. Gulf Coast	3,170	3,094	3,123	3,264	95.7	1,252	356	854	143
N. La. and Ark.	226	192	202	215	94.0	71	8	50	4
New Mexico	154	100	100	113	88.5	89	2	33	—
Dist. 3 total	**8,364**	**7,416**	**7,559**	**8,270**	**91.4**	**3,171**	**765**	**1,887**	**290**
Dist. 4 total	**669**	**496**	**517**	**596**	**86.7**	**338**	**14**	**137**	**13**
Dist. 5 total	**2,930**	**2,606**	**2,733**	**3,173**	**86.1**	**1,777**	**448**	**639**	**107**
Dec. 8, 2006	**18,657**	**15,231**	**15,578**	**17,335**	**89.9**	**9,094**	**1,491**	**4,147**	**583**
Dec. 1, 2006*	**19,204**	**15,536**	**15,749**	**17,335**	**90.9**	**8,925**	**1,467**	**4,204**	**572**
Dec. 9, 2005	**16,632**	**14,779**	**15,129**	**17,115**	**88.4**	**8,809**	**1,499**	**3,849**	**677**

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

OGJ GASOLINE PRICES

	Price ex tax 12-6-06	Pump price* 12-6-06	Pump price 12-7-05
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	178.5	218.2	215.7
Baltimore	176.3	218.2	211.5
Boston	177.4	219.3	204.4
Buffalo	183.3	243.4	212.1
Miami	190.9	241.2	214.5
Newark	176.4	209.3	216.0
New York	173.2	233.3	218.7
Norfolk	174.6	212.2	218.6
Philadelphia	185.5	236.2	219.8
Pittsburgh	174.3	225.0	216.6
Wash., DC	190.6	229.0	219.8
PAD I avg.	180.1	225.9	215.2
Chicago	220.7	271.6	217.1
Cleveland	176.8	223.2	202.8
Des Moines	175.5	215.9	200.8
Detroit	180.0	229.2	204.8
Indianapolis	182.0	227.0	202.7
Kansas City	179.3	215.3	202.6
Louisville	184.3	221.2	203.7
Memphis	173.2	213.0	212.0
Milwaukee	185.9	237.2	214.3
Minn.-St. Paul	182.1	222.5	209.4
Oklahoma City	173.4	208.8	198.4
Omaha	177.5	223.9	208.3
St. Louis	181.2	217.2	211.2
Tulsa	172.7	208.1	199.3
Wichita	175.8	219.2	198.5
PAD II avg.	181.4	223.5	205.7
Albuquerque	186.7	223.1	207.2
Birmingham	185.3	224.0	206.8
Dallas-Fort Worth	179.4	217.8	207.1
Houston	173.6	212.0	205.1
Little Rock	180.0	220.2	207.5
New Orleans	180.2	218.6	246.6
San Antonio	176.6	215.2	211.7
PAD III avg.	180.3	218.7	213.2
Cheyenne	184.9	217.3	207.1
Denver	171.9	212.3	217.1
Salt Lake City	184.6	227.5	212.5
PAD IV avg.	180.5	219.0	212.2
Los Angeles	186.2	244.7	229.7
Phoenix	187.0	224.4	225.7
Portland	199.7	243.0	221.0
San Diego	191.2	249.7	232.1
San Francisco	209.0	267.5	235.1
Seattle	210.5	262.9	226.1
PAD V avg.	197.3	248.7	228.3
Week's avg.	**183.1**	**226.6**	**213.1**
Nov. avg.	**180.1**	**223.7**	**229.9**
Oct. avg.	**183.8**	**228.0**	**263.9**
2006 to date	**213.9**	**257.5**	—
2005 to date	**182.0**	**224.0**	—

*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

	12-1-06 ¢/gal		12-1-06 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	171.55	New York Harbor	180.85
Gulf Coast	167.55	Gulf Coast	177.85
Los Angeles	175.30	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	155.24	ARA	180.81
Singapore	158.24	Singapore	171.74
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	170.55	New York Harbor	101.71
Gulf Coast	166.55	Gulf Coast	107.81
Los Angeles	183.30	Los Angeles	122.31
		ARA	96.30
		Singapore	101.35

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

BAKER HUGHES RIG COUNT

	12-8-06	12-9-05
Alabama	5	6
Alaska	6	11
Arkansas	36	16
California	34	32
Land	31	27
Offshore	3	5
Colorado	91	87
Florida	0	2
Illinois	0	0
Indiana	0	0
Kansas	10	7
Kentucky	8	5
Louisiana	194	162
N. Land	57	46
S. Inland waters	24	20
S. Land	43	35
Offshore	70	61
Maryland	0	0
Michigan	2	1
Mississippi	16	11
Montana	20	28
Nebraska	0	0
New Mexico	94	90
New York	11	5
North Dakota	33	24
Ohio	10	9
Oklahoma	179	152
Pennsylvania	19	16
South Dakota	1	2
Texas	784	667
Offshore	10	7
Inland waters	4	1
Dist. 1	16	21
Dist. 2	23	29
Dist. 3	62	64
Dist. 4	93	72
Dist. 5	141	108
Dist. 6	125	108
Dist. 7B	38	24
Dist. 7C	48	36
Dist. 8	106	73
Dist. 8A	26	28
Dist. 9	38	31
Dist. 10	54	65
Utah	44	31
West Virginia	32	24
Wyoming	86	90
Others—HI-1; ID-1; NV-1; TN-3; VA-2 WA-1	9	5
Total US	**1,724**	**1,483**
Total Canada	**463**	**679**
Grand total	**2,187**	**2,162**
Oil rigs	282	257
Gas rigs	1,437	1,222
Total offshore	85	75
Total cum. avg. YTD	**1,645**	**1,378**

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	12-8-06 Rig count	12-8-06 Percent footage*	12-9-05 Rig count	12-9-05 Percent footage*
0-2,500	46	—	22	—
2,501-5,000	102	38.2	95	45.2
5,001-7,500	229	17.4	181	21.5
7,501-10,000	425	3.7	313	5.1
10,001-12,500	409	2.6	340	1.7
12,501-15,000	245	0.4	300	0.3
15,001-17,500	120	—	107	—
17,501-20,000	77	—	54	—
20,001-over	32	—	25	—
Total	**1,685**	**6.3**	**1,437**	**7.3**
INLAND	35		31	
LAND	1,590		1,357	
OFFSHORE	60		49	

*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]12-8-06	[2]12-9-05
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	20	22
Alaska	803	855
California	703	695
Colorado	59	61
Florida	7	6
Illinois	30	28
Kansas	96	93
Louisiana	1,397	1,021
Michigan	15	14
Mississippi	53	49
Montana	93	97
New Mexico	164	163
North Dakota	104	104
Oklahoma	173	167
Texas	1,385	1,274
Utah	44	48
Wyoming	142	142
All others	66	74
Total	**5,354**	**4,913**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	12-8-06
Alaska-North Slope 27°	49.52
South Louisiana Sweet	57.75
California-Kern River 13°	50.20
Lost Hills 30°	57.70
Southwest Wyoming Sweet	59.03
East Texas Sweet	59.26
West Texas Sour 34°	48.75
West Texas Intermediate	57.50
Oklahoma Sweet	57.50
Texas Upper Gulf Coast	54.25
Michigan Sour	51.75
Kansas Common	57.50
North Dakota Sweet	47.75

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

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

WORLD CRUDE PRICES

$/bbl[1]	12-1-06
United Kingdom-Brent 38°	61.83
Russia-Urals 32°	57.64
Saudi Light 34°	55.87
Dubai Fateh 32°	57.19
Algeria Saharan 44°	62.51
Nigeria-Bonny Light 37°	63.26
Indonesia-Minas 34°	58.43
Venezuela-Tia Juana Light 31°	56.47
Mexico-Isthmus 33°	56.36
OPEC basket	58.58
Total OPEC[2]	57.27
Total non-OPEC[2]	55.32
Total world[2]	56.13
US imports[3]	53.54

[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]

	12-1-06	11-24-06	Change
	Bcf		
Producing region	1,010	1,010	—
Consuming region east	1,946	1,936	10
Consuming region west	450	471	–21
Total US	**3,406**	**3,417**	**–11**
	Sept. 06	**Sept. 05**	**Change, %**
Total US[2]	**3,323**	**3,932**	**13.3**

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

Statistics

International rig count

Region	Nov. 2006 Land	Nov. 2006 Off.	Nov. 2006 Total	Nov. 05 Total
WESTERN HEMISPHERE				
Argentina	72	—	72	82
Bolivia	3	—	3	3
Brazil	14	19	33	30
Canada	427	5	432	600
Chile	1	—	1	—
Colombia	24	—	24	19
Ecuador	13	—	13	12
Mexico	59	27	86	92
Peru	5	—	5	3
Trinidad	1	3	4	4
United States	1,620	87	1,706	1,486
Venezuela	56	19	75	71
Other	2	—	2	1
Subtotal	**2,297**	**160**	**2,456**	**2,404**
ASIA-PACIFIC				
Australia	10	8	18	14
Brunei	1	2	3	2
China-offshore	—	17	17	16
India	53	31	84	85
Indonesia	34	18	52	60
Japan	2	—	2	3
Malaysia	—	12	12	13
Myanmar	8	1	9	10
New Zealand	4	1	5	6
Papua New Guinea	1	—	1	2
Philippines	2	—	2	2
Taiwan	—	—	—	—
Thailand	3	7	10	8
Vietnam	—	9	9	10
Other	2	2	4	6
Subtotal	**120**	**108**	**228**	**237**
AFRICA				
Algeria	27	—	27	21
Angola	—	4	4	1
Congo	3	1	4	3
Gabon	2	1	3	2
Kenya	—	—	—	—
Libya	11	1	12	9
Nigeria	2	6	8	9
South Africa	—	1	1	—
Tunisia	3	1	4	1
Other	3	3	6	3
Subtotal	**51**	**18**	**69**	**49**
MIDDLE EAST				
Abu Dhabi	9	6	15	13
Dubai	1	—	1	3
Egypt	30	8	38	30
Iran	—	—	—	38
Iraq	—	—	—	—
Jordan	1	—	1	1
Kuwait	14	—	14	13
Oman	42	—	42	34
Pakistan	17	—	17	12
Qatar	2	8	10	12
Saudi Arabia	69	8	77	43
Sudan	—	—	—	19
Syria	25	—	25	23
Yemen	17	—	17	13
Other	2	—	2	2
Subtotal	**229**	**30**	**259**	**256**
EUROPE				
Croatia	1	—	1	3
Denmark	—	1	1	1
France	—	—	—	—
Germany	5	—	5	4
Hungary	3	—	3	2
Italy	6	—	6	3
Netherlands	1	3	4	7
Norway	—	10	10	16
Poland	2	—	2	2
Romania	2	—	2	2
Turkey	4	—	4	5
UK	1	22	23	27
Other	4	—	4	3
Subtotal	**29**	**36**	**65**	**75**
Total	**2,726**	**352**	**3,077**	**3,021**

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

Oil import freight costs*

Source	Discharge	Cargo	Cargo size, 1,000 bbl	Freight (Spot rate) worldscale	$/bbl
Caribbean	New York	Dist.	200	205	1.48
Caribbean	Houston	Resid.	380	154	1.23
Caribbean	Houston	Resid.	500	175	1.40
N. Europe	New York	Dist.	200	222	2.54
N. Europe	Houston	Crude	400	170	2.88
W. Africa	Houston	Crude	910	123	2.26
Persian Gulf	Houston	Crude	1,900	71	2.41
W. Africa	N. Europe	Crude	910	120	1.63
Persian Gulf	N. Europe	Crude	1,900	81	2.01
Persian Gulf	Japan	Crude	1,750	73	1.49

*Novemberw 2006 average.
Source: Drewry Shipping Consultants Ltd. Data available in OGJ Online Research Center.

US LNG imports

Country	Sept. 2006	Aug. 2006	Sept. 2005	Change from a year ago, %
	MMcf			
Algeria	—	—	6,016	—
Brunei	—	—	—	—
Malaysia	—	—	—	—
Nigeria	6,025	6,199	—	—
Oman	—	—	—	—
Qatar	—	—	—	—
Trinidad and Tobago	25,197	37,043	34,772	–27.5
Others	8,782	8,880	11,036	–20.4
Total	**40,004**	**52,122**	**51,824**	**–22.8**

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

Baker oil tools workover rig count*

Region	Nov. 2006	Nov.. 2005	Change, %
Gulf Coast	299	276	8.3
Midcontinent	251	241	4.1
Northeastern	79	81	–2.5
Rocky Mountains	220	219	0.5
Southeastern	195	211	–7.6
West Texas	332	285	16.5
Western	146	133	9.8
Total US	**1,522**	**1,446**	**5.3**
Canada	682	790	–13.7
Total N. America	**2,204**	**2,236**	**–1.4**

*Wells over 1,500 ft deep and tubing out of the wellbore. Excludes rigs on rod jobs. Definitions, see OGJ Sept. 18, 2006, p. 42. Source: Baker Hughes Inc. Data available in OGJ Online Research Center.

Propane prices

	Oct. 2006	Nov. 2006	Oct. 2005	Nov. 2005
	¢/gal			
Mont Belvieu	93.82	95.38	113.66	99.93
Conway	93.46	95.05	114.01	100.02
Northwest Europe	95.94	94.50	108.98	99.77

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

Muse, Stancil & Co. refining margins

	US Gulf Coast	US East Coast	US Mid-west	US West Coast	North-west Europe	South-east Asia
	$/bbl					
November 2006						
Product revenues	70.72	67.34	70.82	76.32	64.82	61.98
Feedstock costs	–57.25	–59.60	–52.75	–57.16	–57.16	–58.84
Gross margin	13.47	7.74	18.07	24.64	7.66	3.14
Fixed costs	–2.03	–2.34	–2.28	–2.66	–2.28	–1.77
Variable costs	–2.11	–1.40	–1.87	–3.20	–2.03	–0.73
Cash operating margin	**9.33**	**4.00**	**13.92**	**18.78**	**3.35**	**0.64**
October 2006	8.35	–0.55	13.59	15.01	4.24	0.35
YTD avg.	12.97	15.61	6.36	24.28	5.95	1.16
2005 avg.	12.53	6.98	12.31	20.55	5.51	1.52
2004 avg.	6.16	3.70	6.64	11.76	5.08	1.83
2003 avg.	2.92	2.22	4.84	5.43	2.35	–0.31

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

Muse, Stancil & Co. gasoline marketing margins

October 2006	Chicago*	Houston	Los Angeles	New York
	¢/gal			
Retail price	231.90	208.32	255.20	254.64
Taxes	52.14	38.40	56.26	49.35
Wholesale price	163.84	160.71	180.71	166.05
Spot price	152.48	150.65	167.89	154.27
Retail margin	15.97	9.21	18.23	39.24
Wholesale margin	11.36	10.06	12.82	11.78
Gross marketing margin	**27.33**	**19.27**	**31.05**	**51.02**
September 2006	62.95	45.70	56.30	65.25
YTD avg.	19.57	22.07	19.46	31.54
2005 avg.	19.77	16.26	20.39	27.13
2004 avg.	22.49	17.49	23.61	30.38
2003 avg.	22.69	19.10	30.89	31.42

*The wholesale price shown for Chicago is the RFG price utilized for the wholesale margin. The Chicago retail margin includes a weighted average of RFG and conventional wholesale purchases.
Source: Muse, Stancil & Co. See OGJ, Oct. 15, 2001, p. 46.
Data available in OGJ Online Research Center.
Note: Effective April 2003, Los Angeles margins include ethanol blending.

Muse, Stancil & Co. ethylene margins

	Ethane	Propane	Naphtha
	¢/lb ethylene		
November 2006			
Product revenues	52.84	85.96	101.57
Feedstock costs	–24.67	–54.13	–83.66
Gross margin	28.17	31.83	17.91
Fixed costs	–5.38	–6.36	–7.19
Variable costs	–5.19	–6.12	–8.24
Cash operating margin	**17.60**	**19.35**	**2.48**
October 2006	22.57	24.91	11.08
YTD avg.	20.16	23.15	2.24
2005 avg.	14.43	20.68	1.28
2004 avg.	9.00	12.03	0.51
2003 avg.	8.33	11.36	3.72

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

Muse, Stancil & Co. US gas processing margins

November 2006	Gulf Coast	Mid-continent
	$/Mcf	
Gross revenue		
Gas	7.02	5.48
Liquids	0.97	2.67
Gas purchase cost	7.82	7.36
Operating costs	0.07	0.15
Cash operating margin	**0.11**	**0.64**
October 2006	0.31	0.91
YTD avg.	0.27	1.01
2005 avg.	–0.06	0.25
2004 avg.	0.07	0.33
2003 avg.	–0.08	–0.06
Breakeven producer payment, % of liquids	86%	74%

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

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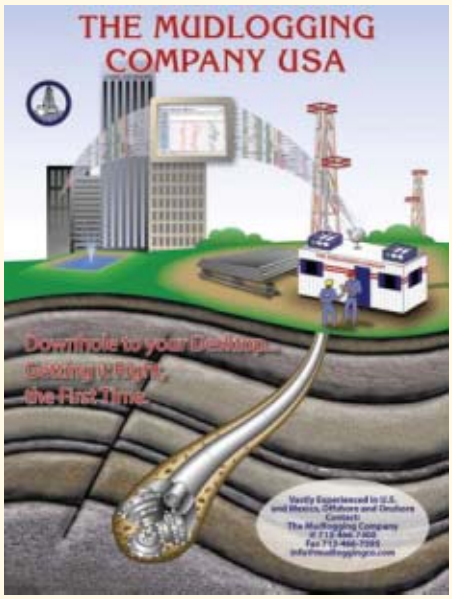

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Congress seethes about the wrong OCS money issue

Congress is coming unhinged about federal revenue from offshore oil and gas activity.

A new Department of the Interior inspector general's (IG) report has invigorated congressional suspicion about royalty management by the Minerals Management Service.

The suspicion arose last January with disclosure that price thresholds designed to limit deepwater royalty relief were missing from Outer Continental Shelf leases awarded in 1998 and 1999. The new IG report criticized MMS procedures; MMS responded with a see-there announcement that it was billing BP for $32 million in underpayment of coalbed methane royalties, which had been under dispute (OGJ Online, Dec. 8, 2006).

Democrats assuming power next year aren't likely to ease the pressure. If they want a scandal, though, they'll be looking in the wrong place.

The IG report didn't say MMS let OCS royalties go unpaid; it cited procedures that might let that happen. The finding wouldn't have made news if Congress weren't already feverish over those missing price thresholds, which might not be the lapses they're made out to be. Whether MMS had authority to impose price limits in deepwater leases issued during 1996-2000 is an open question (OGJ, Dec. 4, 2006, p. 17).

Still, lawmakers from both parties are crusading for the supposedly lost royalty money. They say the missing thresholds have cost the Treasury $2 billion and estimate eventual losses at $10 billion. Their estimates ignore revenues that wouldn't exist from the leases in question without the incentive: bonus bids already paid and royalties payable when production exceeds volumetric thresholds.

If Congress really cared about government OCS receipts it would lease more of the OCS.

At present, 85% of federal water off the Lower 48 and 3% off Alaska is unavailable for oil and gas leasing.

In the single fiscal year that ended Sept. 30, the government collected $7.6 billion from royalties, rents, and bonuses from the small part of the OCS that can be leased. Someone do the math.

The US surely has a problem where OCS revenue is concerned. But it has little to do with royalty collection and much to do with outrageously stingy leasing.

(Online Dec. 8, 2006; author's e-mail: bobt@ogjonline.com)

The Editor's Perspective

by Bob Tippee, Editor

Market Journal

by Sam Fletcher, Senior Writer

Storage uncertainties undercut gas prices

The January natural gas contract registered the lowest closing price in 10 weeks on the New York futures market after the Energy Information Administration reported the withdrawal of 11 bcf of gas from underground storage in the week ended Dec. 1.

The contract finished at $7.67/MMbtu Dec. 7, down 5.6¢ after trading at $7.58-7.82/MMbtu that session on the New York Mercantile Exchange.

The withdrawal was less than expected by Wall Street analysts and left storage in excess of 3.4 tcf. "US natural gas withdrawal rates look modest so far, but the key period for withdrawals is yet to come," said analysts at Barclays Capital Inc., London.

Meanwhile, large withdrawals of gas from storage due to an abnormally cold spell during the same period in 2005 "may lead to a possible increase in the year-over-year natural gas storage surplus over the next few weeks," said J. Marshall Adkins in the Houston office of Raymond James & Associates Inc. "Despite this small hiccup, we still believe we will be an average of approximately 5 bcfd tighter throughout the withdrawal season."

That's based on Raymond James's estimates that gas supplies will be tighter by 250 MMcfd this season, while demand will be higher by 4.5 bcfd due to "the combined effect of a 1.75% year-over-year increase" in industrial demand. "Finally, we are forecasting a normal winter (as it relates to weather), which should translate into running about 2 bcfd tighter for the duration of the winter season. Based on these assumptions, we believe that the natural gas overhang experienced throughout the injection season will dissipate and winter storage levels should be in the range of 1.2-1.3 tcf, more in line with historical averages," Adkins said. As a result, he said, "We remain comfortable with our 2007 gas price forecast of $10[/MMbtu]."

OPEC production

After falling for three sessions, the January contract for benchmark US light, sweet crudes increased 30¢ to $62.49/bbl Dec. 7 on NYMEX when tanker-tracer Oil Movements reported the Organization of Petroleum Exporting Countries apparently had reduced production by 800,000 b/d.

That was still short of the 1.2 million b/d cut that OPEC members agreed to in October, effective Nov. 1, but up from the 550,000 b/d reduction previously estimated. By Dec. 8, the price was down again, to $62.03/bbl. Some observers expected crude prices to escalate on a "risk premium" preceding the Dec. 14 OPEC meeting in Nigeria, "as well as the increased risk that Nigerian rebels use the occasion to embarrass the hosting government," said Olivier Jakob, managing director of Petromatrix GMBH, Zug, Switzerland. Meanwhile, a second production cut proposed by some OPEC members was already being priced in, he said. Any additional cut would "need to be higher than 500,000 b/d to be a surprise," Jakob said.

Raymond James analysts in Houston said, "OPEC seems determined to defend and maintain oil prices above $60/bbl."

In a Dec. 6 report, Barclays Capital's Paul Horsnell said: "OPEC's next decision has been complicated because of exchange rate effects and because all the tightening to date has happened in oil products. We would not expect ministers to want to lessen the pressure on the supply side of the crude oil market. The overhang in US oil product inventories above their 5-year average has now completely disappeared."

Import outlook

EIA expects US imports of energy to grow moderately as a share of total demand during the next 25 years as rising prices spur domestic production of crude and reduce demand growth. It projects imports will rise to 32% of total US energy consumption in 2030 from 30% in 2005.

US demand for liquid fuels and other petroleum products is expected to escalate to 26.9 million b/d in 2030 from 20.7 million b/d in 2005, while domestic liquids production is projected to increase to 10.5 million b/d from 8.3 million b/d through expansion and improvement in refining capacity. EIA predicts US crude production will increase to 5.9 million b/d in 2017 from 5.2 million b/d in 2005, with output expected to decline after 2017 to 5.4 million b/d in 2030. The additional US oil is expected to be produced primarily from the deep waters of the Gulf of Mexico, said EIA officials.

US imports of natural gas are projected to grow to 26 tcf/year by 2030 from 22 tcf/year in 2005, with increased LNG imports compensating for an expected decline in Canadian supplies. Because of permitting problems, a new pipeline to transport Alaskan gas to the Lower 48 likely will not come on line before 2018, almost 3 years later than previously expected, said EIA officials.

(Online Dec. 11, 2006; author's e-mail: samf@ogjonline.com)

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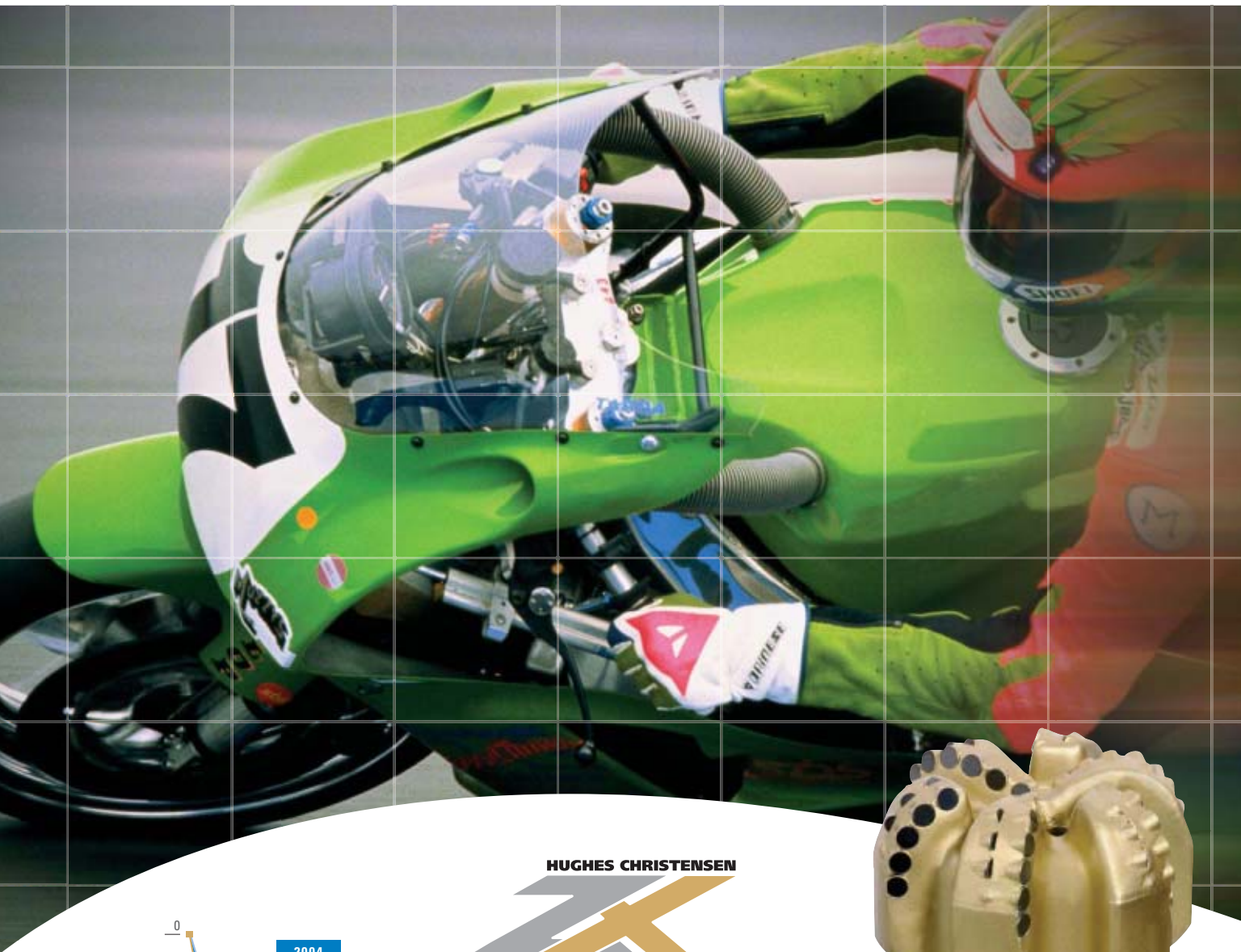

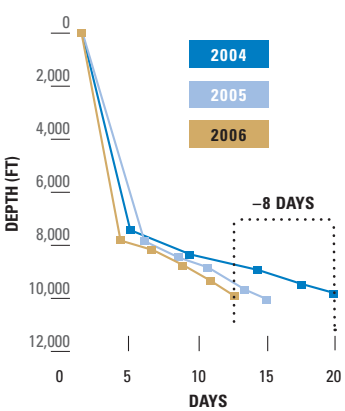

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The Genesis ZX series takes extreme drilling to the next level, with high-performance PDC bits designed for longevity and speed in the most challenging formations. ZX technology enhances the toughness and durability of the layered diamond cutters, sustaining higher rates of penetration through hard and abrasive intervals. On target, ahead of schedule, and under budget — ZX gets the job done. Only from Hughes Christensen. The Drill Bit Company.

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