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International Petroleum News and Technology / www.ogjonline.com

Trends in Unconventional Gas

US, Canadian operators post lower third-quarter earnings
Petrobras to start Tupi oil development by 2011
Syncrude upgrader revamp improves product quality
Sluggish European demand relaxes first-half 2007 LNG

OIL&GAS JOURNAL®

Dec. 17, 2007
Volume 105.47

TRENDS IN UNCONVENTIONAL GAS

REGULAR FEATURES

COVER

Since 2002, Newfield Exploration Co. has drilled and completed more than 200 wells in the Woodford shale play, now producing more than 150 MMcfd. Long laterals and increased frac density are improving capital efficiency—longer laterals could reduce total number of wells needed for development. The company has 165,000 net acres, largely held by production, operates 13 rigs, and is testing 40-acre spacing. Industry attention is increasingly focused on unconventional gas plays, and Oil & Gas Journal's special report begins on p. 39 with the first article in a series on unconventional gas technology. It's followed on p. 46 by a study of a newly developed natural gas production model, which estimates world natural gas production will peak in 2043; conventional natural gas production, in 2038; and unconventional gas, in 2060. Two 1,500-hp rigs from Cactus Drilling are shown working for Newfield in southeastern Oklahoma's Arkoma basin during summer 2007. Photo from Newfield Exploration.

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General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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General Interest — Quick Takes

Iraq refinery attacked by rocket

Iraq's Doura refinery burst into flames Dec. 10 after being hit by a rocket, according to an Oil Ministry official.

Spokesman Asim Jihad said a Katyusha rocket hit a fuel storage tank at the 110,000-b/d refinery at about 6 a.m., starting a fire that sent a large plume of black smoke into the sky.

He said there were no casualties and the refinery's firefighters expected to extinguish the fire quickly. He did not report what effect the attack had on the refinery's output.

The facility, just outside Baghdad, refines crude oil from the north and south of the country to supply products to the Iraqi capital.

N. Sea tax rules to be revamped, not abolished

Despite strong pressure from the oil and gas industry, the UK government has rejected calls to immediately abolish the North Sea Petroleum Revenue Tax (PRT) even though it announced a proposal Dec. 6 to shake up tax rules and decommissioning rules to encourage continuous investment in the mature area (OGJ Online, Dec. 7, 2007).

Abolishing PRT immediately would create "a large number of winners and losers, damage investor confidence, and fail to secure a fair return for the UK taxpayer," the government said. It has proposed, instead, some reforms to the PRT regime, including reducing the administrative burden of complying with PRT and providing operators with PRT relief for decommissioning costs.

Trade organization Oil and Gas UK welcomed the suggestions but said that there are inconsistencies regarding the application of PRT to decommissioning liabilities and tax relief. The government is seeking comments on the suggestions by the end of January 2008.

It also has launched another consultation on the tax burden facing operators because of the fear that this is stopping forthcoming investment. The deadline to submit comments on this and other issues is June 2008.

French companies sign gas deals with Algeria

France and Algeria have signed several natural gas deals as French President Nicolas Sarkozy sought to establish closer ties on his first state visit to the former French colony.

Sonatrach will continue to supply LNG to Gaz de France during 2013-19 under an extended contract signed in Algiers Dec. 4.

The agreement, valued at €2.5 billion/year, means that Algeria will remain a key supplier, accounting for 10 billion cu m in 2006.

Gaz de France also hopes to receive the Algerian government's approval in early 2008 for its development plan for Touat gas field, in which it holds a 75% stake, in the Sbaa basin. Investment is expected to hit $1 billion, but discussions surrounding the construction of an 800 km gas pipeline are not yet finalized. Field production is scheduled to begin in 2011.

In 2006 Gaz de France signed up for 1 billion cu m/year of gas to be delivered through the proposed Medgaz pipeline, which is to start deliveries in 2009. The pipeline will send Algerian gas to Spain. Gaz de France has a 12% share in the project and a 20-year supply contract.

Algeria's state-owned gas and power company Sonelgaz let a €1.3 billion turnkey contract to Alstom and Egyptian Orascom Construction Industries to build a 1,200 Mw gas-fired power plant in Terga, 600 km from Algiers. Operations are expected to start in 3 years.

Alstom will supply a full turnkey, combined-cycle power plant integrating in-house core plant components built around its advanced class GT26 gas turbine with best operational flexibility, Alstom said.

France levies high-profits tax on oil companies

France's oil companies will pay "an exceptional tax" to help fund a heating oil reserve granted by the government to low income households. The tax will be levied on the basis of 25% of the provisions for high prices, which the companies have built up over the past years.

The companies can either pay the tax directly to the state or to the fund. They most likely will choose the second option, said Jean-Louis Schilansky, delegate general of the oil companies' trade group UFIP. He told OGJ the fund could amount to €102 million. ✦

Exploration & Development — Quick Takes

Petro-Canada to invest in Libyan exploration

Petro-Canada of Calgary signed an agreement Dec. 10 with Libya's National Oil Corp. (NOC) for the two companies together to invest $7 billion in exploration and development in the Sirte basin of northern Libya.

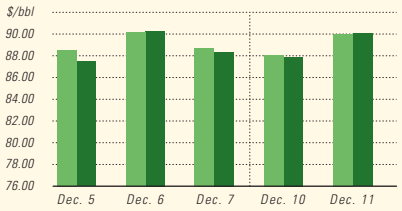
Terms call for NOC to convert existing participation agreements and old exploration and production-sharing agreements to six new EPSA IV agreements. New agreements are to last 30 years compared with an existing 2015 expiration date.

Petro-Canada agreed to pay 50% of development costs and will receive a 12% entitlement share of production. In addition, Petro-Canada will pay a $1 billion signature bonus with the first of three payments due upon contract ratification, expected in 2008.

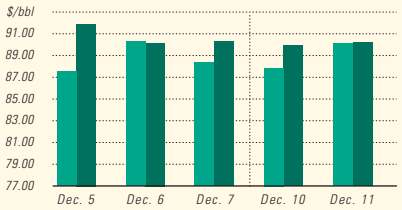
"Through these agreements we have achieved our long-stand-

Industry Scoreboard

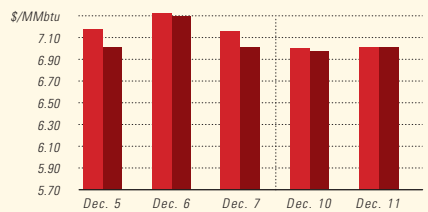
IPE BRENT / NYMEX LIGHT SWEET CRUDE



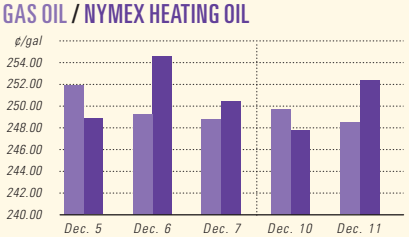
WTI CUSHING / BRENT SPOT



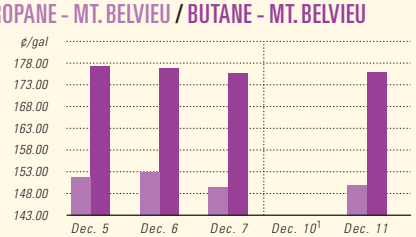
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



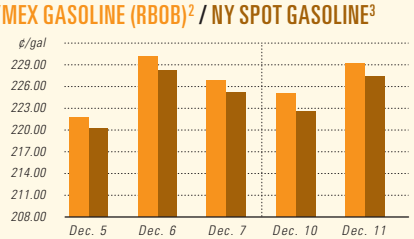
IPE GAS OIL / NYMEX HEATING OIL



PROPANE - MT. BELVIEU / BUTANE - MT. BELVIEU



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



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

US INDUSTRY SCOREBOARD — 12/17

Latest week 11/30	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	9,258	9,244	0.2	9,301	9,245	0.6
Distillate	4,426	4,180	5.9	4,231	4,160	1.7
Jet fuel	1,646	1,613	2.0	1,626	1,633	–0.4
Residual	716	525	36.4	748	685	9.2
Other products	4,863	5,107	–4.8	4,806	4,890	–1.7
TOTAL DEMAND	20,909	20,669	1.2	20,712	20,677	0.2
Supply, 1,000 b/d						
Crude production	5,082	5,105	–0.5	5,134	5,096	0.7
NGL production[2]	2,403	2,487	–3.4	2,382	2,223	7.2
Crude imports	10,009	9,888	1.2	9,998	10,162	–1.6
Product imports	3,388	3,117	8.7	3,512	3,630	–3.3
Other supply[3]	927	627	47.8	984	1,042	–5.6
TOTAL SUPPLY	21,809	21,224	2.8	22,010	22,153	–0.6
Refining, 1,000 b/d						
Crude runs to stills	14,939	15,011	–0.5	15,236	15,228	—
Input to crude stills	15,139	15,342	–1.3	15,471	15,586	–0.7
% utilization	86.8	88.2	—	88.7	89.7	—

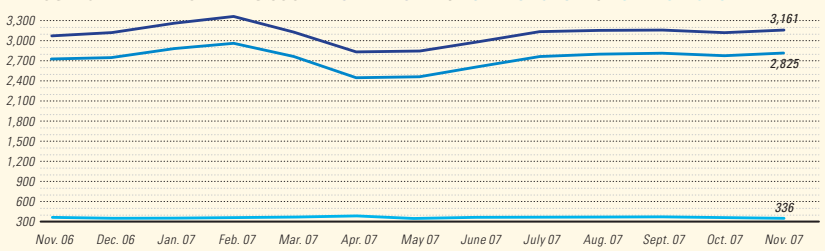
Latest week 11/30	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	305,240	313,153	–7,913	340,774	–35,534	–10.4
Motor gasoline	200,623	196,628	3,995	201,069	–446	–0.2
Distillate	132,344	130,916	1,428	132,818	–474	–0.4
Jet fuel-kerosine	39,939	38,899	1,040	37,932	2,007	5.3
Residual	38,033	38,752	–719	41,816	–3,783	–9.0
Stock cover (days)[4]			Change, %		Change, %	
Crude	20.1	20.8	–3.4	22.6	–11.1	
Motor gasoline	21.7	21.2	2.4	21.8	–0.5	
Distillate	29.9	29.6	1.0	30.5	–2.0	
Propane	47.5	48.3	–1.7	53.2	–10.7	

Futures prices[5] 12/7			Change		Change	%
Light sweet crude, $/bbl	88.73	92.49	–3.76	62.50	26.23	42.0
Natural gas, $/MMbtu	7.21	7.45	–0.24	8.49	–1.28	–15.1

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

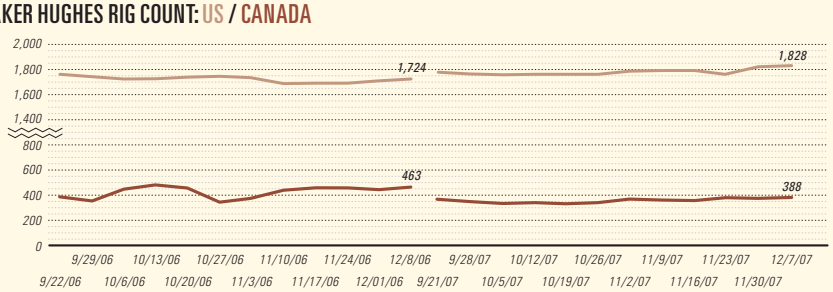
Sources: Energy Information Administration, Wall Street Journal

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



Note: Monthly average count

BAKER HUGHES RIG COUNT: US / CANADA



Note: End of week average count

ing objective of extending our partnership with NOC in Libya," said Ron Brenneman, Petro-Canada's president and chief executive officer.

Petro-Canada estimates gross resources of almost 2 billion bbl of oil associated with the redevelopment program, which includes pipeline and facility upgrades, development drilling, and waterflood expansion.

Currently, Petro-Canada's Libyan concessions produce 100,000 b/d (gross). Under the new agreements, production from the redevelopment program is expected to double in 5-7 years.

In addition to the redevelopment costs and signature bonus, Petro-Canada also proposes to invest $460 million in exploration during 7 years in the Sirte region.

StatoilHydro finds gas in third Hassi Mouina well

Natural gas was tested and proved in Tournaisian sandstones in the third completed exploration well on the Hassi Mouina license in Algeria's Sahara Desert, operator StatoilHydro AS said Dec. 11.

The Tinerkouk well (TNK-1) will provide "valuable information on the resource potential in the block," said Bill Maloney, StatoilHydro senior vice-president, global exploration. Hassi Mouina, which spans four blocks within a 23,000 sq km area in the Gourara basin, is in the western Sahara, northwest of In Salah gas field.

StatoilHydro and its partner Sonatrach are now drilling the fourth exploration well, TMS 1. "Several appraisal wells will also be drilled on the earlier discoveries in order to quantify the volumes with greater certainty," StatoilHydro said. StatoilHydro has a 75% interest in Hassi Mouina, and Sonatrach has 25%.

Libya reports gas licensing round results

OAO Gazprom, Royal Dutch Shell PLC, Polish state-owned PGNiG, and Algeria's Sonatrach have emerged among initial winners of Libya's first gas licensing round.

Gazprom was awarded onshore Area 64 in the Ghadames basin, and senior company officials have discussed additional areas of oil and gas cooperation in Africa with Shokri Ghanem, chairman of Libya's National Oil Co. (NOC).

Gazprom will invest more than $100 million on its exploration program. "According to the preliminary estimations, the Block 64 oil reserves are 20 million tons," the company said.

Shell won Blocks 1 and 3—spanning 1,790 sq km—in the Sirte basin, which is adjacent to other acreage it already has, a company spokeswoman told OGJ. She added that it enables Shell to "open up a new area in the southern flank of the Sirte basin." The new licenses will reinforce the company's relationship with NOC.

Sonatrach will work with partners Oil India Ltd. and Indian Oil Corp. to develop four blocks comprising 6,934 sq km in the Ghadames basin. Sonatrach said the award reinforced its presence in Libya where it operates Block 65 in the same basin.

PGNiG will explore Block 113 in the Murzuq basin in western Libya, which covers 5,494 sq km. "The high prospectively of this area is confirmed both by the adjacent existing fields and the reported discoveries within this petroleum basin," PGNiG said. It plans to sign the exploration and production-sharing agreement with NOC in the next 3 months.

Libya invited companies to bid for 41 onshore and offshore blocks earlier this year to improve gas production to 3 bcfd by 2010 from 2.7 bcfd currently. Ghanem said more winners could be announced in a week.

Total farms into Yemen blocks with Sinopec

Total SA gained a 40% interest in two onshore exploration blocks in Yemen under a farmin agreement signed with Sinopec.

An exploration well is being drilled on Block 69 following the acquisition of 2D seismic. The block spans 1,333 sq km and is in central Yemen's Marib basin, from which gas is directed to the Yemen LNG plant. Block 71, which is 1,800 sq km, is in eastern Yemen's Masilah basin, near Block 10, which Total has operated for 20 years. The partners have acquired 2D seismic for Block 71 as well.

Total will work with operator Sinopec (45.5%), state-owned Yemen General Corp. for Oil & Gas (10%), and the Arabian Group of Cos. (4.5%). Workers have shot 2D seismic on both blocks, and a well is being drilled on Block 69.

Murphy, PTTEP farm in to Australia Block AC/P36

Murphy Oil Corp. and Thailand's PTT Exploration & Production PCL (PTTEP) together have acquired a 60% stake in Block AC/P36 off northwestern Australia.

The farmin reduced the ownership of the 4,000 sq km tract in the Browse basin held by privately-owned Australian concern, Finder Exploration Pty., to 40%.

Under the partnership accord, Murphy Oil, through its local subsidiary Murphy Australia Oil Pty. Ltd., become operator with a 40% share in the acreage.

The Thai majority-state-owned firm, which received an offer to acquire the AC/P36 interest from Murphy Oil, holds 20% through subsidiary PTTEP Australia Offshore Pty. Ltd. It is the first venture into Australia for both Murphy Oil and PTTEP. The consortium plans to drill an exploration well by the end of 2008 or the first quarter of 2009, according to PTTEP Pres. Maroot Mrigadat.

Chitrapongse Kwangsukstith, senior executive vice-president of the parent firm PTT, said PTTEP's initial capital expenditure in the Aussie block would be about $60 million.

Both will provide capital for advance exploration to prove gas reserves in the permit, which lies in water 1,200-1,600 ft deep, according to PTTEP executives. ✦

Drilling & Production — *Quick Takes*

BP to increase King oil field production by 20%

Oil production from King field in the Gulf of Mexico is expected to increase by 20% with the application of multiphase pump equipment that BP PLC has installed (OGJ, Oct. 8, 2007, p. 49).

King produces 27,000 boe/d, and BP expects to improve recovery by 7% and extend the economic life of the field by 5 years. The pump, which BP described as the world's deepest in 5,500 ft below the sea's surface also sets a world record, for distance because the

pumps are 15 miles from the Marlin tension leg platform. King is tied back to Marlin.

Andy Inglis, BP's chief executive of exploration and production, said: "In line with our strategy to maximize reserves from our existing fields, the application of this cutting edge technology across BP's large deepwater portfolio has the potential to unlock significant resources that would otherwise remain unrecoverable."

BP is 100% owner and operator of King, which is 75 miles off Louisiana in Mississippi Canyon Blocks 84, 85, 128, and 129. The pumps will be powered by an umbilical from the Marlin tension leg platform in Viosca Knoll Block 915.

Norway's Njord field starts gas production

After a 2-month delay, StatoilHydro AS produced first gas from the Njord field in the Norwegian Sea, providing a new gas supply for Europe along with oil production.

The field, which will produce 6 million cu m/d of gas, required an investment of 1.2 billion kroner to ensure that Njord will supply gas up to 2020.

A new 40 km pipeline ties Njord gas into the Asgard Transport line, which in turn connects with the Karstø processing complex, north of Stavanger, and the trunklines to continental Europe.

Some 20,000 b/d of oil is being produced through 11 wells from Njord, while four injection wells sent the gas back into the reservoir as pressure support under the initial phase. Several new production wells help continue production by phasing in additional resources near the existing infrastructure under the second phase.

"The new process facility, which has been in operation since Oct. 1, is functioning very well. Regularity was as high as 99.7% for the first month," StatoilHydro said.

It attributed the gas production delay to a faulty weld. The repair on board the Far Saga vessel took "a long time due to bad weather," officials said.

Anadarko makes oil find with West Tonga well

Anadarko Petroleum Corp. has made an oil discovery in its West Tonga prospect on Green Canyon Block 726 in deepwater Gulf of Mexico.

The discovery well, drilled to a TD of 25,680 ft in 4,700 ft of water, encountered more than 350 ft of net oil pay in three high-quality subsalt Miocene sands.

The West Tonga discovery potentially could be tied back to the Constitution spar, Anadarko said.

Anadarko operates West Tonga with 37.5% working interest. Partners in the discovery include StatoilHydro AS 25%, Chevron Corp. 20.5%, and Royal Dutch Shell PLC 17%.

Petrobank to step up Bakken drilling in 2008

Petrobank Energy & Resources Ltd., Calgary, plans to drill 110 horizontal wells next year in the Bakken play in southeast Saskatchewan.

Petrobank expects to operate seven rigs within the Bakken play—an area in which it is expected to have a drilling inventory of 600 (565 net) well locations, based on a future well density of four wells per prospective section.

Drilling will take place after its acquisition of Peerless Energy Inc. for $334 million, including debt. As part of the deal, Petrobank is expected to issue about 4 million common shares. The transaction could lead to combined production from the Bakken play to as much as 7,900 b/d of oil.

Peerless currently is producing about 4,250 boe/d of light oil—primarily from the Bakken play—and natural gas from Alberta and British Columbia.

Peerless also has more than 100,000 net acres (156 sections) of undeveloped land.

Reserves for the acquired properties will be evaluated by Petrobank's independent reserves evaluator at yearend.

The deal is subject to approvals, including that of Peerless shareholders. ✦

Processing — *Quick Takes*

Proposed Canadian refinery first in 23 years

Newfoundland & Labrador Refining Corp. has selected Honeywell International Inc. subsidiary UOP LLC, Des Plaines, Ill., to supply technology, basic engineering services, and equipment for a refinery to be built in the Placentia Bay area of Newfoundland and Labrador.

NLRC's facility will be the first refinery built in North America since 1984. UOP is under way with basic engineering design for the complex, which is scheduled for start-up in 2011. It is projected to process 300,000 b/d of Middle Eastern crudes into transportation fuels for North American and European markets.

The facility also will feature a wide range of trademarked UOP technologies and processes to remove sulfur and upgrade distillate materials to produce clean fuels. A continuous catalytic reforming process will be used to produce aromatics and hydrogen from naphthenes and paraffins. Other procedures will absorb chlorides from regenerated catalyst to enhance efficiency of chloride management and reduce emissions.

NLRC is backed by St. John's-based mining company Altius Resources Inc. and private investors.

California to report GHG emissions in 2009

California's refineries, power plants, cement kilns, and manufacturing plants will be required to report annual greenhouse gas emissions (GHG) starting in 2009, the California Air Resources Board agreed Dec. 6.

The mandatory reporting rule, approved unanimously, is expected to affect about 800 industrial sites accounting for 95% of California's industrial emissions.

The rule covers emissions of carbon dioxide, nitrous oxide, and methane. Initial reports will not have to be audited by a third party, but future reports will have to be verified. Schools and hospitals are exempt from the new rule.

Carbon emissions reports will be made to the California Climate Action Registry, a nonprofit agency created in 2000 to encourage companies to voluntarily track and report GHG emissions.

Contract let for Colombia refinery expansion

Refinería de Cartagena SA has awarded to Chicago Bridge & Iron Co. a contract for a refinery expansion project in Cartagena, Colombia.

CB&I will perform the engineering, procurement, and construction for the expansion, including adding 14 processing units.

The $80 million expansion project is designed to increase processing capacity at the facility to 150,000 b/d from 80,000 b/d.

The upgraded facility will produce ultralow-sulfur gasoline and diesel from a heavy crude oil slate.

Refinería de Cartagena is owned by Glencore International AG 51% and Ecopetrol, Colombia's national oil company 49%.

Neste Oil to build Singapore biodiesel plant

Neste Oil of Finland said it will invest €550 million to construct the world's largest biodiesel plant in Singapore.

The plant, to have a capacity of 800,000 tonnes/year, will primarily use palm oil as feedstock, Neste Oil said, adding that it will use only palm oil certified by the Roundtable on Sustainable Palm Oil as soon as sufficient quantities are available—probably in early 2008. Singapore was chosen because it is the world's third-largest center of refining and occupies a central location in terms of product and feedstock flows and logistics.

Construction of the plant will begin in first half 2008, and operations at the facility are expected to begin by yearend 2010. ✦

Transportation — *Quick Takes*

Metgasco to extend Casino-Ipswitch gas pipeline

Sydney-based coal seam methane explorer Metgasco Ltd. is planning to extend its proposed 140 km Casino-Ipswitch gas pipeline further north to BP Australia's refinery on the Brisbane River. The pipeline previously was designed to deliver gas from the Casino area in northern New South Wales to CS Energy's Swanbank power station near Ipswitch, Queensland.

The extension results from a tentative 15 petajoules/year (about 14 bcf/year) gas supply deal with BP to supply the latter's Brisbane refinery. This contract follows an 18 petajoules/year (16.7 bcf/year) contract signed last year with Queensland-owned CS Energy.

Metgasco says the higher volume through the line will improve the economics of the entire project.

The new schedule allows for another 30 months to complete environmental approvals and an additional 8 months for construction of the pipeline. If the timetable holds true, first gas would flow north towards the end of 2010. Metgasco (formerly Methane Gas Co., formed as a private syndicate of geologists in 1997) is working in the Clarence-Moreton basin coal fields near Casino.

Metgasco's immediate priority is to increase its 2P gas reserves from the 194 petajoules (180.4 bcf) announced in September to 660 petajoules (614 bcf) by mid-2008. The company's drilling contractor, Vectra, is working on ways to improve horizontal drilling techniques in the coal seams and speed up completion times with the aim of bringing on stream as many as 40 wells each year.

Part of the earlier agreement with CS Energy includes CS Energy's paying some of Metgasco's exploration and development costs in return for interests in some of the company's fields. The BP deal includes BP's aid in feasibility studies for the pipeline extension. At the moment BP is supplied with gas via the Roma-Brisbane pipeline, which transports gas mostly derived from conventional fields owned by Santos and Origin Energy in the Surat basin. BP uses the gas for power generation at the refinery, but has been seeking a second source of supply to maintain its energy security.

Angola LNG receives final investment decision

Angola LNG Ltd. will become the latest African export project as the partners have taken the final investment decision to start deliveries in early 2012 to the Gulf LNG's Clean Energy regasification terminal in Mississippi.

The 5.2 million tonne/year onshore liquefaction plant in the Soyo region in Zaire province will commercialize gas from Blocks 0, 14, 31, 15, and 18; gas from nonassociated fields; and gas that is otherwise flared. Related gas liquids products will also be produced from the 1 bcfd of gas that will be sent to the plant. Angola LNG is expected to supply as much as 125 MMcfd of gas to state-owned Sonangol for domestic use.

Cabinda Gulf Oil Co. Ltd., a wholly owned subsidiary of Chevron Corp., has a 36.4% interest in Angola LNG, which has entered into an investment contract with the Angolan government and Sonangol to develop the project. Italy's Eni SPA also joined the consortium on Dec. 10 by taking a 13.6% from Sonangol. "The involvement of Eni in the Angola LNG consortium is part of the strategic cooperation established between Sonangol and Eni, signed in December 2006, and aiming at the development of gas resources," Eni said.

This new development means the Angola LNG shareholders are Sonagas 22.8%, Chevron Corp. 36.4%, Eni 13.6%, Total SA 13.6%, and BP PLC 13.6%. Regasified LNG will be sold to the US affiliates of the partners. Total Gas & Power North America will buy and market Total's 13.6% share, around 100 MMcfd.

Marathon signs deal for Piceance production

Marathon Oil Co. is the latest in a slew of major oil and gas producers that have entered into long-term agreements with Enterprise Gas Processing LLC for the gathering, compression, treating, and processing of natural gas produced in the Piceance basin of northwest Colorado. Enterprise will construct 50 miles of gathering lines to connect Marathon's multiwell drilling sites to the partnership's 48-mile, 36-in. Piceance Creek Gathering System (PCGS) for delivery to Enterprise's Meeker processing complex. Gas production is expected to peak at 180 MMcfd.

The Meeker complex, which was placed into service in October, is designed to process up to 750 MMcfd of gas and has the capability to extract as much as 35,000 b/d of natural gas liquids (NGL). Phase II of the Meeker complex, which will double the facility's capacity to 1.5 bcfd of gas and 70,000 b/d of NGL, is expected to begin operations in summer 2008 (OGJ Online, Nov. 15, 2007).

In addition to gathering pipelines, Enterprise also will build a compressor station to deliver gas into the PCGS. The station, 25 miles south of the Meeker complex in Rio Blanco County, Colo., will provide 22,000 hp of compression, as well as condensate handling and natural gas dehydration facilities. ✦

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OIL&GAS JOURNAL online

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

2008

JANUARY

Middle East Petrotech Conference and Exhibition, Bahrain, +60 3 4041 0311, +60 3 4043 7241 (fax), e-mail: mep@oesallworld.com, website: www.allworldexhibitions.com/oil. 14-16.

World Future Energy Summit, Abu Dhabi, +971 2 444 6011, +971 2 444 3987 (fax), website: www.wfes08.com. 21-23.

API Exploration & Production Winter Standards Meeting, Ft. Worth, Tex., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 21-25.

API/AGA Oil & Gas Pipeline Welding Practices Meeting, Ft. Worth, Tex., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 23-25.

International Forum Process Analytical Technology (IFPAC), Baltimore, (847) 543-6800, (847) 548-1811 (fax), e-mail: info@ifpacnet.org, website: www.ifpac.com. 27-30.

SPE/IADC Managed Pressure Drilling & Underbalanced Operations Conference & Exhibition, Abu Dhabi, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 28-29.

Offshore West Africa Conference & Exhibition, Abuja, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.offshorewestafrica.com. 29-31.

Petroleum Exploration Society of Great Britain Geophysical Seminar, London, +44 (0)20 7408 2000, +44 (0)20 7408 2050 (fax), e-mail: pesgb@pesgb.org.co.uk, website: www.pesgb.org.uk. 30-31.

SIHGAZ International Hydrocarbon and Gas Fair, Hassi Messaoud, Algeria, website: www.sihgaz2008.com. Jan. 30-Feb. 3.

FEBRUARY

Middle East Corrosion Conference, Bahrain, + 973 17 729819, + 973 17 7299819 (fax), e-mail: bseng@batelco.com.bh, website: www.mohandis.org. 3-6.

IADC Health, Safety, Environment & Training Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 5-6.

SPE Unconventional Reservoirs Conference, Keystone, Colo., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 10-12.

International Pipeline Pigging & Integrity Management Conference & Exhibition, Houston, (713) 521-5929, (713) 521-9255 (fax), e-mail: clarion@clarion.org, website: www.clarion.org. 12-14.

Deep Offshore Technology International Conference & Exhibition, Houston, (918) 831-9160, (918)

831-9161 (fax), e-mail: registration@pennwell.com, website: www.dotinternational.net. 12-14.

SPE International Formation Damage Control Symposium & Exhibition, Lafayette, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 13-15.

Alternative Fuels Technology Conference, Prague, +44 (0) 20 7357 8394, +44 (0) 20 7357 8395 (fax), e-mail: Conferences@EuroPetro.com. website: www.europetro.com. 18.

IP Week, London, +44 (0)20 7467 7100, +44 (0)20 8561 0131 (fax), e-mail: events@energyinst.org.uk, website: www.ipweek.co.uk. 18-21.

International Catalyst Technology Conference, Prague, +44 (0) 20 7357 8394, +44 (0) 20 7357 8395 (fax), e-mail: Conferences@EuroPetro.com. website: www.europetro.com.19-20.

Pipe Line Contractors Association Annual Conference (PLCA), Maui, (214) 969-2700, (214) 969-2705 (fax), e-mail: plca@plca.org, website: www.plca.org. 20-24.

International Petrochemicals & Gas Technology Conference & Exhibition, Prague, +44 (0) 20 7357 8394, +44 (0) 20 7357 8395 (fax), e-mail: Conferences@EuroPetro.com. website: www.europetro.com. 21-22.

AAPG Southwest Section Meeting, Abilene, Tex., (918) 560-2679, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org. 24-27.

Laurance Reid Gas Conditioning Conference, Norman, Okla., (405) 325-3136, (405) 325-7329 (fax), e-mail: bettyk@ou.edu, website: www.lrgcc.org. 24-27.

Middle East Refining Conference & Annual Meeting, Abu Dhabi, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 25-26.

CERI Natural Gas Conference, Calgary, Alta., (403) 220-2380, (403) 284-4181 (fax), e-mail: jstaple@ceri.ca, website: www.ceri.ca. 25-26.

SPE Intelligent Energy Conference & Exhibition, Amsterdam, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 25-27.

IADC Drilling HSE Asia Pacific Conference & Exhibition, Kuala Lumpur, (713) 292-1945, (713) 292-1946 (fax), e-mail: conferences@iadc.org, website: www.iadc.org. 26-27.

Middle East Fuels Symposium, Abu Dhabi, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 27-28.

MARCH

GPA Annual Convention, Grapevine, Tex., (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 2-5.

GEO Middle East Geosciences Conference & Exhibition, Bahrain, +44 20 7840 2139, +44 20 7840 2119 (fax), (fax), e-mail: geo@oesallworld.com, website: www.allworldexhibitions.com. 3-5.

Subsea Tieback Forum & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.subseatiebackforum.com. 3-5.

NPRA Security Conference, The Woodlands, Tex., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. 4-5.

ARTC Annual Meeting, Bangkok, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 4-6.

Global Petrochemicals Annual Meeting, Dusseldorf, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 4-6.

IADC/SPE Drilling Conference & Exhibition, Orlando, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 4-6.

✦SPE Indian Oil & Gas Technical Conference & Exhibition, Mumbai, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 4-6.

Annual Middle East Gas Summit, Doha, +971 4 336 2992, +971 4 336 0116 (fax), e-mail: sarita.singh@ibc-gulf.com, website: www.ibcgulfconferences.com. 5-6.

NPRA Annual Meeting, San Diego, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. 9-11.

World Heavy Oil Congress, Edmonton, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 10-12.

New Zealand Petroleum Conference, Auckland, +64 3 962 6179, +64 4 471 0187 (fax), e-mail: crown.minerals@med.govt.nz, website: www.crownminerals.govt.nz. 10-12.

Gastech International Conference & Exhibition, Bangkok, +44 (0) 1737 855005, +44 (0) 1737 855482 (fax), e-mail: tonystephenson@dmgworldmedia.com, website: www.gastech.co.uk. 10-13.

API Spring Petroleum Measurement Standards Meeting, Dallas, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 10-14.

European Fuels Conference & Annual Meeting, Paris, +44 (0) 1242 529 090, +44 (0) 1242 529 060 (fax), e-mail: wra@theenergyexchange.co.uk, website: www.wraconferences.com. 11-12.

IADC International Deepwater Drilling Conference & Exhibition, Rio de Janeiro, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 11-12.

SPE North Africa Technical Conference & Exhibition, Marrakech, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 12-14.

NACE International Conference & Expo, New Orleans, (281) 228-6200, (281) 228-6300 (fax), website: www.nace.org. 16-20.

Offshore Asia Conference & Exhibition, Kuala Lumpur, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.offshoreasiaevent.com. 17-19.

Calendar

Sub-Saharan Oil, Gas & Petrochemical Exhibition & Conference, Cape Town, +27 21 713 3360, +27 21 713 3366 (fax), e-mail: expo@fairconsultants.com, website: www.fairconsultants.com. 17-19.

Turoge and Black Sea Oil & Gas Exhibition & Conference, Ankara, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 18-20.

✦AAPG Prospect & Property Expo (APPEX), London, (918) 560-2679, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org. 24-26.

AAPG Pacific Section Meeting, Bakersfield, Calif., (918) 560-2679, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org. Mar. 29-Apr. 2.

NPRA International Petrochemical Conference, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. Mar. 30-Apr. 1.

SPE Middle East Petroleum Engineering Colloquium, Dubai, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. Mar. 30-Apr. 2.

APRIL

SPE/ICoTA Coiled Tubing & Well Intervention Conference & Exhibition, The Woodlands, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 1-2.

GIOGIE Georgian International Oil & Gas Conference & Showcase, Tbilisi, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 3-4.

Middle East Petroleum & Gas Conference, Doha, +65 6222 0230, +65 6222 0121 (fax), e-mail: mpgc@cconnection.org, website: www.cconnection.org. 6-8.

ACS National Meeting & Exposition, New Orleans, 1 (800) 227-5558, e-mail: natlmtgs@acs.org, website: www.acs.org. 6-10.

American Institute of Chemical Engineers (AIChE) Spring National Meeting, New Orleans, (212) 591-8100, (212) 591-8888 (fax), website: www.aiche.org. 6-10.

CIOGE China International Oil & Gas Conference, Beijing, + (44) 020 7596 5000, + (44) 020 7596 5111 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 7-8.

API Pipeline Conference & Cybernetics Symposium, Orlando, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 7-10.

EAGE Saint Petersburg International Conference & Exhibition, Saint Petersburg, +7 495 9308452, +7 495 9308452 (fax), e-mail: eage@eage.ru, website: www.eage.nl. 7-10.

IADC Well Control Europe Conference & Exhibition, Amsterdam, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 9-10.

ENTELEC Annual Conference & Expo, Houston, (888) 503-8700, website: www.entelec.org. 9-11.

North Caspian Regional Atyrau Oil & Gas Exhibition & Petroleum Technology Conference, Atyrau, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 9-11.

API Spring Refining & Equipment Standards Meeting, New Orleans, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 14-16.

API/NPRA Spring Operating Practices Symposium, New Orleans, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 15.

SPE Gas Technology Symposium, Calgary, Alta., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 15-17.

SPE International Health, Safety & Environment Conference, Nice, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 15-17.

GPA Midcontinent Annual Meeting, Okla. City, (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 17.

AAPG Annual Convention & Exhibition, San Antonio, 1 (888) 945 2274, ext. 617, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org/sanantonio. 20-23.

SPE Improved Oil Recovery Symposium, Tulsa, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 20-23.

ERTC Coking & Gasification Conference, Rome, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 21-23.

WestAsia Oil, Gas, Refining, & Petrochemicals Exhibition & Conference, Oman, +968 24790333, +968 24706276 (fax), e-mail: clemento@omanexpo.com, website: www.ogwaexpo.com. 21-23.

International Pump Users Symposium, Houston, (979) 845-7417, (979) 847-9500 (fax), website: http://turbolab.tamu.edu. 21-24.

SPE Progressing Cavity Pumps Conference, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 27-29.

MAY

IOGCC Midyear Meeting, Calgary, Alta., (405) 525-3556, (405) 525-3592 (fax), e-mail: iogcc@iogcc.state.ok.us, website: www.iogcc.state.ok.us. 4-6.

API International Oil Spill Conference, Savannah, Ga., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 5-8.

Offshore Technology Conference (OTC), Houston, (972) 952-9494, (972) 952-9435 (fax), e-mail: service@otcnet.org, website: www.otcnet.org. 5-8.

GPA Permian Basin Annual Meeting, Odessa, Tex., , (918) 493-3872, (918) 493-3875 (fax), e-mail: pmirkin@gasprocessors.com, website: www.gasprocessors.com. 6.

ERTC Asset Maximization Conference, Lisbon, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 12-14.

International School of Hydrocarbon Measurement, Oklahoma City, (405) 325-1217, (405) 325-1388 (fax), e-mail: lcrowley@ou.edu, website: www.ishm.info. 13-15.

Uzbekistan International Oil & Gas Exhibition & Conference, Tashkent, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 13-15.

NPRA National Safety Conference, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. 14-15.

IADC Drilling Onshore America Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 15.

SPE Digital Energy Conference, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: service@spe.org, website: www.spe.org. 20-21.

NPRA Reliability & Maintenance Conference & Exhibition, San Antonio, (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npradc.org. 20-23.

✦ Mediterranean Offshore Conference & Exhibition (MOC), Alexandria, Egypt, + 39 0761 527976, + 39 0761 527945 (fax), e-mail: st@ies.co.it, website: www.moc2008.com. 20-22.

Society of Professional Well Log Analysts (SPWLA) Annual Symposium, Edinburgh, (713) 947-8727, (713) 947-7181 (fax), website: www.spwla.org. 25-28.

Middle East Refining and Petrochemicals Conference & Exhibition, Bahrain, +973 1755 0033. +973 1755 3288 (fax), e-mail: mep@oesallworld.com, website: www.allworldexhibitions.com. 26-28.

SPE International Oilfield Corrosion Conference, Aberdeen, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 27.

SPE International Oilfield Scale Conference, Aberdeen, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 28-29.

JUNE

ERTC Management Forum, Copenhagen, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 2-4.

Caspian Oil & Gas Exhibition & Conference, Baku, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 3-6.

Oklahoma Independent Petroleum Association (OIPA) Annual Meeting, Dallas, (405) 942-2334, (405) 942-4636 (fax), website: www.oipa.com. 6-10.

Asian Geosciences Conference & Exhibition, Kuala Lumpur, +44 (0) 20 7862 2136. +44 (0) 20 7862 2119, e-mail: geoasia@oesallworld.com, website: www.geo-asia.com. 9-11.

Independent Liquid Terminals Association (ILTA) Annual Operating Conference & Trade Show, Houston, (202) 842-9200, (202) 326-8660 (fax), e-mail: info@ilta.org, website: www.ilta.org. 9-11.

✦SPE Tight Gas Completions Conference, San Antonio, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 9-11.

EAGE/SPE EUROPEC Conference & Exhibition, Rome, +31 30 6354055, +31 30 6343524 (fax), e-mail: eage@eage.org, website: www.eage.nl. 9-12.

ASME Turbo Expo, Berlin, (973) 882-1170, (973) 882-1717 (fax), e-mail: infocentral@asme.org, website: www.asme.org. 9-13.

Global Petroleum Show, Calgary, Alta., (403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. 10-12.

IADC World Drilling Conference & Exhibition, Berlin, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 11-12.

✦CIPC/SPE GTS Joint Conference, Calgary, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 16-19.

American Association of Professional Landmen (AAPL) Annual Meeting, Chicago, (817) 847-7700, (817) 847-7704(fax), e-mail: aapl@landman.org, website: www.landman.org. 18-21.

IPAA Midyear Meeting, Colorado Springs, Colo., (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 19-21.

API Tanker Conference, San Diego, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 23-24.

API Exploration & Production Standards on Oilfield Equipment & Materials Conference, Calgary, Alta., (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 23-27.

Russian Petroleum & Gas Congress, Moscow, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 24-26.

NEFTEGAZ Exhibition, Moscow, +44 207 596 5016, e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 24-26.

World Petroleum Congress, Madrid, +34 91 745 3008, +34 91 563 8496 (fax), e-mail: info@19wpc.com, website: www.19wpc.com. June 29- July 3.

JULY

International Offshore & Polar Engineering Conference, Vancouver, (650) 254 2038, (650) 254 1871 (fax), e-mail: meetings@isope.org, website: www.isope.org. 6-11.

Colorado Oil & Gas Association Conference, Denver, (303) 861-0362, (303) 861-0373 (fax), e-mail: conference@coga.org, website: www.coga.org. 9-11.

IADC Lifting & Mechanical Handling Conference & Exhibition, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 15-16.

Oil Sands and Heavy Oil Technology Conference & Exhibition, Calgary, Alta., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilsandstechnologies.com. 15-17.

AUGUST

ACS National Meeting & Exposition, Philadelphia, 1 (800) 227-5558, e-mail: natlmtgs@acs.org, website: www.acs.org. 17-21.

IADC/SPE Asia Pacific Drilling Technology Conference, Jakarta, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 25-28.

Offshore Northern Seas Exhibition & Conference, Stavanger, +47 51 59 81 00, +47

Calendar

51 55 10 15 (fax), e-mail: info@ons.no, website: www.ons.no. 26-29.

✦Summer NAPE Expo, Houston, (817) 306-7171, (817) 847-7703 (fax), e-mail: info@napeexpo.com, website: www.napeonline.com. 27-28.

SEPTEMBER

China Power, Oil & Gas Conference & Exhibition, Guangzhou, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.chinasenergyfuture.com. 2-4.

✦ECMOR XI-European Mathematics of Oil Recovery Conference, Bergen, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 8-11.

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

API Fall Refining & Equipment Standards Meeting, Los Angeles, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 15-17.

Rio Oil & Gas Conference & Expo, Rio de Janeiro, 55 21 2112 9078, 55 21 2220 1596 (fax), e-mail: riooil2008@ibp.org.br, website: www.riooilegas.com.br. 15-18.

API/NPRA Fall Operating Practices Symposium, Los Angeles, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 16.

GEO India Event, New Delhi, +973 17 550033, +973 17 553288 (fax), e-mail: aeminfo@batelco.com.bh, website: www.allworldexhibitions.com/oil. 16-19.

SPE Annual Technical Conference & Exhibition, Denver, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 21-24.

International Pipeline Exposition, Calgary, Alta., 403) 209-3555, (403) 245-8649 (fax), website: www.petroleumshow.com. Sept. 30-Oct. 2.

Unconventional Gas International Conference & Exhibition, Ft. Worth, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.unconventionalgas.net. Sept. 30-Oct. 2.

OCTOBER

NPRA Q&A Forum, Orlando, Fla., (202) 457-0480, (202) 457-0486 (fax), e-mail: info@npra.org, website: www.npra.org. 5-8.

KIOGE Kazakhstan International Oil & Gas Exhibition & Conference, Almaty, + (44) 020 7596 5000, + (44) 020 7596 5111 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 7-10.

IADC Drilling West Africa Conference & Exhibition, Lisbon, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 8-9.

International Gas Union Research Conference, Paris, +31 50 521 30 78, +31 50 521 19 46 (fax), e-mail: igrc2008@gasunie.nl, website: www.igrc2008.com. 8-10.

ERTC Petrochemical Conference, Nice, +44 1737 365100, +44 1737 365101 (fax), e-mail: events@gtforum.com, website: www.gtforum.com. 13-15.

API Fall Petroleum Measurement Standards Meeting, Long Beach, (202) 682-8000, (202) 682-8222 (fax), website: www.api.org/events. 13-17.

ISA EXPO, Houston, (919) 549-8411, (919) 549-8288 (fax) website: www.isa.org. 14-16.

SPE Asia Pacific Oil & Gas Conference & Exhibition, Perth, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 20-22.

SPE International Thermal Operations & Heavy Oil Symposium, Calgary, Alta., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 20-23.

Permian Basin International Oil Show, Odessa, Tex., (432) 367-1112, (432) 367-1113 (fax), e-mail: pbioilshow@pbioilshow.org, website: www.pbioilshow.org. 21-23.

AAPG International Conference & Exhibition, Cape Town, (918) 560-2679, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org. 26-29.

SPE Russian Oil & Gas Technical Conference & Exhibition, Moscow, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 28-30.

IADC Contracts & Risk Management Conference, Houston, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 29-30.

NOVEMBER

ASME International Mechanical Congress & Exposition, Boston, (973) 882-1170, (973) 882-1717 (fax), e-mail: infocentral@asme.org, website: www.asme.org. 2-6.

Abu Dhabi International Petroleum Exhibition & Conference (ADIPEC), Abu Dhabi, website: www.adipec.com. 3-6.

Deepwater Operations Conference & Exhibition, Galveston, Tex., (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.deepwateroperations.com. 4-6.

Mangystau International Oil & Gas Exhibition, Aktau, + (44) 020 7596 5000, + (44) 020 7596 5111 (fax), e-mail: oilgas@ite-exhibitions.com, website: www.ite-exhibitions.com/og. 5-7.

IADC Annual Meeting, Paradise Valley, Ariz., (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 6-7.

SEG International Exposition and Annual Meeting, Las Vegas, (918) 497-5542, (918) 497-5558 (fax), e-mail: register@seg.org, website: www.seg.org. 9-14.

IPAA Annual Meeting, Houston, (202) 857-4722, (202) 857-4799 (fax), website: www.ipaa.org. 10-12.

Houston Energy Financial Forum, Houston, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.accessanalyst.net. 11-13.

American Institute of Chemical Engineers (AIChE) Annual Meeting, Philadelphia, (212) 591-8100, (212) 591-8888 (fax), website: www.aiche.org. 16-21.

IADC Well Control Middle East Conference & Exhibition, Muscat, (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 24-25.

✦Annual European Autumn Gas Conference (EAGC), Cernobbio, Italy, +44 (0) 1737 855281, +44 (0) 1737 855482 (fax), e-mail: vanessahurrell@dmgworldmedia.com, website: www.theeagc.com. 25-26.

DECEMBER

IADC Drilling Gulf of Mexico Conference & Exhibition, Galveston, Tex., (713) 292-1945, (713) 292-1946 (fax); e-mail: conferences@iadc.org, website: www.iadc.org. 3-4.

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

International Petroleum Technology Conference (IPTC), Kuala Lumpur, +971 (0)4 390 3540, +971 (0)4 366 4648 (fax), e-mail: iptc@iptcnet.org, website: www.iptcnet.org. 3-5.

Seatrade Middle East Maritime Conference & Exhibition, Dubai, +44 1206 545121, +44 1206 545190 (fax), e-mail: events@seatrade-global.com, website: www.seatrade-middleeast.com. 14-16.

AAPG Annual Convention & Exhibition, San Antonio, 1 (888) 945 2274, ext. 617, (918) 560-2684 (fax), e-mail: convene@aapg.org, website: www.aapg.org/sanantonio. 20-23.

XSPE Improved Oil Recovery Symposium, Tulsa, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 20-23.

XSPE Progressing Cavity Pumps Conference, Houston, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 27-29.

2009

JANUARY

Oil & Gas Maintenance Technology Conference & Exhibition, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilandgasmaintenance.com. 19-21.

✦Pipeline Rehabilitation & Maintenance Conference & Exhibition, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.piipeline-rehab.com. 19-21.

✦SPE Hydraulic Fracturing Technology Conference, The Woodlands, Tex., (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 19-21.

FEBRUARY

ASEG International Conference & Exhibition, Adelaide, +61 8 8352 7099, +61 8 8352 7088 (fax), e-mail: ASEG2009@sapro.com.au. 22-26.

MARCH

Middle East Oil & Gas Show & Conference (MEOS), Manama, +973 17 550033, +973 17 553288 (fax), e-mail: aeminfo@batelco.com.bh, website: www.allworldexhibitions.com/oil. 15-18.

MAY

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

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The rise of coalbed methane

Alan Petzet
Chief Editor-Exploration

Coalbed methane (CBM) production has spread to several countries since its meager beginnings in the US.

The US nearly replaced the 1.76 tcf of CBM it produced in 2006, the Energy Information Administration reported.

CBM reserves fell 1.4% to 19.62 tcf at the end of 2006. The reserves-to-production ratio was 9 at year's end, and CBM production was reported in 16 states.

It was 1977 when geologists Ed Dolly and the late Fred Meissner authored a paper on their "recognition of the generation and potential production of gas from coalbeds and carbonaceous shales," the AAPG Explorer noted in its November 2007 issue.

OGJ has ridden along the whole way. A 1977 article by Frank Getz, NEEG Inc., Dusseldorf, is titled, "Molecular nitrogen: clue in coal-derived-methane hunt" (OGJ, Apr. 25, 1977, p. 221).

US CBM reserves

After rising nearly every year since 1989, US CBM reserves fell slightly in 2 of the last 3 years, EIA reported.

At yearend 2006, Colorado had the largest CBM reserves, 6.3 tcf, followed by New Mexico at 4.9 tcf, Wyoming at 2.4 tcf, and Alabama at 2.1 tcf. Virginia, which EIA reported separately for the first time in 2006, had 1.8 tcf.

Colorado has been producing 451-520 bcf/year of CBM the past 7 years, and its 2006 CBM reserve figure is within 350 bcf of the state's all-time high reserves of 6.7 tcf in 2002.

Overall, EIA reported CBM reserves at the end of 2006 in 16 states: Alabama, Arkansas, Colorado, Illinois, Indiana, Kansas, Louisiana, Montana, New Mexico, Ohio, Oklahoma, Pennsylvania, Utah, Virginia, West Virginia, and Wyoming.

EIA tallied a total of 1 tcf of reserves in 2006 for Arkansas, Kansas, Louisiana, Montana, and Oklahoma combined.

Drilling-production

EIA figures show 2006 as the peak year of CBM production in the US.

The 1.76 tcf of 2006 output was up slightly from 1.73 tcf in 2005 and 1.72 tcf in 2004.

The three largest CBM-producing states are in the Rockies. New Mexico led in 2006 with 510 bcf produced, followed by 477 bcf in Colorado and 378 bcf in Wyoming.

Wyoming's Powder River basin is the leader in that state, which has CBM production from several basins (see map, OGJ, Oct. 1, 2007, p. 50).

Alabama produced 114 bcf of CBM in 2006. Its output had been as high as 123 bcf in 1998 and 121 bcf in 2004.

US production of unconventional gas peaked at 24 bcfd in 2006, up from 14 bcfd 1 decade ago, and CBM's share was nearly 5 bcfd.

Producers added more than 20,000 new unconventional gas wells in each of the past 2 years, of which 4,000 wells/year were for CBM and 4,000 wells/year were for gas from shales.

Other trends

US tax credits helped launch economic CBM production in the 1980s, and output in other countries was slow to follow.

The emphasis for CBM exploitation in the US seems to have shifted to deeper coals, lower rank coals, and the opportunity to develop existing plays more intensively, said Advanced Resources International Inc., Arlington, Va., in a six-part series in OGJ on unconventional gas that concluded last month (OGJ, Sept. 24, 2007, p. 51).

For example, 85% of the 314-tcf CBM resource in the Green River basin occurs below 6,000 ft. And as much as 4-8 tcf or more of gas is judged to be in place in Gulf Coast Tertiary coals between Texas and Florida, with 3.4 tcf possibly recoverable.

Other countries are hosting CBM development. In July, Santos Ltd. said it hopes to make a final investment decision by the end of 2009 on a 3-4 million tonne/year LNG plant in Gladstone, Queensland, to be fed by CBM (OGJ Online, July 19, 2007).

That move followed a similar proposal from Arrow Energy Ltd., Brisbane, last May to supply CBM to a planned 1 million tonne facility, also in Gladstone.

Santos, which has more than 4.65 tcf of CBM reserves and contingent resources, said its Surat and Bowen basin permits would supply 158-205 bcf of CBM starting in early 2014.

CBM drilling in Alberta had been rising since 2002. It peaked at nearly 3,400 wells in 2005 and may have relaxed in 2006-07 after gas prices softened, said the Canadian Society for Unconventional Gas.

Great Eastern Energy Corp., London, made India's first CBM sale earlier this year (OGJ Online, July 16, 2007). China is only beginning to exploit CBM in its vast coal reserves. And Indonesia is estimated to have a CBM resource of as much as 337 tcf (OGJ, Oct. 22, 2001, p. 40). ✦

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Editorial

A clean-fuel paradox

December 2007 has been an active month for the climate change issue. Negotiators from around the world met in Bali, Indonesia, under auspices of the United Nations Framework Convention on Climate Change seeking a successor to the Kyoto Treaty. In the US, the Senate Environment and Public Works Committee deliberated a bill that would establish a cap-and-trade system for greenhouse-gas emissions. And Finland's Neste Oil Corp. announced plans for a precedent-setting renewable-diesel plant that illustrates the conflicts that can arise in a global grope for simple answers to complex questions.

Neste Oil's facility, in Singapore, will make renewable diesel using a proprietary process able to run a range of animal fat and vegetable oil feedstocks. The company started up a 170,000-tonne/year plant based on the process this year at its 200,000-b/d refinery at Porvoo, Finland, and plans to bring a second unit on stream there in 2009. The Singapore project is noteworthy for, among other things, its size. The design capacity is 800,000 tonnes/year, which Neste Oil says will make the plant "the largest facility producing diesel fuel from renewable feedstocks anywhere."

Warming antidotes

In the current political climate, any fuel that can be called renewable or that bears the prefix "bio" wins favor. All such fuels are presumed to be effective antidotes to global warming. Yet they're not all alike.

Against environmental and performance standards, diesel from the Neste Oil process measures up well, according to Cal Hodges, president of A 2nd Opinion Inc., a clean fuels and regulatory issues consultancy in The Woodlands, Tex. "This technology is proven and will significantly reduce life-cycle carbon emissions," said Hodge, who is helping Neste win regulatory approvals for its renewable diesel in the US. In a press release, he noted the Singapore plant's capacity exceeds total current production of biodiesel in all the US.

Neste's Singapore plant won't make biodiesel, an ester. Its product will be a hydrocarbon made from palm oil. Hodge said diesel from palm oil has average carbon intensity—a measure of carbon emissions associated with a fuel—30-46% that of gasoline, depending on farming methods. And the product won't require special handling or have the performance drawbacks of biodiesel from transesterification.

Given these advantages, renewable diesel from palm oil should have unanimous support from supporters of aggressive precautions against greenhouse warming. It doesn't.

The market for all edible oils, of which palm oil accounts for 30%, has grown rapidly in recent years. According to the Roundtable for Sustainable Palm Oil (RSPO), Kuala Lumpur, the area under cultivation for palm oil has increased more than 43% since the 1990s, mostly in Malaysia and Indonesia. To make room for oil palms, some plantation owners are destroying forests and draining and burning peat bogs, which act as carbon sinks.

The environmental group Greenpeace has added palm oil to its list of climate-change threats. Last month it anchored one of its ships in position to keep a palm oil tanker from leaving a port in Indonesia. The Greenpeace ship flew a banner reading, "Palm Oil Kills Forests and Climate."

Acknowledging concern

Greenpeace has been known to exaggerate environmental claims. Neste Oil, though, acknowledges the concern. It committed to process in Singapore only palm oil that complies with a new RSPO certification system. While the step shows good faith, it doesn't annul the boost that consumption as a fuel feedstock will give to overall demand for palm oil—and therefore to pressure on oil palm growers to encroach on forests and peatlands. If Greenpeace is correct about the extent of the practice, climate-change benefits of diesel from palm oil are in some measure compromised.

This seems like a paradox: Production of a fuel that lowers carbon emissions meets resistance because of its association with agricultural methods that increase carbon emissions. But it's really just a reminder: There are no energy panaceas. All energy forms have advantages and disadvantages. Markets and science must sort them out and can if allowed to do so. But the sorting can't happen by fiat. And it won't happen overnight. ✦

3rd quarter 07 earnings slide on high costs, low margins

Marilyn Radler
Senior Editor-Economics

Laura Bell
Statistics Editor

The collective third-quarter earnings for a sample of US-based oil and gas producers and refiners declined from earnings a year earlier, softened by lower production volumes and weak downstream margins.

Higher depreciation and operating expenses weighed on earnings, much as they did earlier this year. For the first 9 months of 2007, this group of US companies reported a combined 8% decline in earnings from a year earlier.

A sample of service and supply firms, benefiting from a higher cost of doing business in exploration and production, together reported a surge in profits for the third quarter of 2007 compared with the same 2006 period. Strong demand for equipment and services pushed these companies' earnings 33% higher in the first 9 months of this year.

Meanwhile, a group of oil and gas producers and transporters based in Canada reported a combined 10% decline in earnings for the recent quarter compared with the third quarter of last year. Most of these firms reported that a weaker US dollar relative to the Canadian dollar had a negative impact on recent earnings.

All figures here are reported in US dollars.

US producers

Lower production volumes and much lower refining margins combined to put downward pressure on earnings for the US-based companies. Higher oil prices helped the producers but crimped downstream earnings.

Thirty-six of the firms in a sample of US oil and gas producers reported a decline in earnings from the third quarter of last year. Another 14 companies in the group recorded a loss for the recent quarter.

ExxonMobil's third-quarter net income was $9.4 billion, down 10% from the third quarter of 2006. The company's realized prices for crude oil were up from a year earlier, but downstream and chemical margins were lower. Natural gas realizations were lower, operating expenses were higher, and the company's worldwide oil and gas production volumes declined from a year earlier.

Downstream earnings of $2 billion were down $737 million from the third quarter of 2006, driven by lower refining and fuels marketing margins, ExxonMobil reported.

Marathon Oil Corp. reported third quarter 2007 net income of $1 billion, down from $1.6 billion in third quarter 2006.

Upstream income was $479 million in this year's third quarter, compared with $572 million a year ago, mainly as a result of lower oil and gas sales volumes. Marathon's downstream income was $482 million in the third quarter of this year, compared with $1 billion a year earlier, primarily as a result of 47.5% lower refining and wholesale marketing gross margins.

Weak US refining and marketing conditions had a negative impact on the earnings of Chevron Corp., which reported net income of $3.7 billion for third-quarter 2007, down from $5 billion in the comparable period a year ago.

"Margins were squeezed as escalating costs for crude oil feedstocks could not be fully recovered in a US marketplace that was well-supplied with gasoline and other refined products," said Chevron chairman and CEO Dave O'Reilly.

Chevron's upstream earnings declined slightly from last year's third quarter. Although prices for crude oil increased between periods, this benefit to earnings was more than offset by the impacts of lower sales volumes due to the timing of crude-oil cargo liftings and higher operating and depreciation expenses.

With $216 million in net income, Sunoco Inc. announced a 38.5% decline in third-quarter earnings. Revenue was up 9.5% for the period.

Eitan Bernstein, analyst with Fried-

man, Billings, Ramsey, & Co. Inc., said Sunoco's refining earnings were below expectations. "Operating earnings of $171 million were well below our forecast, primarily due to lower mid-continent refining margins (of $13.10/bbl) and higher operating costs. Total throughput volumes averaged 943,000 b/d, 4% above comparable year-ago levels," he said.

Bernstein said Sunoco's marketing earnings were strong on margins and volumes. "The retail group earned $31 million, above our forecast, due to higher gasoline margins," he said.

Anadarko Petroleum Corp., along with a handful of other independent producers, reported a decline in earnings and revenues. Anadarko posted lower revenue from reduced oil and gas sales compared with a year earlier, and the company's expenses climbed.

In the recent quarter, the company's total expenses were up 35%. Anadarko incurred increased operating, transportation, and exploration expenses, as well as higher costs for gathering, processing, and marketing and for depreciation, depletion, and amortization.

Refiner Valero Energy Corp. reported that its third quarter 2007 operating income was $1.2 billion vs. $2.3 billion in the same period last year. The reduction was mainly due to higher prices for light, sweet crude oils and narrower discounts for sour crude oils, as well as lower US West Coast refining margins.

Relative to the price of WTI, Valero said its feedstocks were about $3/bbl more costly in third-quarter 2007 than in third-quarter 2006, which resulted in a more than $700 million unfavorable impact to operating income.

Canadian firms

A group of oil and gas producers and pipeline operators based in Canada reported a collective 9.5% decline in earnings compared with the third quarter of 2006, even though the firms' revenues climbed almost 13%.

For the first 9 months of this year, the group's earnings moved 10.4% lower, and revenues were up 9.6% from a year earlier.

The companies' results varied, though. Canadian Natural Resources

US OIL AND GAS FIRMS' THIRD QUARTER 2007 REVENUES, EARNINGS (CONTINUED ON P. 24)

Table 1

	Revenues		Net income		Revenues		Net income	
	3rd quarter				Nine months			
	2007	2006	2007	2006	2007	2006	2007	2006
	Million $ (US)							
Abraxas Petroleum Corp.	13.7	13.2	3.0	0.6	40.4	39.8	59.5	2.8
Alon USA Energy Inc.	1,243.2	1,000.2	12.6	38.1	3,395.5	2,257.2	143.8	135.4
Anadarko Petroleum Corp.	3,030.0	3,506.0	504.0	1,385.0	13,003.0	7,047.0	3,628.0	2,826.0
Apache Corp.	2,503.8	2,265.0	613.3	647.1	6,974.8	6,335.2	1,739.8	2,031.6
Apache Offshore Investment Partnership	1.9	2.2	1.3	1.5	5.6	8.5	3.5	6.0
Arena Resources Inc.	26.7	18.2	11.4	8.0	65.0	43.3	25.0	18.0
Aurora Oil & Gas Corp.	7.2	5.3	(3.3)	(2.1)	26.8	16.7	(3.8)	(4.0)
Berry Petroleum Co.	133.5	129.4	26.9	31.4	430.2	370.1	97.7	88.8
Bill Barrett Corp.	105.1	82.9	20.7	0.2	286.7	283.0	51.0	24.3
Brigham Exploration Co.	31.4	26.5	4.2	5.2	93.3	78.5	8.4	14.8
Cabot Oil & Gas Corp.	170.8	184.7	35.5	189.0	538.3	590.3	125.4	289.0
Carrizo Oil & Gas Inc.	30.3	20.5	5.4	4.8	86.4	59.6	11.0	14.0
Cheniere Energy Inc.	21.4	11.8	(53.5)	(33.1)	66.7	32.6	(129.1)	(52.5)
Chesapeake Energy Corp.	2,028.0	1,934.0	372.0	549.0	5,723.0	5,478.0	1,148.0	1,532.0
Chevron Corp.	55,173.0	54,212.0	3,718.0	5,017.0	159,404.0	162,372.0	13,813.0	13,366.0
Cimarex Energy Co.	343.8	322.9	73.2	94.0	992.7	971.5	216.5	287.0
Clayton Williams Energy Inc.	101.8	66.4	1.0	5.3	266.9	200.1	(2.5)	26.7
CMS Energy Corp.	1,282.0	1,288.0	84.0	(101.0)	4,790.0	4,404.0	(91.0)	(50.0)
Comstock Resources Inc.	171.5	129.5	16.4	17.0	492.4	385.9	47.2	62.3
ConocoPhillips	47,933.0	49,585.0	3,673.0	3,876.0	140,197.0	145,988.0	7,520.0	12,353.0
Continental Resources	516.8	140.9	56.4	88.0	423.2	369.7	(32.3)	204.3
Delta Petroleum Corp.	51.9	42.7	(6.4)	(7.1)	140.5	116.2	(119.4)	10.9
Devon Energy Corp.	2,763.0	2,499.0	735.0	705.0	8,165.0	7,349.0	2,290.0	2,264.0
Double Eagle Petroleum & Mining Co.	4.1	4.5	(4.8)	0.3	12.7	13.1	(5.1)	1.4
Edge Petroleum Corp.	48.3	36.0	6.0	(56.9)	125.3	104.9	10.9	(44.2)
EnDevCo Inc.	0.4	0.6	(1.0)	(0.9)	1.3	1.6	(3.1)	(1.9)
EOG Resources Inc.	990.5	968.7	204.0	299.1	2,940.0	2,981.2	728.7	1,057.3
Equitable Supply	117.2	121.0	62.2	63.2	370.3	362.8	188.2	200.7
ExxonMobil Corp.	102,337.0	99,593.0	9,410.0	10,490.0	287,910.0	287,607.0	28,950.0	29,250.0
Fieldpoint Petroleum Corp.	1.1	1.1	0.2	0.4	3.0	3.2	0.5	1.1
Forest Oil Corp.	313.0	202.8	58.0	76.9	750.3	636.1	141.7	137.7
Frontier Oil Corp.	1,386.5	1,381.1	137.2	123.6	3,869.1	3,708.7	455.7	326.8
FX Energy Inc.	5.5	2.0	0.2	(1.7)	14.2	5.6	(5.1)	(8.0)
Gasco Energy Inc.	4.0	6.1	(35.1)	(0.8)	16.6	19.1	(101.6)	(54.0)
GeoResources Inc.	8.6	4.9	1.4	1.9	21.0	13.2	0.9	4.7
GMX Resources Inc.	17.1	8.5	3.6	2.9	46.9	21.7	12.0	6.6
Goodrich Petroleum Corp.	27.3	19.6	(22.1)	8.2	78.8	54.5	(24.4)	24.1
Hess Corp.	7,504.0	7,127.0	395.0	296.0	22,424.0	21,512.0	1,322.0	1,525.0
Holly Corp.	1,213.0	1,175.4	58.1	79.0	3,362.0	3,092.0	284.3	218.9
Infinity Energy Resource Inc.	2.5	3.7	3.2	(28.3)	7.1	9.5	(16.6)	(36.9)
Legacy Reserves LP	36.1	23.0	13.9	2.2	48.9	48.1	6.7	(4.8)
Lucas Energy Inc.	494.1	437.6	61.6	120.2	1,002.6	552.6	87.3	183.5
Marathon Oil Corp.	16,954.0	16,634.0	1,021.0	1,623.0	46,843.0	51,463.0	3,288.0	4,155.0
McMoRan Exploration Co.	133.3	60.4	(52.2)	(18.6)	230.3	153.5	(73.6)	(18.4)
Murphy Oil Corp.	4,780.7	4,153.4	199.5	224.1	12,829.2	10,943.6	560.4	556.3
Newfield Exploration Inc.	419.0	425.0	83.0	266.0	1,384.0	1,246.0	137.0	509.0
Noble Energy Inc.	813.8	741.3	222.7	318.1	2,350.6	2,225.9	643.6	513.4
Occidental Petroleum Corp.	5,055.0	4,483.0	1,324.0	1,170.0	14,442.0	13,365.0	3,948.0	3,261.0

US OIL AND GAS FIRMS' THIRD QUARTER 2007 REVENUES, EARNINGS (CONTINUED FROM P. 23)

	Revenues		Net income		Revenues		Net income	
	3rd quarter				Nine months			
	2007	2006	2007	2006	2007	2006	2007	2006
	Million $ (US)							
Panhandle Royalty Co.	11.0	7.4	2.9	2.1	28.1	28.4	4.7	9.6
PetroQuest Energy Inc.	65.5	55.1	8.0	6.5	196.3	154.9	28.5	23.7
Pioneer Natural Resources Co.	490.4	397.7	101.9	80.8	1,302.5	1,138.2	168.0	712.0
Plains Exploration & Production Co.	299.0	280.9	32.9	272.7	779.2	810.9	78.7	213.9
Pogo Producing Co.	201.1	232.1	(45.9)	33.3	635.5	713.3	(111.9)	462.7
PrimeEnergy Corp.	42.1	24.8	0.8	6.6	106.9	71.2	6.7	15.9
Quest Resource Inc.	16.8	30.4	(10.1)	2.0	53.1	87.4	(7.1)	(5.8)
Questar Corp.	501.1	559.0	113.3	95.0	1,935.8	2,072.6	376.6	322.6
Quicksilver Resources Inc.	159.2	99.2	28.7	22.9	412.2	288.3	83.3	74.0
Range Resources Corp.	242.4	219.6	58.9	51.3	638.7	568.2	196.3	158.3
Royale Energy Inc.	4.8	4.6	(0.1)	(0.8)	11.4	16.6	(1.1)	(0.1)
Southwestern Energy Co.	297.6	168.4	51.0	33.5	852.4	549.1	149.5	128.9
Stone Energy Corp.	183.7	183.0	34.1	21.8	558.6	511.7	116.5	44.3
Sunoco Inc.	11,497.0	10,496.0	216.0	351.0	31,566.0	29,679.0	900.0	856.0
Swift Energy Co.	181.2	173.5	42.3	50.8	490.5	456.8	101.4	126.3
Tengasco Inc.	2.4	2.3	1.6	0.5	6.4	6.7	1.7	1.6
Teton Energy Co.	1.1	1.6	(1.0)	(0.8)	3.1	2.6	(10.0)	(3.6)
The Williams Cos.	2,860.1	2,511.8	198.0	106.2	8,051.8	7,118.6	765.1	162.1
Toreador Resources Corp.	12.7	9.4	(20.7)	5.5	30.0	27.4	(54.6)	10.2
Transmeridian Exploration Inc.	4.5	8.1	(15.6)	(14.2)	23.0	17.0	(43.9)	(40.1)
Ultra Petroleum Corp.	117.4	127.8	37.4	52.5	405.5	359.8	153.1	170.6
Unit Corp.	286.3	299.9	64.1	81.3	840.2	863.1	194.1	231.0
VAALCO Energy Inc.	35.9	26.5	8.8	13.6	91.0	84.5	17.1	35.1
Valero Energy Corp.	23,699.0	23,238.0	1,274.0	1,603.0	66,656.0	68,805.0	4,667.0	4,349.0
W&T Offshore Inc.	255.2	213.4	36.3	66.7	774.3	536.1	94.9	161.0
Warren Resources Inc.	17.2	9.5	3.1	2.5	41.4	26.5	7.3	6.1
Whiting Petroleum Corp.	233.5	207.6	47.7	49.5	586.4	592.2	84.9	128.4
XTO Energy Inc.	1,421.0	1,096.0	412.0	367.0	3,919.0	3,377.0	1,227.0	1,431.0
Total	**303,488.9**	**295,784.0**	**25,733.9**	**30,939.7**	**867,685.5**	**863,903.3**	**80,279.8**	**86,999.4**

Ltd. recorded a 37% earnings decline for the recent quarter, but Nexen Inc. posted $403 million in net income, up from $199 million a year earlier.

Canadian Natural Resources said its cash flow in the third quarter of this year was negatively impacted by the strengthening of the Canadian dollar compared to the US dollar. Higher expenses for depletion, depreciation, and amortization as well as stock-based compensation expenses, interest, and risk management activities also decreased earnings.

Nexen said its improved results reflect increased production from ramping up its North Sea production at Buzzard field, where daily production volumes continued to increase and contributed 76,000 boe/d net (177,000 boe/d gross) to third-quarter volumes.

And although the price of WTI increased during the quarter and averaged $75.38/bbl compared with $70.48/bbl a year ago, Nexen was unable to retain the full benefit of the price increase because of the weakening US dollar.

With net income of $78.1 million, Enbridge Inc. incurred an 18% earnings decline from the third quarter of last year. Revenues for the quarter were up 21% to $2.6 billion.

Enbridge said its earnings were lower due not only to a weaker US dollar, but also because of a lower contribution from its Aux Sable natural gas liquids extraction and fractionation plant, which had derivative losses during 2007. Also, the company reported increased operating costs in the Enbridge and Athabasca pipeline systems.

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

Table 2

	Revenues		Net income		Revenues		Net income	
	3rd quarter				Nine months			
	2007	2006	2007	2006	2007	2006	2007	2006
	Million $ (Can.)							
Bow Valley Energy Ltd.	12.1	6.3	9.1	2.2	21.3	13.0	16.7	5.0
Canadian Natural Resources Ltd.	3,073.0	3,108.0	700.0	1,116.0	9,343.0	8,817.0	1,810.0	2,211.0
Enbridge Inc.	2,634.0	2,184.9	79.8	97.2	8,720.9	7,858.8	456.7	449.4
EnCana Corp.	5,573.1	4,012.5	930.2	1,352.4	15,580.9	12,670.8	2,865.2	4,968.5
Husky Energy Inc.	4,351.0	3,436.0	769.0	682.0	10,758.0	9,580.0	2,140.0	2,184.0
Imperial Oil Ltd.	6,403.6	6,623.7	812.7	818.6	18,626.3	19,078.5	2,292.6	2,240.8
Ivanhoe Energy Inc.	8.8	14.0	(7.2)	(4.4)	27.6	36.8	(20.3)	(14.1)
Nexen Inc.	1,672.0	1,284.0	403.0	199.0	4,758.0	4,105.0	892.0	524.0
Petro-Canada	5,497.0	5,201.0	776.0	678.0	15,816.0	14,119.0	2,211.0	1,356.0
Suncor Energy Inc.	4,466.0	4,114.0	677.0	682.0	12,975.0	12,042.0	1,869.0	2,613.0
Talisman Energy Inc.	1,987.0	1,822.0	352.0	524.0	5,874.0	5,856.0	1,422.0	1,407.0
TransCanada Corp.	2,210.0	1,850.0	324.0	293.0	6,671.0	5,429.0	846.0	810.0
Total	**37,887.6**	**33,656.3**	**5,825.5**	**6,440.1**	**109,171.9**	**99,605.9**	**16,800.9**	**18,754.7**

SERVICE-SUPPLY COMPANIES' THIRD QUARTER 2007 REVENUES, EARNINGS

Table 3

	Revenues — 3rd quarter		Net income — 3rd quarter		Revenues — Nine months		Net income — Nine months	
	2007	2006	2007	2006	2007	2006	2007	2006
	Million $ (US)							
Allis-Chalmers Energy Inc.	147.9	86.8	13.0	11.3	427.1	196.1	44.7	25.3
Baker Hughes Inc.	2,677.6	2,309.4	389.1	358.6	7,687.9	6,574.7	1,113.4	2,092.8
BJ Services Co.[1]	1,279.3	1,216.0	189.4	228.6	1,402.3	1,408.2	753.6	804.6
Bronco Drilling Co. Inc.	76.3	79.8	11.1	17.4	230.0	203.4	31.2	43.4
Cameron Corp.	1,186.2	978.8	150.4	89.3	3,322.3	2,666.2	375.0	221.3
Diamond Offshore Drilling Inc.	644.0	514.5	205.5	164.5	1,901.0	1,474.4	681.6	485.5
Dril-Quip Inc.	130.4	117.8	27.6	23.4	362.8	324.4	75.8	62.0
Foster Wheeler Ltd.	1,299.9	910.6	129.1	75.8	3,641.8	2,301.7	315.8	198.9
GlobalSantaFe Corp.	1,188.2	909.2	448.6	245.6	3,165.2	2,362.0	1,160.1	657.0
Grant Prideco	539.9	471.3	124.2	126.5	1,558.5	1,317.6	390.7	324.5
Grey Wolf Inc.	227.3	245.9	35.6	55.3	829.4	713.6	135.9	167.4
Gulfmark Offshore Inc.	74.7	75.8	31.2	39.9	214.6	181.9	86.3	59.1
Halliburton Co.	3,928.0	3,392.0	727.0	611.0	11,085.0	9,446.0	2,809.0	1,690.0
Horizon Offshore Inc.	148.8	144.6	18.9	20.9	354.5	432.3	14.9	53.2
Hornbeck Offshore Services Inc.	94.7	77.5	28.9	23.9	237.9	209.5	70.0	59.1
Nabors Industries Ltd.	1,225.5	1,256.1	218.0	292.8	3,631.5	3,527.2	708.5	782.9
Noble Corp.	791.3	562.0	318.3	207.2	2,163.7	1,541.4	858.6	532.2
Oceaneering International Inc.	485.7	337.4	53.9	38.5	1,262.0	98.1	134.9	94.7
Parker Drilling Co.	174.3	149.3	22.7	18.6	184.6	141.3	69.5	43.9
Patterson-UTI Energy Inc.	525.1	674.6	98.2	186.0	1,595.6	1,913.8	353.5	516.9
Pioneer Drilling Co.[2]	107.2	107.9	11.8	23.5	210.9	202.5	24.9	43.0
Pride International Inc.	544.2	407.0	401.5	89.3	1,541.5	1,172.5	649.3	227.6
Rowan Cos. Inc.	507.8	423.6	130.8	87.0	1,488.0	1,121.6	345.3	255.8
RPC Inc.	162.0	154.3	14.9	28.8	504.1	436.6	66.8	81.3
Schlumberger Ltd.	5,925.7	4,954.8	1,354.0	999.8	17,028.8	13,880.6	3,793.3	2,579.2
Smith International Inc.	2,245.1	1,914.2	166.8	132.9	6,467.2	5,334.6	480.0	359.0
Transocean Inc.	1,545.0	1,029.0	973.0	309.0	4,317.0	2,710.0	2,075.0	764.0
Weatherford International Inc.	1,972.0	1,696.8	292.7	234.2	5,640.2	4,771.3	739.6	624.4
Total	**29,854.1**	**25,197.0**	**6,586.2**	**4,739.6**	**82,455.4**	**66,663.5**	**18,357.2**	**13,849.0**

[1]Fourth quarter, full year. [2]Second quarter, 6 months.

Service, supply companies

A sample of 28 service and supply firms posted a 39% surge in earnings for the third quarter of 2007. None of the companies reported a loss for the recent quarter, but 10 firms recorded a decline in net income compared with their third-quarter 2006 earnings.

In the final full quarter prior to its merger with Transocean Inc., Houston-based GlobalSantaFe Corp. posted an 83% jump in third-quarter 2007 earnings to $448.6 million. Revenue for the quarter was nearly $1.2 billion. For the first 9 months, net income was $1.16 billion, up 77% from the corresponding 2006 period.

Transocean's net income for the recent quarter was $973 million, up 214%, on record quarterly revenues of $1.5 billion. Third quarter 2006 revenue was $1 billion.

Transocean said the quarter-to-quarter increase in revenues was due primarily to a higher average day rate, partially offset by a slight reduction in the number of days in service. The third-quarter 2007 average day rate reached a record high of $219,700, up 8.5% from the second quarter. And the increase in the average day rate spanned all rig categories, primarily as a result of rigs commencing new contracts at the higher prevailing day rates.

BJ Services Co. reported a 17% slide in third-quarter earnings from a year ago to $189.4 million. The company's revenue moved 5% higher, but earnings were hit by increased operating expenses.

BJ Services' cost of sales and services for the recent quarter was $910.6 million, up 14% from a year earlier. ✦

Reworked energy bill passes House, stalls in Senate

Nick Snow
Washington Editor

US Congressional Democrats passed a reworked energy bill in the House by 235 to 181 votes on Dec. 6, only to see the measure stall in the Senate the following day.

A motion to invoke cloture and limit debate fell 7 votes short of the necessary three-fifths majority in a 53-42 vote on Dec. 7. Senators on both sides pledged to work to resolve differences, but a source said on Dec. 10 that Majority Leader Harry M. Reid (D-Nev.) also was trying to secure additional support for another cloture vote.

Democrats also denied Republican charges of being excluded from formulation of the latest energy bill, which would raise fuel efficiency standards for cars and trucks to an average 35 mpg, increase the federal renewable fuels standard to 36 billion gal/year,

WATCHING GOVERNMENT

Nick Snow, Washington Editor

Preparing for 2008

Marc W. Smith arrived in Washington, DC, from Denver for his latest visit on Dec. 3 as the US House leadership announced its latest energy legislation.

But the Independent Petroleum Association of Mountain States and its executive director were doing more than simply checking in with members and staffs of the 110th Congress from the Rocky Mountains. They also were preparing to mobilize 150,000 oil and gas employees and contractors in those states.

"The political landscape has changed in the Mountain West," Smith told me on Dec. 4. "A number of state legislatures have turned anti-industry. We also have a number of new governors who don't understand the oil and gas business. Even at the county level, support for the industry is not a long-term guarantee."

IPAMS wants to work with state oil and gas associations on a comprehensive plan to educate and mobilize the industry's employees and contractors in the region. The program would include a fair method of grading candidates, irrespective of their party.

Coordinated opposition

Colorado and other states' basic political demographics haven't changed much from the traditional urban-rural split. The primary difference, said Smith, is that industry opponents are reaching out with like-minded individuals to try and convince first, state legislatures and, second, Congress, that support for oil and gas development is waning in the West.

Misleading information comes in three basic forms, he indicated. The first is that a renewable energy economy could be achieved in 10 years. "We're not against renewable fuels. We consistently support a diverse energy portfolio which includes them. But natural gas is critical to a secure US energy future," Smith said.

More than half of the states with renewable portfolio standards for electricity generation list gas as the backup fuel for wind, solar and other intermittent sources, he noted. Biofuels production also requires large amounts of gas for fertilizer and for conversion from corn, cellulose, and other plants.

'Off a cliff'

The second erroneous assumption is that the Mountain West must choose between sacrificing its scenic and recreational assets to develop energy and preserving large tracts for wildlife. The third is that nothing bad will happen if oil and gas activity in the Rockies is slowed or stopped. "They don't appreciate that 50% of the gas we use today comes from wells drilled in the last four years," said Smith.

Unconventional reservoirs, which currently are being produced, deplete about 50% of their reserves in the first 5 years and the remainder over 20 to 40 years, he pointed out. "If you slow down the pace of new drilling, you don't glide into a nice supply curve. You fall off a cliff," he said.

That's why Smith thinks next year's elections will be especially crucial. "Every office, from president to county commissioner, will determine how the United States faces its energy challenges," he said. ✦

and require that at least 15% of generated electricity come from renewable sources.

"Even without a conference, we worked with Republicans, consulting on and sharing proposed language. And that is an understatement. Many provisions were removed and modified at the request of Republican Senate and House members," Reid said on Dec. 7 before the cloture vote.

Minority as well as majority staff members from Senate and House committees with jurisdiction met over a 2-month period starting Sept. 24 to work on the bill's provisions, the House Energy and Commerce Committee's majority staff said in a Dec. 6 e-mail message to journalists. "In fact, we want to commend Republican members for the technical expertise provided by their staffs throughout this process," it said.

'Fairly one-sided'

Rep. Joe Barton (R-Tex.), the Energy and Commerce Committee's ranking minority member, took a different view as the bill arrived on the House floor. "In the debate so far in this Congress on energy legislation, it's been fairly one-sided. It's been the majority trying to put their blueprint for American on energy...without input from the minority party," he maintained.

The bill that passed the House also faced a threatened presidential veto. "We believe that reducing our dependence on foreign oil and increasing energy security is an area where both parties should be able to find common ground. Unfortunately, Democratic leaders in the House today pushed a partisan bill that members had very little opportunity to study before [and] which they knew was unacceptable to the president and had no chance of being signed into law," White House Press Secretary Dana Perino said on Dec. 6.

She said the measure would raise taxes and increase energy prices, points that Senate Minority Leader Mitch McConnell (R-Ky.) also made a day later before the unsuccessful cloture vote.

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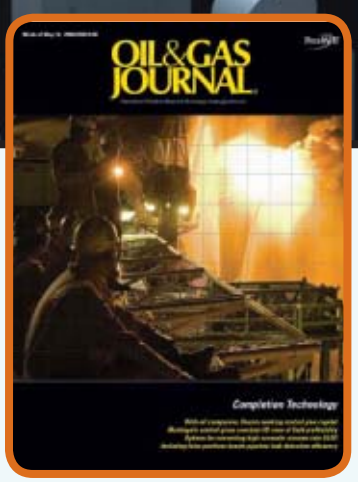

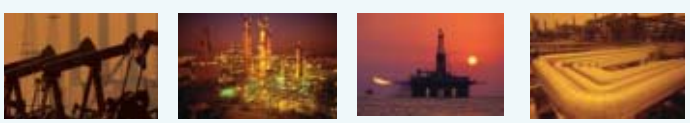

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[1] *Signet Readership Survey (February 2007)*

"It is not a serious attempt to make law, and is not a serious attempt at an accomplishment. It is a partisan bill that must be improved or set aside," he maintained.

Senate Democrats expressed their disappointment after the cloture vote fell short. One key committee chairman suggested that "a few smart changes to some proposals will allow this bill to move forward," however.

"The energy tax package, with its incentives for energy alternatives, energy efficiency, and new and better infrastructure, has strong support in the Senate and will be an essential part of a good energy bill. The Joint Economic Committee has determined that the tax package's offsets are responsible, appropriate, and will have no negative impact on consumer prices," said Finance Committee Chairman Max Baucus (D-Mont.).

Unfavorable tax impacts

Oil and gas trade associations continued to oppose the measure. "The large tax increases the bill would impose on the industry would discourage companies from investing in increased US oil and natural gas production, and it would make us less competitive worldwide at a time when competition for the world's energy resources is intensifying. Further, it would tax away the incentives that have allowed our companies to keep pace with the rising demand in spite of the numerous restrictions, legislative and regulatory, that keep many of the areas rich with energy off-limits to exploration and production," American Petroleum Institute Pres. Red Cavaney said in a Dec. 6 letter to US senators.

Independent Petroleum Association of America Pres. Barry Russell suggested in a separate statement that the bill which passed the House would establish "an unfortunate precedent of funding one energy source at the expense of another. This country needs to develop all sources of energy to increase supply here at home and protect our energy security. While the growth of renewable energy sources and improvements in energy efficiency are essential to America's energy future and should be encouraged, we should not be impairing the development of America's most viable energy resources."

Industry opposition extended to gas utilities, not only because of the bill's possible adverse impacts on supplies, but also because it would roll back a 2005 Energy Policy Act provision which reduced pipeline depreciation periods by 5 years. "Responsible energy legislation should not only encourage increased use of natural gas, but also ensure adequate supply. This legislation moves in the opposite direction," American Gas Association Pres. David N. Parker said on Dec. 6.

The Independent Petroleum Association of Mountain States also expressed concern over the latest bill's tax provisions, but added that its members were pleased that public land use provisions which were part of the House's earlier energy measure in August had been removed. "Congress is starting to get the message from business and consumers that in this time of economic uncertainty, they don't want less domestic energy production; they want more," IPAMS Executive Director Marc W. Smith said.

The bill's provision to expand federal requirements to use ethanol in motor fuels drew fire from the National Petrochemical and Refiners Association as well as API. "NPRA believes that the timetable for overriding and expanding the current Renewable Fuels Standard is unrealistic, and that the broad, mandated reliance on renewable fuels currently unavailable, such as cellulosic ethanol, will only add to costs for consumers and complicate the markets," Executive Vice-Pres. Charles T. Drevna said on Dec. 6, just 4 days before his appointment as NPRA's president.

"The disguised new tax on refiners and ethanol blenders is also unfair, requiring the Environmental Protection Agency to issue and sell credits for advanced biofuels, whether they exist or not," Drevna said. ✦

Global E&P spending forecast to rise 11% in 2008

Global capital expenditures for exploration and production companies are expected to increase 11% to $332 billion in 2008, according to the latest spending survey released Dec. 10 by Lehman Bros. The survey polled 344 companies—the largest survey conducted by the financial services firm.

Meanwhile, Lehman Bros. said, spending in 2007 was "moderately above" original budgets. "As oil prices remained high, global exploration and production capital expenditures in 2007 increased by 14%, as compared with gains of 13% in our 2007 midyear survey, and 9% at the beginning of the year."

Of the companies surveyed with both onshore and offshore operations, 43% expected a larger share of the 2007 budget to be dedicated to offshore spending than was the case in the prior year. In 2008, however, 28% expect the proportion to increase, Lehman Bros. reported. "Deepwater spending continues to increase relative to overall offshore budgets; 85% of companies forecasting a shift intend to focus more on deepwater in 2008 up from 81% in 2007, the study said.

Investment in the US—one of the principal production regions along with the North Sea—is expected to grow by just 3.5% to $81 billion, the study said. This compares with an estimated 7.4% gain in 2007. "We believe that several majors will increase their US E&P spending in 2008," the study said.

Next year, Lehman Bros. said, it is

expected that Canadian outlays will decline for the second consecutive year. "Spending in Canada is likely to decline by 12% to $20.3 billion," Lehman Bros. reported. This compares with a drop of 10% in 2007. "Perceptions of the economics of drilling have dropped sharply in Canada over the past 2 years," it said.

The survey found that increases in spending outside North America will be "substantially stronger" than that in North America. Among the 100 companies surveyed operating internationally, Lehman Bros. estimates they will increase E&P outlays by 16% to $267 billion in 2008 vs. $230 billion in 2007. This gain, the firm said, is believed to be understated and should rise even higher.

Lehman Bros. found that oil price expectations among oil and gas companies has increased. In order to establish their 2008 budgets, the study found, companies assumed a price for oil (West Texas Intermediate) of $67.91/bbl and an average price for natural gas in the US of $6.78/Mcf.

Fewer companies this year, the study said, expect to overspend their cash flow in 2008. Of the companies surveyed, 37% expect 2008 capital spending to exceed total cash flow. This compares with 43% of companies expecting to overspend cash flow in 2007. ✦

Newfield hails Woodford fracs, longer laterals

Longer horizontal laterals in Devonian Woodford shale appear to be improving estimated ultimate recoveries in the Arkoma basin in southeastern Oklahoma, said Newfield Exploration Co., Houston.

And a study of longer-term production from nearly 100 operated horizontal wells indicates that the average frac stage will ultimately recover 600 MMcf of gas, Newfield said.

The company said it has spud 140 operated horizontal wells and has participated in nearly 60% of industry's

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Chavez woos Galp

Venezuelan President Hugo Chavez recently stopped in Portugal and offered to become a main supplier of oil and gas to the small Iberian Peninsula nation.

"Venezuela wants to be a secure source of energy for Portugal," said Chavez. "This is about expanding our strategic range, our presence in the world, in a country like Portugal that we hold in high esteem," he gushed.

Portuguese oil and gas company Galp Energia SGPS SA was not shy in saying it plans to buy as much as 2 billion cu m of LNG from Venezuela. The Portuguese firm said it might even help build a liquefaction plant in the South American nation.

That was back on Nov. 20 and, given ancient rivalries, it sounded a bit odd for Spanish-speaking Venezuela to make such offers in, well, Portuguese-speaking Portugal.

One simply could not help thinking that Brazil—currently Venezuela's arch-rival in Latin America—was somehow the target of this visit by Chavez.

Modern rivalry

After all, Chavez provoked the ire of Brazilian lawmakers on two separate occasions earlier this year when he said Brazil's congress was "submissive" to US interests.

Could Chavez be trying to upstage his rival in Brazil, President Luiz Inacio Lula da Silva, by wooing Portuguese oil and gas investors?

Just before Chavez's visit, directors of Brazil's state-owned Petroleo Brasileiro SA told Lula that the country's ultradeep presalt layer could contain up to 80 billion bbl in oil reserves.

Brazil will need help getting the oil. Its presalt area lies in more than 2,000 m of water, and further beneath 3,000 m of sand and rocks below the ocean floor, as well as a 2,000-m thick salt layer.

Getting the oil is highly worthwhile: Petrobras Chief Executive Sergio Gabrielli said Tupi field would put Brazil's reserves somewhere between those of Nigeria and Venezuela. Oops!

Portuguese investment

Petrobras has a 65% operating stake in the Tupi field, BG Group PLC holds another 25%, and—guess who?—Portugal's Galp Energia has rights to the remaining 10%.

In a word, Galp Energia has access to a lot of Brazilian oil as well as the kind of capital Brazil's development program needs. Would that gall a man of Chavez's sensibilities? Will the sun rise in the East tomorrow?

As we know, Chavez views his oil as a political weapon—something to be dangled before potential allies or withheld from supposed enemies.

Chavez already considers his country to be a main source of oil and gas to much of the world's underprivileged, whether they live in the US, the UK, the Caribbean, or Latin America.

So, word of Brazil's new potential power as major producer of oil and gas might not be welcome news to his ears. It could undermine his self-proclaimed rule in the region and around the world.

Hence, his visit to Portugal and his wooing of that nation's not inconsiderable oil and gas investment money. ✦

400 horizontal wells in the play as of late 2007. Laterals at 10 operated wells are 3,400 ft or longer.

"With production information dating back as far as one year on one-third of this sample, Newfield is confident that these wells will have a significantly higher EUR," the company said. It listed results from three recent extended lateral completions with nine frac stages each:

• Patterson 3H-31, with a 4,240-ft lateral, went on line at 10.3 MMcfd at a completed well cost of $8.5 million.

• Parker 3H-36, with a 4,252-ft lateral, went on line at 9.4 MMcfd.

• Tollett 3H-22 went on line at 12 MMcfd from a 4,366-ft lateral.

Parker and Tollett cost $7 million each to drill and complete.

"The company's recent well results demonstrate that extended lateral completions have the potential to [reduce] finding and development cost toward $2/Mcf," Newfield said. "Additional drilling and recent 3D seismic data will be used to determine what percentage of the total acreage can be developed with extended lateral completions."

Newfield produces 165 MMcfd from the Arkoma Woodford, double its flow this time last year, and holds 165,000 net acres in the play. Industry is running 44 rigs in the play, spudding 90 horizontal wells per quarter. Newfield has 13 operated rigs, 11 of which are drilling development wells. ✦

Ghawar field reserves decline overstated, survey says

Eric Watkins
Senior Correspondent

Concerns about global oil peaking due to declining reserves at Saudi Aramco's Ghawar oil field may be overstated, according to Bernstein Research commenting on the results of a recent satellite survey.

In a note to investors, Bernstein Research said satellite images show that a recent rise in Aramco drilling activity has focused on two major expansion developments and not, as earlier assumed, on keeping older parts of the field producing with enhanced recovery techniques.

"The majority of the increased activity in the Ghawar field can be explained by the Haradh-III, and the Hawiyah natural gas liquids recovery megaprojects, which were not designed as a quick fix to Ghawar's supposed rapid decline," the Bernstein Research note said.

The firm said theories of Ghawar's decline may be based on little or incomplete data from Saudi Arabia on the state of its oil sector.

"Without accurate and detailed data on what Saudi Aramco is undertaking, or with a poor understanding of current Ghawar decline rates, many conspiracy theories have arisen, which argue that we are on the cusp of global peak oil production," the research note said.

Bernstein Research conceded that increased drilling in older sections of Ghawar could suggest efforts to halt some declines, but that such drilling does not by itself point to a sudden drop in the field's output.

The firm concluded that "there is life in this old field yet, as its demise has been overly anticipated." Bernstein said its report was an initial analysis of satellite data from 2004-07, with a final conclusion expected in the coming months. It did not detail the source of the imagery.

The Bernstein Research note counters arguments by experts backing peak oil theories who have warned that sharp global declines could happen at any time, and that Saudi Arabia will only be able to keep production flat for several years but not increase output to meet demand growth. Bernstein Research is a division of Sanford C. Bernstein & Co. LLC which provides investment research to institutional investors. ✦

Action needed to meet climate change challenge

Oil and gas companies and other energy producers are being looked to for assistance in finding a solution to the climate change problem, an energy expert said at the United Nations Climate Change Conference in Bali.

"Much stronger action is needed everywhere to curb, stabilize, and reduce man-made [carbon dioxide] emissions. We don't have any time to lose. Decisions need to be taken now and implementation has to begin immediately," said Nobuo Tanaka, executive director of the International Energy Agency. "The cost of inaction will be high otherwise," Tanaka said.

Climate change, said Tanaka, "is a global problem and needs to be tackled on a global basis with the participation of all emitters."

"For a start, all parts of governments with energy responsibilities must rapidly engage in designing effective policies," he said.

"To realize the tremendous potential for improvements across the board, energy efficiency needs a well-designed and sustained policy push," Tanaka said, adding, "This will pave the way for a least-cost strategy to reduce energy-related emissions in the long run."

He said, "CO_2 emissions are already some 20% higher today than in 1997 and are set to increase even further and faster." He referred to the IEA World Energy Outlook 2007—China and India

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Insights (WEO), showing that, absent new policies, energy-related carbon emissions will increase by almost 60%, reaching 42 gigatonnes (Gt) in 2030. This is higher than last year's projection by 1.5 Gt because of much greater coal use than expected, driven by high oil and gas prices. Despite many ambitious policy instruments and rising energy prices, emissions continue to rise in IEA countries.

IEA analyses show that a departure from current trends is possible by exploiting the immediate benefits of energy efficiency and deployment of known technologies, reinforced by new technologies that will only be available with much greater effort.

Year on year, IEA projections reinforce the critical role that energy efficiency and a better use of our resources can deliver on climate, energy security, and welfare. WEO demonstrates that by implementing policies under discussion today, CO_2 emissions from OECD countries could begin declining by 2015; global emissions would stabilize by 2025, with energy efficiency delivering the bulk of avoided emissions.

The past two G8 Summits have endorsed 16 IEA recommendations covering all energy end-uses, such as buildings (40% of OECD energy use), transportation (using 60% of world oil), and lighting. If implemented globally, these initiatives alone could save 5.7 Gt of CO_2 by 2030—nearly a quarter of what we need to accomplish.

"The triple-win potential of energy efficiency—higher economic performance, higher energy security, and less climate change—leads to three recommendations: implement, implement, implement," Tanaka said. This is required "for developed and emerging economies alike," he added. ✦

China calls for oil worker safety in Sudan, Ethiopia

Eric Watkins
Senior Correspondent

The Chinese government has called for the safety of its oil workers in two African countries, citing the dangers to operations posed by antigovernment rebels in Sudan and Ethiopia.

On Dec. 12, China called for the safety of its citizens in Sudan to be guaranteed just a day after rebels there attacked for the second time an oil field being run by a Chinese company.

"Any threats or attacks on Chinese organizations or people in Sudan are unacceptable," said the Chinese foreign ministry in a statement. "The safety of Chinese personnel in Sudan must be effectively guaranteed," it said.

The Sudanese government acknowledged that about 20 rebels attacked an army camp near an oil facility, but it said that the attack had been repelled.

On Dec. 11, rebels in Darfur said they had seized control of the 35,000 b/d Rahaw oil field operated by China's Great Wall Co., killing and wounding several government protection forces there.

Abdel Aziz Nur al-Ashr, commander of the rebel Justice and Equality Movement (JEM), said his group had neutralized the site's military protection force, taken possession of the facilities, and halted production.

Al-Ashr said JEM's attack represented a second attempt at forcing Chinese companies to leave the country. He said the attacks would continue until China ended its operations altogether.

JEM's earlier attack was on a field in Kordofan run by Greater Nile Petroleum Operating Co. (GNOPC), a consortium comprised of China National Petroleum Corp., India's Oil & Natural Gas Corp., Malaysia's Petronas, and Sudan's Sudapet.

In October, the Sudanese government dismissed threats to attack oil fields made by JEM rebels who claimed to have carried out the assault (OGJ Online, Oct. 29, 2007).

Ethiopia trouble

Meanwhile, in Ethiopia, China's Zhoungyan Petroleum Exploration Bureau (ZPEB), has refused to resume work on oil exploration projects in the Ogaden basin in the southwestern region of that country.

Contracted by Petronas and South-West Energy, a company licensed in Hong Kong, ZPEB had been conducting seismic surveys in the Ogaden region of the Somali regional state.

ZPEB, however, suspended operations in April after an attack by the rebel Ogaden National Liberation Front (ONLF) on the Abole exploration site in the Degeh Bur zone. Seventy-four people, including nine Chinese workers, were killed in the attack.

The Ethiopian Ministry of Mines and Energy has demanded that Petronas and South-West Energy resume work on the exploration projects, but the ministry also has acknowledged that ZPEB's parent company, Sino Tech, will not allow operations to continue until the security of its workers can be assured.

In April, China said it was taking steps to improve the safety of its overseas workers following an Apr. 24 attack on the oil exploration site in Ethiopia in which the nine Chinese workers were killed and seven taken hostage (OGJ Online, Apr. 26, 2007). ✦

COMPANY NEWS

Chevron, Canadian firms report 2008 spending plans

One US major and two Canadian exploration and production companies have recently reported their preliminary capital spending plans for 2008.

These companies include:

- Chevron Corp. plans a $22.9 billion capital and exploratory spending program for 2008, a 15% increase from estimated outlays of $20 billion in 2007.
- EnCana Corp. reported it has budgeted $6.9 billion for its 2008 capital spending plan, which is up about 13% from 2007.
- Nexen Inc. has approved a 2008 capital investment program of $2.4 billion, about $1.2 billion less than its 2007 program.

Chevron's spending plans

Anticipated cash expenditures by Chevron and consolidated companies next year will be $20.3 billion because the budget includes $2.6 billion of expenditures by affiliates.

Dave O'Reilly, Chevron chairman and chief executive officer, said 75% of the 2008 budget is for upstream projects worldwide and 20% is dedicated to downstream businesses.

"Much of our 2008 spending continues to be on large, multiyear projects," O'Reilly said. Much of the upstream budget is allocated to development, including projects in deepwater Gulf of Mexico and western Africa.

George Kirkland, Chevron's executive vice-president of upstream and gas, said, "Production startups of major projects in 2008 are expected to include Blind Faith in the Gulf of Mexico and Agbami offshore Nigeria." He also anticipates significant production increases at Kazakhstan's Tengiz field during 2008.

EnCana's spending plans

EnCana said its 2008 capital investment plan targets US natural gas growth, as well as longer lead time projects such as Canadian oilsands, expanded downstream refining capacity, and the advancement of the Deep Panuke natural gas project off Nova Scotia. EnCana expects to grow 2008 gas production by about 7%, while oil and natural gas liquids production is expected to decrease about 8%, mostly due to natural decline in mature properties. EnCana's total production is expected to increase about 5% to about 4.6 bcfd in 2008.

"With the geological and economic success in our unconventional gas fields in Wyoming and Texas, we are substantially increasing investment in our US natural gas production, which is expected to grow by about 25% this year. Our gas growth is largely driven by our leading-return projects—Jonah in Wyoming and the Amoruso field in East Texas, where a planned investment increase of about 65%, to more than $1 billion, is expected to boost production more than 45%," said Randy Eresman, EnCana's president and chief executive officer.

EnCana's integrated oilsands production is expected to grow about 25% in 2008 to about 34,000 b/d. The company plans to double its investment in integrated oilsands to about $1.2 billion in 2008, split about evenly between growing upstream production and expanding downstream heavy oil processing capacity.

In addition, the planned Alberta royalty increases starting in 2009 have significantly diminished returns for deep gas well drilling and new and emerging resource plays. Compared to EnCana's preliminary capital investment plan for 2008, increases in Alberta royalties have resulted in a reduction of about $500 million of EnCana's Alberta investment next year.

EnCana's Alberta drilling for shallow gas, deep gas, coalbed methane, and its delineation drilling of new oilsands plays will be lower than in previous years. Investment in British Columbia in 2008 is expected to be about the same as in 2007. In Canada, excluding integrated oilsands, about $3 billion is planned for upstream investment, about 10% lower than in 2007.

Nexen's spending plans

Nexen said the decrease in spending for 2008 vs. 2007 reflects reduced investment in several of the company's major development projects, including its coalbed methane operations in Alberta, due to uncertainty surrounding proposed changes to Alberta's royalty regime.

Nexen said its 2008 capital spending will focus on value-adding projects, growing net production by about 8-10%, and generating $2.9 billion in cash flow next year, which compares to its expected cash flow of about $3.4 billion for 2007. About 29% of the capital budget will be allocated to major development projects. This will allow Nexen to bring Long Lake Phase 1 and Ettrick oil field in the North Sea on stream in 2008 as well as progress Longhorn in the Gulf of Mexico and CBM at Fort Assiniboine in Alberta.

About 17% is earmarked for early-stage development projects expected to contribute production and cash flow growth beyond 2008. These include future phases of oil sands in the Athabasca region, Block OPL-222 off West Africa, and its Knotty Head and Golden Eagle discoveries in the Gulf of Mexico and North Sea, respectively.

About 25% will be spent on exploration in North Sea and Gulf of Mexico growth areas and on shale gas in northeast British Columbia. Another 25% it allocated toward existing producing assets. ✦

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ABSTRACT DEADLINE: JANUARY 30, 2008

Petrobras to start Tupi oil development by 2011

Uchenna Izundu
International Editor

Petroleo Brasileiro SA's development plans for ultradeepwater Tupi oil field off Rio de Janeiro state include a 100,000 b/d early production system to be built by 2010-11, said company Pres. and Chief Executive Jose Sergio Gabrielli De Azevedo Nov. 13 at the World Energy Congress in Rome.

The company expects full development of the Santos basin field to begin by 2012 once the company collects required initial data.

Following completion of its 1-RJS-646 (3-BRSA-496-RJS) confirmation well in the field, Petrobras announced possible volumes of recoverable 30° gravity oil from Tupi to be 5-8 billion bbl. If Petrobras's estimates prove out, Tupi would belong in a category with supergiant Kashagan field in Kazakhstan. Industry geologists expect several more appraisal wells will be needed to confirm such volumes.

The discovery well, 1-RJS-628A (1-BRSA-369A-RJS), was found last year in 2,126 m of water in a frontier section of the Santos basin 150 km south of Rio de Janeiro (OGJ, Oct. 6, 2006, Newsletter; see map, Nov. 20, 2006, p. 43). Drilled to a true vertical depth of 19,680 ft, it penetrated an evaporitic salt sequence more than 2,000 m thick. Petrobras said the well flowed 4,900 b/d of 30° gravity oil and 4.3 MMscfd of gas from a deep presalt reservoir through a ⅝-in. choke. Petrobras, operator, has a 65% stake, BG Group holds 25%, and Petrogal-Galp Energia 10%.

The confirmation well is 9.5 km southeast of the discovery well. Noble Drilling's Paul Wolff semisubmersible rig drilled it to 2,166 m, and well tests indicated flows of 2,000 b/d of oil and 65,000 cu m/day of natural gas, with flow limited by equipment and safety factors.

Gabrielli told WEC that Petrobras is "highly confident" about its estimate of the volumes of recoverable oil, which would make Tupi one of the largest deepwater discoveries in recent times and could boost Brazil's current 14 billion bbl oil and gas reserves "by more than 50%."

Petrobras said it has drilled 15 wells in its new presalt frontier, which ranges through the Espirito Santo, Campos, and Santos basins, and has tested eight of them producing 28° gravity oil. It said, "Data from these wells, integrated with a major mapping effort, allowed the company to determine…that the presalt rock formations range from an area extending from the State of Espirito Santo to the state of Santa Catarina. It is about 800 km long and 200 km wide and is found in water depths [of] 2,000-3,000 m."

Gabrielli indicated there may be more oil beyond the Tupi accumulation in the Santos basin, but no figures were offered as to the extent of the reservoir.

He said Petrobras has many rigs under contract that can drill to 3,000 m. "We think it will take 2 years" to create a Tupi development plan. Petrobras is building two other drilling rigs and is in discussions with other contractors to secure rigs.

Costs to develop the project are a key concern because the services market is tight and costs have escalated. "We have very high pressure and low temperature of the oil. Stabilization of casing is a challenge and so is the hardness of the rock," Gabrielli said.

Petrobras had not accounted for Tupi in its $112.4 billion strategic business plan for 2008-12 published earlier this year.

Gabrielli declined to comment on whether Brazil could join OPEC with this latest addition to its reserves, saying that was a decision for government. "We planned to increase refining capacity by 1 million b/d by 2015 before we discovered Tupi, and that would make us self-sufficient. We are probably going to export more oil products than crude oil." This decision, however, would depend on economics, he said.

Brazil aspires to produce 4.5 million b/d of oil by 2015 with Tupi coming on stream. Prior to that, its target was

Brazil official seeks nuclear sub for Tupi

Brazilian Defense Minister Nelson Jobim claims that a new oil discovery off Brazil underlines the need for his country to develop a nuclear submarine for protection.

"When you have a large natural source of wealth discovered in the Atlantic, it's obvious you need the means to protect it," Jobim told a defense conference in Rio de Janeiro.

Jobim's statement followed a Nov. 8 announcement by the Brazilian government and Petroleo Brasileiro SA that 5-8 billion bbl of oil and associated gas had been found in the block containing offshore Tupi field in the Santos basin (OGJ Online, Nov. 16, 2007). The discovery well is in 2,126 m of water.

Meanwhile, Petrobras said it will drill 32 wells to appraise the area around Tupi field, according to Hugo Repsold, general manager for exploration and production.

The field is in a presalt frontier extending through the Espirito Santo, Campos, and Santos basins.

Petrobras has a 65% stake in Tupi field, while BG Group PLC holds 25%, and Portugal's Galp Energia has the remaining 10%.

2.3 million b/d. Refining capacity is expected to leap to 3.5 million b/d from 1.5 million b/d by 2015.

"Brazilian consumption is 1.8-1.9 million b/d, and as we increase refining capacity we think that consumption will grow too," Gabrielli said.

Gabrielli attributed high oil prices to higher demand than supply and a tight balance between the two. "There is a large movement in the capital markets and a weakness of the US dollar, and so some are finding it hard to cope with price increases. There is also a shortage of refining capacity." He said price volatility will continue in the short term. ✦

Seismic to start in New Zealand's Great South basin

Consortia led by ExxonMobil Corp. and OMV AG are starting a new wave of exploration in New Zealand's Great South basin off the southern South Island. Water in the storm-tossed Great South basin is more than 900 m deep.

ExxonMobil and its partner Todd Energy were to take delivery of WesternGeco's Western Trident seismic vessel in late November to begin shooting 960 km of 2D and 1,340 sq km of 3D surveys on PEP 50117. This initial phase of a 27-month exploration campaign on the permit should be completed by February 2008.

ExxonMobil also will reprocess some 1,200 km of existing seismic and complete a range of geological and geophysical studies to determine the oil and gas potential of the virtually virgin acreage. The initial phase is expected to cost as much as $37 million. If successful, it could lead to a drilling program in 2009-10.

ExxonMobil holds 90% interest in the permit, and Todd holds 10%.

OMV is operator on three new permits—PEPs 50119, 50120, and 50121—with a 36% interest. Other interest holders are Mitsui Exploration of Japan 36% and PTTEP Offshore Investment Co. of Thailand 28%.

The Discoverer 2 seismic vessel is to begin work for OMV in December. Preparatory work suggests the potential for structures capable of holding many trillion cubic feet of gas and more than 100 million bbl of oil, OMV said.

Hunt Petroleum attempted to explore the region during 1976-84 and found hydrocarbons in four of eight wildcats, but nothing of commercial size at that time (see map, OGJ, July 19, 1999, p. 78). ✦

Argentina

An exploration well appears to have established continuity between the north and central lobes of Puesto Morales Norte field in the Nuequen basin, said Petrolifera Petroleum Ltd., Calgary.

The PMN 1038 well tested light oil at a rate of 1,500 b/d from the Jurassic Sierras Blancas formation and is expected to go on production at 500-1,000 b/d.

The company said it commissioned a pipeline capable of 35 MMcfd with compression from the field to Medanito that is likely to ship 10 MMcfd initially. The flow will include associated gas and some nonassociated gas from the Cretaceous Loma Montosa and Sierras Blancas formations.

The PMOx-1001 well recently tested 2.3 MMcfd of gas and 20 b/d of condensate on a 14-mm choke near the western boundary of the Puesto Morales concession. The 1007 well in Puesto Morales Sur field, to be dually completed, tested more than 1 MMcfd from a basal Loma Montosa zone and oil from Loma Montosa Zone 10.

Colombia

The Colombian unit of Cia. Espanola de Petroleos SA (Cepsa) plans to take a farmout of a 50% interest in the Garibay block in the Llanos basin from Solana Resources Ltd., Calgary.

Cepsa Colombia SA will fund 100% of the costs associated with the block's third phase exploration well, which must be drilled by October 2008, subject to an E&P contract with Colombia's ANH. Solana shot extensive 3D seismic in early 2007.

Solana said the farmout furthers its exploration strategy to concentrate on the five contiguous blocks it operates in the eastern Llanos—Guachiria, Guachiria Norte, Guachiria Sur, Colona, and San Pablo—and the operated Catguas block in the Catatumbo basin.

EXPLORATION & DEVELOPMENT

Georgia

Schlumberger will ship equipment needed for a hydraulic acid-frac of the Manavi-12 well to former Soviet Georgia from four countries by mid-January 2008, said CanArgo Energy Corp., Guernsey, Channel Islands, UK.

M12 was drilled to appraise the Manavi Cretaceous carbonate oil discovery. The M-11 discovery well cut more than 490 ft of hydrocarbon-bearing limestone reservoir and found 34.4° gravity oil (OGJ Online, Mar. 1, 2005).

New Zealand

Grande Energy, Fort Worth, was awarded PEP 38527 covering 11,800 sq km mostly off the west coast of New Zealand's south island.

The acreage lies between Haast and Franz Josef Glacier and includes a narrow strip of land between them.

The work program calls for shooting 525 line-km of 2D seismic data in the first 2 years and shooting 3D seismic and drilling an exploration well by the fourth year.

Paraguay

Pantera Petroleum Inc., Austin, said it signed an exclusive share purchase agreement to acquire up to 85% of two companies that have 100% ownership rights in five concessions that cover 16,000 sq km in the Chaco basin in nonproducing Paraguay. Pantera did not identify the companies.

Four concessions are in the Curupayty subbasin and one is in the Carandayty subbasin. Only 27 wells have been drilled in the two subbasins in Paraguay.

Pantera said it is seeking to acquire all available data on the concessions. It is in discussion with seismic firms to reprocess 900 km of 2D seismic data and later plans to shoot about 1,000 line-km of new 2D data on the acreage.

Syria

The president of Syria signed parliament's ratification of the exploration, development, and production contract that governs Block 9, said Loon Energy Inc., Calgary.

The block covering more than 10,000 sq km is on the northern edge of the Homs basin, which contains the large Palmyra, Cherrife Da, and Ash Shaer fields.

Loon has committed to shoot 600 line-km of 2D seismic and drill two exploration wells in the 4-year first exploration phase. The phase can be extended for up to 9 years in phases by performing further work.

Loon has 100% interest in Block 9, and Ansco Inc. has the right to acquire a 5% working interest subject to approval of the ministry and Syrian Petroleum Co.

British Columbia

Nexen Inc. said it has secured 123,000 acres of land with 100% working interest in an emerging Devonian shale gas play in Northeast British Columbia.

The area has the potential to be one of the most significant shale gas plays in Canada, the company said.

Nexen in 2008 plans to complete and test two vertical wells it drilled last winter and drill and complete three horizontal wells. It will also drill two vertical wells on a second lease to acquire reservoir information.

Alaska

Fox Petroleum Inc., London, signed an agreement to acquire 100% working interest in 9,000 acres west of and adjacent to the BP-operated Badami Unit on the North Slope from D. Donkel and S. Cade.

Fox plans to run a technical appraisal of the acreage with hopes of defining at least one well location for drilling in the 2008-09 season.

The 9,000 acres is also north of the Anadarko Petroleum Corp.-operated Jacobs Ladder Unit, formed in October 2005 over an oil prospect in the Wahoo formation of the Pennsylvanian-Mississippian Lisburne Group and the overlying Permian Sadlerochit (Ivishak formation).

Arizona

Enhanced Oil Resources Inc., Houston, let a contract to Forster Drilling Corp. to drill 10 wells in St. Johns helium/carbon dioxide field in Apache County, Ariz., and Catron County, NM.

The rig is to begin work in mid-December 2007. The wells are designed to finalize reserves estimates and production characteristics (OGJ, May 28, 2007, p. 41).

Texas

Southwest

Consulting engineers listed a best estimate of 7.24 billion bbl of contingent resources potentially recoverable from the Cretaceous San Miguel tar sands in discovered accumulations in the Maverick basin, said TXCO Resources Inc., San Antonio.

The best estimate of the potentially recoverable volume attributable to TXCO's working interest is 635 million bbl, the company added. TXCO operates two pilot projects with 50% working interest.

These resources are neither currently nor may ever become economic and cannot be considered as proved reserves, the company cautioned. Their recovery could depend on the development of new technology.

TXCO, which has raised the bottomhole temperature at one pilot project to 365° F. after three steam cycles and is starting a fourth cycle. More steam generation equipment for an expansion of the pilot using horizontal wells is to be delivered by mid-January 2008.

UNCONVENTIONAL GAS TECHNOLOGY—1

Advances in fracs and fluids improve tight-gas production

Glenda Wylie
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Houston

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Only 10 years ago, unconventional gas was an emerging resource; now it's a core business of many large independent producers and a growing number of major operating companies. Twenty years ago, it was largely overlooked.

However, gas companies were developing "hard rock" resources in the 1970s-1990s rather than tight gas resources. While they needed hydraulic fracturing, the resources' permeabilities were higher and we focused on the rock. Now we focus on unlocking the gas that is tightly bound in lower permeability resources.

Unconventional gas reservoirs are found worldwide, including onshore US, Canada, Australia, Europe, Nigeria, Russia, China, and India.

Unconventional gas production in the US reached a peak of 24 bcfd (8.6 tcf/year) in 2006, up from 14 bcfd (5.0 tcf/year) 10 years ago. With a 43% share, it is now the dominant source of natural gas production.[1]

Tight-gas reservoirs, shale, and coalbed methane assets are the main sources of what is generally known as unconventional gas. Their flow mechanisms increase in complexity from Darcy flow to Fick's diffusion flow mechanisms and combinations of a variety of other mechanisms.

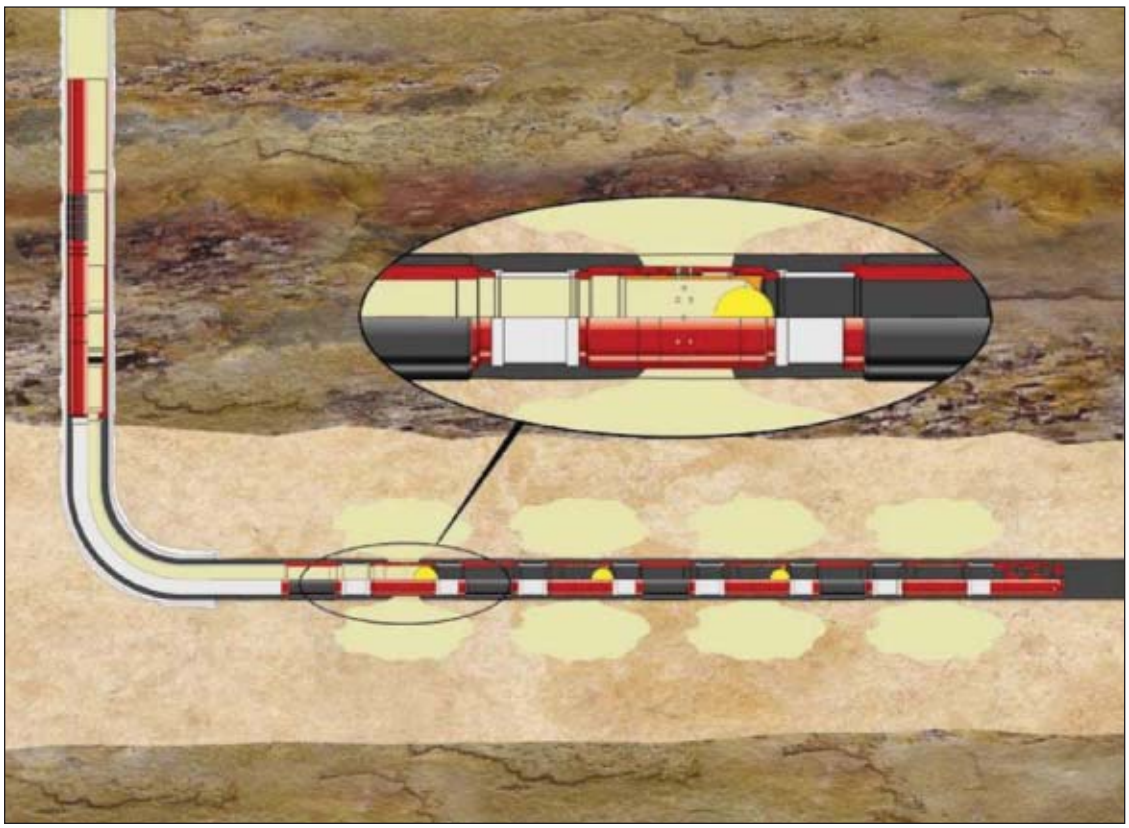
Nothing regarding the drilling, completion, or production can be automatically assumed in these reservoirs. They require increased geological understanding and precision engineering all within a quicker time frame and often within a higher well count development.

This three-part series presents technologies and methods found to be effective in the profitable production of unconventional gas. These technologies have resulted in production increases of up to 100% in some fields, reductions in associated costs up to 25%, and reduction in nonproductive time losses of more than 30%. The second part of the series, to be published next week, addresses shale gas technologies. The concluding part, to be published in January, presents technologies to produce coalbed methane.

Tight gas drilling

Drilling for tight gas requires optimized drill bits, horizontal drilling equipment, and specialized fluids.

- ***Drillbits.*** Analyses with input from seismic data, formation evaluation logs, geomechanical studies, and exploratory drill cuttings have resulted in specially designed bits for the particular unconventional resource (tight gas) with a new generation of PDC cutters that have improved the rates of penetration as much as 118% above previously used bit technology.
- ***Horizontal drilling.*** Much of the unconventional gas resource profitability is based on exposing more formation through horizontal drilling. Until recently, rotary steerables have been available primarily to the offshore market due to cost. New simplified rotary



Multizone completion system swellable packer systems isolate various zones of a horizontal, openhole wellbore. All zones are stimulated in a single trip of the treating string. In this uncemented, openhole example, the ball-drop method was used to operate the completion system (Fig. 1).

steerable designs allow for a smooth borehole making formation evaluation acquisition easier and better.

• **Fluids.** Drilling in unconventional reservoirs often presents lost circulation problems that some special technologies can address. For instance, high-performance, clay-free invert drilling fluids are available that can be formulated with a wide variety of base oils, including diesel, internal olefin, ester-olefin blends, and paraffin or mineral oil.

The emulsion-based gel structure of the fluid helps eliminate barite sag, a serious issue often encountered with invert clay-based systems. Further, these fluids help reduce whole-mud losses by 41% on average, decreasing well costs and nonproductive time. The wide selection of base oils provides operators with options for minimizing environmental impact, conserving costs, and making use of readily available regionally acceptable base oils.

The rheology of this system is managed through application of new emulsifiers and additives that replace conventional organophilic clays and lignite. The interaction of components in these clay-free systems is a key to providing a robust yet fragile gel structure. The gel strength develops rapidly to provide excellent suspension but is easily disrupted when circulation is initiated, even at very low pressures. This helps minimize or eliminate the pressure spikes that typically occur when breaking circulation with invert clay-based fluids.

Other benefits of the clay-free fluid systems include:

• Improved control over equivalent circulating density.

• Increased tolerance to contaminants, including solids and water.

• Smaller footprint on drillsite with fewer additives required for maintenance.

• Real-time response to chemical treatments—no waiting for "yield."

• Thin filter cake and excellent return permeability values.

Reserves optimization

Optimizing development of tight gas sands can be difficult due to characteristically low permeability (<0.1 md) and abnormal pressures. The complexities are both technical and economic. Unconventional reservoirs, in general, require higher capital expenditure compared with conventional reservoirs, and profitable production rates are in most cases achieved by hydraulic fracturing of pay zones.

The perfect fracturing job consists of an inexpensive, long fracture with infinite conductivity, 100% propped, 100% effective length, and precisely contained in the pay zone with 100% fluid recovery. Realistically, however, we know that a tight, gas-bearing zone faces abnormal pressure, low permeability, clay swelling and migration, capillarity effects (capillary action), near-wellbore restrictions, and formation complexity and heterogeneities. These characteristics usually contribute to damage during drilling and cementing operations, water-phase trapping, screenouts, limited proppant advancement into the reservoir, dehydrated polymer, and other problems.[2]

The performance of tight-gas reservoirs cannot be predicted with traditional reservoir evaluation and stimulation methods. While tight-gas reservoirs do require a high density of wells, drilling may result in a number of marginal

or poor-performing wells.

To optimize returns on tight-gas assets, the primary objectives should be to strive for overall asset efficiency in drilling, stimulation, logistics, field surveillance, and operations, and to provide predictable delivery to maximize well rates and ultimate recovery.

An integrated asset model can help exploration and production companies achieve these objectives by integrating all aspects of tight-gas development, including petrophysics, fracturing, production, drilling, scheduling, facilities, and economics. The model provides a complete set of investment scenarios defining better well efficiencies and the means to optimize supply-chain efficiencies.[3]

Well completions

Optimized well completions in tight gas formations require several steps:

1. Set realistic expectations. It is important to understand the limitation of a tight-gas formation and its capability to produce. The low permeability of the formation dictates that we increase the flow area deep into the formation to get economical production.

2. Get better reservoir characterization. Reliable optimization of completion requires better knowledge of the reservoir properties. Reservoir properties include not only the physical properties of the rock, but also its mechanical properties.

These properties may be obtained from the following sources:

- Well tests, logging, and core data.
- Production analysis of offset well.
- Stress-field measurements.
- Understanding of reservoir fluid properties.
- Study of the various completion strategies.

3. Set optimization criterion or criteria (may include production and economic criteria).

4. Define parameters that affect the optimum design, including reservoir properties, and fracture geometry, conductivity, and height.

5. Achieve realistic modeling, a key to optimization of completion.

Fig. 1 illustrates a multizone completion featuring swellable-elastomer packer systems isolating various zones of a horizontal wellbore.

Hydraulic fracturing

Unconventional (tight), continuous-type reservoirs, such as those in the Cretaceous of the northern Great Plains, are not well suited for conventional formation evaluation. Pay zones frequently consist only of thinly laminated intervals of sandstone, silt, shale stringers, and disseminated clay. Potential producing intervals are commonly unrecognizable on well logs and thus are overlooked.

To aid in the identification and selection of potential producing intervals, Hester developed a calibration system that empirically links the gas effect to gas production. The calibration system combines the effects of porosity, water saturation, and clay content into a single gas-production index that suggests the production potential of different rock types. The fundamental method for isolating the gas effect for calibration is the interpretation of a crossplot of neutron porosity minus density porosity vs. gamma-ray intensity.[4]

The geomechanical effect on reservoir performance should always be considered, especially when producing from thick formations or creating multiple fractures in horizontal wells.

Recovering fracturing fluids is often difficult in underpressured, tight, deep formations. CO_2, N_2, and binary high-quality foams are widely used in this type of reservoir because of their capacity to energize the fluid and improve total flowback volume and rate. CO_2- and N_2-assisted (foam) fracs are also believed to allow less water to reach the formation matrix and, with their superior proppant-transport properties, allow use of far less gel.

Reducing gel volume decreases the amount of gel likely to be left behind in the propped fracture; the result is believed to be greater conductive fracture half-length. The foam fracture fluid is full of energy and begins to flow back to the surface readily when fracture pumping has ceased. The energized fluid is especially helpful in promoting frac-fluid flowback where formations are depleted and have lost significant pore pressure due to production.

Surfactants designed to reduce surface and interfacial tension are also key elements in the design of fluid systems to enhance recovery and reduce entrapment of fluid barriers within the formation. Enhanced fluid recovery improves overall completion economics due to the lower total treatment cost and shorter time required for flowing back fluids. The most important benefit is achieving a less-damaged proppant pack, resulting in higher fracture conductivity.

"To optimize returns on tight-gas assets, the primary objectives should be to strive for overall asset efficiency in drilling, stimulation, logistics, field surveillance, and operations, and to provide predictable delivery to maximize well rates and ultimate recovery."

Fracturing horizontal wells

Fracturing horizontal wells is the most promising production-enhancement technique in some formations. Fracturing in general is the more attractive completion option. It is even more attractive than multilateral completions, especially in tight, thick formations. In general, horizontal lateral wells have to be fractured to improve the economical outlook of the well. The geomechanical effect on reservoir performance should always be considered, especially when

producing from thick formations or creating multiple fractures in horizontal wells.

Hydraulic-fracture stimulation can improve the productivity of a well in a tight-gas reservoir because a long conductive fracture transforms the flow path natural gas must take to enter the wellbore.

After a successful fracture stimulation treatment, natural gas enters the fracture from all points along it in a linear fashion. The highly conductive fracture transports the gas rapidly to the wellbore. Later, the gas in the reservoir is flowing toward an elliptical pressure sink and most of the gas enters near the tip of the fracture.

Conventional wisdom in designing hydraulic-fracture treatments for tight-gas sands suggests that successful stimulation requires creating long, conductive fractures filled with proppant opposite the pay zone interval. This is accomplished by pumping large volumes of proppant at high concentrations into the fractures, using fluids that can transport and uniformly distribute proppant deeply into the fracture.[5]

SurgiFrac

Combined hydrajetting, fracturing, and jet-pump (CHF) technology is the first known successful method to resolve the problem of openhole fracture placement control by using dynamic diversion techniques. The technique (SurgiFrac) is a combination of three separate processes: hydrajetting, hydraulic fracturing (through tubing), and coinjection down the annulus (using separate pumping equipment).

One important aspect of this technique is the dynamic sealing capability. Unlike other techniques that require hardware-type packers or plugs, or even chemical plugs, this process essentially relies upon sealing by using fluid movement. Because packers are not used in most cases, the existence of passageways behind liner or through fractures rarely affects the performance of this process.

The technique is based primarily on the Bernoulli principle, which states that the energy level of a fluid is generally maintained constant. To perform the SurgiFrac service, a jetting tool is placed near the toe of the well and used to jet-perforate the casing and the formation rock, forming a 4-6-in. deep cavity.

Based on the Bernoulli equation, as pressurized fluid exits the jetting tool the pressure energy is transformed into kinetic energy or velocity. Since the fluid velocity around the jet stream is at its greatest, pressure in this area is at its lowest, meaning the fluid does not tend to "leak" out somewhere. Conversely, fluid from the other areas of the well will flow into the jetted area.

The fluid generally contains some abrasives to help the fluid penetrate the steel liner and the formation rock. As cavities are formed by each jet, high-velocity fluid impacts the bottom of the cavity (e.g., velocity becomes zero, an energy change from kinetic back to potential energy or pressure), causing pressure inside the rock to become high enough to create a fracture. Annulus pressure is then increased to help extend the fracture.

After the fracturing process is completed, the tool is moved to the next fracturing position and another fracture is placed.

The conversion of low-pressure, high-velocity kinetic energy to high-pressure, low-velocity potential energy is extremely useful for fracture initiation and fracture placement. The breakdown pressure in a conventional treatment requires a tensile failure of the rock achieved by pressuring up the entire wellbore.

Because, in most cases, fracture initiation pressure is much higher than fracture extension pressure, achieving multiple fracture initiation points along a horizontal wellbore requires achieving multiple fracture initiation pressures. This is very difficult in practice without some form of isolation along the wellbore.

Since the energy of the jetting fluid is converted to pressure inside the eroded rock, the tensile failure of the rock occurs at the jetting point without exposing the wellbore to breakdown pressures. This enables precise control of the location of fracture initiation in the horizontal section. Multiple fractures can be created by simply moving the jetting tool to another location in the lateral and using hydrajet fracturing.

Another attribute of the hydrajetting fracturing process is the creation of a dominant fracture through continued hydrajetting during fracture extension. As the fracture grows in width, the net pressure increase resulting from fracture extension induces stress normal to the direction of the fracture propagation; i.e., reopening previous fractures becomes more difficult due to the increased stress induced by the dominant fracture.

The SurgiFrac service has been applied successfully in a variety of fracturing conditions:

- Multiple propped fractures in open hole.
- Multiple acid fractures in open hole.
- Deviated cased hole.
- Horizontal slotted liner.
- Coiled-tubing acid-frac to bypass damage.
- Multiple fractures in a cased horizontal wellbore.

A case history illustrates the utility of the multizone fracturing method. The first subsea CHF fracture stimulation was in 1,000 ft of water in Brazil's Campos basin. Because the stimulated well had two branches (abandoned due to drilling problems), it behaved like a triple lateral for stimulation design. The treatment resulted in five acid fractures, completed in 2.5 days.

Production rate for the first 15 production days following the treatment was almost double the maximum historical rate of this well and almost four times the monthly production rate during the months preceding the SurgiFrac. As a result of this treatment and two other treatments for proof-of-concept, a major international company has approved SurgiFrac service for all its scenarios—land, offshore, and subsea—worldwide.

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As our industry confronts new challenges, it has never been more important to submerse yourself in them. This year's theme is "Subsea is here, the game is changing." As our game changes, the sharing of knowledge and collective experiences becomes more and more crucial to improving the quality, safety, and economics of the subsea tieback industry.

The conference board will once again solicit a number of key presentations by industry leaders. As in the past, only by participating in this conference will you be able to receive its benefits, as proceedings will not be published and no Press is ever allowed in the conference area. This is truly a closed forum with open discussion, where the information shared inside the conference room stays inside the conference room. We hope you will join us.

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Microemulsion surfactants

If the formation permits, often water-based hydraulic fracturing is carried out in tight gas formations. Traditionally, they have not been as optimally effective as they could be due to water blocking.

A microemulsion surfactant (MS) has the potential vastly to increase the world's recoverable reserves of natural gas from tight-gas reservoirs by helping control fracture-face damage and boosting production from these difficult formations.

The special surfactant was designed to replace methanol or conventional surfactants. Based on new microemulsion technology GasPerm 1000, the surfactant helps remove water drawn into the formation during the fracturing process. Desaturating water and removing phase trapping can improve inflow of gas from the fracture face and help increase gas production.

Tight-gas reservoirs (as well as coalbed methane and shale formations) typically have low production due to low permeability and-or low reservoir pressures. The low permeability of these formations creates a capillary effect, in which water can be drawn or "imbibed" into these tight formations during fracturing treatment.

The low reservoir pressures do not create enough flow for the gas to displace the liquid from the formation. Phase trapping can occur, in which the liquid becomes trapped within the low-permeability formation at the fracture face, and the gas cannot displace it. This trapped liquid can inhibit production-gas flows.

Using a microemulsion surfactant can specifically mitigate fracture-face damage caused by capillary effects and phase trapping. The surfactant can also enhance phase displacement and spatial flow behavior and help enhance mobility if liquid hydrocarbons are present.

This can help increase recoverable gas and improve well economics by:

1. Increasing actual production rates.
2. Increasing recoverable reserves.
3. Shifting projects above the economic threshold.
4. Extending lifecycle of wells.

The microemulsion additive is more effective at much lower concentrations than methanol, significantly reducing the volume required during fracturing treatment. It is a less flammable alternative to methanol-based fracturing fluids, thus improving safety and reducing environmental risk.

The MS additive is compatible with both acidic and basic fluid systems and can be used as an acidizing additive or a fracturing fluid additive. The range of applications for this product continues to expand. MS service has been used in reservoirs with matrix gas permeability as low as the nanodarcy permeability range.

"Desaturating water and removing phase trapping can improve inflow of gas from the fracture face and help increase gas production."

Two case studies illustrate the effectiveness of this technology:

- Ten horizontal shale wells in Oklahoma were recently completed with massive slickwater fracturing. Four of these wells were fractured with MS service and six wells did not have the MS treatment.

Using MS, early load recovery improved by 43%. The surfactant reduced water saturation and capillary pressures along the fracture faces, which improved relative permeability to gas. The wells treated with MS had initial gas production rates comparable to the best wells in the field.

- A Cotton Valley tight-gas sand in East Texas was fracture-stimulated with microemulsion surfactant. The well produced more than 14 times the wellhead pressure (100 psi vs. 1,400 psi) and almost doubled the initial production rate (862 Mcfd vs. 1,432 Mcfd) compared to a conventionally treated offset well.

Refracturing

Hydraulic fracturing, especially in a horizontal well, is probably the best way to complete a well in a tight-gas formation. Fracture performance often declines with time, however.

Reasons for performance degradation include:

- Loss of fracture conductivity near the wellbore due to embedment.
- Degradation of proppant with time and stress.
- Loss of fracture height with time.
- Loss of fracture length caused by degradation of proppant.
- Loss of fracture conductivity from fines migration.
- Loss of formation permeability near the fracture, forming a barrier.
- Entrapment of liquid around the fracture face by capillary force. This effect may be aggravated by fluid loss during drilling and fracturing and by later movement of fines. This may be of special importance in tight-gas formations where a very high capillary pressure may be expected in cases having a water phase.

Refracturing can expose more reservoir area to the high-conductivity fractures, thus improving well productivity and reservoir exploitation. ✦

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Model proposed for world conventional, unconventional gas

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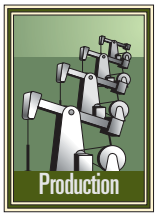


A long-term conventional and unconventional natural gas production model has been developed for the world.

This model estimates world natural gas production to peak in 2043. World conventional natural gas production will peak in 2038, and world unconventional natural gas production peaks in 2060.

World demand and supply for natural gas begin to diverge around 2030.

Unconventional gas reserves cannot significantly delay the peak in natural gas production. If methane hydrate estimates continue to decline, then hydrates will have no significant impact on world natural gas production.

Ultimately natural gas supplies will be adequate for the next 2 decades, but further research is needed to implement alternative sources of energy for the future and to ensure a smooth transition.

Definitions

Natural gas is a mixture of hydrocarbons that are gaseous at atmospheric conditions.[1] Conventional natural gas is located in porous permeable reservoir rock and produced with standard producing methods. Unconventional natural gas is any natural gas that is not conventional and, in particular, can include coalbed methane, tight gas, shale gas, methane hydrates.

Tight gas is generally considered natural gas located in sandstone reservoirs with permeabilities less than 0.1 md.[2] Shale gas is natural gas for which the source and reservoir is organic shale. Coalbed methane is produced from coal seams.[3] Methane hydrates consists of natural gas trapped in solid water (ice).[4]

Natural gas, discussed as such, includes both convention and unconventional natural gas. This article will model for the next 100 years the world's conventional and its unconventional natural gas, the latter including gas from shale, tight gas, and coalbed methane. Natural gas from methane hydrates is excluded from the current analysis due to the lack of meaningful data.

Previously we modeled natural gas production for North America,[5] and here we will extend to the rest of the world. Due to limited LNG transportation worldwide, we will analyze conventional natural gas on a regional basis.

Unconventional gas production is analyzed on a world basis due to the limited data currently available in the literature. The same modeling approach mentioned above is used, but the coalbed-methane production model is modified. The new model is described in detail below.

The combined natural gas production model required only two inputs: an estimate of ultimately recoverable resources (URR) and historic production data. Initially we will approximate a conventional natural gas URR value for various world regions. Next we will determine unconventional natural gas URR estimates for tight gas, shale gas, and coalbed methane for the world.

An explanation of the coalbed meth-

LITERATURE, ASSUMED CONVENTIONAL URR ESTIMATES

Table 1

Region[1]	URR estimate, tcm — Laherrere[2]	Rempel[3]	Assumed value	Comments on assumed value
North America	42.0	63.0	42.5	From previous article[4]
South America	23.0	23.0	23.0	Average of Laherrere and Rempel's estimate
Europe	23.0	25.0	24.0	Average of Laherrere and Rempel's estimate
Asia	33.0	43.0	38.0	Average of Laherrere and Rempel's estimate
Africa	23.0	28.0	28.0	Rempel's estimate used, based on the creaming curve data from Laherrere
Middle East	85.0	109.0	97.0	Average of Laherrere and Rempel's estimate
FSU	57.0	175.0	93.0	Calculated from government figures, scaled downward with literature estimations[5]
Total	**283.0**	**467.0**	**346.0**	

[1]North America includes only US and Canada; South America includes Mexico; Europe includes Greenland; more detail on the FSU assessment is given in the text. [2]Reference 9. [3]Reference 13. [4]Reference 5. [5]References 14, 16, and 17.

ane model will be given. A model of natural gas demand for the future will be explained. The models of natural gas demand and supply will then be presented and discussed. Finally a conclusion and note of caution will be stated.

Conventional URR

A conventional natural gas URR estimate needs to be determined for the conventional natural gas production model; literature estimates 208-467 trillion cu m (tcm).[6-13]

Guseo,Imam,and Al-Fattah calculate world conventional natural gas URR estimate from mathematical and statistical models.[6-8] Campbell, Sandrea, and the US Geological Survey estimate conventional natural gas URR for the world only, although Sandrea calculates conventional natural gas URR for some countries as well.[10-12]

Laherrere estimates the conventional natural gas URR on a regional basis,[9] whereas Rempel's estimate is calculated for every country.[13] Laherrere's conventional natural gas URR estimate is based on creaming curves. Rempel has determined conventional natural gas URR estimate as produced + reserves + yet-to-find.

The conventional natural gas URR estimate was limited to estimates that were determined geologically and where the estimate was broken into regions. Hence only Laherrere and Rempel's conventional natural gas URR estimates were used.

Laherrere's estimate of 283 tcm is low, and Rempel's estimate of 467 tcm is high, relative to literature estimates range. While Laherrere and Rempel have significantly different world conventional natural gas URR estimates, their conventional natural gas URR estimates agree for many regions. Table 1 shows the conventional natural gas URR estimate that is assumed in this article.

FSU estimate

The estimated FSU conventional natural gas URR value (Table 1) was determined as follows: We first attempted to approximate the Russia conventional natural gas URR, obtained from the mid 1990s and then used the same technique to determine the FSU conventional natural gas URR.

In 1998 Russia had produced about 11 trillion cu m of conventional natural gas.[14 15] In 1998, typical conventional natural gas reserve estimates for Russia were around 47 tcm.[16]

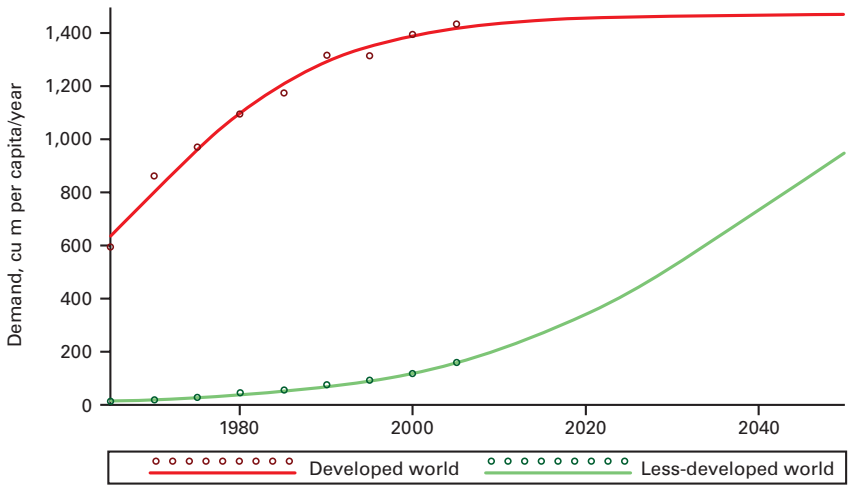
Hirschhausen has estimated Russian conventional natural gas reserves by looking at individual fields and indicates reserves are 18-20 tcm.[16]

Are the Russian conventional natural gas estimates from Hirschhausen valid? Some Russian conventional natural gas fields have been analyzed by Laherrere, who plots annual production vs. cumulated production for a conventional natural gas field and, by extrapolating, approximates the field's URR.[9]

Laherrere's estimate of conventional natural gas reserves for Orenburg and Medvezhye gas fields relative to 1998 is about 0.5 tcm for both fields, which is slightly less than Hirschhausen's estimate of 1 and 0.6 tcm, respectively, for these fields.

NATURAL GAS DEMAND

Fig. 1



FSU CONVENTIONAL GAS RESOURCE DATA*

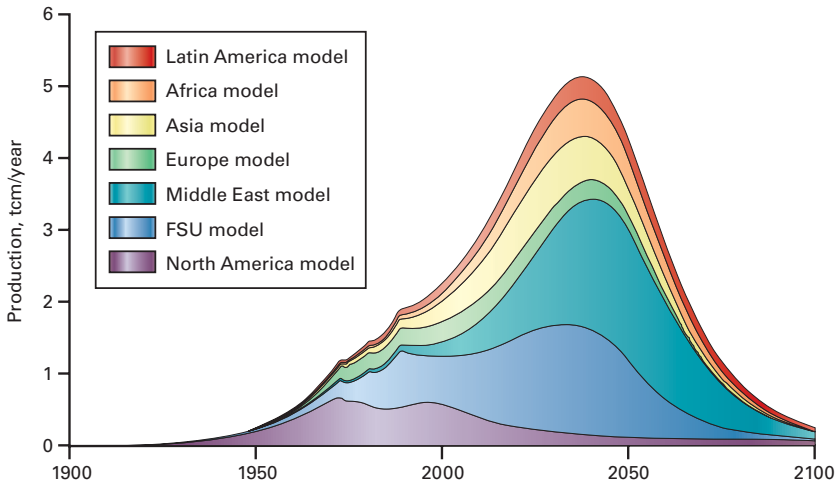
Table 2

Region	Cum. prod.	A+B+ C_1	C_2	C_3	D_1	D_2	C_3+ D_1D_2	I.R.P.
Total Russian Federation	7.05	48.0	13.3	28.6	46.6	68.2	143.5	211.7
Total onshore	7.04	45.5	11.2	19.2	38.0	38.4	95.6	159.3
Total offshore	0.01	2.5	2.1	9.4	8.6	29.8	47.9	52.4
West Siberia	4.89	38.6	9.1	17.8	32.7	18.3	68.8	121.4
Onshore	4.89	38.4	8.6	10.4	26.5	6.3	43.2	95.1
Offshore	—	0.2	0.5	7.4	6.2	12.0	25.6	26.3
East Siberia & Far East	0.13	2.5	1.4	4.1	8.5	39.4	52.0	56.0
Onshore	0.13	2.0	1.2	3.9	7.9	28.8	40.6	43.9
Offshore	—	0.5	0.2	0.2	0.6	10.6	11.4	12.1
European Russia	2.03	6.9	2.8	6.7	5.4	10.5	22.7	34.3
Onshore	2.02	5.1	1.4	4.9	3.6	3.3	11.8	20.3
Offshore	0.01	1.8	1.4	1.8	1.8	7.2	10.9	14.0
Turkmenistan	1.3	2.8	0.9	—	—	—	8.4	13.4
Kazakhstan	0.1	1.8	0.1	—	—	—	8.5	10.5
Uzbekistan	0.9	1.9	0.1	—	—	—	3.4	6.3
Ukraine	1.5	1.1	0.3	—	—	—	3.5	6.4
Other FSU	0.3	0.1	0.1	—	—	—	1.9	2.4
Total FSU	**11.15**	**55.7**	**14.8**	**—**	**—**	**—**	**169.2**	**250.7**

*Reference 14; original source N.N. Nemchenko and V.I. Staroseisky. Data for the Russian Federation are as of Jan. 1, 1992. Data for the other FSU countries are as of Jan. 1, 1991. Separate data on C_3, D_1, and D_2 resources for the FSU countries outside of Russia are not available. Totals may not sum due to rounding. I.R.P. initial recoverable potential (sum of cumulative production and all resource categories).

WORLD CONVENTIONAL GAS PRODUCTION

Fig. 2



The low estimate of 18 tcm for conventional natural gas reserves from Hirschhausen has therefore been chosen. The Stockman and Yamal conventional natural gas fields are currently uneconomic and hence do not meet the definition of reserve.[16] Ignoring the Stockman and Yamal fields, Russian conventional natural gas reserves have decreased from 34.8 tcm to 18 tcm, or approximately halved. We will therefore assume that half of the Stockman and Yamal fields' values is accurate, and hence a further 6 tcm is added as stranded and uneconomic gas.

We now require an estimate of conventional natural gas still to be discovered in Russia. Table 2 shows the FSU conventional natural gas URR statistics, based around 1991-92.[14]

In Table 2, $A+B+C_1$ is generally regarded as conventional natural gas reserves, although Hirschhausen shows this to be an overestimate. The C_2 value is generally referred to as probable conventional natural gas reserves.[17] A 50% reduction in the C_2 value is typically assumed; hence we will assume 6.7 tcm of C_2 is extractable for Russia.

Grace states that $C_3+D_1+D_2$ values were "subject to considerable exaggeration."[14] The stated $C_3+D_1+D_2$ value for onshore West Siberia is 43.2 tcm, whereas other assessments indicate it is around 8-15 tcm.[14] This is about a quarter of the stated value.

We will therefore assume that only a quarter of the $C_3+D_1+D_2$ value is valid for Russia; hence a value of 36 tcm will be assumed for the total Russia $C_3+D_1+D_2$ value. The conventional natural gas URR for Russia is then estimated at about 78 tcm. The rest of FSU has produced 4.1 tcm of gas by 1991.[14]

Assuming similar reductions used for Russia are valid for the rest of FSU, then $A+B+C_1$ and C_2 are reduced by 50% to 3.9 tcm and 0.8 tcm, respectively, and $C_3+D_1+D_2$ reduced by 75% to 6.4 tcm. Hence, the rest of FSU has a conventional natural gas URR of about 15.2 tcm, and FSU has a conventional natural gas URR of about 93 tcm.

The conventional natural gas URR for FSU was estimated at 57 tcm and 175 tcm by Laherrere and Rempel, respectively. The FSU data require a detailed independent assessment by geologists before the error in estimate can be reduced.

Unconventional URR

An estimate of the unconventional natural gas URR is needed for the models. There has been limited work in the literature on unconventional gas URR estimates for the world.

For this reason the unconventional models will be determined on a world basis rather than on a regional basis. Table 3 shows the world unconventional natural gas URR estimates that are assumed for the models.

CBM estimate

The coalbed methane URR estimate was determined by estimating the worldwide coalbed methane resource and by then determining a reasonable recovery factor. Table 4 shows the numerous resource estimates for coalbed methane.

It is important to note that the only regions with significant coalbed methane resources are North America, FSU, and Asia. North American coalbed methane URR estimate was determined previously to be around 10 tcm.[5] Table 4 shows the coalbed-methane resource estimates that have been assumed for this article.

Typical coalbed-methane average recovery estimates range 20-33%;[18-20] we will assume a 25% recovery factor. Based on resource

WORLD UNCONVENTIONAL URR: LITERATURE ESTIMATES, ASSUMED VALUES

Table 3

Type	URR, tcm: Laherrere[1]	Sandrea[2]	Rempel[3]	Assumed value	Comments
Tight			91	91	Using Rempel's estimate as it's the only known estimate
Shale	[4]28	7		28	Previous estimate North America has 7 tcm; hence used Laherrere's estimate
CBM	8.5-11	15.6	144	62	• Resources estimated from literature[5] • Assumed 25% recovery factor • North American estimate from Mohr and Evans[6]
Total	**57**			**181**	

[1]Reference 9. [2]Reference 11. [3]Reference 13. [4]Resource estimate; Laherrere notes that there is significant uncertainty in the value. [5]References 21-23. [6]Reference 5.

estimates found elsewhere[21-23] and on a 25% recovery, we estimate a URR of 62 tcm for coalbed methane (Table 4).

CBM model

The production curve for coalbed methane is a parabola to the year x_d and beyond that the curve follows an exponential decay. Regression analysis is used to fit the parabola portion of the curve, expressed by Equation 1 (see accompanying equation box), to the data.

At the point (x_d, y_d), the model shifts into an exponential decay.

Equation 3 shows the coalbed methane production model M(x).

The point x_d (in Equation 3) is assumed is the point where $x_d - x_p / r_2 - x_p = 0.15$, which ensures the overall shape of the curve resembles the general coal bed methane production.24

Note x_p and r_2 are defined as shown in Equations 5 and 6.

In this way we make y_d a function of x_d. Lastly, x_d is solved so that the area under the curve matches the URR estimate.

Demand

Natural gas demand is modeled by analyzing demand per person and population forecasts. The population and natural gas consumption data are split into two groups, the developed world and the less-developed world.

The developed world consists of Europe, FSU, North America, Australia, New Zealand, and Japan, and the less-developed world consists of the rest. The natural gas consumption data were obtained from the BP Statistical Review,[15] and the historic and predicted population data were acquired from the UN World Population Prospects.[25]

Consumption was divided by the population to obtain a natural gas demand per average developed and less-developed person, and the data were fitted to the function shown in Equation 7, as shown in Fig. 1.

D(x) Equation 7 estimates demand per average person. Multiplying the demand per average person with the projected population from the UN yields the estimated worldwide demand for natural gas.

Models

Coalbed methane was approximated by the model described above, and the conventional North American model is from Mohr and Evans;[5] all other regions and gases have been approximated with the model from the literature.[26] In particular, both shale and tight natural gas production curves are expected to follow bell curves.

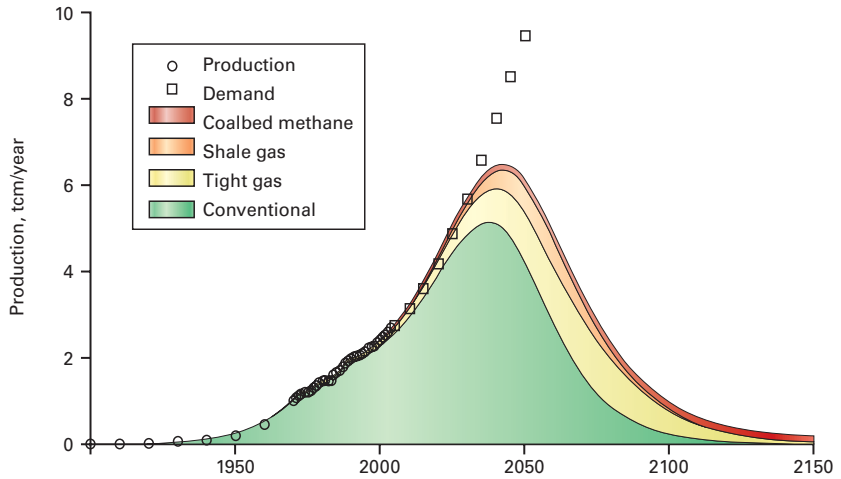
All models required only the historic production data and a URR estimate. Total natural gas production data were determined from BP, US Energy Information Administration, the Netherlands Environmental Assessment Agency, and DeGolyer and MacNaughton.[15 27-29]

Unconventional gas production was approximated from a variety of sources.[20 30-38] Conventional production was assumed to be total production less unconventional production. Fig. 2 shows the conventional gas model; Fig. 3 shows the conventional and unconventional gas production with demand. Table 5 shows the respective peak dates.

It is interesting to observe that, although the coalbed methane resource is significant, its production is relatively minor in comparison to other unconventional sources. It is uncertain why tight-gas resources have generally been overlooked and ignored, given the significant contribution they make. It has been assumed that shale and tight-gas production follow bell curves, and whereas coalbed methane follows a

WORLD GAS PRODUCTION, DEMAND

Fig. 3



WORLD CBM RESOURCE: LITERATURE, ASSUMPTION

Table 4

Region	Resource estimates, tcm: Aluko[1]	Boyer[2]	Scott[3]	Assumed value	Assumed URR, tcm	Comments
North America	17-87	15-88	27-124	NA	10	Estimate from Mohr and Evans[4]
FSU	20-116	[5]17-113	113-456	113	28	Highly uncertain; 25% recovery factor
Asia	[6]36-71	[6]39-49	18-95	85	21	25% recovery factor
Rest	10	13	6-10	13	3	25% recovery factor
Total	**85-283**	**84-263**	**170-680**	**NA**	**62**	

[1]Reference 21. [2]Reference 22. [3]Reference 23. [4]Reference 5. [5]Listed for Russia only. [6]China and Australia only.

different curve.

This assumption has been based on the historic production data from the US. The model indicates that worldwide natural gas production will peak around 2043. Conventional natural gas peaks about 5 years earlier. So that, while unconventional gas is an important source of energy, it can only slightly delay the inevitable decline. Natural gas supply begins to deviate from demand around 2030. It is noted that European production remains flat before steadily declining.

The current resource estimates for methane hydrates are about 1,000 tcm.[39] With an assumption of a 10% recovery factor, the methane hydrates URR would be about 100 tcm, which is about 20% of the natural gas URR estimate used in this article.

Methane hydrates resource estimates, however, are decreasing by an order of magnitude every decade.[39] In a decade, therefore, the methane hydrates URR may be about 10 tcm and only 2% of the natural gas URR estimated in this article. A model of methane hydrates is meaningless until the resource estimates of methane hydrates stabilize.

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Equations

$$M_p(x) = a(x - x_d)^2 + b(x - x_d) + y_d \quad (1)$$

$$M_e(x) = y_d \exp\left(b(x - x_d)/y_d\right) \quad (2)$$

$$M(x) = \begin{cases} 0, & x \le r_1 \\ M_p(x), & r_1 < x < x_d \\ M_e(x), & x_d \le x \end{cases} \quad (3)$$

$$r_1 = \frac{-b + 2ax_d + \sqrt{b^2 - 4ay_d}}{2a} \quad (4)$$

$$x_p = \frac{-b + 2ax_d}{2a} \quad (5)$$

$$r_2 = \frac{-b + 2ax_d - \sqrt{b^2 - 4ay_d}}{2a} \quad (6)$$

$$D(x) = \frac{y_{max}}{2}[\tanh(R(x - x_p)) + 1] \quad (7)$$

Natural gas model summary

Table 5

Region	Peak year	Peak production, tcm/year
Conventional		
North America	1973	0.66
South America	2036	0.31
Africa	2037	0.52
Asia	2028	0.72
Middle East	2045	1.90
FSU	2036	1.51
Europe	2016	0.32
World	**2038**	**5.12**
Unconventional		
Tight	2065	1.33
CBM	2085	0.17
Shale	2056	0.66
Total	**2060**	**2.10**
Gas total		
World	**2043**	**6.48**

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Syncrude upgrader revamp improves product quality

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Edmonton

As part of the Upgrading Expansion Stage 1 (UE-1) project completed in 2006, Syncrude Canada Ltd. revamped all existing five hydrotreaters and installed an additional diluent recovery unit, a fluid coker, and an aromatics saturation unit for light gas oil. The UE-1 project substantially increased production capacity and improved product quality, such as diesel cetane number and jet fuel smoke point.

This article reviews Syncrude's operations after the UE-1 revamp and presents a monitoring tool for diesel cetane number and jet fuel smoke point, and its application to the commercial plant.

In the past, Syncrude distilled bitumen in two diluent recovery units and a vacuum distillation unit, and upgraded in two fluid cokers and one ebullating bed hydrocracker, followed by five hydrotreaters.

Based on a presentation to the Oil Sands and Heavy Oil Technologies Conference, Calgary, July 18-20, 2007.

Syncrude

Syncrude Canada Ltd. is a joint venture owned by seven participants:

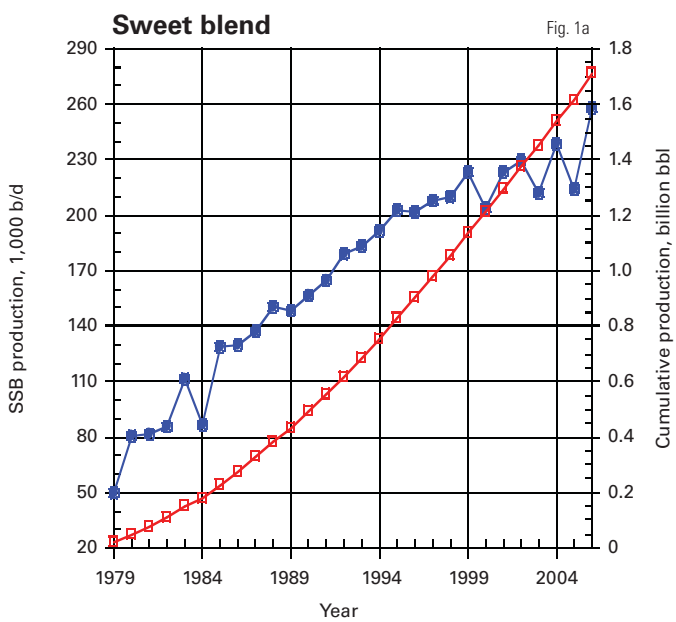
- Canadian Oil Sands Ltd., 36.74%.
- ConocoPhillips Oil Sands Partnership II, 9.03%.
- Imperial Oil Resources, 25%.
- Mocal Energy Ltd., 5%.
- Murphy Oil Co. Ltd., 5%.
- Nexen Oil Sands Partnership, 7.23%.
- Petro-Canada Oil & Gas, 12%.

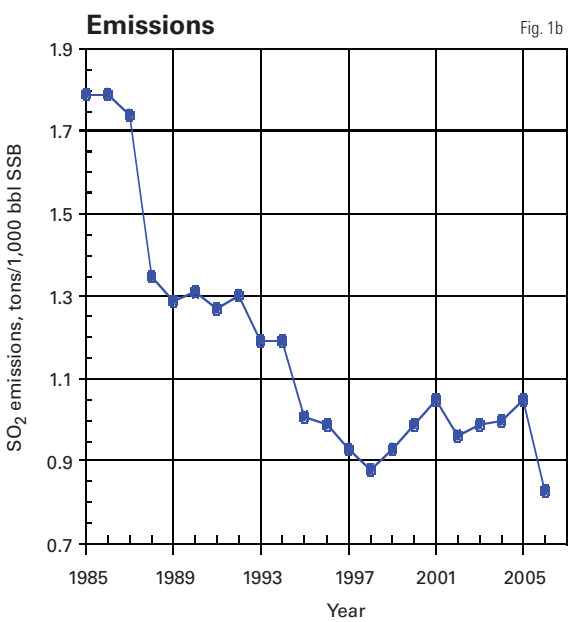
It operates a surface-mining oil sands plant at the Athabasca oil sands deposit in northern Alberta and produces synthetic crude oil from the extracted bitumen. Operations started in 1978 and production has increased to 94 million bbl (258,000 b/d) in 2006 from 28 million bbl (77,000 b/d) in 1979. Cumulative production has exceeded 1.7 billion bbl, while environmental impacts have been substantially reduced.

Fig. 1a illustrates Syncrude production history. The production volume in 2006 was equivalent to 12% of the Canadian crude oil consumption. Fig.

SYNCRUDE PRODUCTION

Fig. 1





PROPERTIES OF TYPICAL SSB

Table 1

Cut range, °C.	Total SSB	Naphtha C_5-143	Naphtha C_5-177	Jet fuel 143-260	Diesel fuel 177-343	Diesel fuel 260-343	Gas oil 343+
Yield, wt %	100.00	10.1	14.1	21.8	44.8	27.0	38.9
Yield, vol %	100.00	12.7	17.1	23.3	45.7	27.0	37.1
Density at 15° C., g/ml	8697	0.7192	0.7402	0.8391	0.8776	0.8952	0.9409
Sulfur, ppm (wt)	1,098	<4	5	6	234	403	2,458
Nitrogen, ppm (wt)	623	<1	1.9	17	99	162	1,437
Hydrogen, wt %	12.63	14.57	14.38	13.29	12.09	11.97	12.18
Carbon, wt %	86.6	84.6	84.7	86.8	87.7	88.0	88.0
H:C atomic ratio	1.738	2.052	2.023	1,825	1,643	1.621	1.649
Aniline point, °C.	55.2	21.0	48.6	43.4	47.3	50.7	67.8
Supercritical fluid chromatography aromatics, wt %							
mono-	28.8	10.9	15.6	32.0	33.2	33.3	—
di-	11.2	0.1	0.1	1.6	8.4	12.4	—
poly-	2.7	—	—	—	0.6	1.0	—
Total	**42.7**	**11.0**	**15.7**	**33.6**	**42.2**	**46.7**	—
Distillation by ASTM D2887, °C.							
Initial boiling point	0.3	21.3	22.2	111.2	168.0	243.7	345.9
5%	75.3	34.8	35.7	151.3	191.6	265.0	362.1
10%	118.6	36.2	57.6	161.4	204.4	272.0	371.0
20%	190.8	61.5	76.0	178.1	226.7	281.5	386.5
30%	245.0	70.0	90.8	194.2	246.3	290.5	401.0
50%	310.3	97.7	116.7	217.8	278.3	306.3	432.7
70%	371.1	113.3	139.3	237.0	305.9	321.6	469.8
80%	409.3	122.3	153.2	246.7	318.8	329.5	494.6
90%	452.8	134.8	166.2	255.8	331.9	337.7	525.2
95%	485.1	140.5	173.8	261.3	339.0	342.8	549.6
Final boiling point	539.8	151.2	183.3	269.1	348.8	251.0	596.0

1b illustrates historical SO_2 emissions.

The UE-1 project substantially increased production capacity and improved product quality while reducing environmental effects. The new improved-quality product is called Syncrude Sweet Premium (SSP), and the product prior to the UE-1 project was known as Syncrude Sweet Blend (SSB).

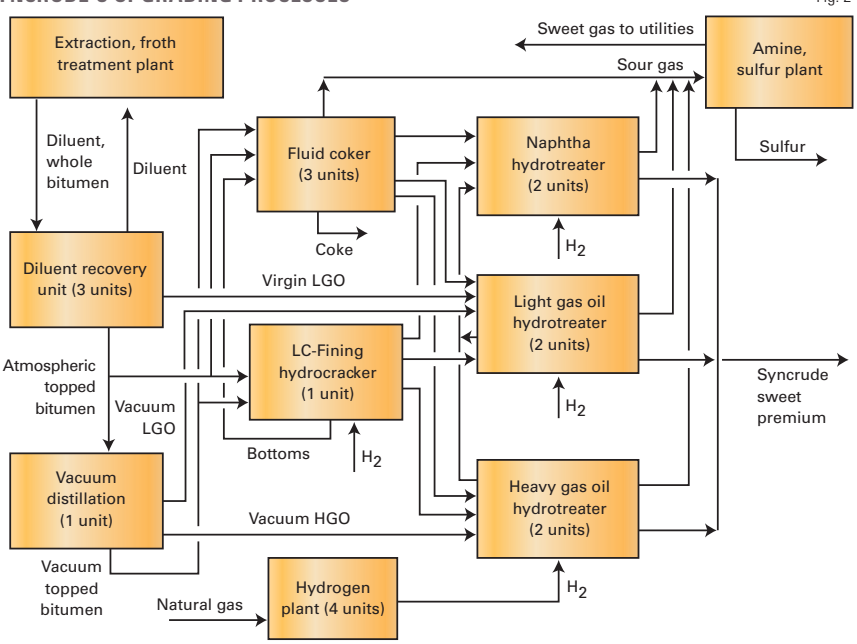
The UE-1 project provided facilities to improve of diesel cetane number (CN) and jet fuel smoke point. Syncrude will address the improvement of heavy gas oil (HGO) quality in a future expansion project. Improving the processes for oil sands bitumen recovery and product quality is part of Syncrude's R&D focus.

In an earlier article (OGJ, Apr. 23, 2001, p. 46), we reviewed Syncrude's upgrading operations and R&D activities on bitumen chemistry, process improvement, and product-quality improvement.

This article highlights the scope of the UE-1 project in the upgrading area, updates the configuration of the upgrading processes for SSP production, reviews new cetane index (CI) and smoke point correlations suitable for bitumen-derived middle distillates, and discusses how the new CI correlations can be applied to the light gas oil (LGO) streams to monitor the UE-1 processes.

SYNCRUDE'S UPGRADING PROCESSES

Fig. 2



Syncrude's UE-1 project

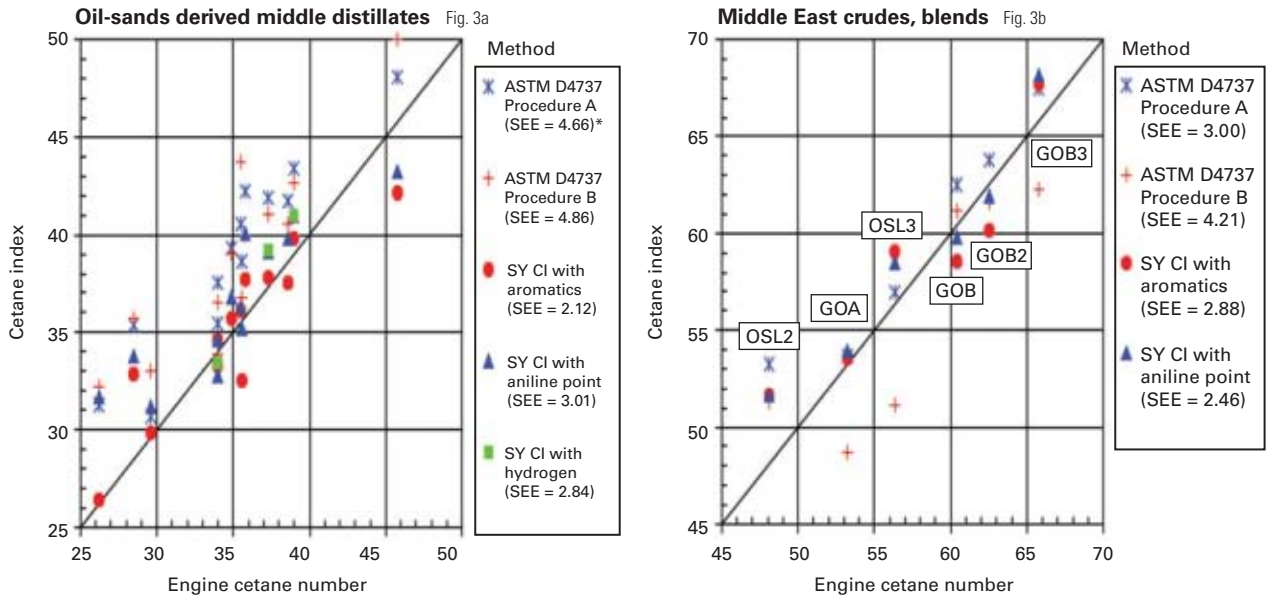
Fig. 2 is a simplified flow diagram of Syncrude's current upgrading process that includes newly installed units completed as part of the UE-1 project in 2006.

Diluent recovery

The diluent recovery unit (DRU) includes three units, the third of which was installed with UE-1 in 2006. Di-

SY CI CORRELATIONS

Fig. 3



*SEE = Standard error of estimate

luted bitumen from the extraction and froth treatment plants is fractionated in the atmospheric DRU. Diluent (heavy naphtha) and some of the virgin LGO contained in the bitumen are recovered.

Diluent returns to the extraction plant and the LGO is routed to the LGO hydrotreater. Part of the atmospheric topped bitumen (ATB) feeds the vacuum distillation unit. The remaining ATB feeds the fluid cokers and LC-Finer hydrocracker.

The nameplate capacity is 330,000 b/d/unit for the earlier two units and 217,000 b/d for the new unit.

Vacuum distillation

The vacuum distillation unit (VDU) further distills ATB into light vacuum gas oil (LVGO), heavy vacuum gas oil (HVGO), and vacuum bottoms (or vacuum topped bitumen, VTB). LVGO and HVGO feed the LGO hydrotreater and HGO hydrotreater, respectively, and VTB feeds the fluid cokers and LC-Finer. The nameplate capacity is 285,000 b/d.

Fluid coker

Syncrude has three fluid cokers; the third was installed with UE-1 in 2006.

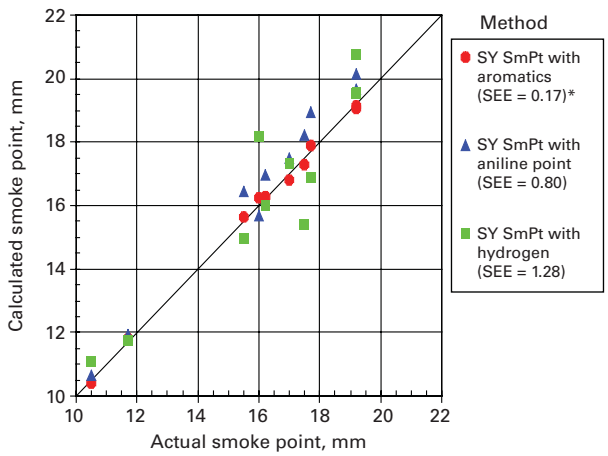
The feeds are combined ATB and VTB, and LC-Finer bottoms. The products are sour hydrocarbon gases, liquid products, and coke. The liquid products are fractionated into naphtha, LGO, and HGO.

Naphtha is treated in the naphtha hydrotreater. Before UE-1, LGO and HGO were combined and treated in the HGO hydrotreater; they are now treated in the LGO hydrotreater and HGO hydrotreater, respectively.

The new coker is equipped with a flue gas desulfurization unit to convert sulfur in burner offgas into ammonium sulfate fertilizer as a by-product. The nameplate capacity is 107,000 b/d/unit for the older two units and 95,000 b/d for the new unit.

SMOKE POINT CORRELATIONS

Fig. 4



*SEE = Standard error of estimate

LC-Finer

The LC-Finer hydrocracker cracks combined ATB and VTB in an ebullating catalyst bed with hydrogen. The total liquid products are fractionated into light naphtha, heavy naphtha, LGO, HGO, and bottoms.

Light naphtha is treated in the naphtha hydrotreater. Heavy naphtha is used as make-up diluent for the upstream froth treatment process. LGO and HGO are treated in the LGO hydrotreater and HGO hydrotreater,

EQUATIONS

Procedure A CCI = 45.2 + 0.0892 (T_{10N}) + [0.131 + 0.901 (B)] (T_{50N}) + [0.0523 – 0.420 (B)] (T_{90N}) + 0.00049 [(T_{10N})^2 – (T_{90N})^2] + 107 (B) + 60 (B)^2 (1)

Procedure B CCI = 297.42 – 386.26 (d_{15}) + 0.1740 (T_{10}) + 0.1215 (T_{50}) + 0.01850 (T_{90}) (2)

B = [exp (-3.5)(DN)] – 1 (3)

DN = d_{15} – 0.85 (4)

T_{10N} = T_{10} – 215 (5)

T_{50N} = T_{50} – 260 (6)

T_{90N} = T_{90} – 310 (7)

T_{10} (ASTM D2887) = 15.17260 + 0.20149 (t_5) + 0.30606 (t_{10}) + 0.48227 (t_{20}) (8)

T_{50} (ASTM D2887) = 5.41890 + 0.07763 (t_{30}) + 0.68984 (t_{50}) + 0.18302 (t_{70}) (9)

T_{90} (ASTM D2887) = 0.09966 + 0.24335 (t_{80}) + 0.32051 (t_{90}) + 0.37357 (t_{95}) (10)

SY CI with SFC aromatics = 696.58 – 1,306.432 (d_{15}) + 521.0933 (d_{15})^2 + 0.000140 (t_{30})^2 + 0.757 (t_{50}) – 0.00105 (t_{50})^2 – 0.415 (MA) + 1.374 (TA) – 0.00876 (TA)^2 – 19.390 [ln(TA)] – 39.983 / ln(TA) (11)

SY CI with aniline point = 8.822 – 75.017 (d_{15}) + 0.000227 (t_{10})2 + 0.429 (t_{50}) – 0.000586 (t_{50})^2 + 0.0445 (t_{90} – t_{10}) + 4.142 (ANP) – 4.661 (d_{15})(ANP) (12)

SY CI with NMR hydrogen = – 1,808.264 + 871.109 / (d_{15}) + 905.827 (d_{15})^2 – 1,845.152 / (t_{30}) + 3.295 (t_{50}) – 2.754 (d_{15})(t_{50}) + 0.656 (H)^2 – 0.0532 (H)(t_{50}) – 0.000789 (H)(t_{90} – t_{10}) (13)

SY smoke point with SFC aromatics = – 436.51 + 293.826 (d_{15}) + 112.767 / (d_{15})2 + 0.235 (t_{10}) + 2,801.837 / (t_{50}) – 0.000335 (t_{90})2 – 0.0720 (t_{70} – t_{30}) + 0.255(t_{90} – t_{10}) + 0.00143 (MA)^2 + 34.312 / (MA) – 55.219 / (MA)^2 – 0.188 (TA) (14)

SY smoke point with aniline point = 19.137 – 0.100 (d_{15})(t_{50}) + 0.000286 (t_{50})^2 + 0.00642 (ANP)^2 + 0.458 (ANP)(d_{15}) – 0.00291 (ANP)(t_{50}) (15)

SY smoke point with NMR hydrogen = 277.302 – 45.357 (d_{15})^2 – 1,672.572 / (t_{30}) – 39.348 (H) + 1.724 (H)^2 (16)

NOMENCLATURE

ANP = Aniline point, °C.
d_{15} = Density at 15° C., g/ml
H = Hydrogen determined by proton nuclear magnetic resonance, wt %
MA = Monoaromatics determined by supercritical fluid chromatography, wt %
t_i = i% recovery temperature by ASTM D2887, °C.
T_{10} = 10% recovery temperature determined by ASTM D86, °C.
T_{50} = 50% recovery temperature determined by ASTM D86, °C.
T_{90} = 90% recovery temperature determined by ASTM D86, °C.
TA = Total aromatics determined by supercritical fluid chromatography, wt %

respectively. Bottoms are routed to a coker. Nameplate capacity is 50,000 b/d.

Hydrogen plants

There are four hydrogen generation units at Syncrude. The fourth was installed with the UE-1 project in 2005. Hydrogen is produced via steam reforming natural gas.

Hydrotreating

Syncrude had five fixed-bed hydrotreating units before UE-1: two naphtha hydrotreaters, one LGO hydrotreater, and two HGO hydrotreaters. The UE-1 project revamped the five existing units to improve operability and product quality, and added a new LGO hydrotreater for aromatics saturation to substantially improve the diesel cetane number and jet fuel smoke point.

Some key features include:

- *Naphtha hydrotreater.* There are two identical units in parallel. Each unit has three reactors in series: a diolefin reactor and two main reactors. The diolefin reactor hydrogenates diolefins in the feed (mostly coker naphtha) at a relatively low temperature to prevent polymerization, which can lead to fouling of the catalyst bed at main reactor conditions (OGJ, Sept. 6, 1999, p. 64).

Main reactors reduce the nitrogen content to 1 ppm (wt), so that downstream refiners can use the hydrotreated naphtha in catalytic reformers with noble metal catalysts.

The reactor configuration before UE-1 resulted in gas-liquid mixed phase reactions, thereby causing flow maldistribution and hot spots in the reactors. The UE-1 project eliminated the mixed-phase reactions by splitting the product from the diolefin reactor into light and heavy fractions, and charging them separately into the two main reactors. By doing so, flow maldistribution and hot spots in the reactor are minimized, and catalyst utilization is enhanced.

Nameplate capacity is 48,500 b/d/unit.

- *LGO hydrotreater.* Feeds are LGOs from the DRUs and VDU, and part of the HGO from the VDU. The process objective is to reduce the sulfur and nitrogen content. Aromatics saturation is an incidental but desirable reaction.

Compared to the coker LGO that is treated in the new aromatics saturation unit, straight run LGO to this hydrotreater contains less sulfur and nitrogen. Target sulfur and nitrogen removal is therefore easily achieved even with twice-regenerated catalysts,[1] although the activity of regenerated catalysts is about 20% lower than fresh catalyst.[2]

The UE-1 project added three more parallel reactor vessels to handle higher feed rates and improve product quality. The nameplate capacity is 100,000 b/d.

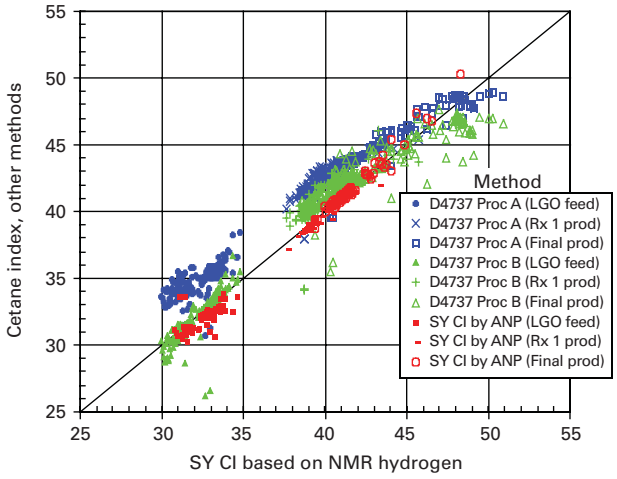
- *HGO hydrotreater.* Feeds are HGOs from the coker, LC-Finer, and VDU. Each unit has two trains and each train has two reactors in series: a guard reactor and a main reactor. The guard reactor protects the main reactor catalysts by removing metals and entrained matter. The main reactor, comprised of three consecutive beds, is intended to reduce sulfur and nitrogen. Incidental reactions such as cracking and aromatics saturation also occur.

The UE-1 project revamped the fractionator to draw an LGO cut from the total liquid products. The LGO side stream is further treated in the new UE-1 aromatics saturation unit. The nameplate capacity is 75,000 b/d/unit.

- *Aromatics saturation unit.* This new unit

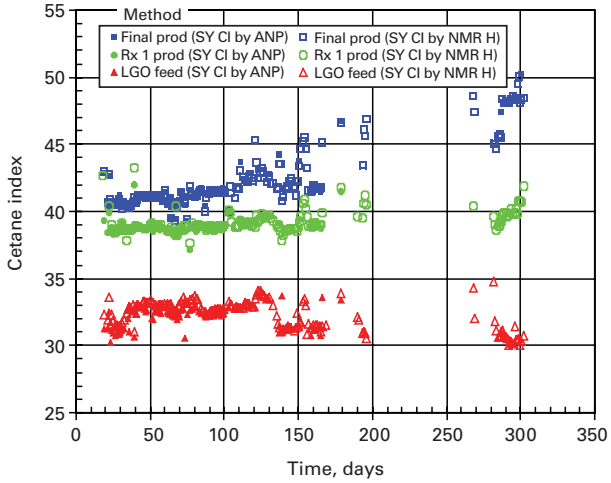
SY CIs ARE COMPARABLE

Fig. 5



SY CI CORRELATIONS IN COMMERCIAL PLANT

Fig. 6



was installed in 2005 to produce higher CN diesel and smoke point jet fuels, thereby producing average 40 CN diesel and 19 mm smoke point jet fuels in SSP. The SSB typically had a 34 CN diesel and 16 mm smoke point jet fuels.

The feeds are combined LGOs from the DRUs, cokers, LC-Finer, and HGO hydrotreaters. The unit has two trains with two reactors in series: a hydrotreating reactor with a typical NiMo catalyst to reduce sulfur and nitrogen, and a hydrogenation reactor with a typical NiW catalyst to reduce aromatics. The nameplate capacity is 85,000 b/d.

Syncrude Sweet Premium

The liquid products from all hydrotreaters are blended as SSP (SSB before the UE-1 project). Table 1 summarizes the properties of typical SSB.

Compared to SSB, SSP is lighter, contains less sulfur, nitrogen, and aromatics, and its diesel CN and jet fuel smoke point are higher (typically 40 CN and 19 mm smoke point). Unlike conventional crude oils, the SSB and SSP do not contain any residue.

The SSP is shipped to refineries in Canada and the US via pipeline. Refiners use the naphtha, LGO, and HGO fractions of the SSP as catalytic reformer feed, diesel and jet fuel blending stock, and FCC or hydrocracker feed, respectively. With more stringent diesel fuel specifications being developed, refiners continually look for new options to improve diesel fuel quality. SSP, a premium product, is designed to meet such requirements.

For optimum operation of the aromatics saturation unit and SSP marketing, it is now imperative to monitor its performance and product quality for not only sulfur and nitrogen, but also aromatics, CN, and smoke point.

Correlations

Determining CN by engine testing (ASTM D613) is costly and time-consuming; therefore, this method is unsuitable as a unit-monitoring tool. The ignition quality tester (ASTM D6890) is an emerging tool to measure ignition delay that some refiners may consider. For practicality, however, most refiners are still using the indirect, but rapid ASTM D4737 calculated Cetane Index (CCI) from readily available laboratory data.

There are two CCIs in ASTM D4737-04 adopted in 2004, Procedure A and Procedure B (see equation box).

Both CCIs need T_{10}, T_{50}, and T_{90} by ASTM D86 distillation. These can be obtained from simulated distillation using the correlations in Equations 8-10, which are given in Appendix X5 in ASTM D2887-04a.

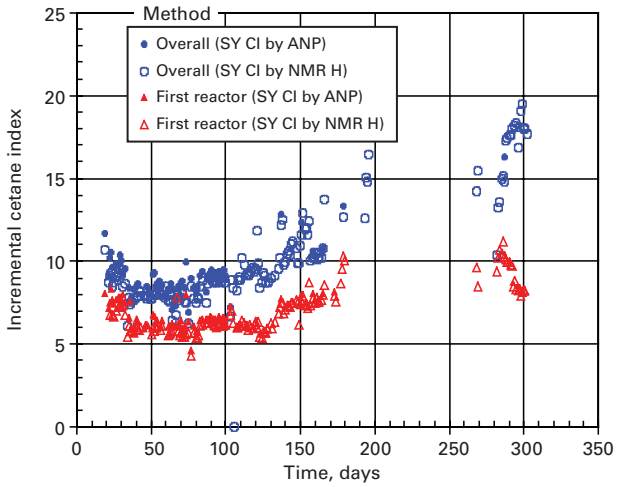
Equation 1 is the same as the one in D4737-90 adopted in 1990. It was developed based on a data set of 1,229 fuels, including commercial diesel fuels, refinery blending components and fuels derived from oil sands, shale, and coal. It is unclear how many oil-sands-derived diesel fuels were used, but they were likely coker-derived fuels from either Syncrude or Suncor Energy Inc.

Equation 2 that was adopted in 2004 is to be used for low-sulfur diesel with less than 500 ppm (wt), but there is no explanation regarding what data set this correlation was based on.

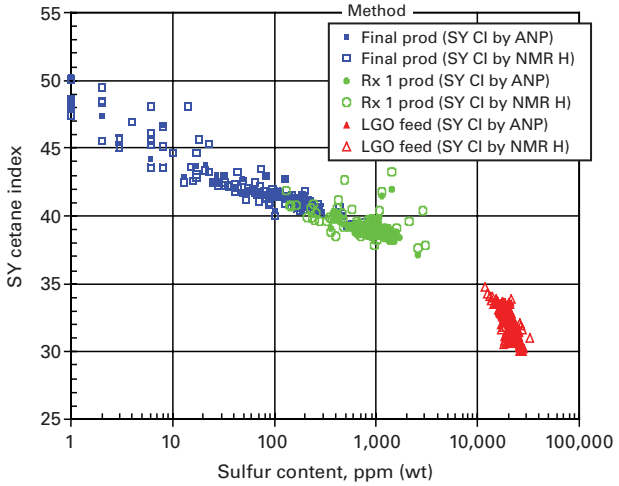
Syncrude installed an LC-Finer hydrocracker and a related hydrotreater in 1987, and a two-stage aromatics saturation unit in 2005. The CN of the diesel fraction from the Syncrude product was therefore improved over the diesel fraction from earlier coker-derived synthetic crude oil that might have been used for developing Equation 1. It is suspected, therefore, that Procedure A CCI may have a limitation for current and future oil-sands-derived middle distillates.

Syncrude Research therefore developed new CI correlations that include density, simulated distillation, and supercritical fluid chromatography (SFC) aromatics (OGJ, Nov. 20, 2000, p. 58); aniline point (OGJ, Nov. 14, 2005, p. 46); and nuclear magnetic resonance (NMR) hydrogen[3] instead of SFC aro-

INCREMENTAL CI IN REACTORS Fig. 7



SY CI, SULFUR Fig. 8



matics (Equations 11-13).

Smoke point correlations (Equations 14-16) were also developed using the same lab items.

The calculated CN (SY CI) and smoke point were obtained using Equations 11-16. The hydrogen content in Equations 13 and 16 was obtained by thermal conductivity measurement after oxidation, not by NMR.

The correlations were tested with the diesel and jet fuel samples that were not used for developing the correlations.[3]

Fig. 3a shows the results of total 13 samples from various individual and blended Syncrude commercial LGO feeds, intermediate and final hydrotreated products, and the diesel cuts from a typical SSB and SSP. This shows that the SY CI correlations are more accurate for oil-sands-derived middle distillates.

Fig. 3b shows the results for the diesel fuels from mixed Middle East crude and their blends with counterparts from SSB. In the figure, GOA and GOB are the diesel cuts from mixed Middle East crudes at refineries A and B in Japan; GOB2 and GOB3 are further hydrotreated GOB at different operating conditions; and OSL2 and OSL3 are blends of 40 vol % of hydrotreated LGO cut from SSB and 60 vol % of respective GOB2 and GOB3.[4]

Fig. 4 shows the fit of the smoke point data. The hydrogen content in Figs. 3a and 4 was obtained by NMR and thermal conductivity after oxidation, respectively.

These figures suggest that the new CN and smoke point correlations should be applicable to oil sands bitumen-derived diesel and jet fuels from a wide range of upgrading processes, untreated feeds, and products regardless of sulfur content, and a wide range of boiling points, as well as to conventional crude-derived diesel and jet fuels, and their blends with counterparts from bitumen-derived products.

The correlations may be useful as a tool for process development, synthetic crude marketing, and monitoring product quality and the operation of middle distillate hydrotreaters.

LGO feeds, products

Two ASTM CCIs (Equations 1 and 2) and the two SY CIs (Equations 12 and 13) were applied to monitor operation of the new aromatics saturation unit. The samples of the LGO feeds, intermediate products from the first reactor, and the final LGO products from the second reactor are regularly taken, and characterized for sulfur, nitrogen, density at 15° C., simulated distillation, aniline point, and NMR hydrogen. SFC aromatics are not available on a regular basis.

The results for the first 7 months of operation are shown here.

Fig. 5 compares the CIs based on various correlations and SY CI based on NMR hydrogen, Equation 13. We found that:

- Both SY CIs based on aniline point Equation 12 and NMR hydrogen Equation 13 are comparable for all three streams; i.e., LGO feeds, intermediate, and final products.
- CIs based on ASTM D4737 Procedure A are 3-4 numbers higher than SY CIs and that based on Procedure B.

Fig. 6 shows daily SY CIs for all three streams. Fig. 7 shows the incremental CIs in the first reactor and overall two reactors, respectively. Fig. 8 shows the relationship between SY CI and sulfur content.

These figures show that:

- The SY CI correlations can be applied to monitor the aromatics saturation unit operation.
- The CIs of the LGO feeds are 31-34.
- 50 CI with ultralow-sulfur LGO products could be produced from the UE-1 aromatics saturation unit.

Acknowledgments

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Sluggish European demand relaxes first-half 2007 LNG

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Sluggish European LNG demand helped relax supply tensions in the first half of 2007, despite numerous liquefaction plants producing below nameplate capacity. LNG cargoes were pulled away from initially targeted European markets and redirected to higher-priced US or Asian markets.

Outside of an exceptionally early cold winter or supply disruptions, the LNG market should remain relatively relaxed. In addition to greater volumes from Equatorial Guinea, Trinidad, and Norway, European demand will likely remain sluggish, freeing supply for the Asian market.

The price-driven nature of the US market will produce record spot trading activity between the Atlantic and Asia Pacific basin in 2007.

LNG demand

Initial estimates for first-half 2007 show global LNG demand at 86 million tonnes, a 6.3 million tonne, or 8%, increase compared to the first half of 2006. Demand was stronger in the second quarter of the year, growing by 8.8% on the strength of Asian and US buying.

Deliveries to the Asia-Pacific region increased by 2.5 million tonnes (10.5%) in second-quarter 2007 as compared to the same period a year earlier, reaching nearly 55 million tonnes by the end of June 2007. European LNG demand continued to collapse, falling nearly 12% in the second quarter, with cargoes making their way to the US instead, leading to a record high level of LNG imports to the Americas, up 64.1% in the first half of 2007 (Fig. 1).

Asia-Pacific

LNG demand in the Asia-Pacific region increased by 8.6% to 54.8 million tonnes in the first half of 2007 from 50.4 million tonnes in the first half of 2006 (Table 1).

Japan, the world's largest LNG market, continued to show solid growth, with a 9.8% increase in imports in second-quarter 2007, compared to the same period in 2006. Economic recovery and attractive LNG prices compared to oil prices drove industrial demand, while power generation sector demand was bolstered by a series of nuclear plant closures.

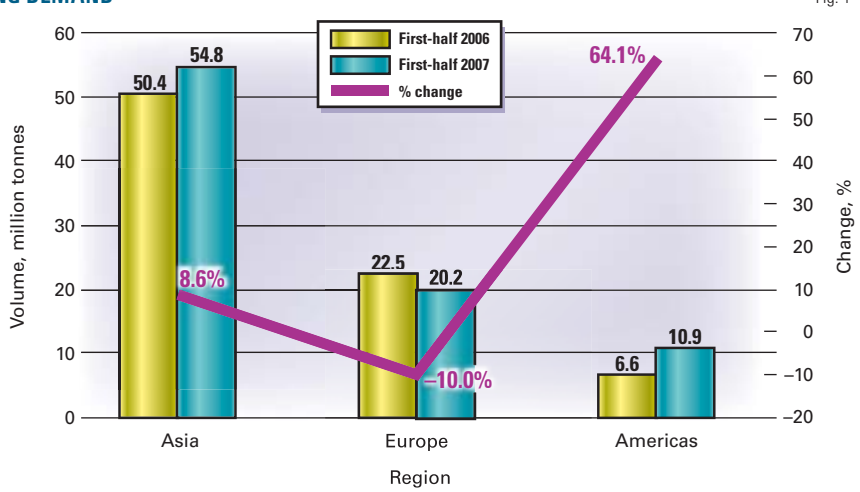
LNG imports into Korea totaled 13.3 million tonnes in the first half of 2007, a decrease of nearly 9% compared to a year ago, as warm temperatures, technical problems at four major storage tanks at the Incheon terminal, and fuel-substitution curbed demand.

In Taiwan, LNG import growth slowed in second-quarter 2007 to 4.8%, following a strong 19.6% demand increase for the same period in 2006. LNG demand in the country totaled 3.7 million tonnes at the end of June 2007, drawn mainly into the power generation sector.

Indian LNG demand remains extremely strong, showing 70.7% growth in second-quarter 2007, and reaching 4.1 million tonnes at the year's midpoint. The country has been very active in the spot LNG market and imports are nearing the maximum capacity of Petronet LNG's 5 million tonne/year Dahej terminal, and Shell-Total's 2.5

LNG DEMAND

Fig. 1



million tonne/year Hazira terminal.

CNOOC's Guangdong terminal received its first Australian cargo in late May 2006. Imports have grown rapidly in 2007, with the buildup of Northwest Shelf production, and totaled 1 million tonnes at the end of June 2007. China also entered the spot LNG market, receiving its first cargo from Oman in April 2007.

Europe

European LNG imports were down 2.3 million tonnes in the first half of 2007 compared to 2006. Exceptionally warm temperatures since fall 2006 curbed demand for heating in most Western European countries last winter, whereas first-quarter 2006 was colder than average. Hydrogeneration also increased in many European countries, thanks to heavier rainfalls. As a result, LNG imports fell nearly 12% in second-quarter 2007 as compared to second-quarter 2006.

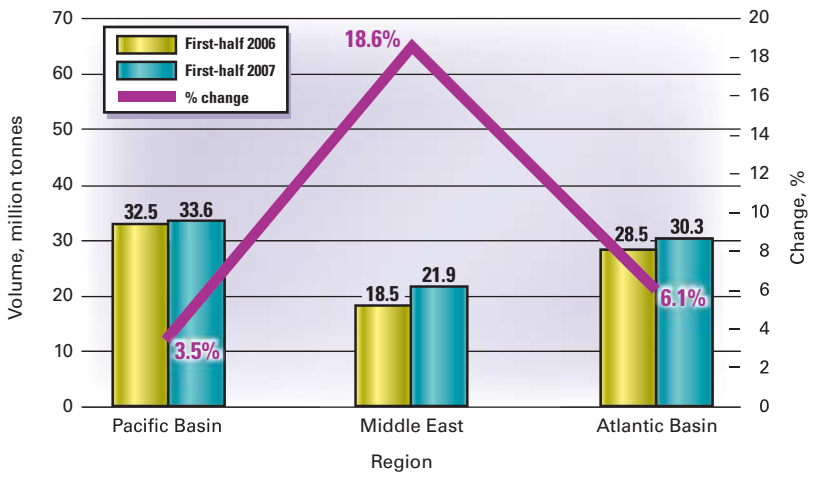
In Belgium, Algerian LNG imports under a 3.3 million tonne/year contract have ceased, replaced in April 2007 by a 2 million tonne/year long-term contract between RasGas II and Distrigas. Low gas prices at the Zeebrugge Hub have, however, failed to attract complementary spot cargoes.

In the UK, the start of two new pipelines at yearend 2006 (Langeled, 2.4 bcfd from Norway in September 2006, and the 1.5 bcfd Dutch Interconnector in December 2006) opened additional natural gas supply routes to the country, contributing to a decline in UK gas prices and deterring LNG imports despite the start of Excelerate's Teesside on-board regasification terminal in February 2007.

Only two European countries, Turkey and Portugal, increased LNG imports in the first half of 2007. Turkey's LNG demand rose 27.5%, from 1.9 million tonnes to 2.4 million tonnes, mostly making up for volumes lost due to pipeline supply disruptions from Iran.

LNG SUPPLY

Fig. 2



Americas

Warm weather in Western Europe led to record LNG imports in the Americas, as the US confirmed its position as market-of-last-resort. LNG demand in the Americas increased by 4.2 million tonnes, or 64%, in the first half of 2007 compared with the same period in 2006, due to US demand.

Mexico imported 800,000 tonnes into the Altamira LNG terminal in the first half of 2007 from Nigeria, Egypt, and Trinidad.

Demand in Puerto Rico and the Dominican Republic also increased slightly in the first half of 2007, as the countries took advantage of the generally more plentiful Atlantic Basin supplies.

LNG supply

The largest supply growth occurred in the Middle East at 18.6%, followed by the Atlantic Basin at 6.1%, and Pacific Basin at 3.5% (Fig. 2).

Qatar replaced Indonesia as the world's largest LNG producer with 14.4 million tonnes of supply put into the market during the first half of 2007, the increase coming mostly from the start of RasGas Train 5 in December 2006. Overall Qatari production increased about 2.5 million tonnes compared with the first half of 2006. LNG supply in Oman and Abu Dhabi also increased by 20% each compared to the first half of 2006.

Nigeria showed the strongest growth in the Atlantic basin, with production increasing by nearly 2 million tonnes, to 7.9 million tonnes in the first half of 2007. Nigerian production growth came mostly from renewed operations at NLNG Train 4 in December 2006 and Train 5 during first-quarter 2007, both of which had experienced production problems in 2006.

Algerian production increased 5.6% in second-quarter 2007, which brought exports for the first half of 2007 to the same level as the year-earlier period. Libyan exports were also virtually flat year-to-year, while Egyptian production dropped 22.4% in second-quarter 2007 compared with the same period in 2006. Egypt's Damietta plant experienced technical difficulties, leading to an overall reduction of 370,000 tonnes of LNG during the first 6 months of 2007.

LNG IMPORTS, ASIA

Table 1

Exporter	First-half 2007	First-half 2006	Change, %
	Million tonnes		
Japan	32.7	30.0	8.9
Korea	13.3	14.6	-8.7
India	4.1	2.4	66.3
China	1.0	0.1	1,685.8
Total	**54.8**	**50.4**	**8.6**

The Pacific Basin posted the smallest nominal production increase (1.12 million tonnes). The start of the Darwin liquefaction plant in February 2006, and its production ramp-up in 2006, allowed Australia to increase exports by 18% in the first half of 2007. In Malaysia, LNG production from the Bintulu complex rose 7% in the first half of 2007 due to 21.5% second-quarter growth.

Indonesian LNG supply decreased 10.8% in second-quarter 2007, following a 6% first-quarter drop in the face of continued production problems. During the first 6 months of 2007, Indonesian supply dropped 1 million tonnes as compared with the first half of 2006.

Brunei increased its supply by 300,000 tonnes in the first half of 2007 compared to the year-earlier period.

Outlook

Lower LNG imports into Europe should continue until winter. Wet spring 2007 weather helped boost European hydropower reserves, and mild summer temperatures lowered power generation demand for air conditioning in Western Europe. Demand, however, is likely to increase slightly in Southeastern Europe (Italy, Greece, and Turkey) due to the summer heat wave experienced in the region.

Comfortable European storage levels as winter begins could help sustain imports to the US, although the spread between North European and Henry Hub market prices that ha emerged since the end of September 2007 provides incentive for cargo redirections to northern Europe.

Asian LNG demand, by contrast, will spike late in the year. In addition to the region's natural LNG demand growth, Japan needs to secure additional LNG as a result of ongoing nuclear power outages. TEPCO alone plans to procure an additional 1.3 million tonnes of LNG by March 2008, as it scrambles to make up for output lost following the July 16 closure of its 8.21 Gw Kashiwazaki-Kariwa nuclear plant in the wake of the 6.8 magnitude Chuetsu offshore earthquake.

New supply

All incremental supply in the immediate term will come from the Atlantic Basin, especially from two greenfield projects.

In Trinidad and Tobago, Atlantic LNG Train 4, which had experienced numerous technical and supply problems since its start-up in December 2005, could finally reach its full 5.2 million tonne/year nameplate capacity after October 2007, when new fields are due to start feeding the plant.

The first cargo from Equatorial Guinea's LNG plant (3.7 million tonne/year nameplate capacity) was lifted in late May 2007, and the plant is now reported to be running at more than 3 million tonnes/year. BG has rights to the first train's entire output and has been marketing the volumes to the US. Some cargoes, however, are likely to make their way to Europe and Asia if prices justify the diversion.

Statoil's 4.1 million tonne/year Snohvit LNG project at Melkoya, Norway, is also on schedule to start shipping regular cargoes by December 2007.

Nigerian LNG Train 6 (4.1 million tonnes/year), however, initially scheduled to start-up by yearend 2007, is now expected to not start-up until first-quarter 2008, after peak winter demand. ✦

LNG IMPORTS, EUROPE

Table 2

Exporter	First-half 2007 Million tonnes	First-half 2006 Million tonnes	Change, %
Spain	9.1	9.7	–6.6
France	5.0	5.5	–9.3
Turkey	2.4	1.9	27.5
Belgium	0.9	1.8	–49.8
UK	0.6	1.3	–52.9
Italy	1.0	1.4	–24.7
Portugal	1.1	0.8	41.0
Greece	0.2	0.2	–16.3
Total	**20.2**	**22.5**	**–10.0**

LNG IMPORTS, AMERICAS

Table 3

Exporter	First-half 2007 Million tonnes	First-half 2006 Million tonnes	Change, %
US	9.6	6.3	53.3
Puerto Rico	0.3	0.2	11.3
Dominican Republic	0.3	0.1	101.6
Mexico	0.8	0.0	n/a
Total	**10.9**	**6.6**	**64.1**

GLOBAL LNG SUPPLY

Table 4

Exporter	First-half 2007 Million tonnes	First-half 2006 Million tonnes	Change, %
Alaska	0.5	0.6	–25.1
Australia	7.6	6.4	18.0
Brunei	3.9	3.6	8.2
Indonesia	10.2	11.1	–8.3
Malaysia	11.5	10.7	7.0
Total, Pacific Basin	*33.6*	*32.5*	*3.5*
Abu Dhabi	2.9	2.4	20.3
Qatar	14.4	11.9	20.2
Oman	4.6	4.1	12.9
Total, Middle East	*21.9*	*18.5*	*18.6*
Algeria	9.8	10.0	–1.7
Libya	0.3	0.3	–9.2
Egypt	5.4	5.7	–6.4
Trinidad	6.9	6.6	5.4
Nigeria	7.9	6.0	32.8
Total, Atlantic Basin	*30.3*	*28.5*	*6.1*
World total	**85.9**	**79.5**	**8.0**

The author

Cecile Jovene is principal consultant and head of gas team at FACTS Global energy, Honolulu. Before joining FGE, she was a senior executive with Gaz de France, where she was responsible for procuring the company's southern supplies. This included negotiating bilateral short-term contracts with gas producers, developing Gaz de France's LNG trading activities in the Mediterranean basin, and optimizing the company's Spanish assets by OTC gas and LNG contracts. She holds degrees in management, finance, and business.

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DeepStar is an ongoing project that brings industry leaders together for the purpose of advancing technology to help increase deepwater hydrocarbon production and reserves.

DEEPSTAR WEBCAST OVERVIEW

Recently, Offshore's Editor, Eldon Ball, moderated a webcast presentation on the successful collaboration of DeepStar VIII and RPSEA (Research Partnership to Secure Energy for America). You can view the entire webcast online at www.offshore-mag.com.

The program identifies four generic Gulf of Mexico fields that frame current opportunities, facility requirements, operating limitations, and technical gaps that challenge developments today. These challenges have been matured and jointly prioritized by RPSEA and DeepStar experts into a promising ultra-deepwater program portfolio.

Presenters:

Christopher Haver
DeepStar Director

Chris received his degree in Metallurgical & Materials Engineering from California State Polytechnic University and has 17 years of experience with Unocal and Chevron. He has held positions in Brea, California as a Research Engineer at Unocal's Science and Technology Center; in Lafayette, Louisiana as an Operations Engineer; and in Houston, Texas in a variety of deep and shallow water Facilities Engineering roles. Chris' experience includes facilities design and operation in the Gulf of Mexico, Venezuela, Thailand and Indonesia. Chris has been focused on the Early Conceptual Phases of Major Capital Projects since the Unocal and Chevron merger. In his current position as DeepStar Director, Chris is responsible for leading the DeepStar Project and managing the RPSEA Ultra-Deepwater Technology Program. Chaver@chevron.com

Jim Chitwood
Chevron DeepStar Project Consultant

Mr. Chitwood is an offshore engineer and R&D consultant. His principal project since 1991 has been the Chevron DeepStar Project. The DeepStar consortium of 10 oil companies and 50+ service companies routinely extends deepwater production limits and is currently working on 10,000 ft water depth and marginal field development technologies.

Mr. Chitwood began his career in 1971 with Brown & Root on the BP Forties Development, after which he concentrated on subsea production systems at Vetco. He went on to acquire intervention and field service experience while he was employed with Comex SEAL. Since 1984, he has served as a consultant to the offshore industry. He has worked on many long-term projects for several Operators including Statoil, Shell, Chevron and ExxonMobil.

Mr. Chitwood has a Masters in Mechanical Engineering from Texas A&M University. He is a registered Engineer in the State of Texas and a member of ASME and SPE. He has several patents and has authored numerous technical papers.

Equipment/Software/Literature

New software for well planning, drilling

Newly released Sysdrill Version 3.0 is an evolved product suite of well planning and drilling software solutions that combines new modules with existing functionality in a single unified application.

Version 3.0 focuses on four areas of improvement to existing industry software: functionality, efficiency, accessibility, and interoperability. The software features enhancements to existing Sysdrill technology, including the following advanced components:

- Automatic well planning.
- Advanced target definition.
- Casing wear prediction.
- Dual gradient modeling.
- Temperature modeling.
- Well control kill sheet.
- Volume calculator.
- Packer calculation.
- DEX/WITSML interoperability.

Source: **Paradigm Geophysical Corp.,** Two Memorial Plaza, 820 Gessner, Str. 400, Houston, TX 77024.

System keeps track of oil field equipment

New intelligent field resource management (IFRM), a radio-frequency identification-driven solution for oil-field equipment, answers these questions for those in oil and gas field operations and maintenance (O&M): What do I have? When did I get it? Where is it?

Previously, those in O&M relied on bar codes or other inventory control methods for their heavy industrial material, consumables, and equipment, the company points out.

The system will tell field engineers such things as exactly where a piece of equipment is, what kind of shape it's in, whether it's even functioning at any precise moment, and if it needs to go back for a rebuild. All the information related to the tagged equipment is tied to this firm's Navigator process management services and stored securely online where it is available for collaborative initiatives. This means you can not only find the particular piece of machinery you're looking for, but at the same time you can get the manual on it, the service record on it—anything about the item you want to know.

Source: **Wescorp Energy Inc.,** 8711 50th Ave., Edmonton, Alta. T6E 5H4.

New work-flow management tool for E&P firms

New AssetConnect open software platform allows exploration and production companies to plug multiple applications into a single user interface and then run automated production work flows.

The company developed the software in partnership with Engineous Software Inc., a Cary, NC-based company that develops software designed to integrate work flows in a unified environment, while also automating them. The resulting product allows production engineers and asset managers to design or operate fields and wells using end-to-end models of the entire producing system.

Source: **Landmark Div., Halliburton,** 2101 CityWest Blvd., Bldg. 2, Houston, TX 77042-3021.

Services/Suppliers

Mustang Gas Compression Ltd.

Houston, has announced that it has been acquired by Hoak Fund Inc. and a group of investors and industry executives, and is now organized as Mustang Gas Compression LLC. The new owners announced that Mark Story has joined Mustang as president and CEO. Story, a 25-year veteran of the natural gas industry, previously was vice-president of US sales for Hanover Compression.


Story

Mustang Gas Compression LLC provides natural gas compression services to producers and gas gathering and processing operators, with operations currently in the states of Texas, Louisiana, Oklahoma, and Wyoming.

EPD Inc.

Houston, has opened a new manufacturing facility in Yangzhou, China to serve the Pacific Rim shipbuilding market.

EPD Inc. and EPD Asia are global providers of electrical systems integration, and custom designers of power systems for vessels, offshore drilling, alternative energy systems, and industrial facilities.

Varel International

Dallas, has announced completion of its sale to Arcapita Inc., a private equity firm based in Atlanta. Varel's current executive management team and employees will remain in place.

Varel International is an independent manufacturer of roller cone and fixed cutter drill bits for the oil and gas, mining, and industrial markets.

EMS Group

Houston, has announced that Tony Rizk has joined the company as vice-president of corrosion & integrity services for North America. Rizk holds a master's degree in civil and structural engineering from California State University, and brings 20 years of corrosion engineering experience to EMS.

EMS Group provides a full range of operations and maintenance services to major pipeline operators, local distribution companies, and independent power, oil, and gas producers.

Industrial Defender Inc.

Mansfield, Mass., has announced a global expansion plan to address growing worldwide demand for cyber security technology and services with the appointment of Donald Simoneau as senior vice-president of worldwide operations. In addition, Jonathan Pollet has been appointed vice-president of North American field operations, and Dan Davis has been named vice-president of international field operations. The company has also established a Singapore sales office to serve the Asia-Pacific region, and appointed Peter Lee as business development manager.

Industrial Defender Inc., formerly known as Verano Inc., is the first company to offer a completely integrated cyber security solution designed to protect the real-time process control and SCADA environment in a flexible, cost-effective platform.

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Worldwide Oil Field Production Survey — Field name, field type, discovery date, and depth.
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Enhanced Oil Recovery Survey — Covers active, planned and terminated projects worldwide. Updated biennially in March.
E1048 $300.00 US Current E1148C $1,000.00 US Historical, 1986 to current

Worldwide Gas Processing Survey — Gas processing plants worldwide with details.
E1209 $395.00 US Current E1219C $1,195.00 US Historical, 1985 to current

International Ethylene Survey — Information on country, company, location, capacity, etc.
E1309 $350.00 US Current E1309C $1,050.00 US Historical, 1994 to current

LNG Worldwide — Facilities, Construction Projects, Statistics
LNGINFO $495.00 US

Worldwide Construction Projects — List of planned construction products updated in May and November each year.

	Current		Historical 1996–Current	
Refinery	E1340	$395.00 US	E1340C	$1,495.00 US
Pipeline	E1342	$395.00 US	E1342C	$1,495.00 US
Petrochemical	E1341	$395.00 US	E1341C	$1,495.00 US
Gas Processing	E1344	$195.00 US	E1344C	$ 795.00 US

U.S. Pipeline Study — There are 14 categories of operating and financial data on the liquids pipeline worksheet and 13 on the natural gas pipeline worksheet.
E1040 $600.00 US

Worldwide Survey of Line Pipe Mills — Detailed data on line pipe mills throughout the world, process, capacity, dimensions, etc.
PIPEMILL $695.00 US

OGJ 200/100 International Company Survey — Lists valuable financial and operating data for the largest 200 publicly traded oil and gas companies.
E1345 $435.00 US Current E1145C $1,695.00 US Historical 1989 to current

Oil Sands Projects — Planned Canadian projects in four Excel worksheets. Includes mining, upgrading, in situ projects, and historical table with wells drilled back to 1985.
OILSANDPRJ $395.00 US

Production Projects Worldwide — List of planned production mega-projects.
PRODPROJ $395.00 US

www.ogjresearch.com

Imports of crude and products

	Districts 1-4		District 5		Total US		
	11-30 2007	11-23 2007	11-30 2007	11-23 2007	11-30 2007	11-23 2007	12-1 2006
	1,000 b/d						
Total motor gasoline	1,107	835	62	—	1,169	835	877
Mo. gas. blending comp.	645	396	62	—	707	396	420
Distillate	299	203	—	—	299	203	303
Residual	331	215	19	—	350	215	394
Jet fuel-kerosine	84	110	156	110	240	220	141
Propane-propylene	174	159	36	16	210	175	119
Other	820	939	4	84	824	1,023	662
Total products	**3,460**	**2,857**	**339**	**210**	**3,799**	**3,067**	**2,916**
Total crude	**8,355**	**9,123**	**1,019**	**1,231**	**9,374**	**10,354**	**10,299**
Total imports	**11,815**	**11,980**	**1,358**	**1,441**	**13,173**	**13,421**	**13,215**

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

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

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OGJ crack spread

	*12-7-07	12-8-06	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	98.91	70.69	28.23	39.9
Brent crude	90.86	63.70	27.16	42.6
Crack spread	8.05	6.99	1.06	15.2
FUTURES MARKET PRICES				
One month				
Product value	99.11	71.20	27.91	39.2
Light sweet crude	88.73	62.32	26.41	42.4
Crack spread	10.38	8.88	1.50	16.8
Six month				
Product value	101.63	78.97	22.66	28.7
Light sweet crude	87.42	66.70	20.72	31.1
Crack spread	14.20	12.27	1.93	15.7

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

Purvin & Gertz LNG netbacks—Dec. 7, 2007

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	7.30	5.55	6.86	5.44	6.18	6.78
Everett	5.78	3.59	5.39	3.67	4.19	6.08
Isle of Grain	8.91	6.57	8.32	6.46	7.21	8.23
Lake Charles	4.54	2.55	4.31	2.72	3.00	5.20
Sodegaura	5.57	7.48	5.83	7.57	6.84	4.87
Zeebrugge	7.07	4.96	6.55	4.84	5.57	6.55

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

Crude and product stocks

District	Crude oil	Motor gasoline		Jet fuel, kerosine	Fuel oils		Propane-propylene
		Total	Blending comp.[1]		Distillate	Residual	
	1,000 bbl						
PADD 1	14,676	51,593	25,236	9,646	58,858	14,428	5,211
PADD 2	63,350	48,541	16,489	7,246	27,481	1,069	21,835
PADD 3	153,810	66,258	29,772	12,888	31,213	16,442	31,135
PADD 4	15,221	5,610	1,680	500	2,745	336	2,884
PADD 5	58,183	28,621	22,054	9,659	12,046	5,758	—
Nov. 30, 2007	**305,240**	**200,623**	**95,231**	**39,939**	**132,344**	**38,033**	**61,065**
Nov. 23, 2007	**313,153**	**196,628**	**92,324**	**38,899**	**130,916**	**38,752**	**61,513**
Dec. 1, 2006[2]	**339,725**	**200,031**	**90,199**	**38,194**	**132,359**	**42,624**	**68,826**

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

Refinery report—Nov. 30, 2007

District	REFINERY OPERATIONS		REFINERY OUTPUT				
	Gross inputs	Crude oil inputs	Total motor gasoline	Jet fuel, kerosine	Fuel oils		Propane-propylene
					Distillate	Residual	
	1,000 b/d						
PADD 1	1,551	1,587	1,689	103	491	137	68
PADD 2	3,288	3,253	2,130	181	1,035	51	194
PADD 3	7,448	7,370	3,465	702	2,122	316	746
PADD 4	570	555	280	29	138	14	148
PADD 5	2,749	2,685	1,528	446	559	179	—
Nov. 30, 2007	**15,606**	**15,450**	**9,092**	**1,461**	**4,345**	**697**	**1,156**
Nov. 23, 2007	**15,606**	**15,470**	**9,020**	**1,409**	**4,302**	**703**	**1,114**
Dec.. 1, 2006[2]	**15,731**	**15,480**	**9,167**	**1,439**	**4,173**	**588**	**1,112**
	17,448 operable capacity		**89.4% utilization rate**				

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

OGJ GASOLINE PRICES

	Price ex tax 12-5-07	Pump price* 12-5-07	Pump price 11-29-06
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	272.2	311.9	218.2
Baltimore	262.5	304.4	218.2
Boston	260.0	301.9	219.3
Buffalo	263.9	324.0	243.4
Miami	276.1	326.4	241.2
Newark	259.0	291.9	209.3
New York	245.4	305.5	233.3
Norfolk	259.3	296.9	212.2
Philadelphia	260.7	311.4	236.2
Pittsburgh	259.7	310.4	225.0
Wash., DC	269.5	307.9	229.0
PAD I avg.	262.6	308.4	225.9
Chicago	294.0	344.9	271.6
Cleveland	268.0	314.4	223.2
Des Moines	261.5	301.9	215.9
Detroit	271.8	321.0	229.2
Indianapolis	263.1	308.1	227.0
Kansas City	254.3	290.3	215.3
Louisville	267.6	304.5	221.2
Memphis	263.7	303.5	213.0
Milwaukee	263.6	314.9	237.2
Minn.-St. Paul	264.1	304.5	222.5
Oklahoma City	262.8	298.2	208.8
Omaha	241.1	287.5	223.9
St. Louis	267.4	303.4	217.2
Tulsa	259.6	295.0	208.1
Wichita	256.5	299.9	219.2
PAD II avg.	263.9	306.1	223.5
Albuquerque	271.0	307.4	223.1
Birmingham	265.2	303.9	224.0
Dallas-Fort Worth	262.0	300.4	217.8
Houston	253.0	291.4	212.0
Little Rock	263.7	303.9	220.2
New Orleans	259.5	297.2	218.6
San Antonio	253.5	291.9	215.2
PAD III avg.	261.1	299.6	218.7
Cheyenne	267.5	299.9	217.0
Denver	266.6	307.0	212.3
Salt Lake City	260.0	302.9	227.5
PAD IV avg.	264.7	303.3	219.0
Los Angeles	274.4	332.9	244.7
Phoenix	257.5	294.9	224.4
Portland	273.6	316.9	243.0
San Diego	283.9	342.4	249.7
San Francisco	300.0	358.5	267.5
Seattle	277.5	329.9	262.9
PAD V avg.	277.8	329.3	248.7
Week's avg.	**265.2**	**308.7**	**226.6**
Nov. avg.	**264.0**	**307.6**	**223.7**
Oct. avg.	**237.3**	**280.9**	**228.0**
2007 to date	**233.8**	**277.4**	—
2006 to date	**213.9**	**257.5**	—

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

REFINED PRODUCT PRICES

	11-30-07 ¢/gal		11-30-07 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	224.18	New York Harbor	249.91
Gulf Coast	216.43	Gulf Coast	248.00
Los Angeles	230.93	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	216.71	ARA	254.34
Singapore	233.36	Singapore	251.36
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	223.68	New York Harbor	162.81
Gulf Coast	217.06	Gulf Coast	162.74
Los Angeles	232.93	Los Angeles	207.30
		ARA	167.60
		Singapore	176.67

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

BAKER HUGHES RIG COUNT

	12-7-07	12-8-06
Alabama	5	5
Alaska	10	6
Arkansas	50	36
California	38	34
Land	36	31
Offshore	2	3
Colorado	117	91
Florida	0	0
Illinois	0	0
Indiana	2	0
Kansas	15	10
Kentucky	8	8
Louisiana	160	194
N. Land	60	57
S. Inland waters	27	24
S. Land	27	43
Offshore	46	70
Maryland	1	0
Michigan	1	2
Mississippi	12	16
Montana	9	20
Nebraska	0	0
New Mexico	79	94
New York	5	1
North Dakota	55	33
Ohio	13	10
Oklahoma	201	179
Pennsylvania	17	19
South Dakota	0	1
Texas	872	784
Offshore	12	10
Inland waters	1	4
Dist. 1	17	16
Dist. 2	33	23
Dist. 3	72	62
Dist. 4	79	93
Dist. 5	186	141
Dist. 6	115	125
Dist. 7B	43	38
Dist. 7C	63	48
Dist. 8	113	106
Dist. 8A	21	26
Dist. 9	44	38
Dist. 10	73	54
Utah	35	44
West Virginia	36	32
Wyoming	74	86
Others—NV-3; TN-6; VA-4	13	9
Total US	**1,828**	**1,724**
Total Canada	**388**	**463**
Grand total	**2,216**	**2,187**
Oil rigs	340	282
Gas rigs	1,482	1,437
Total offshore	61	85
Total cum. avg. YTD	**1,765**	**1,645**

Rotary rigs from spudding in to total depth.
Definitions, see OGJ Sept. 18, 2006, p. 42.

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

SMITH RIG COUNT

Proposed depth, ft	Rig count	12-7-07 Percent footage*	Rig count	12-8-06 Percent footage*
0-2,500	63	6.3	46	—
2,501-5,000	114	60.5	102	38.2
5,001-7,500	216	25.4	229	17.4
7,501-10,000	442	1.5	425	3.7
10,001-12,500	434	3.9	409	2.6
12,501-15,000	283	—	245	0.4
15,001-17,500	117	—	120	—
17,501-20,000	64	—	77	—
20,001-over	33	—	32	—
Total	**1,766**	**8.6**	**1,685**	**6.3**
INLAND	41		35	
LAND	1,677		1,590	
OFFSHORE	48		60	

*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]12-7-07	[2]12-8-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	15	20
Alaska	669	707
California	652	681
Colorado	51	61
Florida	6	6
Illinois	31	28
Kansas	97	96
Louisiana	1,394	1,336
Michigan	14	15
Mississippi	50	47
Montana	96	98
New Mexico	175	165
North Dakota	109	115
Oklahoma	170	174
Texas	1,374	1,344
Utah	45	50
Wyoming	144	146
All others	61	68
Total	**5,153**	**5,157**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	12-7-07
Alaska-North Slope 27°	78.19
South Louisiana Sweet	88.75
California-Kern River 13°	75.95
Lost Hills 30°	84.15
Southwest Wyoming Sweet	79.78
East Texas Sweet	84.25
West Texas Sour 34°	77.25
West Texas Intermediate	84.75
Oklahoma Sweet	84.75
Texas Upper Gulf Coast	81.25
Michigan Sour	77.75
Kansas Common	83.75
North Dakota Sweet	76.50

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

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

WORLD CRUDE PRICES

$/bbl[1]	11-30-07
United Kingdom-Brent 38°	94.79
Russia-Urals 32°	90.55
Saudi Light 34°	89.94
Dubai Fateh 32°	88.23
Algeria Saharan 44°	95.32
Nigeria-Bonny Light 37°	95.99
Indonesia-Minas 34°	95.99
Venezuela-Tia Juana Light 31°	89.13
Mexico-Isthmus 33°	89.02
OPEC basket	91.82
Total OPEC[2]	90.74
Total non-OPEC[2]	89.81
Total world[2]	90.32
US imports[3]	87.22

[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]

	11-30-07	11-23-07	11-23-06	Change, %
	bcf			
Producing region	1,045	1,074	1,010	3.5
Consuming region east	1,932	1,977	1,945	–0.7
Consuming region west	463	477	453	2.2
Total US	**3,440**	**3,528**	**3,408**	**0.9**
	Aug. 07	**Aug. 06**	**Change, %**	
Total US[2]	**3,017**	**2,969**	**1.6**	

[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. 2007 Land	Nov. 2007 Off.	Nov. 2007 Total	Nov. 06 Total
WESTERN HEMISPHERE				
Argentina	75	—	75	72
Bolivia	2	—	2	3
Brazil	21	21	42	33
Canada	369	3	371	432
Chile	2	—	2	1
Colombia	38	—	38	24
Ecuador	9	—	9	13
Mexico	56	27	83	86
Peru	8	1	9	5
Trinidad	1	6	7	4
United States	1,737	61	1,798	1,706
Venezuela	56	14	70	75
Other	3	—	3	2
Subtotal	**2,376**	**133**	**2,509**	**2,456**
ASIA-PACIFIC				
Australia	11	12	23	18
Brunei	2	4	6	3
China-offshore	—	21	21	17
India	55	30	85	84
Indonesia	42	22	64	52
Japan	1	1	2	2
Malaysia	—	11	11	12
Myanmar	7	—	7	9
New Zealand	4	2	6	5
Papua New Guinea	2	—	2	1
Philippines	—	1	1	2
Taiwan	—	—	—	—
Thailand	4	8	12	10
Vietnam	—	4	4	9
Other	1	2	3	4
Subtotal	**129**	**118**	**247**	**228**
AFRICA				
Algeria	27	—	27	27
Angola	—	5	5	4
Congo	2	1	3	4
Gabon	2	—	2	3
Kenya	—	—	—	—
Libya	14	—	14	12
Nigeria	2	8	10	8
South Africa	—	—	—	1
Tunisia	2	1	3	4
Other	2	3	5	6
Subtotal	**51**	**18**	**69**	**69**
MIDDLE EAST				
Abu Dhabi	9	4	13	15
Dubai	1	—	1	1
Egypt	37	11	48	38
Iran	—	—	—	—
Iraq	—	—	—	—
Jordan	—	—	—	1
Kuwait	12	—	12	14
Oman	51	—	51	42
Pakistan	20	—	20	17
Qatar	3	8	11	10
Saudi Arabia	68	7	75	77
Sudan	—	—	—	—
Syria	18	—	18	25
Yemen	16	—	16	17
Other	—	—	—	2
Subtotal	**235**	**30**	**265**	**259**
EUROPE				
Croatia	1	—	1	1
Denmark	—	2	2	1
France	1	—	1	—
Germany	4	1	5	5
Hungary	2	—	2	3
Italy	4	1	5	6
Netherlands	2	4	6	4
Norway	—	14	14	10
Poland	2	—	2	2
Romania	2	1	3	2
Turkey	5	—	5	4
UK	3	14	17	23
Other	8	—	8	4
Subtotal	**34**	**37**	**71**	**65**
Total	**2,825**	**336**	**3,161**	**3,077**

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	202	1.70
Caribbean	Houston	Resid.	380	144	1.36
Caribbean	Houston	Resid.	500	155	1.45
N. Europe	New York	Dist.	200	330	4.41
N. Europe	Houston	Crude	400	167	3.27
W. Africa	Houston	Crude	910	119	2.58
Persian Gulf	Houston	Crude	1,900	59	2.39
W. Africa	N. Europe	Crude	910	120	1.92
Persian Gulf	N. Europe	Crude	1,900	87	2.55
Persian Gulf	Japan	Crude	1,750	76	1.82

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

Waterborne Energy Inc. US LNG imports

Country	Dec. 2007	Nov. 2007	Dec. 2006	Change from a year ago, %
	MMcf			
Algeria	—	—	—	—
Egypt	—	3,030	11,420	—
Equatorial Guinea	—	—	—	—
Nigeria	—	—	3,080	—
Qatar	—	—	—	—
Trinidad and Tobago	30,420	19,360	36,620	–16.9
Total	**30,420**	**22,390**	**51,120**	**–40.5**

Source: Waterborne Energy Inc.
Data available in OGJ Online Research Center.

Propane prices

	Oct. 2007	Nov. 2007	Oct. 2006	Nov. 2006
	¢/gal			
Mont Belvieu	143.15	155.64	93.82	95.38
Conway	140.36	151.67	93.46	95.05
Northwest Europe	143.66	168.75	95.94	94.50

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					
Nov. 2007						
Product revenues	106.46	102.30	104.32	109.43	106.02	99.99
Feedstock costs	–93.08	–94.35	–83.88	–87.50	–92.03	–94.49
Gross margin	13.38	7.95	20.44	21.93	13.99	5.50
Fixed costs	–2.07	–2.39	–2.33	–2.71	–2.33	–1.81
Variable costs	–1.98	–1.33	–1.76	–2.99	–3.59	–1.06
Cash operating margin	**9.33**	**4.23**	**16.35**	**16.23**	**8.07**	**2.63**
Oct. 2007	8.73	3.71	15.00	16.05	5.24	0.53
YTD avg.	12.95	6.88	19.11	21.38	6.29	2.34
2006 avg.	12.49	6.01	14.91	23.73	5.88	1.06
2005 avg.	12.53	6.98	12.31	20.55	5.51	1.52
2004 avg.	6.16	3.70	6.64	11.76	5.08	1.83

Source: Muse, Stancil & Co. See OGJ, Jan. 15, 2001, p. 46
Data available in OGJ Online Research Center.

Muse, Stancil & Co. gasoline marketing margins

Oct. 2007	Chicago*	Houston	Los Angeles	New York
	¢/gal			
Retail price	293.19	264.06	306.09	285.17
Taxes	56.33	38.40	59.98	50.71
Wholesale price	220.03	216.25	242.76	220.69
Spot price	210.74	205.30	234.47	209.53
Retail margin	16.72	9.41	3.35	13.77
Wholesale margin	9.29	10.95	8.29	11.16
Gross marketing margin	**26.01**	**20.36**	**11.64**	**24.93**
Sept. 2007	40.23	22.99	14.16	30.00
YTD avg.	27.23	22.19	18.14	30.39
2006 avg.	19.74	20.34	18.03	27.90
2005 avg.	19.77	16.26	20.39	27.13
2004 avg.	22.49	17.49	23.61	30.38

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

Muse, Stancil & Co. ethylene margins

	Ethane	Propane	Naphtha
	¢/lb ethylene		
Nov. 2007			
Product revenues	70.38	112.61	133.41
Feedstock costs	–43.61	–88.84	–126.75
Gross margin	26.77	23.77	6.66
Fixed costs	–5.38	–6.36	–7.19
Variable costs	–5.27	–6.22	–8.38
Cash operating margin	**16.12**	**11.19**	**–8.91**
Oct. 2007	10.71	5.90	–10.70
YTD avg.	14.28	14.18	–7.79
2006 avg.	19.55	22.53	1.77
2005 avg.	14.43	20.68	1.28
2004 avg.	9.00	12.03	0.51

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

Muse, Stancil & Co. US gas processing margins

Nov. 2007	Gulf Coast	Mid-continent
	$/Mcf	
Gross revenue		
Gas	6.73	4.94
Liquids	1.62	4.45
Gas purchase cost	7.50	6.63
Operating costs	0.07	0.15
Cash operating margin	**0.79**	**2.61**
Oct. 2007	0.71	2.07
YTD avg.	0.41	1.40
2006 avg.	0.26	0.97
2005 avg.	–0.06	0.25
2004 avg.	0.07	0.33
Breakeven producer payment % of liquids	50%	40%

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

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New House bill highlights US energy instability

When US lawmakers fret about energy supply from unstable regimes, they should look closely at themselves.

In the Energy Policy Act of 2005 (EPACT), which became law, Congress created a bundle of incentives for a variety of energy forms, including a few selective tax breaks for oil and gas.

That bill contained one big move and one big omission. The big move was a mandate for vehicle fuels made from renewable sources—mainly ethanol. The big omission was meaningful opening of access to federal land off-limits to oil and gas drilling.

The big move and big omission combined to make EPACT, whatever its other virtues, a big error.

This year, with Democrats newly in control, both houses have revisited energy. Each has passed legislation.

Among other things, the House annulled oil-company tax breaks enacted in EPACT and other recent laws. The Senate outlawed fuel prices above nebulous levels during supply emergencies, toughened fuel-efficiency standards for new vehicles, and raised the ethanol mandate.

The House and Senate made no formal effort to reconcile their bills. Instead, House leaders stitched together a hybrid.

In its first version, the new House measure, which raises the mandate for renewable vehicle fuels and stiffens fuel-economy standards, contained no taxes on oil and gas companies.

Now it does—$13 billion or more from rollbacks of recently enacted incentives for activities like offshore gas production from deep reservoirs. Lawmakers say they need the money to bring uncompetitive energy to market.

So taxes fall, and taxes rise. Taxes fall and rise again. Mandates for uneconomic fuel additives, some of which are raising food prices, keep growing. No one mentions expanded leasing, the fastest way to raise supply of the cheapest energy on the greatest scale.

One stated reason for all this is to reduce the need of US energy consumers to buy oil—cheaper though it be than the alternatives being forced to market—produced in countries that someone in Congress deems unstable.

There are, to be sure, unstable countries in the world. With energy, the US is earning itself a leading position among them.

(Online Dec. 6, 2007; author's e-mail: bobt@ogjonline.com)

The Editor's Perspective

by Bob Tippee, Editor

Market Journal

by Sam Fletcher, Senior Writer

OPEC holds pat on production

As was generally expected, the Organization of Petroleum Exporting Countries agreed Dec. 5 not to raise crude production since commercial oil inventories remained at comfortable levels.

Energy prices fell Dec. 4-5 before rebounding above $90/bbl Dec. 6, then dropping below $89/bbl Dec. 7. OPEC officials blamed the volatility on "the perception of market tightness...exacerbated by nonfundamental factors, including the heavy influx of financial funds into commodities and speculative activity in the markets."

OPEC assigned production allocations of 1.9 million b/d to new member Angola and 520,000 b/d to Ecuador, which recently rejoined OPEC. For the 12 members with official quotas, OPEC production allocations totaled 29.67 million b/d; Iraq, the only member not bound by a quota, is struggling to regain prewar production levels.

In Paris, the International Energy Agency said OPEC's inaction "may do little to calm market anxiety." However, IEA said OPEC's actual production has been "much higher" than indicated at its September meeting when it raised production 500,000 b/d effective Nov. 1. Much of the additional supply comes from Iraq and Angola. "And there are signs that more OPEC oil may be on its way in December," said IEA officials. "Our concern is that there are uncertainties that surround the sustainability of some of that supply, and winter demand is as variable as the weather. The market is clearly uncomfortable that it has lost some stock cover in recent months and with prices near $90/bbl it is telling producers it wants to see that flexibility restored."

The OPEC meeting was "largely ignored" as the market focused on the strength of the US dollar, said Olivier Jakob, managing director of Petromatrix GMBH, Zug, Switzerland. "The dollar index gained close to 1% [on Dec. 5] and is now back to the levels of early November," he said. "With no clear signs from oil fundamentals, the dollar index should be a key directional input."

The only reason for OPEC to increase production would be a rising momentum in energy prices, said Paul Horsnell at Barclays Capital Inc., London. Besides, the previous OPEC hike "is yet to come through, with that delayed increase having been even further delayed by heavy UAE maintenance [of wells] in November," he said.

The 'Iranium' issue

A Dec. 3 government report said US intelligence agencies now agreed Iran stopped its nuclear weapon program in 2003 and hasn't revived it. That should reduce some of the "Iranium" risk premium in energy prices, Jakob said. "Nigeria remains a volatile environment, but we could see militants in the Bayelsa state signing a new ceasefire agreement," he said.

However, Horsnell said, "The latest US National Intelligence Estimate on Iranian nuclear intentions and capabilities muddies the waters fairly significantly." He said, "The emphasis has gone from Iran being considered likely to build a weapon, to Iran having the material to make a weapon. Different in content, but perhaps not so different in policy implications. The more significant impact of the NIE is in the likely weakening of the chances of further [United Nations] Security Council action, with both Russia and China more likely to decouple from the process."

US inventories

The Energy Information Administration reported benchmark US crude inventories fell 8 million bbl to 305.2 million bbl in the week ended Nov. 30. Gasoline stocks jumped 4 million bbl to 200.6 million bbl in the same period. Distillate fuel inventories increased 1.4 million bbl to 132.3 million bbl. "The crude oil stock draw was much larger than any expectations but part of it is probably due to fog delays on the Houston Ship Channel," Jakob said. Imports of crude into the US fell 980,000 b/d to 9.4 million b/d during that week.

A Nov. 28 explosion and fire that killed two workers and temporarily shut down Houston-based Enbridge Energy Partners LP's main pipeline system carrying 1.5 million b/d crude—15% of total US oil imports—from Canada to Midwest refineries had "absolutely nothing to do" with the drop in US imports, "particularly into the Gulf Coast," Horsnell said. "US crude inventories have now fallen by just short of 50 million bbl over the past 5 months, and are now at their lowest level since September 2005."

Horsnell said, "The rise in distillate inventories follows seasonal norms and is made up of a large fall in heating oil and a larger rise in diesel." He said, "The bearish element is the larger-than-normal build in gasoline, bringing them back close to their 5-year average."

(Online Dec. 10, 2007; author's e-mail: samf@ogjonline.com)

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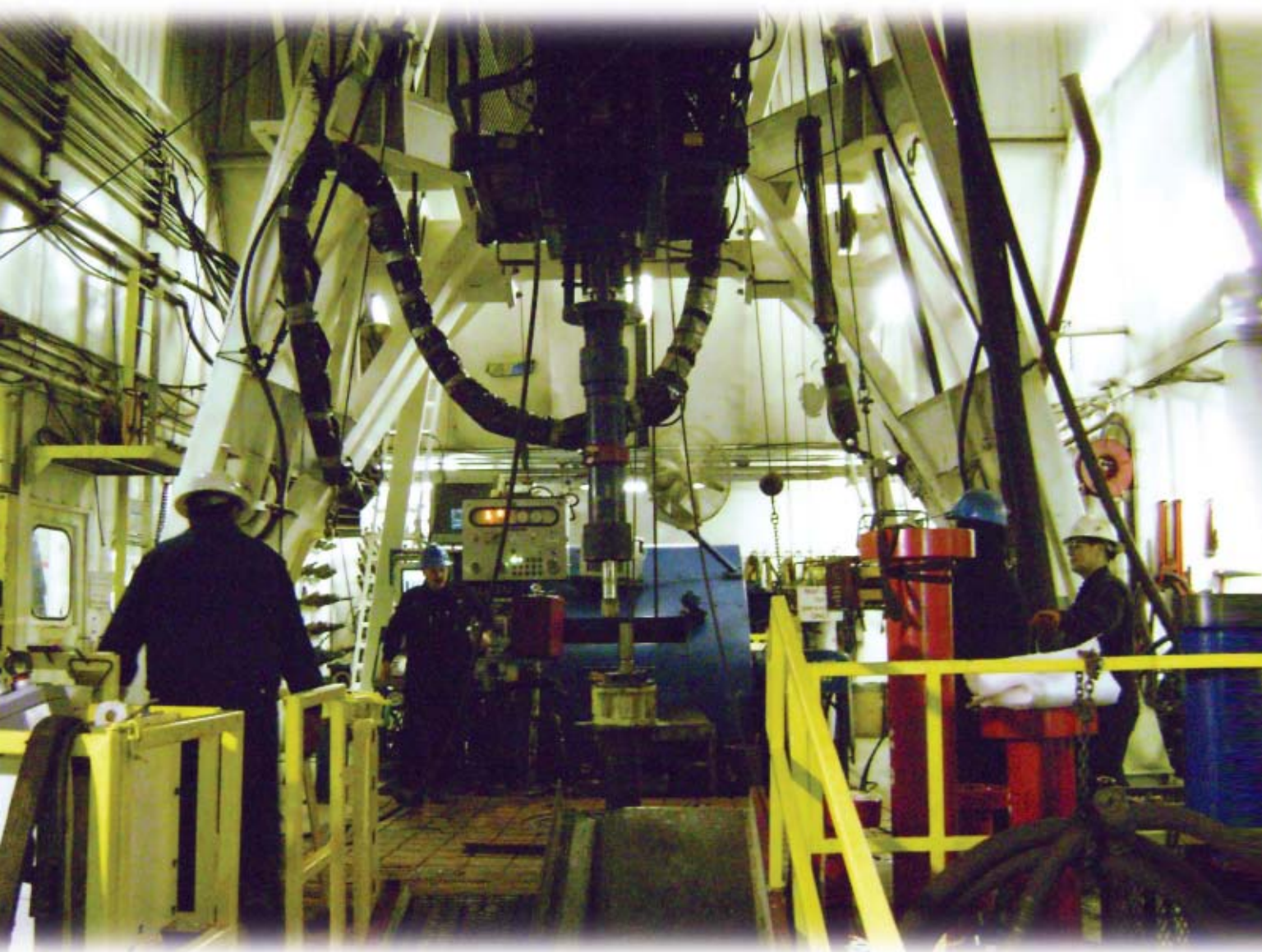

Technology Forum

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Technology Forum

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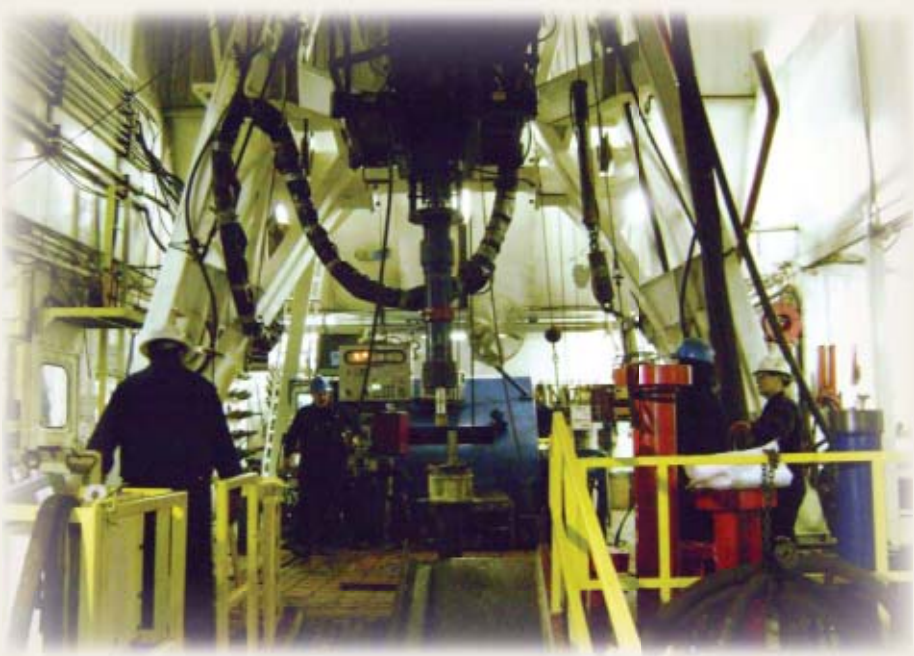
Technology collaboration key in well intervention today



The frontier of coiled tubing-related technology in the well intervention business is shown being tested in the Last Frontier state as Western Well Tool loads its drilling tractor into a well at the site of the Nordic Rig No. 2 at Prudhoe Bay oil field on Alaska's North Slope. The company contends that, with the aid of advanced drilling tractors, coiled tubing use will grow as industry drills more extreme-profile wells. Photo courtesy of Western Well Tool.

Oil & Gas Journal's Technology Forum series, produced by the OGJ Group Publisher, supplements the magazine with topical features on cutting-edge technology, services, and equipment, all expertly written from the technology provider's perspective. Inquiries should be directed to Bill Wageneck, Group Publisher, at billw@pennwell.com.

Technology collaboration key in well intervention today

There are many daunting technology challenges for service and supply companies in the well intervention business today.

But the biggest challenge of all may be in these companies' ability to enhance collaboration with operating companies on new technology at a time of high costs for equipment and services.

"Technology is the key to tomorrow's production," notes Mark McGurk, product line director, Baker Oil Tools. "Service companies like Baker Oil Tools are working in partnership with operating companies to develop pragmatic, technology-based solutions designed to banish uncertainty, manage operational risk, and minimize NPT [nonproductive time].

"The industry needs to overcome its risk-averse culture to accept technology advancements that will provide the incremental growth in production that is needed to support the world's continuing need for energy."

One development that Blake Hammond, global product line manager for Weatherford International Ltd.'s Thru-Tubing division, finds encouraging in this and other technical challenges is that "the industry as a whole is more cognizant today of these challenges, and an atmosphere of collaborative endeavor is developing between operating and service companies to address them.

"As a result, the economics of any technical solution is more carefully evaluated, and resulting solutions will be more economically viable."

> "The industry needs to overcome its risk-averse culture to accept technology advancements that will provide the incremental growth in production that is needed to support the world's continuing need for energy."
>
> — *Mark McGurk, Baker Oil Tools*

> "We're programmed in many respects to tout the virtues of the latest 'widget,' as opposed to educating our clients as to how we can use those developments to solve problems."
>
> — *Blake Hammond, Weatherford International*

Technical challenges

Regarding specific technical challenges in well intervention, McGurk says the technical objective is "holistic, all-encompassing system solutions that eliminate discrete steps and save days of rig time, increasing the value to the operating company.

"The importance of real-time information systems and smart intervention to achieve this objective cannot be underestimated—nor can improved technologies for deepwater service and isolation systems, composite tools that add value by their quick removal, V0-rated systems, and metal-to-metal sealing."

Ever-increasing water depths, harsh downhole environments, and the proliferation of exotic well profiles pose the biggest technology hurdles for the well intervention sector.

The most daunting technical challenge for today's well intervention operations is actually twofold, according to McGurk: "First, we must meet the performance requirements imposed by deepwater, hostile environments and extreme well profiles. The second part of the challenge involves working within the limitations of the exotic materials required to operate in these environments."

In many situations, developments in new well profiles and exotic completion components have outpaced the capabilities of existing wellbore intervention equipment, McGurk contends.

"For example, in ultradeep, high-angle wells, surface measurements of hook-load, torque, etc., no longer provide sufficiently accurate assessments of tool performance at the bottom of the hole," he says. "To achieve the level of performance that today's hostile operating environments demand, well teams need to have a better understanding of what is happening at the 'business end' of [bottomhole assemblies] and downhole tools during the intervention operation."

Bruce Moore, director of engineering for Western Well Tool Inc., thinks that the greatest well intervention challenge today is the same as it has been for years: how to get further down the hole in extended-reach (ER) wells.

"With high rotary rig rates, an increasing number of tasks are being allocated to coiled tubing rigs that can offer substantial cost savings and better availability. The depth that can be reached in either cased or barefoot ER wells can be increased by friction-reducing fluids and larger-diameter pipe, but in an increasing number of cases these methods are still insufficient to reach bottom, pointing to the need for new technology such as Western Well Tool's Intervention Tractors for coiled tubing."

For Knight Oil Tools Pres. Mark Knight, the most daunting technical challenge specific to fishing and plugging and abandonment (P&A) services would be developing an accurate plan of action that is adaptable to circumstances encountered in today's more complex well environments. "Increased downhole pressures and temperatures, deepwater, complex completions, horizontal wells, and environmental considerations require that the plan be adaptable to revisions as operations progress," he points out. "Every plan and revision must include economic considerations with the ever-increasing cost of doing business."

Hammond contends that the technology strides that have been made in the intervention business have in many respects outstripped the service companies' ability to effectively communicate those improvements to their customers.

"We're programmed in many respects to tout the virtues of the latest 'widget,' as opposed to educating our clients as to how we can use those developments to solve problems," he says. "As we see a transformation, not only on the service side of the business but in our industry as a whole, we have to more effectively communicate with our clients the value of these developments. What each of these tools does independently of the others is irrelevant; what matters are the problems we can solve by screwing them together in various ways and creating the system that solves our client's problem."

McGurk believes that well service companies today "are doing a much better job than in the past of working with our operating company clients to understand their requirements and produce high-reliability, high-performance solutions to reduce uncertainty, manage risk, and drive down NPT and overall costs.

"Improved communication, combined with advanced planning and modeling tools, has helped service company/operator relationships evolve into partnerships with both parties working together to meet objectives."

Coiled tubing

Coiled tubing (CT) will play an expanding role in well intervention services as technology improvements have made this versatile tool even more ubiquitous.

"Over the next 5 years, there will be an increasing demand for coiled tubing services to perform a wide variety of tasks, including sand control, water injection, acidizing, setting plugs, and logging," says Moore.

> "The most daunting technical challenge specific to fishing and P&A services would be developing an accurate plan of action that is adaptable to circumstances encountered in today's more complex well environments."
>
> — *Mark Knight, Knight Oil Tools*

However, as many CT operators are now at their limit of depth that can be reached with existing technology, new CT tractor technology will have an increasing impact, facilitating reaching targets that are unachievable otherwise, he contends.

"As operators become increasingly familiar with the use of CT tractors, broader applications will become more commonplace, including CT drilling with tractors into re-entry wells," Moore says.

HTHP wells

As industry presses the search for deep gas and thus must contend with hotter and higher-pressure environments in high-temperature/high-pressure (HTHP) wells, "motor reliability will be of paramount importance," says Hammond. "And the key to their improved performance is the development of the next generation of elastomers to work effectively in the ever more exacting conditions that we anticipate."

McGurk cites high-temperature motor systems, sealing element systems, metal-to-metal sealing technologies, setting tools, and isolation tools as the key areas for breakthroughs in tackling HTHP wells.

Over/underbalanced wells

Industry is making big strides in overcoming the problem of massive formation damage with overbalanced drilling. At the same time, the formation damage that already exists poses a strong business opportunity for well intervention specialists.

"Underbalanced completions were the reason that I got into the well testing business," says Mike Mayer, president of Well Testing Inc., a division of Oil States International. "The ability to drill a new or depleted zone without damaging the formation should be a huge improvement and help producers find and bring to the surface new and bypassed reserves."

Mayer adds, "The ability to make a decision while the well/zone is being drilled via 'real-time testing' can help the producer evaluate early and reduce the time required to make the go/no go decision."

Hammond contends that as the use of underbalanced methods of drilling continue to gain acceptance, "so the days of massive formation damage will slowly come to an end and perhaps overbalanced drilling will go the way of the dinosaur.

"We have seen a major increase in the use of nitrogen as a portion of the drive fluids in milling and other operations, with the objective of protecting the formation, and it is clear that management of the formation from the beginning is now a priority with reservoir considerations overriding drilling needs.

"The problem is that there are huge quantities of wells still producing that have major damage inhibiting their productive capacity, and we feel that there is a great potential to address this and make improvements using well intervention techniques."

One such approach is the concept of underbalanced underreaming of open-hole sections to attempt to clean up near-wellbore damage, Hammond notes.

> "Over the next 5 years, there will be an increasing demand for coiled tubing services to perform a wide variety of tasks, including sand control, water injection, acidizing, setting plugs, and logging."
>
> — *Bruce Moore, Western Well Tool*

Frac jobs

Improving fracturing techniques has and will continue to make unconventional plays practical, contends Mayer.

Hammond points out that there are many wells completed with multiple perforations for which stimulation is a continuing problem.

"Diverter systems to try to channel the stimulant to the less productive perforations can be ineffective, and so production potential remains untapped," he points out. "A through-tubing and monobore straddle system has been developed that can be accurately placed in the well via coiled tubing or jointed pipe, which offers the potential to selectively treat specific sets of perforations.

"Initial trials of this system have proved very successful, and we feel that pinpoint stimulation may well become a very effective and efficient stimulation technique in the near future."

The same system can be applied to other stimulation techniques, Hammond adds.

Slickline services

Slickline intervention is a "huge" market for development, says McGurk, with well intervention specialists moving many traditional pipe-conveyed intervention technologies to slickline, particularly the setting of solid and inflatable plugging and isolation devices.

"The environmental benefits are significant—replacing explosive setting tools and reducing the need to ship explosives, particularly in areas of higher political risk and times of increasing regulation," he says.

In areas where the use of slickline intervention is mandated—due to platform structure weakness such as in the swamps of the Nigerian delta or in jungle and desert locations where mobilization is an economic issue, the running of certain tools such as packers and bridge plugs can be limited by the requirement for an explosive charge, Hammond notes.

"The development of the 'Slickpump'—essentially a slickline-operated hydraulic setting mechanism to perform the function of a power charge ignition system—has made slickline intervention more versatile," he says. "This system can be used instead of electric line units or coiled tubing to set packers, plugs, and straddles, making such interventions more economically justifiable."

Fishing

Good data are the key to improving fishing operations, not just the surface indications but also the downhole measurements that are going to become available in the near future with the development of wellbore data gathering systems, according to Hammond.

"Fishing today is still a black art, and any 10 fishing experts will have a total of 10 ways to do a given job—it's the nature of the beast," he says. "We believe that with better and more readily available data on past fishing problems, we may see the day when those same 10 experts will have only four or five suggested approaches. That would represent a quantum leap in fishing job evaluation: It's fishing smarter."

McGurk cites these breakthroughs in fishing techniques:

- Smart Intervention with the Sentio tool.
- Advanced cutting and milling technologies.
- Innovative new casing exit technologies that are far removed from traditional methodologies.

Wellbore data

The industry continues to push the envelope on gathering wellbore data in real time, and that is advancing well intervention technology as well.

"The opportunities afforded by Smart Intervention technologies are tremendous," says McGurk. "Smart Intervention integrates real-time bottomhole tool optimization data into well intervention to provide a new level of process control with real-time decision-making capabilities during well intervention work."

The Sentio tool contains an array of sensors that simultaneously sample downhole measurements of weight or tension on tool, torque, RPM, bending stress, vibration, and pressure at a high data rate. A digital signal processor analyzes the data stream and provides static parameters and diagnostics.

"This information can be transmitted to a rig-floor monitor and a remote real-time operating center," notes McGurk. "It also can be recorded in onboard memory and stored, then retrieved later at surface for detailed evaluation. By enabling well teams to have a better understanding of what is happening at the 'business end' of BHAs [bottomhole assemblies] and downhole tools during an intervention operation, Smart Intervention technology can lead to more-efficient and reliable well intervention and significantly reduce operators' risk exposure."

> "At the end of the day, all the technology in the world will not help unless the tester on location understands the information provided by the well itself. Each well is different and should be treated as such."
>
> — *Mike Mayer, Well Testing Inc.*

Well testing

The advent of real-time wellbore data is changing the game in well testing as well.

With some exceptions, how a well flows initially can impact the long-term production capacity of the well, Mayer points out.

"Proper initial flow can prevent irreversible damage to the wellbore and reservoir," he says. "Careful attention to well data as it occurs in real time can be helpful in making the decisions about flowing the well.

"Technology improvements in data acquisition systems that can communicate accurate, real-time well data from remote locations is becoming more useful as reservoirs deplete and well control becomes more vital to the success of a project. Information and communication technologies will continue to influence well testing."

As the industry workforce becomes more technologically proficient, the implementation and utilization of such technology becomes more feasible, Mayer notes.

" At the end of the day, all the technology in the world will not help unless the tester on location understands the information provided by the well itself," he cautions. "Each well is different and should be treated as such."]

Banish Uncertainty

Don't gamble on well intervention operations

Uncertainty about what is happening at the "business end" of an intervention BHA can cause an operator to gamble—and lose. Baker's SMART Intervention℠ Service uses downhole rather than surface-acquired job information to banish that uncertainty.

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