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New Latin American Energy Regimes

How coverage has evolved for offshore storm risks
Rig building persists while North American fleet use drops
Method relates diesel cetane, octane ratings
Field inputs guide internal pitting corrosion model

OIL&GAS JOURNAL®

Dec. 3, 2007
Volume 105.45

New Latin American Energy Regimes

Regular Features

Cover

In the 1990s, there was a move toward privatization and deregulation in most Latin American countries in an effort to lure international companies to put their money and expertise into exploration and development of oil and gas resources. Although a few countries have stayed the course, the recent move to "resource nationalism" among several Latin American countries has replaced some of the earlier policy changes and legal reforms to encourage private investment. In this issue, a special report starting on p. 20 provides a short review of what has transpired in eight major oil and gas producing countries in recent years. A second article on p. 24 takes a look at a major figure behind that change, Venezuelan President Hugo Chavez. Few other politicians are as well known internationally in Latin America as Chavez, whose policies are debated throughout that region. Almost every Latin American country has had presidential elections in the last 2 years, and Chavez and his policies have been a factor in most of those elections.

General Interest

Exploration & Development

Drilling & Production

Processing

Transportation

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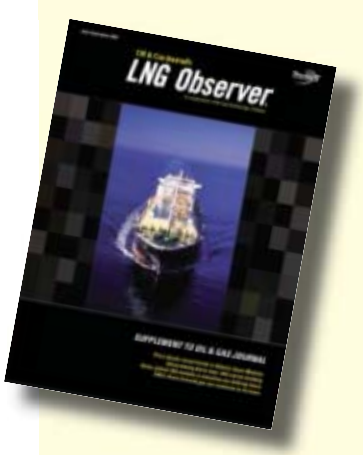

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Dec. 3, 2007

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General Interest — Quick Takes

Iraqi oil minister defends stance on oil contracts

Iraqi Oil Minister Husayn Al Shahristani has defended his country's efforts to prevent international oil companies from signing exploration and production contracts with the Kurdish Regional Government.

In an interview televised via Dubai's Al-Arabiyah satellite channel, Al Shahristani said current Iraqi law does not allow any governorate or ministry other than the oil ministry to conclude oil contracts until the new oil and gas law is enacted.

When the law is enacted, he said, a Federal Oil and Gas Council will be established, and it will be the authority to which oil contracts are submitted for approval.

Until then, he said, the constitution is clear: "Iraqi oil is for Iraq. The only side that represents all Iraq is the federal government, and it is not permissible for any part of Iraqi oil to be extracted and taken by whatever quarter without the Iraqi government's agreement."

Al Shahristani denied that any intimidation was behind Baghdad's decision to exclude companies that have concluded agreements with the KRG from signing contracts in other areas of Iraq. "It is not a policy of arm-twisting," he said, "It is a purely legal position."

He said dealings with the KRG and companies have not shifted from diplomacy to threats to dissuade them from concluding contracts: "I do not call what is happening a threat to anyone. All I said is that they should consider—and we are advising those companies—that when they violate Iraqi laws that are in force, they must bear the consequences."

Asked about his statement that foreign companies that produce oil on the basis of agreements concluded with the KRG will not be able to export the oil without the federal authorities' agreement, Al Shahristani said that is clear, and the companies know it.

He repeated that revenues from the export of Iraqi oil must be paid into a single federal fund and distributed among all Iraqis in their various areas according to the density of population.

Earlier this month, Al Shahristani said India's Reliance Industries Ltd. may find the going tough in acquiring future oil blocks in Iraq (OGJ Online, Nov. 20, 2007).

His remarks followed earlier reports that the KRG had signed five production-sharing contracts previously approved by its Regional Oil and Gas Council (OGJ Online, Nov. 13, 2007).

Kazakhstan, Eni JV near Kashagan tax agreement

Kazakhstan's Deputy Finance Minister Daulet Yergozhin said the ministry is moving forward with tax checks into the Eni SPA-led Agip KCO consortium just days ahead of a Nov. 30 deadline for a deal between the consortium and the government on the Kashagan oil field.

"We have questions," Yergozhin said. "We will expect answers to our inquiries over the next few days." He said the ministry will be ready to present a tax claim against Agip-KCO before yearend.

Yergozhin's statement followed recent reports of progress in talks between the government and the Agip-KCO consortium.

The Interfax-Kazakhstan news agency, citing an unnamed government source, said there is progress on the standpoints set forth in a memorandum to the effect that KazMunayGaz's share in the project should be raised, that the amount of profit oil should be increased, and that spending should be cut.

"Now a proposal agreed by all contractors remains to be received in order for the government to consider it and take the appropriate decision," said the official, adding that members of the consortium must submit their ideas to the Kazakh government by Nov. 30.

Court drops Ecuadorian suits against Chevron

The US District Court for the Northern District of California has dismissed the remaining two claims against Chevron Corp. alleging health impacts to Ecuadorian citizens resulting from a subsidiary's oil operations that ended in 1992.

"The ruling, based on California's 2-year statute of limitations, effectively brings the matter to an end," Chevron said in a statement. It said the lawsuit was the third in a series of suits that had been launched by Cristobal Bonifaz, a Massachusetts-based trial attorney claiming to represent Ecuadorian plaintiffs.

The suits claimed chemicals and wastewater dumped by Chevron subsidiary Texaco Petroleum in the years it operated in Ecuador caused several inhabitants to develop cancer. In October, however, the judge imposed sanctions and a $45,000 fine against Bonifaz after the plaintiffs admitted they did not have cancer.

Chevron is still fighting a major lawsuit in Ecuador over claims of environmental damage. In October, the firm filed a petition with the Ecuador Superior Court seeking dismissal of that suit. ✦

Exploration & Development — Quick Takes

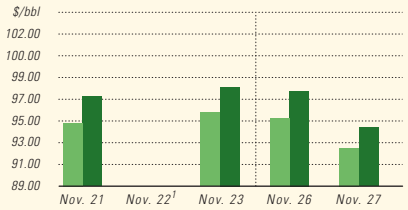
Brunei Shell makes Bubut offshore gas discovery

Brunei Shell Petroleum Co. Sdn. Bhd. has reported a natural gas discovery in the Bubut structure 7 km off Brunei and some 15 km from the Brunei LNG plant.

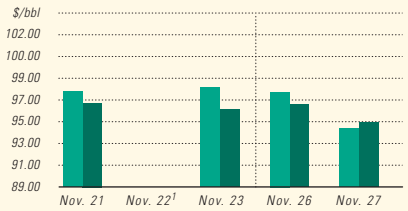
The Deep Driller 2 jack up drilled the exploration well in deep, high-pressure sand reservoirs. Shell said well logs and hydrocarbon samples confirmed the finding, but it did not release details.

Industry Scoreboard

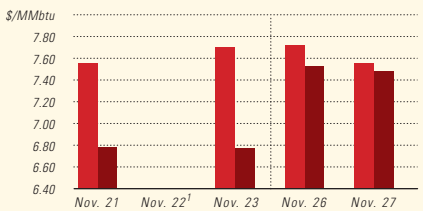
IPE BRENT / NYMEX LIGHT SWEET CRUDE



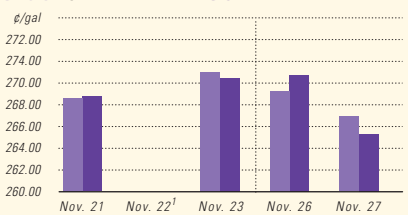
WTI CUSHING / BRENT SPOT



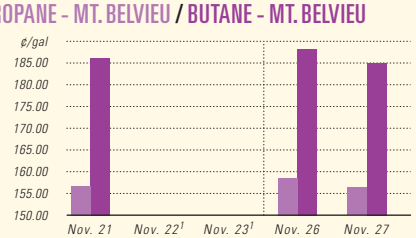
NYMEX NATURAL GAS / SPOT GAS - HENRY HUB



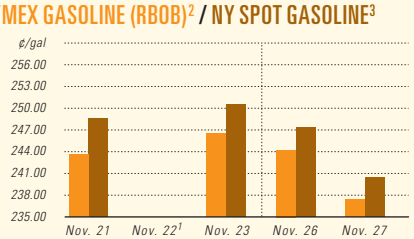
IPE GAS OIL / NYMEX HEATING OIL



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 — 12/3

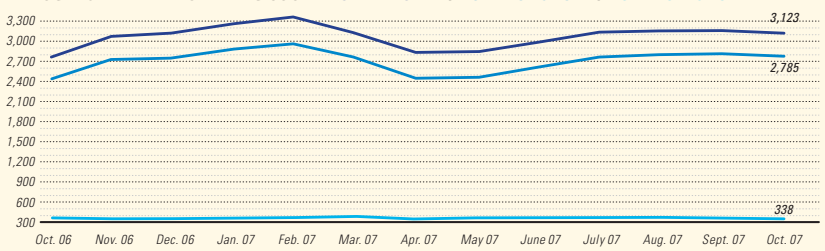
Latest week 11/16	4 wk. average	4 wk. avg. year ago[1]	Change, %	YTD average[1]	YTD avg. year ago[1]	Change, %
Demand, 1,000 b/d						
Motor gasoline	9,283	9,255	0.3	9,301	9,245	0.6
Distillate	4,379	4,243	3.2	4,228	4,159	1.7
Jet fuel	1,671	1,609	3.9	1,629	1,634	–0.3
Residual	616	566	8.8	746	692	7.8
Other products	4,814	5,043	–4.5	4,803	4,890	–1.8
TOTAL DEMAND	20,763	20,716	0.2	20,707	20,678	0.1
Supply, 1,000 b/d						
Crude production	5,079	5,106	–0.5	5,134	5,096	0.7
NGL production[2]	2,425	2,414	0.5	2,381	2,212	7.6
Crude imports	9,836	9,989	–1.5	10,004	10,174	–1.7
Product imports	3,520	3,161	11.4	3,515	3,653	–3.8
Other supply[3]	902	803	12.3	987	1,059	–6.8
TOTAL SUPPLY	21,762	21,473	1.3	22,021	22,194	–0.8
Refining, 1,000 b/d						
Crude runs to stills	14,939	15,006	–0.4	5,226	15,228	—
Input to crude stills	15,139	15,328	–1.2	15,465	15,586	–0.8
% utilization	86.8	88.1	—	88.7	89.7	—

Latest week 11/16	Latest week	Previous week[1]	Change	Same week year ago[1]	Change	Change, %
Stocks, 1,000 bbl						
Crude oil	313,605	314,676	–1,071	335,973	–22,368	–6.7
Motor gasoline	195,190	195,027	163	200,252	–5,062	–2.5
Distillate	131,005	133,412	–2,407	135,018	–4,013	–3.0
Jet fuel-kerosine	38,830	40,933	–2,103	38,814	16	—
Residual	39,097	39,294	–197	42,720	–3,623	–8.5
Stock cover (days)[4]			Change, %		Change, %	
Crude	21.0	21.0	—	22.3	–5.8	
Motor gasoline	21.0	20.9	0.5	21.4	–1.9	
Distillate	29.9	31.0	–3.5	30.3	–1.3	
Propane	48.7	52.2	–6.7	56.9	–14.4	

Futures prices[5] 11/23			Change		Change	%
Light sweet crude, $/bbl	97.04	96.68	3.36	57.28	39.76	69.4
Natural gas, $/MMbtu	7.63	7.89	–0.26	7.99	–0.36	–4.5

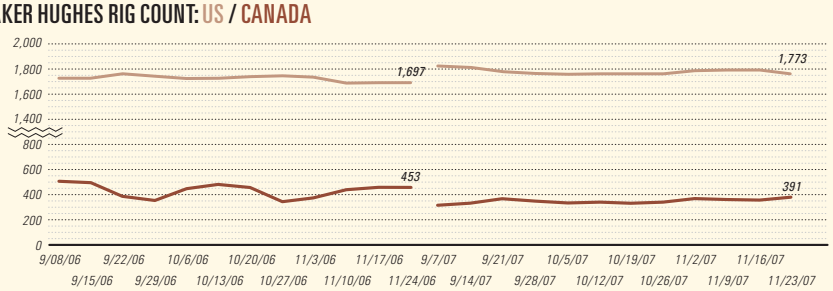
[1]Based on revised figures. [2]Includes adjustments for fuel ethanol and motor gasoline blending components. [3]Includes other hydrocarbons and alcohol, refinery processing gain, and unaccounted for crude oil. [4]Stocks divided by average daily product supplied for the prior 4 weeks. [5]Weekly average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

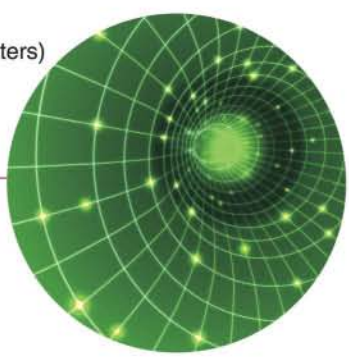


Note: End of week average count

Highest pressure:
30,440 psi (210 MPa)
LWD world record
Gulf of Mexico, 2006

Highest temperature:
379°F (193°C)
LWD world record
North Sea, 2005

Highest dogleg:
61° per 100 feet (33 meters)
LWD world record
Middle East, 2007



Deepest offshore:
34,189 feet (10,421 meters)
Including deepest
LWD data transmission
Gulf of Mexico, 2005

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Reports said that as a result of the Bubut discovery, Shell will reevaluate the nearby Danau structure, which was drilled in the 1970s. Additional appraisal work will be conducted in both fields to define their full potential.

Both fields would be developed in a single, integrated program, the company said.

"You can see the BLNG plant from the exploration rig. The discovery is in shallow waters and close to existing infrastructure and, as such, we are confident of bringing production on stream in the shorter term," said Grahaeme Henderson, Brunei Shell managing director, in making the announcement to local media.

CNPC, PDVSA reach deal for Orinoco exploration

China National Petroleum Corp. said Venezuela has granted oil exploration rights in Sumano oil field to its joint venture with state-owned Petroleos de Venezuela SA (PDVSA).

CNPC said it will take a 40% interest in any commercial production in the block, with the balance reserved for PDVSA. The two firms will set up a joint venture to develop two additional blocks in Venezuela's Orinoco heavy oil belt, but CNPC did not name the blocks.

China and Venezuela signed a series of oil development deals during Venezuelan President Hugo Chavez's visit to China in August 2006, including one for CNPC and PDVSA to jointly develop a block in the Junin area of the Orinoco belt.

Afren to acquire block interests in Ghana, Angola

Afren PLC has agreed to acquire Devon Energy Corp.'s interests in two exploration blocks in Ghana and Angola. Afren will acquire a 95% working interest in and operatorship of the Keta Block off eastern Ghana and a 15% working interest in Angola's Block 16.

The acquisition, which is subject to certain conditions, preferential rights, and governmental approvals, is in line with Devon's strategy to sell off its West African assets, the company said. The Keta Block lies in the Volta River basin and covers 5,500 sq km. Devon, which had carried out extensive technical work in the area, identified primary targets as Upper Cretaceous deepwater sandstone reservoirs that have not yet been drilled. The play type is similar to the Mahogany and Hyedua discoveries to the west.

Further evaluation of reprocessed seismic data is ongoing, and the expected mean potential reserves are about 250-500 MMboe.

The current license on the block expires at the end of 2008 and includes one commitment well. The license can be extended for an additional 6 years, which is divided into three 2-year periods, each with a firm well commitment.

Ghana National Petroleum Corp. has a 5% carried interest in the block.

Block 16 off Angola lies within the Lower Congo basin and covers an area of 4,936 sq km. AP Maersk Co. Ltd. holds a 50% interest and operates the block. Other partners include Brazilian firm Odebrecht SA (15%) and Angola's Sonangol EP (20%).

This exploratory block has nine wells and two discoveries of Miocene and Oligocene age. The discoveries, prospects, leads, and play types mapped in Block 16 are analogous to adjacent fields in Blocks 15, 17, 31, and 32. The plays are considered to be highly prospective with several leads and prospects identified. The expected mean potential reserves are about 1,000 MMboe. The discoveries on Block 16 are under appraisal with the potential for early development.

Trinidad and Tobago to award Block 2 PSC soon

Trinidad and Tobago's Ministry of Energy and Energy Resources reported it will reach an agreement within the next 6 weeks with Tullow Oil PLC and Centrica Resources, enabling them to explore Block 2 (ab) off the eastern coast of Trinidad and Tobago.

The Caribbean island's Director of Resource Management Helena Innis-King said she also expects a production-sharing contract (PSC) to be signed with Tullow Oil for the Guayaguayare shallow and Guayaguayare deep Blocks.

The three blocks are near BP PLC's 163,000 b/d oil fields, which were discovered in the early 1970s, and not far from most of the country's gas reserves.

Innis-King said failure to sign the PSCs more than 2 years after the blocks were first put out for bids was due to several factors, including the creation of new terms for PSCs and the fact that some bids did not meet the ministry's expectations.

She explained, "I know it has taken longer than it should have, but the reality is that we were kept back because we were dealing with many issues, including local content, but I expect we will agree to production-sharing contracts by the end of the year."

Innis-King also revealed that the merger of Statoil and Norsk Hydro ASA delayed negotiations with then-Statoil for a PSC in Trinidad's ultradeep water. ✦

Drilling & Production — *Quick Takes*

BHP brings Stybarrow project on stream

BHP Billiton Ltd. has begun production, ahead of schedule, from the Stybarrow development on Block WA-32-L in the Exmouth subbasin 65 km off Western Australia's North West Shelf. The $760 million development initially was expected to start up in early 2008.

Stybarrow lies in some 825 m of water, making it Australia's deepest offshore development. It contains nine subsea wells that are connected to the 80,000 b/d Stybarrow Venture floating production, storage, and offloading vessel. Oil is produced from Eskdale field via a single well tie-back to Stybarrow field. This will be followed by production from adjacent wells in the field. Production is expected to ramp up to full flow during the next few months.

Eskdale and Stybarrow fields were discovered in February 2003 and have estimated to have total recoverable reserves of 60-90 million bbl, with a field life of 10 years.

Corvina oil field starts producing off Peru

BPZ Energy has begun oil production through the CX11 plat-

form in Corvina field on Block Z-1 off northwestern Peru (OGJ, Nov. 5, 2007, Newsletter).

First production came from the CX11-21XD well, which reached a stabilized rate of 2,500 b/d of oil. The 21XD well was shut in after the first of two leased tankers was filled with 5,000 bbl of oil to allow the company to finish the dual completion of the CX11-14D well.

The 14D well, which has an expected maximum design throughput of 28 MMcfd of gas, flowed at a stabilized rate of 1,900 b/d through its oil tubing, producing 5,000 bbl into the second tanker. No formation water was detected in either well.

The two Navy tankers will deliver this first 10,000 bbl of Corvina oil to a recently refurbished 40,000 bbl transport barge moored adjacent to Petroperu's 62,000 b/d Talara refinery 70 miles south of the field. Once the transport barge is filled to near capacity, the oil will be off-loaded into the refinery.

The company expects to achieve average oil production rates of up to 2,500 b/d.

Production is expected to increase to 4,000 b/d by yearend or early next year when a 40,000 bbl floating production, storage, and offloading vessel is in service.

BPZ plans to bring the next well, CX11-18D, on line in the first quarter of 2008.

Juanambu discovery on stream in Colombia

Gran Tierra Energy has placed the Juanambu-1 discovery well on production on the Guayuyaco Block in the Putumayo basin of southern Colombia, said partner Solana Resources Ltd. Both companies are based in Calgary.

Juanambu was discovered and tested in the first half of this year (OGJ Online, Aug. 28, 2007). It is currently producing about 1,400 b/d of oil, 450 b/d net to Solana.

State-owned Ecopetrol recently approved Juanambu field commercial and exercised an option to back in for a 30% interest. Gran Tierra and Solana each will retain a 35% interest in the field.

Meanwhile, on the Catguas Block in northeastern Colombia, operator and 100% interest holder Solana on Nov. 16 spudded the Cocodrilo-1 well, which is expected to take 3 weeks to drill.

Cocodrilo-1 targets the Eocene Barco and Paleocene Catatumbo formations, which are oil-bearing in the Solana's nearby Tres Curvas-1 new field discovery (OGJ Online, Sept. 17, 2007).

Sakhalin Energy shuts in oil at Vityaz complex

Production of 80,000 b/d of oil has been suspended from the Vityaz complex off northeastern Sakhalin Island because of turbulent weather, Sakhalin Energy Investment Co. (SEIC) said Nov. 26. It also has stopped using the Okha floating storage and offtake vessel.

"While preparing to reconnect the Okha over this weekend it became apparent that the single-anchor leg mooring (SALM) buoy at the Vityaz complex has suffered damage. The cause of the damage is being investigated," SEIC added. "Oil spill response and other vessels are at the scene to avoid the chance of further release of oil."

A company spokesman told OGJ it would be impossible to predict when the weather would become calm. He added that SEIC estimates that less than 10 l. of oil had escaped into the sea because of damage to the SALM. "Before [the investigation] is concluded, it is hard to say when it will be repaired."

Oil production from Vityaz is usually shut in from mid-December until early May or June because of ice. ✦

Processing — *Quick Takes*

Argentina to hike taxes on oil, products exports

Argentina plans to increase taxes on exported oil and refined products to keep domestic prices at below-market levels, according to a statement issued by the ministry of planning.

In the statement, Minister of the Economy Miguel Peirano said that when prices rise on international markets, taxes are an instrument the government can use to guarantee prices on the internal market. The government did not issue specific details of the planned tax increases.

Foreign-owned refinery licensed in Vietnam

Vietnam's central Phu Yen Province has licensed a joint venture of the UK's Techno Star Management (51%) and Russia's Telloil (49%) to build a 4 million tonne/year refinery.

Capitalized at more than 27,480 billion Vietnamese dong ($1.7 billion), the Vung Ro refinery in the province's Dong Hoa district will be the country's first wholly foreign-owned refinery.

An official from the Phu Yen Planning and Investment Department said the Vung Ro refinery should become operational in 2012, when Vietnam's demand for petroleum products will surge to an estimated 20 million tonnes/year from 12.5 million tonnes in 2006.

Meanwhile, a $3.7 billion project to build the Long Son refinery complex in southern Ba Ria Vung Tau Province is awaiting an investment license, according to the Vietnam Oil & Gas Group (Petrovietnam).

Nguyen Viet Son, director of Petrovietnam's Oil Processing Department, said his group and the Vietnam Chemical Corp. will contribute 29% of the total investment. The remaining 71% will be provided by two Thai partners, Siam Cement Group and Thailand Plastic Co. If licensed, the first phase of the project is scheduled for completion in 2011 and the whole project in 2013.

Petrovietnam plans to build three refineries with combined capacities of 20 million tonnes/year, two in central Thanh Hoa and Quang Ngai Provinces and one in southern Ba Ria Vung Tau Province. Vietnam imported nearly 10.4 million tonnes of petroleum products in the first 10 months of 2007, 12.1% over the comparable 2006 period, according to the General Statistics Office.

Suncor's Sarnia plant upgrade nears completion

Suncor Energy Inc. said the final phase of a 3-year upgrade project at its 70,000 b/cd refinery in Sarnia, Ont., is almost complete.

The final phase involved a 3-month shutdown of certain units to facilitate tie-in of new facilities. The company said the refinery

currently is ramping up to full production.

The tie-ins are a part of a $1 billion investment to increase the refinery's ability to process sour crude from the company's oil sands operations in Northern Alberta, as well as to improve the facility's environmental performance by reducing sulfur dioxide emissions, and to enable the production of ultralow-sulfur diesel.

The upgrades to enable production of ultralow-sulfur diesel were completed in 2006. ✦

Transportation — *Quick Takes*

Steady flow may be near for Colombia's Rubiales

Petro Rubiales Energy Corp., Vancouver, BC, said it plans to truck Rubiales field crude to Guaduas field in Colombia for export via the OCENSA pipeline, gradually ending local sales of the heavy oil and as much as doubling netbacks eventually.

Once it reaches Guaduas, the 12.5° gravity Rubiales crude will be blended with crude as light as 18° gravity and the diluted blend will be shipped via the pipeline to the Covenas terminal on the Caribbean Sea as part of the Vasconia stream.

Volumes of as much as 4,000 b/d are to be trucked shortly. New Guaduas unloading facilities expected to be available at the end of first quarter 2008 are to be able to handle 20,000 b/d.

Shipments are expected to grow later to 200,000 b/d with construction of a pipeline to eliminate the trucking. The line is expected to begin service in third quarter 2009.

Petro Rubiales, which said it plans to expand production capacity at Rubiales field to 126,000 b/d from 24,000 b/d, has announced a plan to merge with Pacific Stratus Energy Ltd., Toronto, which owns the tank farm at Guaduas field on the Caguan Block (OGJ Online, Nov. 13, 2007).

Sinopec, Iran gas supply dispute halts LNG plant

Sinopec has stopped work on an LNG receiving terminal in the coastal city of Qingdao, in China's Shandong Province, because it has been unable to secure sufficient gas supplies following the collapse of a planned agreement with Iran.

The $607 million regasification project—a joint venture of Sinopec and power firm China Huaneng Group—was to have an initial capacity of 3 million tonnes/year of LNG, rising to 5 million tonnes/year during a second phase. Construction was originally scheduled to start in 2006 and complete in 2007.

China and Iran signed a memorandum of understanding in 2004 for Sinopec to buy 10 million tonnes/year of LNG from Iran for 25 years, but reports suggest that the two sides have failed to agree on contract terms. The Iranians reportedly think Sinopec's price offer is too low, while Sinopec is said to be concerned that Iran's political instability poses investment risks to the project.

Sinopec reportedly is seeking new supply sources in Australia and is considering changing the location of the proposed plant. Reports did not say where.

Two Japanese partnerships order LNG carriers

Nippon Yusen Kaisha (NYK) Line has signed partnership agreements with two other Japanese firms for joint ownership of LNG carriers.

In the first, NYK and Tokyo Gas Co. subsidiary Tokyo LNG Tanker Co., Ltd., both of Tokyo, signed a joint ownership contract with Kawasaki Shipbuilding Corp. for construction of a 177,000 cu m capacity LNG carrier. The companies also signed a heads of agreement for joint ownership and a long-term charter for the carrier.

NYK Line will hold a 90% stake in the ship, while Tokyo LNG will hold the remaining 10%. NYK Line also was appointed ship manager under the 20 year-term time charter that will start from 2011, when the vessel will be completed.

Construction of the tanker will start in fiscal 2009. The Moss-type carrier will be equipped with four spherical tanks and will be equipped with a Kawasaki advanced reheat turbine plant for propulsion, enabling 15% higher fuel efficiency.

After its completion, the ship will transport LNG from the Northwest Shelf Expansion, Malaysia I and III, the Darwin Project, Sakhalin-2, Pluto, and Gorgon among others.

The agreement marks the second new carrier that NYK will co-own solely with Tokyo LNG Tanker, following a 153,000 cu m capacity carrier planned to be completed in 2009. After completion, this newbuild carrier will be used in an LNG transportation project for Tokyo Gas Co. Ltd., said NYK Line.

In another joint ownership deal, NYK and Mitsui raised $700 million through a syndicated loan to cover some 70-80% of the construction costs for four 145,000 cu m LNG carriers.

Mitsui and NYK will jointly own the four vessels, which are being built by Mitsubishi Heavy Industries and Kawasaki Heavy Industries. The first ship will be delivered in 2009, with the others being delivered in 2010-11.

NYK and Mitsui have already chartered these ships to Taiwan's Chinese Petroleum Corp. for 25 years. CPC will use the vessels to transport 3 million tonnes/year of LNG to Taiwan from Qatar.

TransCanada applies for pipeline expansion

TransCanada Corp. has requested approval from Alberta regulators to construct a 300-km, 42-in. natural gas pipeline on the northern Alberta system to deliver more gas to oil sands producers.

The Calgary company filed an application Nov. 21 with the Alberta Energy and Utilities Board for a construction permit for the 800 MMcfd capacity line. The estimated capital cost of this expansion is $983 million (Can.). The expansion, called the North Central Corridor pipeline project, is intended to address anticipated increased gas demand, resulting largely from increased oil sands development, TransCanada said.

The proposed pipeline would connect the northwestern Alberta system at the existing Meikle River compressor station to the northeast portion of the system at the existing Woodenhouse compressor station.

Construction is anticipated to begin in late 2008.

The first segment of the pipeline is expected to be completed in April 2009. TransCanada anticipates completing the second segment and putting it in service in April 2010, the company said. ✦


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Letters

Upward price bias

This is in response to your editorial, "The curse of $95 oil" (OGJ, Nov. 12, 2007, p. 17).

The headline article in a recent Wall Street Journal (Nov. 19, 2007) was: "Oil Officials See Limit Looming on Production" (Russell Gold and Ann Davis).

ExxonMobil has forecast a peak in non-OPEC crude production by about 2010, after which only OPEC nations will be able to increase supply to meet relentlessly increasing demand from the 1.3 billion people in China and the 1 billion people in India, among other places. OPEC has done its own study and also projects a peak in non-OPEC crude production in the near future. Like it or not, we are about to enter a new world, where "the era of easy oil is over," as Chevron has termed it in one of its advertisements.

There will certainly be large fluctuations in the price of oil in this era, but with a strong upward bias. OPEC producers are fully aware of how valuable petroleum is to modern industrial societies and are gradually raising prices to reflect more fully that value. Fortunately, we have many ways in which to cope in this new world, primarily by beginning to take energy efficiency and conservation seriously. When US consumers buy more hybrids than sport utility vehicles, you will know that the message has finally hit home.

Alfred Cavallo
Energy Consultant
US Department of Homeland Security
Environmental Measurements Laboratory
New York

Calendar

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

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International Oil and Gas Industry Exhibition & Conference, Suntec, +44 (0)20 7840 2100, +44 (0)20 7840 2111 (fax), e-mail: osea@oesallworld.com, website: www.allworldexhibitions.com. 2-5.

Middle East Nondestructive Testing Conference & Exhibition, Bahrain, +973 17 729819, +973 17 729819 (fax), e-mail: bseng@batelco.com.bh, website: www.mohandis.org. 2-5.

International Petroleum Technology Conference, Dubai, +971 4 390 3540, +971 4 366 4648 (fax), e-mail: iptc@iptcnet.org, website: www.iptcnet.org. 4-6.

IADC Drilling Gulf of Mexico Conference & Exhibition, Galveston, Tex., (713) 292-1945, (713) 292-1946 (fax), e-mail: info@iadc.org, website: www.iadc.org. 5-6.

Oil & Gas Maintenance & Technology Conference & Exhibition, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilandgasmaintenance.com. 9-13.

Pipeline Rehabilitation & Maintenance Conference & Exhibition, Manama, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.oilandgasmaintenance.com. 9-13.

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

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 Heavy Oil Challenge: Completion Design and Production Management Forum, Sharm El Sheikh, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 9-13.

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:

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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.

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.

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.

SMN/SPE European Sand Management Forum, Aberdeen, +44 (0) 1483 598000, +44 (0) 1483 598010 (fax), e-mail: dawn.dukes@otmnet.com, website: www.sandmanagement.com. 18-19.

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Offshore Asia Conference & Exhibition, Kuala Lumpur, (918) 831-9160, (918) 831-9161 (fax), e-mail: registration@pennwell.com, website: www.offshoreasiaevent.com. 18-20.

AAPG Prospect & Property Expo (AAPEX), 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.

SPE Deepwater Forum, Phuket, (972) 952-9393, (972) 952-9435 (fax), e-mail: spedal@spe.org, website: www.spe.org. 11-16.

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.

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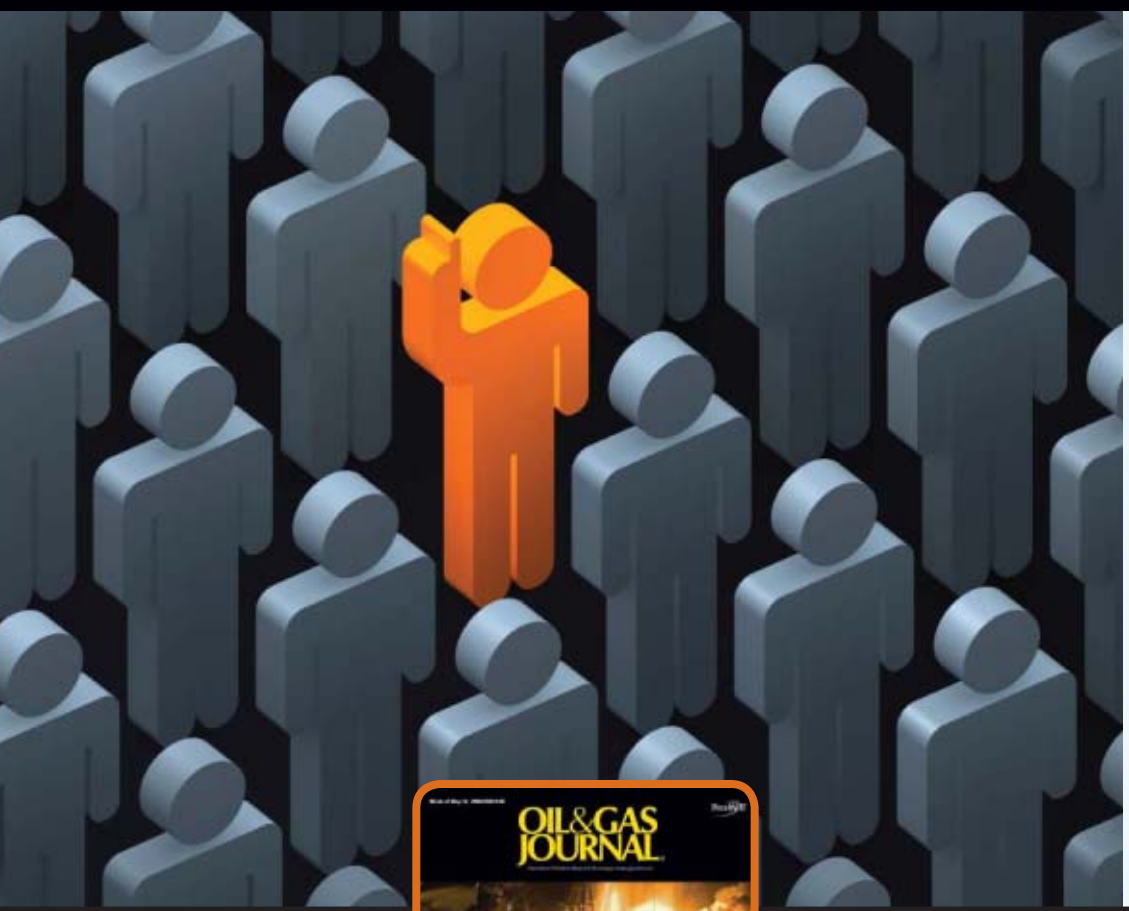

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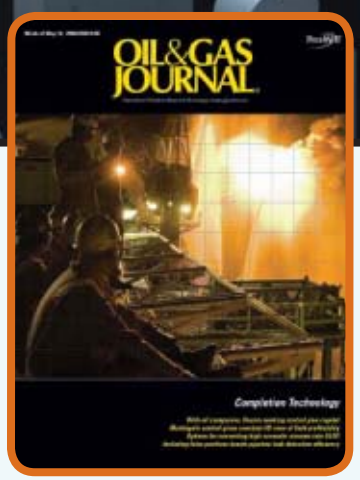

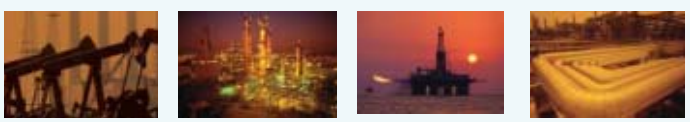

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[1] *Signet Readership Survey (February 2007)*

It's not easy going green

Sam Fletcher
Senior Writer

Panda Ethanol Inc., Dallas, was granted an air permit for its proposed ethanol refinery in Muleshoe, Tex., that is to be fueled by cow manure.

"Unlike other ethanol facilities which burn natural gas to generate the steam used in the ethanol manufacturing process, the Muleshoe facility will be engineered to gasify up to 1 billion lb of cattle manure per year," said company officials. By doing so, they said, "Panda is both conserving the energy equivalent of 1,000 b/d of oil and helping to address a significant environmental problem for the Texas Panhandle."

It might also stifle public complaints about the comparative stench of sour gas from some Texas fields.

The proposed refinery is designed to produce 115 million gal/year of ethanol from 38 million bushels of feedstock-grade corn.

Ethanol outlook

The recent spike of crude prices toward $100/bbl "should be positive for ethanol prices and ethanol producer stocks because it suggests attractive discretionary blending economics," said Eitan Bernstein of Friedman, Billings, Ramsey & Co. Inc., Arlington, Va. Moreover, he said, "We believe a big increase in legislated demand is all but inevitable."

However, Bernstein reported, "Our updated supply-demand analysis strongly suggests that the abundance of new supply expected to come on line over the next 12 months will increase downward pressure on ethanol prices, producer profits, and valuations."

US Department of Energy reports indicate US demand for ethanol surged to 7.1 billion gal/year in August from 6.3 billion gal/year in April, with most of the new demand centered in the Midwest. "This makes sense, given that it requires the least transportation and capitalizes on local loyalties, a reminder that the easiest fruit is typically picked first. However, for US demand to rise materially further, ethanol consumption will have to make substantial gains in other regions," Bernstein said.

He expects the US ethanol market to be "well supplied" next year. "Moreover, with many new plants just starting production and eagerly looking to sell their volumes, we expect petroleum blenders and refiners will have a great deal of leverage in negotiating low prices," Bernstein said.

Green vs. red line

With some advocates pushing to increase auto mileage to 40 mpg while car manufacturers hustle sales with television ads emphasizing speed and performance, there's little wonder auto owners are torn between a desire to be environmentally green vs. an urge to put the pedal to the metal.

And then there's the National Association for Stock Car Auto Racing (NASCAR) in Daytona Beach, Fla.—the largest motorsports organization in the US—which annually sanctions more than 1,500 races at 100 tracks in 39 US states, Canada, and Mexico. Based on television ratings, auto racing is the second-most popular professional sport in the US, behind the National Football League.

It's fast, exciting, and entertaining, and outstanding drivers like Jimmie Johnson, Jeff Gordon, and Dale Earnhardt Jr. are heroes to millions of fans. No wonder it feeds "the need for speed" among many conventional drivers who choose high performance engines over slower but more environmentally friendly vehicles.

With US refiners under government mandate to remove lead and later to find a substitute for methyl tertiary butyl ether in reformulated and oxygenated gasoline, NASCAR continued using lead additives in race cars up until the Auto Club 500 race in California in February. It earlier announced plans to transition to unleaded fuel in the three main racing divisions it sanctions—the Nextel Cup, Busch, and Craftsman Truck series—but not the annual Daytona 500.

These events feature custom-built race cars that gulp down fuel and average only 2-5 mpg at race speeds. It's estimated that some 6,000 gal of fuel are used at an average weekend Nextel Cup event. And that's just on the race track, not including the thousands of fans some of whom drive great distances to attend races. Moreover, NASCAR remains essentially free of the federal regulations of the Environmental Protection Agency, and most of the race cars have no mufflers or catalytic converters or other emission controls.

But privately owned NASCAR has been debating environmental issues with racing partners like Sunoco Inc., the Philadelphia-based refiner that produces the official fuel used in NASCAR races. Although still in the talking phase, NASCAR says it is looking at the development of alternative fuels for racing cars. That, said NASCAR officials, should have "a very small but symbolic impact" on the fuels market. ✦

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Editorial

Congress and royalties

Braying in Congress about a court decision on deepwater royalty relief looks more like blame-shifting than serious concern for federal revenue.

Forty-three senators have sent US President George W. Bush a letter asking what his administration will do about royalty revenue they consider lost (OGJ, Nov. 26, 2007, p. 29). He might start by asking senators and representatives to get their facts straight and learn how to write law.

The oil industry has reason to encourage such an effort. Congress is blaming it, too, for a problem that stems—if it really exists—from legislative ineptitude.

Authority questions

The senators wrote Bush after an Oct. 30 ruling in a federal case involving price thresholds in deepwater leases issued in 1996-97 and 2000. The suit, filed by Kerr-McGee Oil & Gas Corp., now part of Anadarko Petroleum Corp., argued that the Deepwater Royalty Relief Act of 2005 didn't give the Department of the Interior authority to limit royalty suspension with anything but production caps in leases issued in the 5 years after enactment. The judge agreed.

The ruling comes while lawmakers remain angry about deepwater leases issued in 1998-99 without price thresholds. Interior officials have been excoriated in congressional hearings on the omissions, which occurred in a different administration for reasons that remain unclear.

The senators' letter to Bush calls the decision in the Kerr-McGee case "an apparently successful attempt by the oil industry to overturn the requirement in law that they pay royalties when oil and gas prices are above certain threshold levels." But the court saw no such requirement for 1996-2000 deepwater leases.

Indeed, the law treats those leases differently than it does leases issued before enactment and those issued after 2000, when the program reverted to administration by Interior's Minerals Management Service. The short section on 1996-2000 leases contains a clause specifying minimum production volumes for the suspension of royalty relief. It says nothing about price thresholds and in fact contains wording that suggests lawmakers intended production amounts to be the only limit on relief during the 5 years in question.

If that wording in fact conflicts with congressional intent, the fault doesn't lie with an industry trying "to overturn the requirement in law," as the senatorial letter alleges. It lies instead with lawmakers who didn't make "the requirement in law" clear in the first place.

Ultimately, the Supreme Court might decide what the law means. Meanwhile, lawmakers agitated by the court decision should quit exaggerating the cost. The letter to Bush cites an estimate made last year by the Government Accountability Office that a decision favoring Anadarko could keep $60 billion out of the federal Treasury.

That number appears frequently in news reports and statements by politicians. Yet last April GAO called it too high. GAO initially relied on an MMS estimate made in October 2004 but later determined that MMS had overestimated lifetime production volumes of affected leases. "MMS officials agreed with this assessment and said that an updated estimate of foregone revenue from these leases might be considerably lower than the $60 billion figure but that they are not currently working to develop a revised estimate," GAO said.

So the supposedly lost revenue won't be anywhere near $60 billion. That MMS hasn't produced a new estimate is no excuse for repeating a known mistake. Doing so amplifies a controversy that's being distorted to smear an industry that has done nothing wrong. For many lawmakers, of course, smearing the oil business is the whole point.

Royalty concern

The real measure of congressional concern about royalty revenue is oil and gas leasing. The US government denies or restricts access to acreage representing a technically recoverable resource estimated by the Interior Department at 40 billion bbl of oil and 250 tcf of natural gas. With $90/bbl oil and $7/Mcf gas, that's potentially $670 billion in royalty alone. Where's the outrage over that foregone revenue and the associated boosts to national prosperity and energy supply?

Congress should improve more than its handling of facts and writing of laws. Its priorities need work, too. ✦

Changing oil and gas fiscal and regulatory regimes in Latin America

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At the beginning of the 1990s all producing countries in Latin America permitted limited participation of the private sector in the oil and gas industry. The general rule was that the participation was through some form of association with the state-owned oil company with the outside investor bearing all exploration risk. The fiscal regime consisted either of service fees and taxes or of profit oil and taxes. As the decade progressed, all those countries, to varying degrees, introduced policy or legal reforms to allow more private sector participation in the industry. Privatization and deregulation were in vogue. Some countries went as far as dismantling or selling off their state-owned oil companies (Bolivia, Argentina, and Peru). Other countries kept their state companies but broke their monopolies and allowed private companies to come in on a stand-alone basis (Brazil, Colombia). Companies were granted direct and independent rights by new state agencies, and the fiscal regime for the most part switched to tax and royalty. Ecuador and Venezuela maintained the mandatory association with the state companies but increased the opportunity for participation of the private sector. The only country that was and has remained closed is Mexico.

A few countries have stayed the course, notably Brazil, Colombia, and Peru; in the other countries those new policies didn't last long. Some have made a U-turn and become more restrictive than they were at the beginning of the 1990s. "Resource nationalism" has replaced privatization and deregulation. This article provides a short country-by-country review of what has transpired in Latin America in the last 10-15 years.

Argentina

The Argentine state controlled all segments of the oil and gas industry and all public services prior to 1990. The state-owned Yacimientos Petrolíferos Fiscales SA (YPF) had the monopoly of the oil industry. Private companies could conduct exploration and production (E&P) only pursuant to service contracts with YPF. Natural gas distribution and transportation were under the exclusive control of the state company Gas del Estado SE (GdE). Oil and gas production had to be delivered to YPF and GdE under controlled prices.

Starting in 1990, Argentina fundamentally changed its energy policy as part of a broader reform of state activities. Most state companies in all industries were privatized. Private companies are now awarded oil and gas concessions directly by a state agency and ownership of production is vested at the wellhead. The fiscal regime for E&P became one of low tax and a maximum 12% royalty at the wellhead, plus certain bonuses and a surface area-based production cannon. Gas and electric

production, transmission, and distribution also were privatized and deregulated. All through the 1990s oil and gas companies in Argentina had the right to market freely internally or export all hydrocarbon production at unregulated prices.

The Argentine industry thus attracted billions of dollars in investment in exploration, development, and infrastructure, fueled by both domestic demand growth and demand for exports of electricity and natural gas. But this ended with the economic and currency crisis at the end of 2001. Since then the Argentine oil industry began to experience changes. The government made the private sector shoulder the economic burden of policies designed to curry popular favor and to control inflation. Domestic prices were reregulated, and exports were curtailed and taxed. The result has been a steady decline in exploration investment. Price controls encourage record high consumption at the same time that the country now has known gas reserves only for the next 10 years. Oil, gas, and electric production and transportation are operating at their limits. There are fuel and power shortages throughout the country.

The policy responses to this energy crisis in Argentina are not meaningful so far. The production cannon has recently been raised to $1,088/sq km of land used for crude oil or natural gas production. Relaxation of price controls has been limited. The government has created again a state-owned oil company, Energía Argentina Sociedad Anónima (Enarsa). Fiscal incentives for E&P activities are available only to those who agree to associate with Enarsa. Lacking capital, Enarsa must be carried through the exploration phase.

The government is using Enarsa to import gas from Bolivia in order to make up domestic shortfalls. Bolivia sells its gas at a price higher than the regulated price in Argentina. The difference so far is being made up by squeezing more taxes from the dwindling exports to Chile. Once the goose that lays those golden eggs is finally dead, dependence on Bolivia is going to be more costly.

Bolivia's President Evo Morales (front row, center) nationalized the oil and gas industry to return hydrocarbon wealth to the people. Photo from YPFB.

This overall situation will present two problems. The first is that the government is going to have to make up the price difference unless it is willing to increase controlled prices at home. The government seems to abhor this option. The second problem is that Bolivia is going to have a hard time delivering the needed volumes. In the meantime, Venezuela is offering gas to Argentina, selling it fuels, and buying its bonds. Will Argentina go back to having a market oil and gas economy and rely on a vibrant and prosperous private sector as in the 1990s or walk into the crushing enfold of Venezuela? We'll know soon; the current situation is critical and can't last long.

Bolivia

Bolivia has come full circle in a short 10 years. In 1994 under the first government of President Gonzalo Sánchez de Losada, the E&P, transportation, and refinery assets of state-owned Yacimientos Petrolíferos Fiscales Bolivianos (YPFB) were privatized. Up to that point, following the norm in the region, private companies could operate in the country only through associations with YPFB. The 1996 hydrocarbons law allowed private companies to come in on a stand-alone basis under a tax and royalty regime. Companies became entitled to own and freely dispose of all hydrocarbon production upon commercial discovery. Under this law major international oil companies such as Total SA, BG Group PLC, BP PLC, Petroleo Brasileiro SA (Petrobras), and Repsol YPF SA entered the country and investment in hydrocarbons surged. Within a new framework conducive to investment in exploration and infrastructure, Brazil signed up to buy Bolivian gas over the long term and to finance the construction of a pipeline from Bolivia to Sao Paulo. An LNG project to export additional gas through the Pacific was also in active development and seriously considered.

The abrupt ending in the fall of 2003 of Sánchez de Losada's second term in office also ended significant new investments. Serious political instability and growing discontent of the indigenous people feeling disfranchised by successive governments came to light and resulted in serious popular unrest. On July 18, 2004, a referen-

dum was held in which the majority of Bolivian nationals voted in favor of recovering for the state full control over hydrocarbon resources.

In 2005 congress approved a new hydrocarbons law that repealed the 1996 law. The new law reconstituted YPFB and radically changed the framework for the industry but lay dormant until Juan Evo Morales Ayma took office as president of Bolivia a year later. Morales was leader of both the Movement for Socialism political party and of Bolivia's cocalero movement resisting US efforts to eradicate coca crops in that country. Having promised his constituency that the hydrocarbon wealth of the country would effectively go back to the people, Morales issued on May 1, 2006, a decree nationalizing the industry and setting a 180-day deadline for companies to convert their contracts to the new contract regime provided by the 2005 hydrocarbons law or to surrender their operations to YPFB. The new contract regime is that of the "operating contract," under which all production belongs to the state and the contractor has the obligation to deliver to YPFB all the hydrocarbons produced. All the oil companies operating in Bolivia under the 1996 law have now converted to operations contracts under the 2005 law. Another type of contract permitted by the 2005 law is the joint venture or association contract under which YPFB must have a minimum 51% participation. Reportedly, the first association would be with Petróleos de Venezuela SA (PDVSA), the Venezuelan national oil company.

The operations contract is a sort of service contract with YPFB whereby the contractor undertakes to conduct petroleum operations at its sole risk and expense, assuming all costs and providing all required personnel, technology, facilities, materials, and capital in exchange for the reimbursement of certain costs and a fee. YPFB does not assume any risk or liability for the petroleum operations or its results. The production is sold by YPFB as agreed by YPFB. Proceeds from production are divided as follows: first, royalties at the rate of 18% and a direct tax on hydrocarbons of 32% come off the top, then the contractor is reimbursed for the contractually recoverable costs. A portion of the remaining proceeds is the contractor's fee, subject to Bolivian income taxes.

Contractors are currently submitting their work programs and development and investment plans to YPFB for approval under the new contracts. Morales has warned the companies that if they fail to meet their investment obligations, the operations contracts will be rescinded without compensation.

Bolivia soon must deliver the maximum gas export volumes contracted with Brazil. It also is exporting gas to Argentina under a contract which requires a large volume ramp up in a few short years. Domestic demand is surging. To meet domestic requirements and export commitments Bolivia needs several billion dollars in investment in exploration, production, and transportation infrastructure—$3 billion to almost double current production in the next 4-5 years, by some estimates. YPFB does not have the required economic and technical capacity. The private sector has not exactly been nurtured lately to meet this challenge. Bolivia, despite having the second largest gas reserves of the region, thus has international contractual problems to go with never-ending political instability and social unrest. Enter Venezuela again to support a state with investments in replacement of the private sector.

Brazil

Brazil successfully continues on the course charted at the time of its energy reforms in the late 1990s. The Petrobras monopoly over the industry was broken up via a constitutional amendment in 1995, and by 1997 Brazil put in place regulatory bodies and agencies to govern equally the activities of foreign and Brazilian oil companies, state-controlled Petrobras included. E&P blocks are awarded competitively. Contracts grant E&P rights under a tax and royalty fiscal regime with the average royalty rate being 10%. By the end of 2007 there will have been nine international bid rounds. The energy policy and fiscal regime instituted by the Fernando Henrique Cardoso administration have been maintained stable by current socialist President Luiz Inacio Lula da Silva, formerly a labor leader and organizer of the Workers Party.

Brazil is the tenth largest energy consumer in the world and the largest in Latin America. Brazil is the fifth-largest country by geographical area, the fifth most populous country, and the fourth most populous democracy in the world. It is the world's eighth largest economy in terms of purchasing power. Between its local oil production and its leading production of sugar-based ethanol, Brazil is self sufficient in liquid fuels. It is on the natural gas front that things remain challenging. Strong economic growth, together with a sensible policy of avoiding overreliance on hydropower for electric generation, require that Brazil find long term, reliable, and ever growing sources of natural gas supply.

There are three such sources. The first one is local production, but most scenarios show that in the short to medium term it is not going to be near enough to satisfy projected demand. The second source is imported gas from Bolivia. These volumes are limited, however. Bolivia attempted unilaterally to renegotiate the price Brazil pays for this gas. Additionally, Bolivia nationalized refinery assets of Petrobras and

Chavez dominates Latin American political debate

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Venezuelan President Hugo Chavez wields considerable influence in Latin America. Aside from the countries aligned with policies that he favors and supports (i.e., Bolivia, Ecuador, and, to some extent, Nicaragua), Chavez is directly or indirectly part of the political debate in other Latin American countries.

Perhaps with the sole exception of the US president, there is no other political figure who is as well known and whose policies are talked about as much in the whole region. Chavez says his aims are to help the poor and redress inequalities, but what is subject to debate is the means he proposes to achieve that end and whether those means are sustainable over the long term.

Obstacles ahead

There are two fundamental obstacles to Chavez's influence actually taking root in a wider area of Latin America. The first is economic: the availability of cash to pay for the revolution and feed, clothe, and house the people. Unlike prior socialist experiments around the globe, Chavez's policies could have a chance of success in Venezuela, at least in the short term, given the massive amounts of cash easily available to his administration from the export of oil and the increasing global demand for that resource. Monopolizing oil revenue allows for the payment of subsidies in housing, food, health care, and energy and makes up for declining domestic productivity in Venezuela.

Unemployment can be masked by inflating the payroll of state-owned enterprises as needed. Chavez may assume total political control, monopolize all major industries, and take away the independent means for citizens to create wealth because there is state cash available to the president without any controls to pay for the subsistence of citizens.

There are politicians in other countries who would not hesitate to adopt the Chavez model, if they could. Bolivia illustrates this point. President Evo Morales thought that because Bolivia had large natural gas resources it was automatically a wealthy country and proceeded upon his election to dictate new terms to foreign investors (on a take-it-or-leave-it basis) while declaring that the natural gas was going to help to develop Bolivia and improve the condition of the poor.

Unfortunately for Morales, it is not playing out that way. With the private sector in (chased) retreat, Bolivia has no capacity to make the necessary investments to expand production infrastructure and to generate the revenues required to pay for the subsistence of the people.

Unlike oil, natural gas is not a readily marketable global commodity. With no cash, Bolivia's Chavez-like experiment is imploding. Shortages of fuels are seriously affecting other industries, especially agriculture. Inflation looms behind the shortages. Chavez is offering to step in with the needed investments and cash, but he can't spread himself too thin given that Ecuador is positioning itself to be next in needing this type of foreign assistance. Some politicians prone to this policy approach in other countries are watching this and putting their instincts on hold.

The second obstacle is political: forced the conversion of Petrobras's E&P contracts into service contracts at far less favorable terms. Brazil therefore does not view Bolivia as a reliable source of supply or as a country in which long-term investments can be made with confidence. Brazil will continue receiving gas from Bolivia under the current contract but will not seek to increase volumes or to extend its term. Bolivia's populist energy policy is going to cost it its biggest costumer.

The third source is LNG. Petrobras is currently developing two LNG terminal projects and is talking about a third. For Brazil, LNG is the only real solution to long-term reliable gas supply to supplement domestic production. The interconnection with Argentina and Bolivia never translated into real integration. The policies in these countries are devised for short-term political gain and are too disparate with that of Brazil's. The conditions for true integration do not exist.

Colombia

Colombia has followed and successfully maintained a policy similar to that of Brazil. Up to 2003, private sector companies could operate in the country only through production-sharing agreements with state-owned Ecopetrol SA. Now private sector companies can obtain E&P rights directly through the Agencia Nacional de Hidrocarburos (ANH). The fiscal regime is one of tax and royalty. Ecopetrol has been stripped of any regulatory and policy roles, and it operates along side other companies under the same rules and contract terms. The government has sold a mi-

some people just make different choices. Chavez's influence has had intrinsic limits when tested at some elections against well-presented alternatives. Almost every single country in Latin America has had presidential elections in the last 24 months. In most of those elections Chavez and his policies were a factor.

Some of the candidates supported by him made it to the runoff elections. But more often than not, alternative policy models were voted for. Mexico and Peru clearly illustrate this different choice, where candidates proposing Chavez-type policies lost.

High political risks

Elections, however, will take place again. One can be fairly confident that a Chavez-like candidate is unlikely to win the presidency in a country like Chile, which seems to have consolidated a system based on a pluralistic democracy, the rule of law, and a market economy. Yet the fact remains that in many other countries such an event may still happen.

Only time will tell whether those countries that rejected a Chavez-like candidate in the last round of elections will do so in the next. In this sense, while in the short term a number of countries remain committed to open and free economies, the political risk long term is still somewhat high.

nority interest in Ecopetrol in the local stock market.

Colombia is benefiting from better internal security and legal stability. After the reelection of President Álvaro Uribe Vélez for a second 4-year term in May 2006 [making him the first president to be consecutively re-elected in Colombia in more than 100 years], the local economy has continued growing steadily, and foreign direct investment in hydrocarbons is soaring, having reached the record level of $1.8 billion in 2006 and $582.6 million in the first quarter of 2007. In its fourth year of activities as a licensing entity, ANH has proven that the new fiscal regime and model contract are effective tools to attract new foreign investment. Such new fiscal regime includes royalties on production of 8-25% for crude oil, 6.4-20% for onshore and offshore natural gas to 1,000 ft depth, and 4.8-15% for offshore gas at greater depths. There also is a windfall profits payment to ANH that applies when the accumulated production exceeds a certain volume and the price exceeds a predetermined benchmark. Colombia has among the most competitive terms in Latin America, having signed a total of 105 new E&P contracts as of Aug. 31.

Colombia's oil reserves, production, and exports have been declining for years, and the government is determined to arrest this trend before the country becomes a net oil importer. New policies in dealing with the guerrillas are resulting in fewer reported attacks on production and transportation facilities. The kidnapping count also is down. As a whole, the investment climate for oil and gas companies in Colombia is better now than it has been in recent memory.

Ecuador

Ecuador has maintained the dominant role of state-owned Empresa Estatal Petróleos del Ecuador (Petroecuador). Companies operate there through production-sharing contracts with Petroecuador. The fiscal regime is one of profit oil and tax. Up until a few years ago the government intended to reform the role of Petroecuador, simplify E&P contracting, and improve the fiscal regime. Those initiatives never materialized, as they were routinely blocked and boycotted by nationalist and populist politicians, indigenous groups, the military, environmentalists, labor unions, and other interest groups. Private companies have been involved in tax and environmental disputes and contract cancellations.

The bad news became worse recently with the announcement by President Rafael Vicente Correa Delgado that the windfall profits tax rate was going to be increased to 99%, on the basis of oil revenues from sales at prices exceeding those in effect at the time the original contracts were signed. This tax was created with a 50% rate in early 2006. "We are not going to be cheated again," said President Correa, an economist who previously served as finance minister. This comes at a time when Ecuador exports crude oil and imports almost all the oil products it uses and is looking at having to import natural gas from Colombia and Peru.

Ecuador recently elected members of an assembly that will rewrite the constitution. Allies of the president won a majority. The stated aims include having a new framework to increase social spending, strengthen the government's control over natural resources, and reform property rights.

It is not expected that Ecuador will become closed to foreign investment, but the government is expected to turn existing contracts into service contracts through which companies would be paid a production fee and reimbursed for investment costs. All production would be owned by the state. Similar to Bolivia, Ecuador is not creating the conditions necessary to have the private sector contribute to meeting its challenges. But although he and Venezuelan President Hugo Chavez are friends, Correa has said he is not part of the Venezuela-Bolivia movement. PDVSA has said that it will build a refinery in Ecuador and invest in exploration there.

Mexico

Mexico remains closed. It is illegal for private companies to risk investment capital in the oil and gas business in Mexico. The state monopolizes all segments of the industry and operates through Petróleos Mexicanos (PEMEX). This monopoly is maintained in the face of declining oil reserves, soon-to-occur declining oil production and export revenues, inadequate capital investment in infrastructure, and continued increases in domestic demand

Exploration in Venezuela requires a joint-venture with PDVSA as majority participating partner.

for gas and oil products. Mexico exports crude and imports oil products and natural gas.

The multiple service contracts (MSC) for exploration, development, and production of nonassociated gas reserves in the Burgos basin in northeastern Mexico are as much as the law permits. These are not true E&P contracts in the traditional sense. They are fee-based service contracts for units of work performed. There is no upside, but there is downside: the contractor receives its fees only if there is enough increased production sold by Pemex in exchange for funds that are sufficient to cover the fees. Production under the MSC regime is not going to bridge the gap between gas demand and production in Mexico.

Peru

Until the early 1990s, E&P contracts in Peru were in the form of risk service agreements with state owned Petróleos del Peru SA (Petroperu). The fiscal regime was one of service fee (in cash or kind) and taxes. Peru's system changed with the privatization of Petroperu's assets and the passage of the hydrocarbons law of 1993. This law created an independent licensing agency, Perupetro, which grants E&P rights to private companies under a tax and royalty regime with royalty rates of 5-20% based on production levels. Peru has had remarkable policy continuity and stability through succeeding presidents since then. The country has made a genuine effort to improve the terms and conditions offered to oil companies and to provide incentives for investment. These include alternative methods for calculating royalties, free sharing of technical information, reimbursement of sales taxes incurred during the exploration period, accelerated bidding procedures, etc. The result has been a noticeable revival of interest in upstream activities. Together with Colombia, Peru offers the most attractive fiscal terms in the region.

The biggest testament to policy continuity was the arrival of Camisea gas in Lima in August 2004 and the subsequent development of an LNG export terminal. The LNG production facility just south of Lima, the first in Latin America, is currently under construction. Output from this project has been committed to Mexico. Additional gas availability in the country also is generating strong investor interest for petrochemical projects.

Venezuela

Venezuela first nationalized its oil industry in 1975, when PDVSA was created. Under the nationalization law of that time, exploration and production rights could be obtained by private companies only if authorized by an act of congress. This law was used only for four heavy crude oil projects in the Orinoco Belt under a tax and royalty regime with low rates. Under the administration of President Rafael Caldera in the early 1990s, Venezuela subsequently started a policy of increasing investment opportunities to the private sector and thus attracted numerous foreign and domestic oil companies under "operating service" contracts with PDVSA. The objective of these contracts was to grant operating rights over marginal fields (by PDVSA standards) and compensate the contractor with a cash fee per barrel of oil produced and delivered to PDVSA. In practice these contracts did not impede exploration.

After President Chavez first took office in December 1998, several energy policy changes have taken place in Venezuela. He started by raising taxes and royalties, then decided to alter fundamentally the contract regime. All private sector companies had to convert their contracts into joint ventures with PDVSA, with PDVSA taking more than 50% participating interest. This was done under threat of total nationalization. Most companies complied, but a few did not. Those that did not are no longer operating in the country.

The oil E&P framework today in Venezuela is that of a joint-venture company with PDVSA, where PDVSA must have more than 50% participating interest. All production is acquired by PDVSA. The joint ventures pay taxes and royalties. ✦

The author

Jose L. Valera is a partner in King & Spalding LLP's Global Transactions Group. Valera's practice focuses on project development, mergers and acquisitions, privatizations, and financing of oil and gas and electric energy projects. He is a native Spanish speaker and is fluent in French. Valera has provided counsel to the Angola LNG project on all feed gas supply matters and development of gas gathering pipeline network. He has provided presentation of major and independent oil companies in the negotiation and drafting of operations, production sharing, and license agreements throughout Latin America as well as representation of electric utilities and independent power producers in the development and construction of electric generation facilities, the purchase and sale of electric generation, transmission, and distribution assets, and the privatization of electric generation and distribution companies. Valera obtained his first JD in 1981 from Catholic University in Lima, Peru. He received his second JD from the South Texas College of Law in Houston, Texas, in 1986. He is a member of the Lima, Texas, and Louisiana Bar Associations.

US House chair asks EPA about groundwater agreement

Nick Snow
Washington Editor

A US House committee chairman raised new questions about whether the Environmental Protection Agency is effectively monitoring a 2003 memorandum of agreement intended to eliminate injection of diesel fuel into underground drinking water.

Henry A. Waxman (D-Calif.), chairman of the Oversight and Government Reform Committee, said that Benjamin H. Grumbles, EPA's assistant administrator for water, described the MOA between EPA and the three biggest US oil field service companies during a hearing by the committee on Oct. 31.

"This MOA, which appears unenforceable, had been executed to address EPA's concerns that benzene, toluene, ethyl benzene, and xylene (the BTEX compounds) were being introduced into underground sources of drinking water during hydraulic fracturing activities," Waxman wrote in a Nov. 26 letter to Grumbles.

He said written testimony submitted by Grumbles said the companies (BJ Services Co., Halliburton Energy Services Inc., and Schlumberger Technology Corp.) "have certified in written reports that they have converted to nondiesel fluids and are in full compliance with the MOA." Grumbles also testified orally that EPA "was monitoring to see if the three signatories were living up to that agreement" on "an annual basis," according to Waxman.

'Informal e-mails'

"Contrary to your testimony, however, the documents EPA has provided to the committee to support your testimony are not certified statements of compliance. Rather, they are three informal e-mails from the companies," he wrote in his letter to Grumbles.

Waxman said the e-mail messages show that EPA contacted the companies to determine whether they were continuing to comply with the MOA 2 days before the hearing. Only Halliburton responded by Oct. 30 when EPA submitted Grumbles's written testimony to the committee. The other two arrived at EPA the morning of the hearing, the lawmaker said.

"Your testimony also states that 'the three companies . . . have converted to nondiesel fluids.' Of the three responding companies, however, only BJ Services explicitly states that diesel fuel is no longer used. This is relevant because a company can be in compliance with the MOA and still use diesel fuel as a fracturing fluid," Waxman continued.

In his Oct. 31 appearance before the committee, Grumbles said the three service companies voluntarily agreed to quit using diesel fuel in their fracturing fluids in 2004 after a study by EPA, the US Department of Energy, US Geological Survey, and several states found that diesel posed the only significant health risk in coalbed methane fracturing operations. The 2005 Energy Policy Act specifically exempted hydraulic fracking of CBM from regulation under the Safe Drinking Water Act as long as diesel fuel was not used, the EPA official added.

'Less than impressive'

Waxman said Grumbles "assured the Congress and the public that the 2003 MOA was being actively monitored and complied with. But the basis of your statement appears to be less than impressive: a hastily collected set of three e-mails amounting to just half a dozen sentences.

If EPA has a solid basis for its assurances that these companies are not using diesel fuel when fracturing oil and gas wells, please provide it to the committee," he told the EPA official. He requested a response by Dec. 16.

He also wrote letters to chief executives J.W. Stewart of BJ Services, David J. Lesar of Halliburton Co., and Andrew Gould of Schlumberger Ltd. requesting documents showing the number of wells the company hydraulically fractured in each state in 2005, 2006, and 2007; the identity and total volume of chemicals and other products used in such operations; the percentage of products recovered from such operations if available; and any documents related to the products' environmental effects by Dec. 17.

Waxman also wrote a letter to Randy Eresman, president and chief executive of Encana Corp. in Calgary, requesting the same information he sought from the service companies by the same deadline. The independent producer was mentioned during the committee's Oct. 31 hearing, where some witnesses alleged illnesses from oil and gas operations in the Rocky Mountains. ✦

UK's HSE criticizes North Sea energy structure

Uchenna Izundu
International Editor

More than half of the oil and gas industry's basic assets in the UK North Sea that have been inspected over the past 3 years are in poor condition, and companies will face closure or prosecution if they do not improve safety standards, warned the UK Health and Safety Executive (HSE) in a report.

After inspecting almost 100 oil and gas platforms, HSE said various safety-related incidents had occurred because of the poor upkeep of basic structures, and that some maintenance backlogs were "unacceptable."

In the KP3 report, which investigated

WATCHING GOVERNMENT

Nick Snow, Washington Editor

Distant events, local impacts

Testimony at a US Senate subcommittee hearing in North Dakota took a close look at how local markets can feel the impacts of seemingly distant events.

US Sen. Byron L. Dorgan (D-ND), who chairs the Appropriations Committee's Energy and Water Development Subcommittee, held the hearing in Bismarck to examine gasoline and diesel shortages in upper Great Plains states this summer and fall. Officials from area refiners, a pipeline, and two petroleum marketer associations testified.

So did Howard Gruenspecht, deputy administrator of the US Energy Information Administration. North Dakota, he observed, receives oil products through the NuStar and Magellan pipelines and from northern refineries such as Tesoro's plant in Mandan, ND, and Cenex's in Laurel, Mont. Several refineries that serve the state experienced outages, both planned and unplanned. "The Coffeyville refinery in Kansas that flooded this past summer feeds directly into the Magellan system," Gruenspecht said.

Pull on supply

Refinery outages elsewhere also had an impact. Some of the biggest, such as at BP PLC's 400,000-b/d Whiting, Ind., plant, increased pressure for products from upper Midwest refineries. But competition also grew for supplies from Explorer and other pipelines from the Gulf Coast. "This pull on supply competes with volumes that might otherwise move further west," Gruenspecht said.

Planned outages can be less disruptive but still limit supplies, he added. While a refiner planning maintenance usually lines up supplies from other sources to meet contractual needs, it might not include noncontract or spot purchasers. A planned outage also might take longer because problems are found when maintenance begins, forcing a refiner to buy more spot market products for contract customers, according to Gruenspecht.

"During times such as were seen this past summer, the federal and state governments looked at options to relieve the situation," he said. "At the end of August, the federal government granted North Dakota's request for a waiver to use some gasoline supplies from Canada that were thought to be slightly 'off-spec' from US summer gasoline requirements. Still, gasoline supplies remained tight."

No diesel waiver

Meanwhile, diesel prices started to rise from growing harvest demand. Gruenspecht said he understood federal and state officials discussed distillate fuel supply and decided not to provide a waiver because supplies were not available.

Terminal outages also made truck drivers travel greater distances to find oil products, he said. North Dakota and other affected states issued executive orders approved by the Federal Motor Carrier Safety Administration to extend service hours for fuel supply truck drivers.

"Refineries are returning to more normal operations, which will ease the tight balance in North Dakota, but we cannot predict exactly when the problems will cease," Gruenspecht said. ✦

the safety and integrity of offshore installations and their equipment, HSE noted that the sector had made some improvements in its safety record but stressed that "more must be done."

Health and Safety Commission Chair, Judith Hackitt said: "In the light of the findings from the KP3 report, asset integrity will continue to be one of the main priorities for HSE's offshore division in 2008 and for the foreseeable future, but it must also be clear that it is for the industry itself to show leadership and face up to its responsibility." No companies were named in the report, but she said HSE would "name and shame" if necessary.

The criticisms followed comments by trade unions, which argued that some operators jeopardize their workforce's safety. Royal Dutch Shell PLC has been given several HSE "improvement notices" in recent years, and it has suffered strong criticism from its staff about safety. However, Shell stressed that safety is a priority in its operations.

Ian Whewell, Head of HSE's offshore division, recommended that companies coordinate activities across the board to prevent safety incidents. "The report identified that significant improvements in the sector could be achieved without major capital expenditure but through better planning, improved training, and clear statements of performance standards in testing and maintenance routines," said Whewell.

Oil and Gas UK, which represents the industry, welcomed the report, saying it would work closer with HSE to ensure that good practices are learned. The industry has spent £3 billion on asset integrity. Malcolm Webb, chief executive of Oil and Gas UK said the publication of the KP3 report "will help us sharpen our industry's focus on those areas that require greater attention and help steer our on-going industry initiatives."

But David Smith, vice-president, energy sector, with Celerant Consulting, an operational advisory firm, warned that unless asset integrity was viewed as

key to profitability, it would be difficult to see any significant improvements in the industry's safety record.

"Assets that demonstrate high levels of integrity are more productive, and more consistently productive, over time," he said. According to Celerant, many companies collect too much or inappropriate data, which prevents senior and middle management from truly understanding their operational picture.

Earlier this year at Offshore Europe, Whewell accused many companies of being dismissive of their safety representatives on offshore platforms as an unnecessary regulatory burden. ✦

Eurogas: EU to use gas as link to sustainable energy

Doris Leblond
OGJ Correspondent

Natural gas can play an important role in the 27 European Union member states over the next decades as "a bridging fuel" to a sustainable energy future, said the gas trade group Eurogas in its first evaluation and analysis of the future role of natural gas in Europe. Current president of Brussels-based Eurogas is Domenica Dispenza, Eni SPA gas and power chief operating officer.

Eurogas's newly established forecasting taskforce noted that expected investments in new energy efficiency and climate change commitments will reduce energy consumption growth in

Tombua Landana platform template complete

Chevron Corp. subsidiary Cabinda Gulf Oil Co. Ltd. took delivery Nov. 26 of the giant Tombua Landana platform template, which was loaded from Heerema Fabrication Group BV's Heerema Vlissingen construction yard in Zwijndrecht, the Netherlands, to a seagoing barge for transport to Angola. The 1,554-ft, 76,000-ton platform will be installed about 50 miles off Angola in 1,200 ft of water. Construction on the template and the 12 625-ft piles—the longest ever built—began in July 2006. The template has been built with a tolerance of only 3 mm between the cylinders, where the piles have to be driven into the seabed. Photo from Heerema Fabrication.

WATCHING THE WORLD

Eric Watkins, Senior Correspondent

Corruption lurks in Brazil's waters

Brazilian Defense Minster Nelson Jobim claims that an 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 said. But lost production at Brazil's platforms has recently cost more than any attack that would require a nuclear submarine.

That's clear to anyone who follows the news about Brazil these days. The real enemy is not lurking offshore. The real enemy appears to be well ensconced in onshore boardrooms.

Evidence of that emerged recently when Brazil's Federal Audit Court, better known as TCU, halted the payment of $182 million by state-run Petroleo Brasileiro SA (Petrobras) to two local shipyards.

Petrobras overcharged?

The payments were the remainder of the construction cost for the P-52 and P-54 oil platforms that Petrobras is about to take on stream just off Brazil's coast in coming weeks.

The court halted a $92.2 million payment to the Keppel Fels shipyard and an $89.3 million payment to the Jurong shipyard, arguing it found signs that Petrobras was being overcharged for the construction of the two structures.

In June Petrobras had already said construction costs for the P-52 were coming in at $1.1 billion, or 20% over their original budget.

On Nov. 20 Brazilian officials acknowledged that Petrobras is having problems increasing production in existing fields with new offshore platforms and floating units.

Average production by Petrobras during January-September reached 1.796 million b/d, an increase of just 33,000 b/d over the same period in 2006. This is considerably lower than the 440,000 b/d of additional production expected from the new platforms and floating units purchased over the past 21 months.

Corruption at play?

Petrobras Chief Financial Officer Almir Barbassa, in a conference call with investors, admitted that the firm has problems bringing the new units to full production and fully exploiting their installed capacity.

"We're looking for other ways to make full use of them," he said, adding, "It's part of the process. Some oil wells respond in a different way because of the geological structure of the deposit. We still don't have the solution."

He did not mention the corruption which has hit the country's offshore units in the past year—and hit them hard.

Remember? In July Brazilian federal police arrested three top Petrobras executives, along with the directors of three shipyards—Angraporto Offshore, Maua Jurong, and IESA—and others for alleged involvement in fixing bids of contracts for the repair of at least three offshore oil platforms.

Petrobras said it had suspended its employees and installed a commission to eliminate immediately any possible irregularities. Maybe some of those possible irregularities have yet to be fully torpedoed. ✦

the EU 27 over the next 25 years to the "disproportionately" low level of 0.5%/year, compared with 1.6%/year for the rest of the world. Data for the forecast were compiled from industrial sources, including 30 gas companies of members and also of Switzerland and Turkey, and from many associated national gas industry federations.

While the taskforce points to a 34% energy efficiency improvement to 2030, it indicates that under a number of different scenarios examined, fossil energy sources will continue to be the backbone of Europe's energy supply.

Eurogas expects the largest increase in gas consumption will come from electric power generation at a growth rate of 2.7%/year. Its share will increase to 38% of the total 625 million tonnes of oil equivalent (MMtoe) of gas demand in 2030, up from 28% in 2005. Volume growth in residential-commercial use will slow to 0.4%/year to 194 MMtoe. In the industrial sector, with some support from emissions trading, gas sales will increase by only 1%/year to 156 MMtoe in 2030.

Gas supply will continue to rely on long-term contracts despite increasing short-term agreements. The task force indicated that the EU gas industry has already contracted gas deliveries from regions outside Europe that fully cover foreseeable demand until 2015, at which time a "substantial gap emerges between demand and the supplies from European production or imported from outside Europe."

Demand for additional gas supplies will jump to 22% in 2020 and to about 39% in 2030—from 10% in 2015. This is why the European gas industry is now focusing its gas procurement on the period after 2015. A huge effort and substantial investments by suppliers will be required to mobilize this gas in time, considering the growing global gas demand and decreasing indigenous production in Europe, cautions the task force, which also points to stiffer competition for supplies on international markets. ✦

Usumacinta rig leak may force Pemex to shut down well

Eric Watkins
Senior Correspondent

Petroleos Mexicanos may close its Usumacinta oil rig and the Kab 121 oil well in the Bay of Campeche due to a continuing oil and gas leak, according to a senior company executive.

Pemex Exploration & Production first is "analyzing the corresponding technical alternatives" to determine if the leak can be stopped. "It is a very technical issue." said Mariano Ruiz-Funes, coordinator of advisors to Pemex general director Jesus Reyes Heroles.

Ruiz-Funes told Mexico City's El Universal newspaper that the firm has had problems at the site since Oct. 23, when the Usumacinta slammed into the valve tree of the Kab 121 oil well, causing the leak that has yet to be controlled.

Meanwhile, he said, Pemex will return to "its roots and exploit land reserves, mainly in the municipality of Chicontepec, Veracruz, in order to obtain crude oil, but especially gas in the short term."

Pemex's investment plan

Regarding main investment projects at Pemex during 2007-12, he said it is fundamental to carry them out "together with the investment and participation of the private sector, in its diverse forms."

He said Cantarell reserves will require investments of $11-14.5 billion, despite the field's being in a phase of decline, because 98 oil wells are needed, along with three marine structures and 84 km of pipeline.

Ruiz-Funes also said Chicotepec will require investment of $10.5-14.5 billion for 5,421 new oil wells, while Burgos needs between $7.5-10.5 billion for 2,681 new wells, and Ku-Maloob-Zapp will need $6.5-9 billion for 164 new wells, 18 oil rigs, 50 pipelines, and three storage tanks.

Meanwhile, regarding security in the country's oil industry and the recent attacks that took place on Pemex installations, Ruiz-Funes said Pemex alone cannot protect all its surface installations, some 20,000 in all. Saying it is "physically impossible" to watch over all these installations with its own personnel or other methods, Ruiz-Funes said the task is for the federal government.

In July, Mexico's Navy, with an eye on potential terrorist attacks as well as recent acts of sabotage, began installation of a radar system to operate in the Bay of Campeche region, home to 70% of the country's crude oil production (OGJ Online, July 27, 2007).

Earlier, Mexico increased security measures at strategic installations in the country following a series of bombings on Pemex-operated fuel pipelines (OGJ Online, July 17, 2007). ✦

COMPANY NEWS

Penn West Energy to acquire Canetic Resources

Penn West Energy Trust announced that it would buy fellow Canadian trust Canetic Resources Trust, Calgary. The combined company, to be called Penn West, will have production of 200,000 boe/d. The transaction is valued at about $3.6 billion (Can.).

In other recent company news:

- Separately, Canetic said it signed a preacquisition agreement under which it will make an offer to acquire Titan Exploration Ltd., Calgary, for $116 million.
- Colombian operators Pacific Stratus Energy and Petro Rubiales Energy plan to merge as Pacific Rubiales Energy Corp. in a deal worth $2.5 billion (Can.).
- Oranje-Nassau Groep BV subsidiary Oranje-Nassau Energie BV has agreed to acquire all of Devon Energy Corp.'s oil and gas interests off Gabon for $205.5 million.
- UK-based Centrica PLC subsidiary Direct Energy of Toronto agreed to buy Canadian oil and gas company Rockyview Energy Inc. for $113 million (Can.), including assumed debt.
- The European Commission has approved the acquisition of Romanian refiner and product distributor Rompetrol Group by KazMunaiGaz PKOP Investment NV.
- Chevron Corp. agreed to pay $30 million to settle charges that it violated the Foreign Corrupt Practices Act by allowing kickbacks to be paid to the Iraqi government during 2001-02, the US Securities and Exchange Commission said on Nov. 14.
- Cal Dive International Inc. and its parent, Helix Energy Solutions Group Inc., agreed to pay $2 million as part of a settlement to resolve alleged violations of a 2005 consent decree, the US Department of Justice said on Nov. 26.

Penn West to buy Canetic

Penn West and Canetic's combined assets will include interests in Western Canada's conventional oil and natural gas pools and also will include oil sands, coalbed methane, shale gas, and

PERSONNEL MOVES AND PROMOTIONS

Pioneer makes several executive appointments

Pioneer Natural Resources Co., Dallas, announced three executive appointments related to continued expansion of its operations in the US, South Africa, and Tunisia.

The company has divided executive responsibility for US operations, naming **Jay Still** executive vice-president, domestic operations, a position also held by **Danny Kellum**.

Kellum will continue to direct the asset teams in the Permian, Midcontinent, South Texas, and Mississippi areas, while Still will assume responsibility for the asset teams in the Rockies, Alaska, and the Barnett shale.

Previously, Still served as Pioneer's executive vice-president, western division. He joined the company in 1995 and was appointed head of the western division in September 2004. Prior to joining Pioneer, Still spent 10 years with Mobil Oil Co. in various drilling, operations, and reservoir engineering assignments.

Additionally, the company has promoted **David McManus** to executive vice-president, international operations. He joined the Pioneer team in early 2005 as vice-president, international operations, directing operations in South Africa and Tunisia. Before joining Pioneer he served as executive vice-president with BG Group. He also served as president of ARCO Europe and held senior positions with Lasmo PLC, Ultramar, and Royal Dutch Shell PLC.

Also, **Denny B. Bullard** has been promoted to vice-president, operations services. Bullard will have oversight of drilling, facilities, purchasing, and various compliance functions of the company.

Bullard previously was vice-president, engineering and development, of Pioneer's operating subsidiary. He joined the company in 1991 and has served in various senior capacities, including as vice-president, Gulf Coast operations, for Pioneer's operating subsidiary. Prior to joining Pioneer, Bullard held engineering and managerial positions with Conoco Inc. and Damson Oil Corp.

Other moves

ExxonMobil Lubricants & Petroleum Specialties Co. (ExxonMobil LPS) has appointed **Alan J. Kelly** as president and has elected him vice-president of the parent company effective Dec. 1. Kelly succeeds **Jerry L. Kohlenberger**, who will retire Jan. 31, 2008, after more than 33 years of service.

Kelly began his career with the company in 1981. He held a variety of positions in the UK, the Netherlands, Japan, and the US, working in the company's fuels and lubricants marketing activities and refinery logistics and

enhanced oil recovery projects.

Closing, subject to regulatory approvals, is expected during January. The combination is subject to approval of at least two thirds of Canetic unitholders.

Penn West unitholders will own 67% of the combined trust, and Canetic unitholders will own 33%.

Terms call for Canetic unitholders to receive 0.515 of a Penn West unit for each Canetic unit on a tax-deferred basis for Canadian and US tax purposes.

Canetic unitholders are scheduled to receive $15.84/unit for every Canetic unit based on the closing price of Penn West units on the Toronto Stock Exchange as of Oct. 30.

Canetic may buy Titan

Titan's board agreed unanimously to support the offer. Materials were to be filed and provided to Titan shareholders by mid-November.

Canetic said it will acquire production of more than 1,800 b/d of oil equivalent, 63% oil, and a Canetic-estimated 7.3 million boe of proved and probable reserves.

Canetic also will assume a dominant position in a strategic Saskatchewan trend. The acquisition includes more than 49,000 gross acres in the Leitchville area of Southwest Saskatchewan near Canetic's existing 45,100 gross acres in the Jurassic Lower Shaunavon trend, where Titan produces more than 900 boe/d.

Canetic said the Leitchville area is an emerging play with great development and long-term reserve addition potential.

The acquisition will expand Canetic's position in the trend by more than one-third to 300 gross drilling locations.

The Lower Shaunavon trend contains large reservoirs with pay zones 4-16 m thick, relatively low permeability, and 22° gravity oil.

Development has been focused on the Upper Shaunavon for several years due to difficulty in producing from the Lower Shaunavon, Canetic said, but improvements the past year in drilling and completion techniques similar to those in the emerging Bakken play "have proved key to the potential 'unlocking' of significant reserves and production in the Lower Shaunavon trend," Canetic said.

Canetic contemplates drilling four horizontal wells/sq mile at Leitchville.

The rest of Titan's production is in northern Alberta and British Columbia.

Firms form Pacific Rubiales

The combined Pacific Rubiales will have production estimated at 30,000 boe/d in 2008, the largest independent acreage portfolio in Colombia, and several blocks in Peru.

The merger requires approval by two thirds of Pacific Stratus shareholders.

supply operations. In 2001, he was appointed regional director, North America, for ExxonMobil LPS.

Kelly became general manager, corporate planning for ExxonMobil in 2003. In 2006, he commenced a special assignment as project director of the National Petroleum Council's Global Oil and Gas Study, commissioned by the US Department of Energy.

Kohlenberger started his career with the company in 1974. He held numerous engineering, technical, and management positions at refineries in California, Illinois, and New Jersey. In 1994, Kohlenberger was appointed general manager of the Jurong refinery in Singapore, and in 1996 became vice-president and general manager, central engineering, for Mobil Corp. In 1997, he was appointed general manager, global information systems, and became president, ExxonMobil Global Services Co., in 2000.

Kohlenberger was appointed president, ExxonMobil LPS, in 2002.

Royal Dutch Shell PLC has appointed **Willem Schulte** chief scientist, reservoir engineering.

Schulte

Schulte has more than 28 years of experience as a reservoir engineer and is recognized for his expertise in improved and enhanced oil recovery technologies with Shell and in the oil and gas industry.

Schulte has spent a large part of his career researching complex displacement mechanisms, and has contributed to key areas such as chemical flooding and field depressurization.

He has served as Shell's value assurance team leader and in this capacity has seen many of the challenges around improving recovery in existing oil fields.

Calvalley Petroleum Inc., Calgary, has made several executive appointments.

Grant Harms was named vice-president, engineering and operations. Harms has 26 years of industry experience, including 7 years in Indonesia, Russia, and Kazakhstan. Most recently Harms cofounded and served as chief operating officer and vice-president of production for Los Altares Resources Ltd., a private western Canada company.

Terry McCoy has been named vice-president, exploration. McCoy has more than 37 years of senior oil and gas executive experience. He has served as vice-president of exploration and land at Murphy Oil Co., Poco Petroleums Ltd., and Burlington Resources Canada Ltd., where he also served as president. Prior to 1990, McCoy held executive positions at Columbia Gas Development of Canada Ltd., Conwest Exploration Co. Ltd., Union Oil Co. of Canada, and Amoco Canada Resources.

Calvalley also has named **Geoff Martin** as manager of geophysics, and **Lorne LeClerc** as manager of exploration.

A vote will be set for early 2008. Both boards approved the deal unanimously, but they have not yet signed a definitive agreement.

Petro Rubiales owns 100% of Meta Petroleum Ltd., a Colombian concern that operates Rubiales and Piriri oil fields in the Llanos basin. Pacific Stratus produces a net 1,900 b/d of oil and has working interests in the Caguan, Dindal, Rio Seco, Puli B, La Creciente, Moriche, Guama, and Arauca blocks in Colombia and Blocks 135, 137, and 138 in Peru.

Devon divests Gabon assets

Oranje-Nassau Energie's acquisition, subject to approvals, is expected to close by yearend. Devon said it does not expect to incur any taxes on this transaction.

The assets being acquired includes an 18.8% interest in the Kowe block, which contains the Tchatamba oil field complex with three producing fields operated by Marathon Oil Corp. These fields are expected to add 3,750 b/d of oil to Oranje-Nassau's net production of about 14,500 boe/d at yearend.

The other assets are a 50% interest in the Agali exploration block operated by Anadarko Petroleum Corp. and an option to earn a 53% interest in a portion of the Gryphon Marin exploration block, operated by Forest Oil Corp.

The Gabon properties are a part of Devon Energy's West African divestiture package announced early this year.

Devon Pres. John Richels said, "Negotiations are also under way with potential buyers of the other properties in the West African divestiture package. We now expect to complete the balance of the transactions during the first half of 2008."

Oranje-Nassau said it will continue to actively pursue other opportunities to grow its asset base both in Western Europe, as well as in Africa and the Far East. The company currently produces oil and gas from blocks off the Netherlands and the UK.

Direct Energy buys Rockyview

Direct Energy's acquisition, subject to shareholder and regulatory approvals, is expected to close in January.

Rockyview owns conventional oil and gas assets and coalbed methane assets in central Alberta, western Alberta, and the Peace River Arch. It produces 2,700 boe/d, of which 97% is gas.

Direct Energy owns and operates about 3,000 gas wells in Alberta and three gas-fired electric power plants in Texas.

EC okays Rompetrol purchase

KMG signed an equity acquisition contract with Rompetrol Holding SA (Switzerland) for Rompetrol in August. The commission's investigation found

that the transaction would not impede competition in the European Economic Area (EEA).

KMG produces crude oil and natural gas in Kazakhstan, Russia, and Azerbaijan, the commission said. KMG has a single refinery in Kazakhstan and sells petroleum products mainly in Kazakhstan, Russia, and China. It sells no products in the EU. It is also active in the transport of crude oil and natural gas by pipeline and ships.

Rompetrol, Amsterdam, is a private refiner and distributor with minor exploration and production and oil service operations. Its refining subsidiary Rompetrol Rafinare operates the 96,000 b/d Petromidia refinery north of Navodari on the Black Sea and the 10,000 b/d Vega refinery at Ploiesti, both in Romania.

The company also operates a chain of more than 600 service stations in Romania, France, Bulgaria, Albania, Georgia, and Ukraine.

The commission found that the two parties' activities in Europe are complementary. "KMG sells no crude oil or refined petroleum products in the EU, and Rompetrol sells refined products but has no production of crude oil or natural gas," it said.

Chevron settles bribe charges

Chevron's kickback payments allegedly occurred in connection with 78 million bbl of oil purchased under the United Nations' Oil-for-Food program from Apr.17, 2001, through May 6, 2002.

The charges were the fifth action by the agency against a company for allegedly paying kickbacks under the program, which was in effect during 1996-2003 to help Iraqis cope with sanctions imposed after Saddam Hussein's 1990 invasion of Kuwait.

"Despite all cargoes purchased by Chevron having all appropriate US government and United Nations approvals, the settlement recognizes that certain third-party merchants from which Chevron purchased Iraqi crude oil paid illegal surcharges to the government of Iraq," Chevron said in a Nov. 14 statement.

SEC said in its complaint that third parties under contract to Chevron paid about $20 million directly to Iraqi-controlled bank accounts in Jordan and Lebanon, bypassing the Oil-for-Food escrow account. It said Chevron knew, or should have known, that third parties were using parts of the premiums they received from the company's oil purchases to pay illegal surcharges to Iraq.

Chevron learned of surcharge demands by Iraq's State Oil Marketing Organization in January 2001 and adopted a company-wide policy prohibiting such payments, according to the complaint filed in US District Court for the Southern District of New York. The policy required traders to obtain prior written approval for proposed Iraqi oil purchases and charged management with reviewing each proposed Iraqi oil deal.

The company said it previously ceased purchases under the Oil-for-Food program in 2000 when rumors surfaced that third-party suppliers were paying illegal surcharges. "From the very beginning, Chevron intended to comply fully with the trade sanctions then in force against Iraq and with the requirements of the Oil-for-Food program," Chevron said.

It said the US government advised the company that one former Chevron crude trader participated in transactions where he knew or should have known that surcharges were to be paid by the third party merchants from which Chevron bought the crude. "There are no allegations that Chevron paid surcharges, and the trader is no longer affiliated with Chevron," the company said in its statement.

SEC, however, alleged that Chevron failed to devise and maintain a system of internal accounting controls to detect and prevent such illicit payments. The company's accounting for its Oil-for-Food transactions failed to properly record the true nature of its payments to third parties, SEC said.

Chevron, which cooperated in this investigation, neither admitted nor denied the charges in the settlement. Other investigations of the Oil-for-Food program are continuing, according to SEC.

Cal Dive settles charges

Cal Dive International Inc. and its parent, Helix Energy Solutions Group Inc., agreed to pay $2 million as part of a settlement to resolve alleged violations of a 2005 consent decree, the US Department of Justice said on Nov. 26.

DOJ said the Houston marine contractor violated provisions of a decree mandated when the company acquired assets from Stolt Offshore Inc. and S&H Diving LLC. It required the sale of two saturation diving vessels and another, separate saturation diving system.

Saturation diving services in the Gulf of Mexico are used for subsea construction projects; for inspection, maintenance, and repair services; and for recovery and salvage after offshore structures are damaged by weather or accident, according to DOJ. By living in air-tight chambers aboard diving vessels in which the air pressure equals pressure at the subsea work site, saturation divers can work for longer periods and in deeper water than surface divers, it said.

It said Cal Dive and Stolt were two of only three major saturation diving service providers in the Gulf, and the transaction eliminated Stolt as a competitor and would have given Cal Dive more than half of the capacity in the market.

Cal Dive failed to sell the vessels and diving system promptly and continued to use the Seaway Defender vessel, profiting from cleanup work following Hurricanes Katrina and Rita, according to DOJ. Ultimately, a court-appointed trustee sold the assets after the company failed to do so within the period specified by the consent decree, it said.

The $2 million payment represents profits gained as a result of not selling the assets and reimbursement to DOJ for investigation costs, the federal department said. ✦

CATASTROPHIC EVENT MODELING—1

How coverage has evolved for offshore storm risks

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Modeling offshore energy risk presents a special set of design challenges. Actuarial techniques cannot be applied due to the relative infrequency of events and scarcity of historical loss data.

Each hurricane is unique, and the response of platforms, pipelines, and rigs in the path of each storm is also unique. To model the low frequency-high severity risk associated with catastrophic events, it is necessary to develop physical models of the event and the manner in which the event creates vulnerability and interacts with infrastructure.

The purpose of this two-part article is to review the goals of catastrophic event modeling and its application to the offshore energy industry and to quantify the expected losses to property damage in the Gulf of Mexico based on historical storm events.

Probabilistic scenarios for storm simulations are applied to quantify exceedance probability curves, average annual losses, and expected losses. In Part 1, we review the evolution of offshore energy insurance markets and the conceptual stages of model development. In Part 2, we quantify losses to property damage for historic weather events.

2004-05 hurricane season

Over the past 2 years, operators in the gulf have been blessed by uneventful weather, as most major hurricanes have bypassed the region.

This is in marked contrast to the 2004-05 hurricane season, when Hurricanes Ivan, Katrina, and Rita caused unprecedented damage and production interruption (Figs. 1-4). Hurricane Ivan caused energy losses of $2.5-3 billion, while Katrina and Rita were responsible for a record $15 billion loss.

Extensive physical damage, business interruption, and contingent business interruption losses from the 2005 hurricane season have led to substantial increases in insurance premiums for the offshore industry and restrictions in coverage for insurance underwriters. The possibility exists that the industry could experience a comparable or greater loss in the future.

Losses incurred in a hurricane are a combination of physical damage and time element losses. Both are of critical importance because of the business need to maintain operating income. When production operations are disrupted, either by damage on site or elsewhere, cash flow is impacted.

Insurance claims on time element coverage are typically categorized as business interruption from damage to assets (e.g., platforms, pipelines, etc.) owned by the assured, and contingent business interruption, associated with damage to upstream facilities such as processing plants, trunk lines, and refineries, owned by third-parties, which prevent production from being received.

In Ivan, about two thirds of the total losses were due to business interruption and contingent business interruption, while for Katrina-Rita, physical damage was the major cause of losses (Table 1).

HURRICANES KATRINA AND RITA ENERGY LOSS ESTIMATES[1] Table 1

Hurricane	Sector	Physical damage[2]	Operators' extra expense	Business interruption	Total
		$ billion			
Katrina	Upstream ex rigs	4.137	1.228	0.832	6.197
	Rigs	0.474		0.583	0.532
	Downstream	1.791		0.629	2.420
	Total	6.402	1.228	1.519	9.148
Rita	Upstream ex rigs	2.763	0.870	0.853	4.486
	Rigs	0.498		0.050	0.548
	Downstream	0.482		0.365	0.846
	Total	3.742	0.870	1.268	5.880

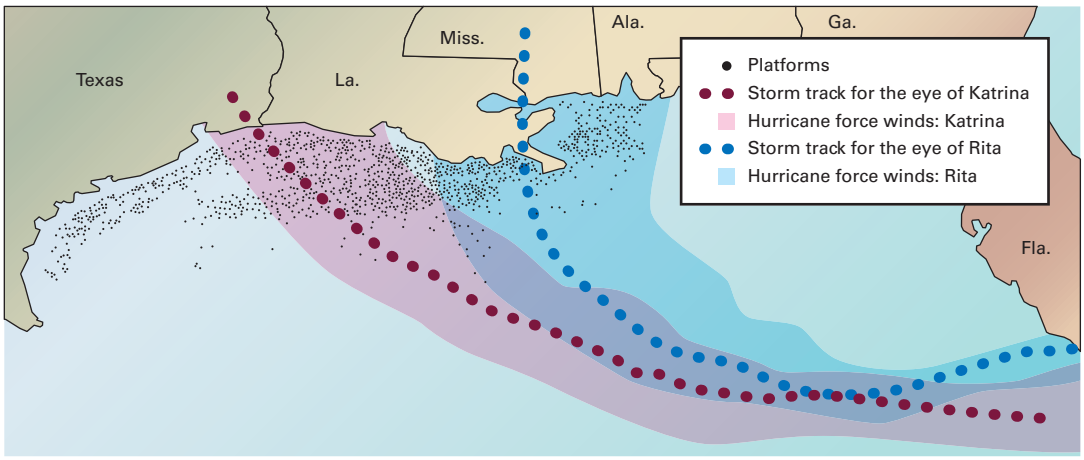
[1]Loss estimates are for the energy industry as a whole and are not necessarily insured amounts. [2]For loss claims without business interruption or operators' extra expense identified, the loss claim is included in the physical damage entry.
Source: Willis Energy Sector Review 2006

Two thirds of the energy losses due to Katrina and Rita have been attributed to physical damage, followed by business interruption (18%) and operators extra expense (14%).

The impact of the hurricanes to the offshore infrastructure has been widely reported in the trade press, the Offshore Technology Conference, and other conferences. For Katrina, losses have been estimated at $2.53 billion onshore, $6.63 billion offshore; for Rita, losses have been estimated at $915 million onshore, $4.98 billion offshore.[1]

HURRICANE KATRINA AND RITA TRACKS WITH OIL, GAS INFRASTRUCTURE

Fig. 1



Source: US Minerals Management Service

Over the past half century, operators in the gulf have responded to extreme weather events on a regular basis. In an average year, three tropical storms enter the gulf at hurricane strength, causing production to be temporarily shut-in and personnel evacuated to shore.

After the storm makes landfall, crews return to assess the damage and make repairs. If repairs are needed, they are usually made in a reasonable period of time and production quickly resumed.

It has been about a century since the gulf has witnessed two major hurricanes in one season, although in the 1960s there was a string of major storms (Carla in 1961, Hilda in 1964, Betsy in 1965, and Camille in 1969) that caused significant damage to offshore infrastructure. It was from these early events that much of today's design standards evolved.[2]

Offshore insurance coverage

The offshore energy industry involves numerous operating hazards incident to drilling and producing oil and natural gas wells, such as blowouts, explosions, oil spills, and fires, as well as hazards peculiar to marine operations, such as collision, grounding, and damage or loss from severe weather.

All hazards can cause personal injury and loss of life, damage to and destruction of property and equipment, pollution or environmental damage, and suspension of operations. Operators, contractors, and service companies insure against or have indemnification from customers for some, but not all, of these risks.

Offshore oil and gas insurance can be traced to exploration activities in the gulf in the early 1960s.[3] The first policies were associated primarily with the control of blowouts. As the costs of drilling escalated with more complex targets and deeper water depths, it was recognized that additional expenditures following the loss of well control would be substantial.

The London market began to cover the costs to redrill a blowout well as a separate policy from control expenditures. Over time, these two coverages merged to provide the basis of the operators extra expense (OEE) coverage.

Pollution liability policies resulted in a separate market covering clean up and containment risks. By the late 1960s, the market expanded to cover the risks of direct physical loss or damage to platforms, rigs, and equipment.

Today, two basic coverages apply to offshore installations. For fixed platforms, pipelines, and subsea developments, the market has developed an "all risks" coverage based on the London Standard Platform form. Areas of coverage include property and casualty (P&C), liability, business interruption, workers compensation, life, and health. P&C coverage is intended to provide post-loss financing for any physical property that is damaged or destroyed by an event. For floating production systems, marine policy forms such as the Institute Time Clauses Hull Port Risks, which covers maritime perils such as stranding, collision, and contacts, are in common use.

Business interruption refers to coverage for gross earnings less noncontinuing expenses, or net income (loss) plus fixed and continuing expenses. The intention of business interruption coverage is to indemnify the insured for lost net income that would have been earned had the damage to facilities not occurred, as well as for refunding fixed expenses incurred during the period of indemnity.

Contingent business interruption coverage entitles the policyholder to damages based upon loss of income due to damage to a property, which an insured business does not own, operate, or control, but upon which the insured's income depends.

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Companies purchase insurance policies tailored to their needs and asset portfolio. An operator may purchase a well control policy to cover well control cost, redrilling costs, and third party pollution liabilities, while a company with a portfolio of assets may retain its own risk through the establishment of a captive insurance company.

A mutual insurance company may be formed by oil companies to underwrite the risk, or a portion of the risk, of the owner companies. The most well-known mutual insurance firm is the Oil Insurance Co., formed in 1971 in response to a shortage in insurance capacity and high well control premiums.[3]

Offshore energy insurers have traditionally been defined by their willingness to take risk without relying on technical analysis. Unlike downstream insurers, which depend on risk surveys and reports conducted by professional engineers to evaluate risk and identify unknown or unquantifiable exposures, upstream insurers have not historically attempted to model or further quantify their risk.

The damage to the oil and gas infrastructure by Katrina and Rita and resulting insurance claims and large losses in the energy insurance market changed this perspective. Underwriters are now attempting to control their exposures to contingent losses through exclusionary wording or policy sublimits similar to what the downstream sector has been doing for decades.

Catastrophe modeling goals

A natural catastrophe generally results in a large number of individual losses involving many insurance policies and insured parties.[4]

The goal of catastrophe modeling is to allow users to estimate the probability of occurrence of an event, the upper intensity limits of a particular occurrence, and the financial loss that will result if an event of a particular intensity occurs.[5]

Models cannot be expected to predict when or where an event will occur, its intensity, or provide an exact assessment of financial losses. Rather, models are meant to provide a formalized framework that allows the distribution of future events and expected loss patterns to be developed so that rational pricing and risk decisions can be made.

The primary users of catastrophe models include insurers-reinsurers and other financial intermediaries that provide risk capacity, corporations with a large amount of property exposure and active risk management programs, and government agencies responsible for monitoring risk mitigation requirements.

Risk management stages

Risk management involves four stages centered on identification, quantification, management, and reporting.[6]

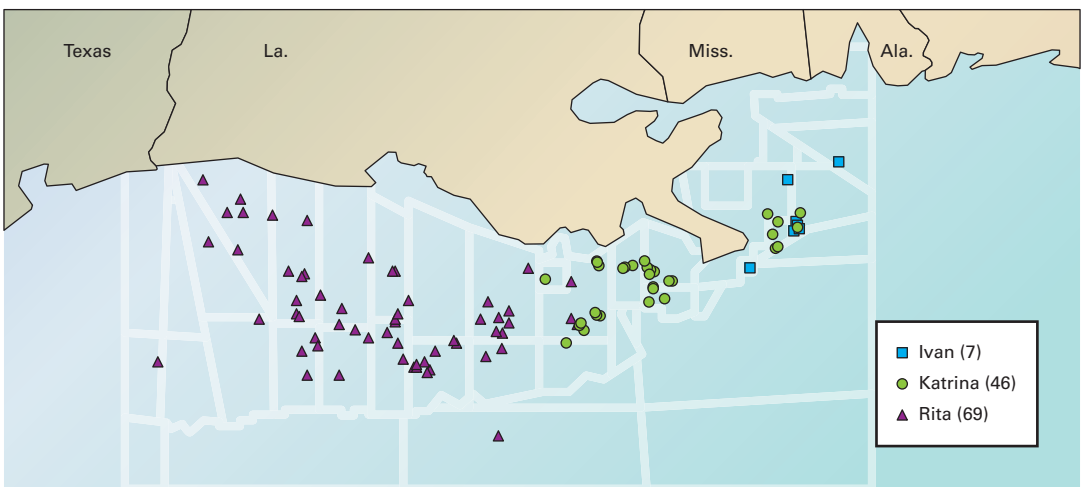
It is usually a straightforward task for a company with offshore production to identify potential exposure to catastrophic damage. Scenarios are developed to quantify the various levels of risk, from small losses due to equipment damage and temporary business interruption, to larger losses arising from total destruction. Risk can vary significantly from one location to another, depending on a number of factors, including the severity and frequency of storms, structure type and location, and differences in vulnerability.

When risks have been identified and quantified, the company will then manage the risks in ways that depend on the financial resources of the firm, operating philosophy, the expectations of shareholders, and the costs and benefits of various risk strategies. The potential cost of sustaining partial or complete destruction of a facility may be too great for a midsize firm, so the firm might decide to transfer the exposure entirely.

With major changes in insurance premiums and deductibles, a company may consider implementing a captive insurance program (self-insure), choose to increase risk retention, or join a mutual insurance company. Many companies do not insure business interruption or loss of hire risk.

After a company decides how it

STRUCTURES DESTROYED IN HURRICANES IVAN, KATRINA, AND RITA Fig. 2



wants to manage its risk profile, it then monitors its exposures. Exposures are unlikely to change often, unless the operator is involved in an extensive newbuild program, field development, acquisition activity, or analysis reveals a significant change in environmental conditions or perceptions.

Risk modeling

Quantitative models using stochastic and actuarial processes have been used for decades in the banking, insurance, and corporate sectors to estimate the financial effects of high frequency-low severity risks and their impact on risk transfer/retention strategies.

To model the low frequency-high severity risk characteristic of catastrophic events, it is necessary to develop physical models of the event and the manner in which the event causes damage and interacts with infrastructure.

Model development

Catastrophic risk models are developed following three stages.[5]

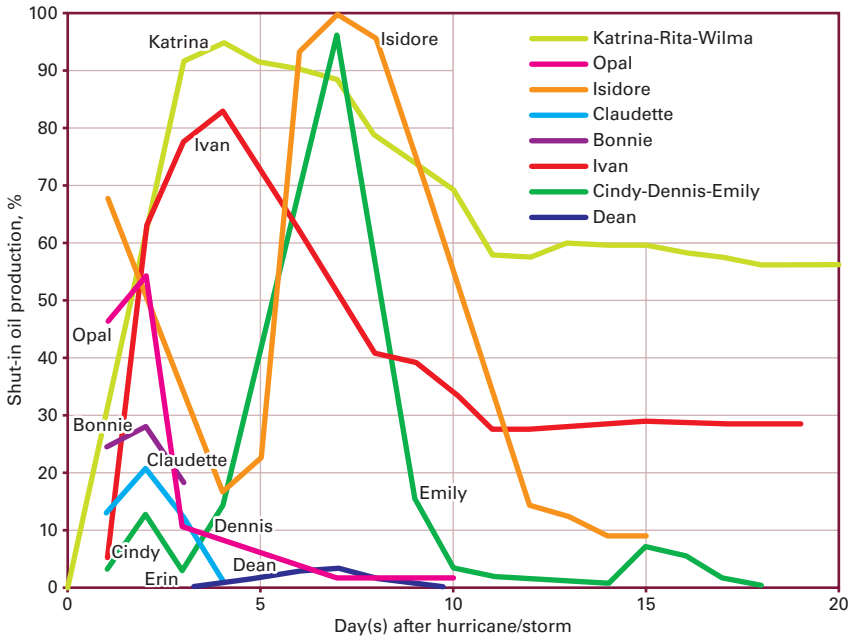
The first step is the hazard/peril assessment (Fig. 5). Hazard assessment defines events by physical characteristics (severity) and probabilities of occurrence (frequency). The event generation component is designed to generate realistic storm scenarios in accordance with their relative probability of occurrence.

The result of hazard/peril modeling is used in the vulnerability assessment phase, which estimates the degree of local/regional damage and the potential for direct and indirect losses caused to infrastructure, contents, and operating activities. The final stage is contract assessment, which determines individual and portfolio losses based on the terms of coverage.

To estimate loss in contract assessment, the policy for each asset (with coverage limits, excess points, policy limits, etc.) is obtained for well control, physical damage, business interruption, loss of hire, and removal of wreck. If the policy conditions are unknown, standard contract conditions are applied.

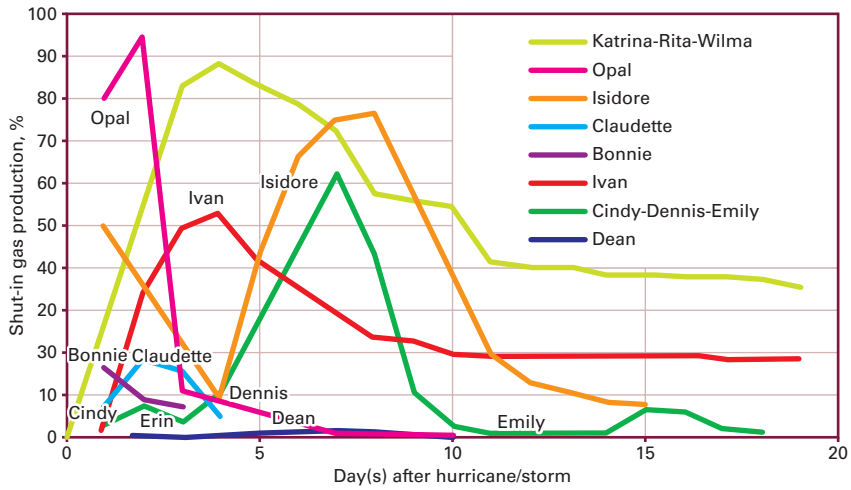
SHUT-IN OIL PRODUCTION IN THE GULF OF MEXICO

Fig. 3



SHUT-IN GAS PRODUCTION IN THE GULF OF MEXICO

Fig. 4



Event generation

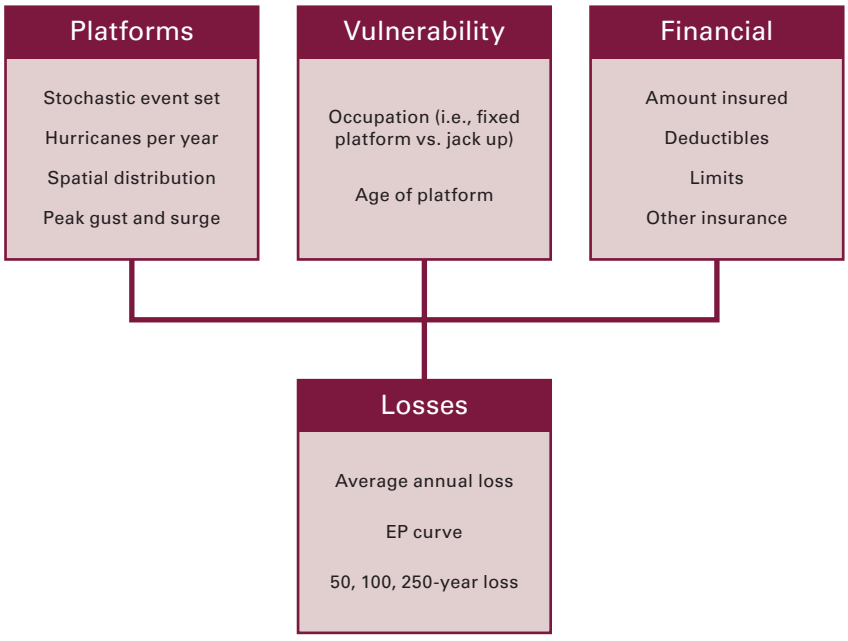
The first step in creating and using a catastrophe model is to generate the events that cause the hazard.

The path and intensity of a hurricane event is modeled using meteorological data and physical equations, weather prediction models, and expert opinion. Event characteristics follow historical patterns and meteorological constraints, with primary variables of interest: frequency, storm track, minimum central pressure, maximum wind speed, radius to maximum winds, and angle of landfall.[7]

A hurricane can travel in any direction, with its path determined by meteorological conditions at the time of the event. Typically, a hurricane moves at speeds less than 20 mph. Storms generate waves that travel out ahead of the

CATASTROPHIC RISK MODELING STAGES

Fig. 5



generating area. The most severe wind and wave action of a hurricane typically occurs in a band 50-100 miles wide centered on the path of the storm.

At each point along the storms track, the area impacted by the hurricane can be divided into four quadrants. The "dangerous quadrant" is the one in which the storm's forward movement (translation) adds to the orbital (circular) wind velocity. As waves and swells move from deep water into shallow water, their wavelength shortens and the height increases, causing the wave to eventually break.

A wave is a traveling disturbance of the sea surface. Waves are primarily caused by the action of wind on water. Waves that have been transmitted beyond the wind-affected zone are called "swells." The total energy in a wave is proportional to the square of the wave height; the energy of a swell is proportional to its length. Wave height is governed by wind speed, duration, fetch, and other factors, such as the temperature of the air relative to the sea.

The winds experienced at a location change direction and intensity as a hurricane approaches, and are further impacted by surface roughness upwind as the storm interacts with land. Maximum winds experienced at a particular point may not occur when a hurricane's center of circulation is closest.

Vulnerability module

After an event is generated, it propagates across the affected area. Local intensity is estimated, based on site-specific data and engineering algorithms, and superimposed on the built environment.

The production and transportation infrastructure in the GOM is a highly integrated network, so damage to any part of the system—upstream, midstream, or downstream—can affect the entire supply chain. Repair times depend on the extent of damage, facility location relative to support services, and availability of equipment and contractors.

Production shut-ins may be due to damage to third-party onshore facilities such as refineries, terminals, and processing stations. The costs to repair structures and the associated cash flow impairment due to delayed production, whether from a flow line or umbilical, product transport line, or onshore infrastructure, varies with each structure.

Loss due to physical damage is normally based on the estimated replacement value of the facility, along with the damage ratio. The damage ratio is expressed as the fraction of replacement cost that must be incurred to fix physical damage. Vulnerability curves that provide the mean damage ratio along with the uncertainties on the damage ratio are developed in the patented RMS Offshore Platform Model based on damage potential at a component level.

Insurance claims, as well as engineering studies of component damage to specific platforms in historical events, are used to construct the vulnerability curves. Design, analysis, and recommended offshore practice codes are also applied.[7]

Business interruption losses are typically modeled using restoration curves developed from a connectivity analysis.[7,8] Repair times are typically estimated from historical events and validated by reference to claims and field survey data. Network redundancies in the pipeline system may allow some flows to be rerouted.[9,10] Simulated event characteristics should parallel patterns observed in the historical record, but in many instances, the historical record is scant and does not provide adequate benchmarking.

Contract assessment

Offshore energy insurance contracts are more complex and sophisticated than their onshore counterparts, typically including deductibles by coverage, blanket deductibles, coverage limits and sublimits, coinsurance, attachment points and limits for multiple location policies, and risk reinsurance terms.

Total losses refer to all the financial losses directly attributable to an event irrespective of whether the losses are insured or not, including losses due to business interruption as a consequence of the property damage. Generally, since total losses are estimated and communicated in different ways, they are not directly comparable and should

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- Never started but well-maintained facility can receive a variety of hazardous and non-hazardous waste feedstocks.
- Potential revenue stream comprises tipping fees for feedstock and the production of syngas and process steam. (Neighboring chemical company has purchase interest in both.)
- Utilities and all required process gas and syngas pipelines, infrastructure, laboratories, warehouse, office buildings and other required facilities are in place.
- All engineering files, permitting files, documentation manuals, safety and operations procedures are in place at the plant.
- Extensive permitting work previously completed and progressive permitting authorities.
- Asking price: $25 million.

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be viewed only as an indication of the order of magnitude.

Ground-up property loss represents loss before insurance and is frequently the preferred reporting mechanism. Gross loss is based on the application of insurance coverage.

Next week: Quantifying offshore losses to hurricane event. ✦

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Chile

Methanex Corp., Vancouver, BC, agreed to provide $40 million to accelerate GeoPark Holdings Ltd.'s exploration and development program on the Fell Block in the Austral basin in southern Chile.

GeoPark, which will sell Methanex gas from the Fell Block for 10 years, has been increasing its gas supply to Methanex since 2006. Its goal is to provide up to 10% of Methanex's gas needs by the end of 2008 (OGJ Online, Nov. 16, 2007).

Indonesia

CGGVeritas completed 3,000 line-km of nonexclusive 2D seismic survey in the Savu Sea between the Indonesian islands of Savu, Rote, and Sumba.

The South Flores area survey, which highlights prospective Triassic plays and hydrocarbon systems north of Australia's Browse basin, will undergo processing and become available in January 2008.

Portugal

Mohave Oil & Gas Corp., private Houston operator, plans to resume drilling the Lapaducos-2 well in western Portugal in December 2007.

It plans to deepen the well to 1,500 m to evaluate fractured Upper Jurassic Montejunto carbonate and Middle Jurassic Candieiros limestone targets.

The rig will then move to deepen Aljubarrota-4 by 400 m into the lower fractured Brenha carbonate zone and the underlying Brenha carbonate grainstone zone, said interest holder DualEx Energy International Inc., Calgary.

Meanwhile, surveying and permitting continues on the Torres Vedras 3D seismic program. Field recording is to start before the end of 2007.

The 117 sq km 3D survey will be shot to follow up on a well drilled by another operator on a Jurassic reef prospect using older 2D seismic. A 130 sq km second 3D survey will be shot in the Aljubarrota Concession after the Torres Vedras survey.

DualEx has a 10% working interest in the Torres Vedras-3 and Aljubarrota-3 Concessions, which cover 321,000 acres and 311,000 acres, respectively.

Louisiana

The Louisiana Office of Conservation banned the issuance of drilling permits within a quarter mile of interstate highways in the state for 120 days starting Dec. 1, 2007.

Gov. Kathleen Blanco asked the office to protect public safety after a well blew out and burned in Iberville Parish Nov. 15, causing closure of Interstate 10 through the Atchafalaya basin until 7 p.m. Nov. 25.

Utah

Ameriwest Energy Corp., Houston, plans to drill an 8,000-ft wildcat in early 2008 seeking oil in Devonian Guilmette dolomite in nonproducing Tooele County, Utah.

Ameriwest signed a letter of intent to acquire a 100% working interest in the Skull Valley Prospect from Geochem Exploration LLC.

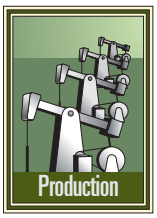
Ameriwest said the prospect is a soil gas anomaly that was first identified by geochemical surveying by the former Gulf Oil Corp. in the 1970s. The location is on a geological low and in an area of propane and ethane anomalies more than 100 miles north-northwest of Covenant oil field in Sevier County, Utah.

West Virginia

Cabot Oil & Gas Corp., Houston, plans to drill two more wells to Devonian Huron shale in 2007 and 19 wells in 2008 to further develop an unnamed gas field in Mason County, W.Va.

The company is hooking up a horizontal well that flowed gas from Huron shale while drilling. The Meadows A-1H well flowed at natural rates higher than 1 MMcfd during drilling. TD is 6,816 ft, and the well has a 3,530-ft lateral in Huron.

Cabot, with 100% working interest, drilled the well in 18 days for less than $600,000.



GULF UPDATE—1

Gulf of Mexico P&A costs begin to recover from 2005 hurricanes

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Center for Energy Studies
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Baton Rouge

Richard Dodson
Tetra Applied Technologies LP
The Woodlands, Tex.

In the aftermath of the widespread hurricane destruction in the Gulf of Mexico in 2005, the cost of operations dramatically increased with increased demand for support services, but market conditions appear to be slowly reverting to prehurricane conditions.

This article reports on an assessment of trends in plug and abandonment costs in the US Gulf of Mexico 2002-07, based on a sample of 1,156 wells performed by Tetra Applied Technologies LP. It summarizes descriptive statistics and investigates the impact of scale economies. In addition, the article constructs relations that estimate the cost of P&A activities based on the number of wells in a job and the number of days of service.

Kaiser and Dodson have described applicable technologies and procedures and P&A cost statistics from 1999-2001.[1]

This is the first of two articles updating recent trends in costs of gulf P&A activities and of net-trawling operations. The concluding article will appear next week.

Regulations

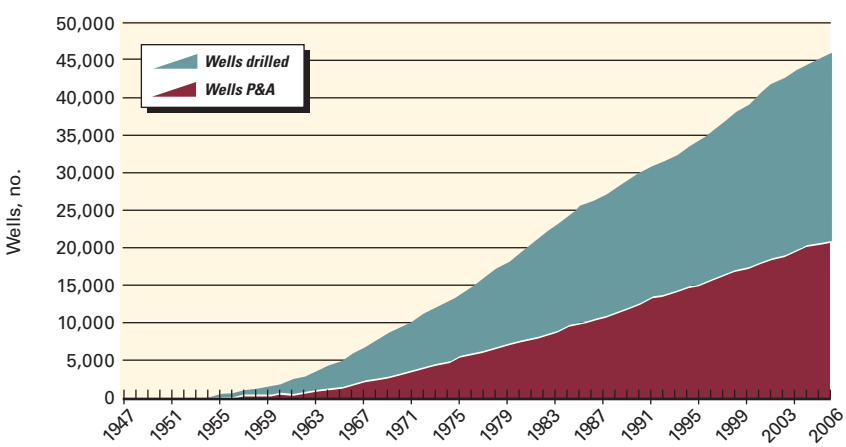
Wells are drilled to explore for, delineate, and produce hydrocarbon reservoirs. At the ends of their useful lives, wellbores are permanently abandoned in a process known as plugging and abandonment. The purpose of P&A is to prevent migration of fluids from the wellbore and establish a permanent barrier to the existing geologic formation.

P&A is the first stage of an offshore decommissioning program in which tubing, casing strings, and conductors are cut and removed below the mud line and cement plugs are set at various depths across former producing horizons.

The operator designs a P&A operation based on the reservoir and wellbore conditions and applies for regulatory approval. In most states, rules have evolved over many years with standards based on experience and conformance with industry guidelines.[2,3] Different governmental bodies regulate wellbore abandonment; the body with primary responsibility depends on the location of the well. Onshore and in state waters, county, city, or state government is responsible for oversight; in the federal Outer Continental Shelf, the Minerals Management Service is lead agency.

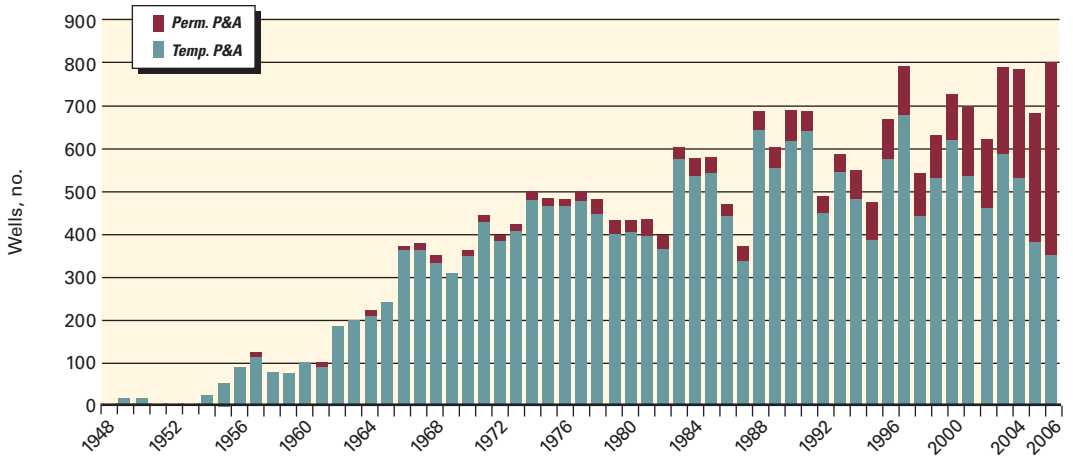
GULF OF MEXICO WELLS DRILLED: 1947-2006

Fig. 1



GULF OF MEXICO WELLS P&A: 1947-2006

Fig. 2



Wells in the OCS must be permanently plugged and abandoned within 1 year after the lease terminates. The MMS may require that a well be permanently plugged before lease production ceases if it endangers safety or the environment or if it is not useful for lease operations and is incapable of producing in economic quantities.[4] Wells may also be shut-in or temporarily abandoned throughout their life cycles for mechanical or technical reasons or because they are not producing in economic quantities.

Wellbore inventory, classification

More than 46,000 exploration and development wells have been drilled in the gulf since production activities began after World War II. Slightly more than 20,000 of these wellbores have been permanently plugged and abandoned in the gulf (Fig. 1). Wells not permanently plugged and abandoned may be producing, shut-in, temporarily abandoned, or in an indeterminate status.

Producing wells currently represent about 20% of the wells not permanently plugged and abandoned. Fig. 2 shows the annual number of wells permanently and temporarily abandoned in the gulf. Over the past decade, 600-800 wells/year have been plugged and abandoned. After the 2005 hurricane season, a large number of wells were temporarily abandoned as operators assessed damaged infrastructure and considered redevelopment strategies.

- *Well life cycle.* Every well's cost, duration, recovery, and value reflect its unique life cycle. Although these attributes are specific to each wellbore, all producing wells pass through the same initial and final states, beginning with completion and ending with abandonment.

Eventually, all wells become inactive because of diminished economic returns or technical problems.

When a well stops producing, it may be shut-in, temporarily abandoned, or permanently abandoned. The MMS provides specific regulations for each operation.

- *Shut in.* A shut-in well is a flowing well that has its christmas tree, master valves, wing valves, and subsea safety value closed. A well is usually shut in because of temporary technical or operational problems (e.g., wells are shut in with the approach of a hurricane).

A well can be maintained shut-in for any length of time as long as periodic maintenance is performed. MMS regulations (20 Code of Federal Regulations, Ch. 11, Part 250.801 (f)) specify that "completions shut-in for a period of 6 months shall be equipped with either (1) a pump-through type tubing plug; (2) a surface-controlled subsea safety valve, provided the surface control has been rendered inoperative; or (3) an injection valve capable of preventing backflow."

- *Temporarily abandoned.* When an exploratory well is under evaluation or when a flowing well is no longer

PLUG & ABANDONMENT STATISTICS, 2002-05*

Table 1

	2002			2003			2004			2005		
Parameter (unit)	DR	TK	ALL	DR	TK	ALL	DR	TK	ALL	DR	TK	ALL
Avg_cost_well, $1,000/well	61.0	136.0	107.0	54.0	157.0	115.0	91.0	155.0	128.0	93.0	189.0	149.0
SD_Acw	8.0	17.0	12.0	13.0	34.0	22.0	14.0	15.0	11.0	20.0	24.0	16.0
Avg_cost_day, $1,000/day	5.6	15.8	11.8	8.5	22.3	16.5	13.0	19.4	16.8	10.0	22.2	17.2
SD_Acd	0.7	1.7	1.3	1.4	4.7	2.9	1.9	1.2	1.1	1.6	1.2	1.3
Avg_days_well, days/well	12.7	10	11.0	7.0	8.5	8.1	8.2	8.4	8.3	11.2	8.3	9.5
SD_Adw	2.0	1.0	1.0	1.5	1.4	1.0	1.2	0.8	0.7	2.1	0.8	1.0
Number_jobs	20.0	31.0	51	24.0	35.0	59.0	22.0	29.0	51.0	18.0	25.0	43.0
Number_wells	24.0	104	128.0	59.0	152.0	255.0	55.0	138.0	193.0	44.0	148.0	192.0
Number_wells/Number_job	1.2	3.4	2.5	2.5	4.3	4.3	2.5	4.7	3.9	2.4	5.9	4.1

*DR = day-rate contracts; TK = turnkey contracts; ALL = day-rate and turnkey contracts; SD = standard deviation

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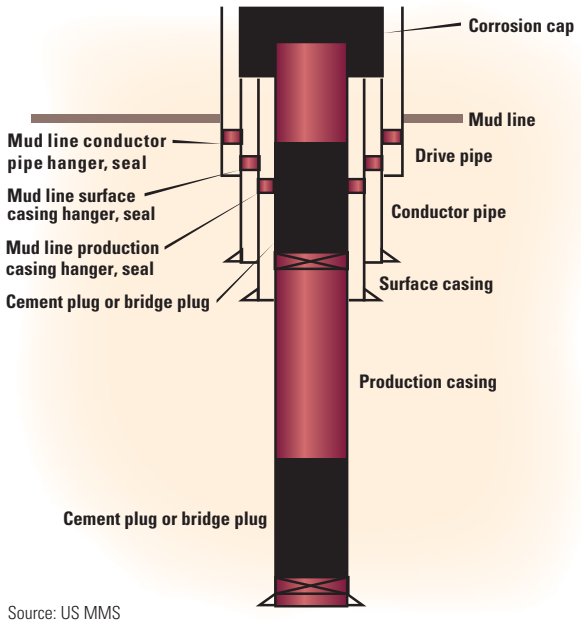
TEMPORARY ABANDONMENT

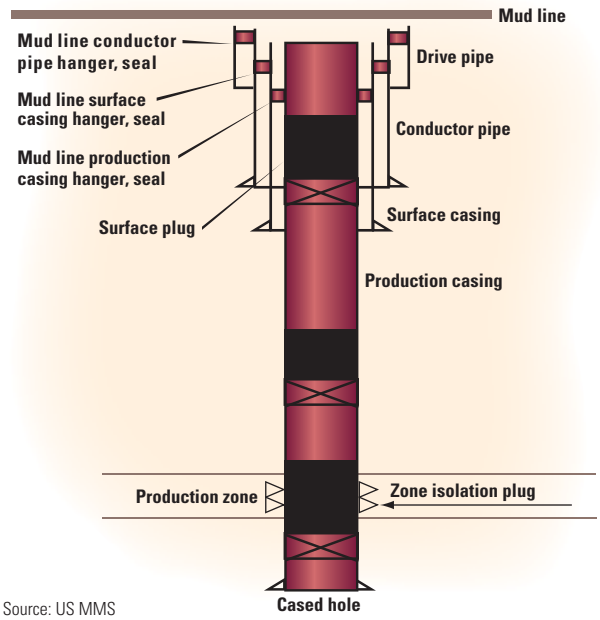
Fig. 3



Source: US MMS

PERMANENT ABANDONMENT

Fig. 4



Source: US MMS

economic to produce, the well will often be temporarily abandoned. Wells on destroyed infrastructure may also be temporarily abandoned if operators intend to reenter or redrill them in redevelopment.[5]

In temporary abandonment, the wellhead is removed, the producing formation isolated with plugs, casing plugged below the mud line, and a corrosion cap inserted above the mud line (Fig. 3). For wells temporarily abandoned, MMS requires the operator provide within 1 year of the abandonment and at 1-year intervals a report describing plans for reentry to complete or permanently abandon the well (30 CFR, Ch. 11, Part 250.703).

The decision to shut in a well vs. performing a tempoarary abandonment is a well and company-specific decision, depending on many considerations, including maintenance and monitoring requirements, workover costs, remaining recoverable reserves, and strategic objectives.

- *Permanently abandoned.* At the end of a lease's life, when production ceases, all its wells must be permanently abandoned. A shut-in or temporarily abandoned well is a temporary or transitory stage, while a permanently abandoned well is the terminal state of a wellbore.

In a permanently abandoned operation, former producing horizons are plugged and casing is cut off below the mud line according to regulatory guidelines (Fig. 4). In a permanently abandoned well, there are at least two, and often three, zone isolating plugs. Procedures and verification testing in a permanent abandonment are more rigorous than in temporary abandonment.

P&A STATISTICS, 2006-07*

Table 2

Parameter (unit)	2006 DR	2006 TK	2006 ALL	2007 DR	2007 TK	2007 ALL
Avg_cost_well, $1,000/well	237.0	51.0	167.0	195.0	107.0	178.0
SD_Acw	27.0	12.0	22.0	62.0	—	51.0
Avg_cost_day, $1,000/day	28.0	23.2	26.1	28.0	11.0	24.5
SD_Acd	3.6	30.0	2.5	12.7	—	10.5
Avg_days_well, days/well	10.2	2.4	7.3	8.5	10.0	8.8
SD_Adw	1.0	0.8	0.9	2.5	—	2.0
Number_jobs	31.0	19.0	50.0	4.0	1.0	5.0
Number_wells	94.0	296.0	390.0	22.0	8.0	34.0
Number_wells/Number_job	3.0	15.6	7.8	5.5	8.0	6.8

*DR = day-rate contracts; TK = turnkey contracts; ALL = day-rate and turnkey contracts; SD = standard deviation

Factors

P&A operations are one of the more variable portions of decommissioning because the operation is influenced by numerous variables and events and, as in most other offshore activities, tend to depend on factors that cannot be predicted.

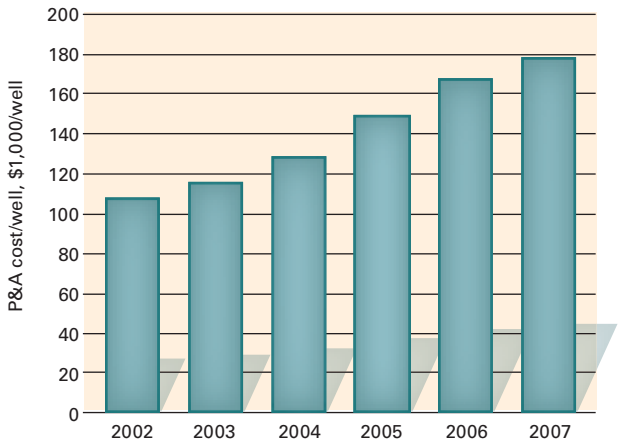
Some factors that influence the time and cost to plug and abandon a well include the contract type, site location, job specification, water depth, and such exogenous events as weather and problem wells. Such factors as wellbore complexity, job preparation, and contractor experience are also important variables but are generally considered unobservable.

- *Contract type.* P&A contracts are written on a day-rate or turnkey basis and both are popular in the Gulf of Mexico.

Under a day-rate contract, the service company performs activities for a fixed fee per day worked under the supervision of the operator. The contract speci-

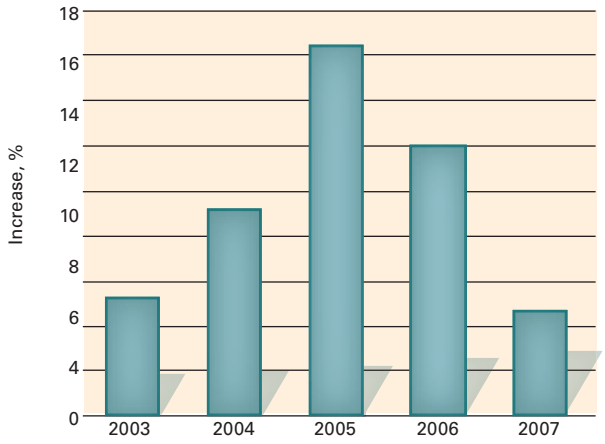
AVERAGE P&A AGGREGATE COST: 2002-07

Fig. 5



ANNUAL INCREASE IN AVERAGE WELLBORE COST

Fig. 6



fies the responsibilities of each party.

The contractor is normally responsible for service equipment, a fully staffed crew, and specified materials and supplies. The operator of the well will usually retain ownership of the wellhead and all recovered tubulars (casing, tubing) and be responsible for disposal of all fluids circulated from the wellbore and any other waste generated on location.

Under a turnkey contract, the service company is paid a fixed fee ("lump sum") in return for completing the job according to contract specification. Turnkey contracts offer contractors incentives to finish a job in a timely manner because the contractor retains the cost savings of early completion.

Unless the job requirements are well known and predictable, turnkey contracts also expose the contractor to additional risk in the form of capital, environmental, and technical risk. Because of the additional exposure, uncertainty, and potential cost overruns, turnkey contracts are priced at a premium relative to day-rate contracts. Risk premiums vary with market conditions and the experience of the contractor, job specification, and other, mostly unobservable, factors.

COMPOSITE AVG. P&A STATISTICS, 2002-07*

Table 3

Parameter (unit)	DR	TK	ALL
Avg_cost_well, $1,000/well	122.0	143.0	134.0
SD_Acw	11.0	11.0	8.0
Avg_cost_day, $1,000/day	15.0	20.3	17.9
SD_Acd	1.4	1.3	1.0
Avg_days_well, days/well	9.8	8.0	8.8
SD_Adw	0.7	0.5	0.4
Number_jobs	116.0	140.0	256.0
Number_wells	300.0	856.0	1,156.0
Number_wells/Number_job	2.6	6.1	4.5

*DR = day-rate contracts, TK = turnkey contracts, ALL = day-rate and turnkey contracts; SD = standard deviation

- *Job type.* Jobs are classified as permanent or temporary abandonment operations. The number of sites per job and wells per site determines the total work requirement. A site may have more than one well to plug and abandon; if the job specification involves several sites, economies of scale may result because mobilization and demobilization time would be reduced and the contractor is already "primed" for work.

In the gulf, P&A contracts are frequently written on a site-by-site basis, making the resulting economies from reduced mobilization and demobilization minor. Jobs performed on a multiple well package may lead to economies from learning, discounts offered by the service provider, or a combination of these factors.

- *Well complexity.* Complex wells arise from diverse factors, including the nature of the geologic formation, depth of the target, size of the reservoir sands, trajectory of the wellbore, and technology applied. Well complexity is difficult to quantify and frequently ambiguous because downhole conditions are often unobservable and practices, opinions, and experiences among contractors vary so dramatically.

Typically, a complex well will have high deviations at the surface casing shoe, severe doglegs, or be extended reach. Liner, tubing strings with gas-lift mandrels, submersible pumps, and packers can also create problems. Other difficulties may include sustained casing pressure, hydrogen sulfide, parted casing, or milling work. Junk found in holes, or equipment which cannot be retrieved, can increase cost significantly.

- *Location.* The location of the job determines mobilization time to the site.

For most infrastructure in the gulf, it usually takes a day at most to arrive on location and prepare for service. Costs for most operations in the gulf are, therefore, not strongly influenced by distance to shore. The distinction between near-shore and far-offshore can be significant, however, because the uncertainty associated with offshore

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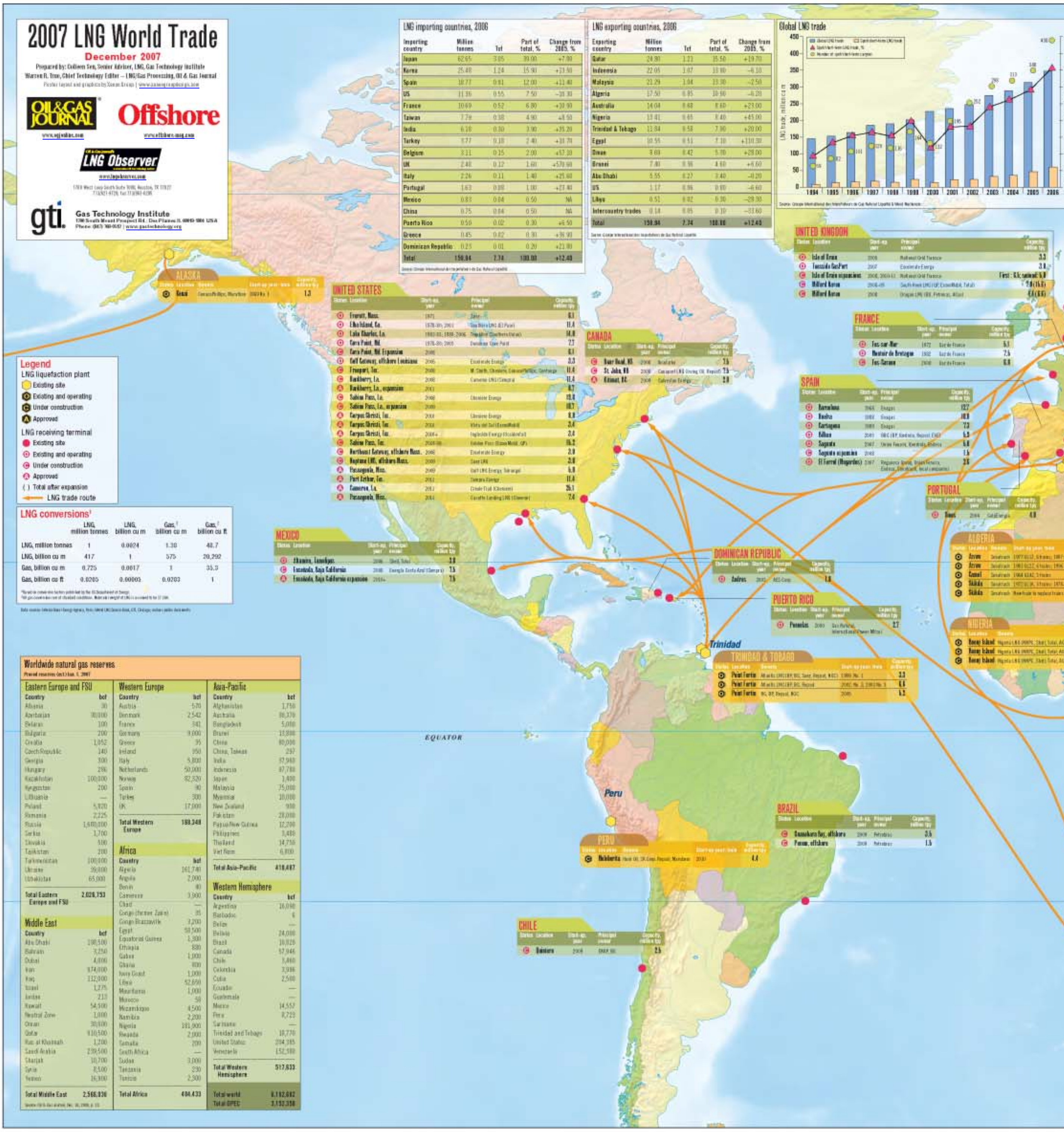


LNG importing countries, 2006

Importing country	Million tonnes	Tcf	Part of total, %	Change from 2005, %
Japan	62.65	3.05	39.00	+7.00
Korea	25.48	1.24	15.90	+13.50
Spain	18.77	0.91	12.00	+11.40
US	11.36	0.55	7.50	–10.30
France	10.69	0.52	6.80	+30.90
Taiwan	7.79	0.38	4.90	+8.50
India	6.18	0.30	3.90	+35.20
Turkey	3.77	0.18	2.40	+10.70
Belgium	3.11	0.15	2.00	+57.10
UK	2.48	0.12	1.60	+570.60
Italy	2.26	0.11	1.40	+25.60
Portugal	1.63	0.08	1.00	+27.40
Mexico	0.83	0.04	0.50	NA
China	0.75	0.04	0.50	NA
Puerto Rico	0.50	0.02	0.30	+6.50
Greece	0.45	0.02	0.30	+36.90
Dominican Republic	0.25	0.01	0.20	+21.90
Total	158.94	7.74	100.00	+12.40

LNG exporting countries, 2006

Exporting country	Million tonnes	Tcf	Part of total, %	Change from 2005, %
Qatar	24.80	1.21	15.50	+19.70
Indonesia	22.05	1.07	13.80	–6.10
Malaysia	21.29	1.04	13.30	–2.50
Algeria	17.50	0.85	10.90	–6.20
Australia	14.04	0.68	8.60	+23.00
Nigeria	13.41	0.65	8.40	+45.00
Trinidad & Tobago	11.84	0.58	7.90	+20.00
Egypt	10.55	0.51	7.10	+110.30
Oman	8.69	0.42	5.70	+28.00
Brunei	7.40	0.36	4.60	+6.60
Abu Dhabi	5.55	0.27	3.40	–0.20
US	1.17	0.06	0.80	–6.60
Libya	0.51	0.02	0.30	–29.30
Intercountry trades	0.14	0.05	0.10	–33.60
Total	158.94	7.74	100.00	+12.40

UNITED STATES

Status	Location	Start-up year	Capacity, million tpy
Existing and operating	Everett, Mass.	1971	8.1
Existing and operating	Elba Island, Ga.	1978-80; 2001	11.4
Existing and operating	Lake Charles, La.	1982-83; 1989-2006	14.8
Existing and operating	Cove Point, Md.	1978-80; 2003	7.7
Under construction	Cove Point, Md. Expansion	2008	8.1
Existing and operating	Gulf Gateway, offshore Louisiana	2005	3.3
Under construction	Freeport, Tex.	2008	11.4
Under construction	Hackberry, La.	2008	11.4
Approved	Hackberry, La., expansion	2011	8.7
Under construction	Sabine Pass, La.	2008	19.8
Under construction	Sabine Pass, La., expansion	2009	10.7
Approved	Corpus Christi, Tex.	2011	8.8
Approved	Corpus Christi, Tex.	2011	3.4
Approved	Corpus Christi, Tex.	2010+	3.4
Under construction	Sabine Pass, Tex.	2008-09	[illegible]
Under construction	Northeast Gateway, offshore Mass.	2008	2.9
Under construction	Neptune LNG, offshore Mass.	2009	2.8
Approved	Pascagoula, Miss.	2009	6.0
Approved	Port Arthur, Tex.	2011	11.4
Approved	Cameron, La.	2011	26.1
Approved	Pascagoula, Miss.	2011	7.4

LNG conversions[1]

	LNG, million tonnes	LNG, billion cu m	Gas,[2] billion cu m	Gas,[2] billion cu ft
LNG, million tonnes	1	0.0024	1.38	48.7
LNG, billion cu m	417	1	575	20,292
Gas, billion cu m	0.725	0.0017	1	35.3
Gas, billion cu ft	0.0205	0.00005	0.0283	1

Worldwide natural gas reserves

Proved reserves (bcf) Jan. 1, 2007

Eastern Europe and FSU

Country	bcf
Albania	30
Azerbaijan	30,000
Belarus	100
Bulgaria	200
Croatia	1,052
Czech Republic	140
Georgia	300
Hungary	286
Kazakhstan	100,000
Kyrgyzstan	200
Lithuania	—
Poland	5,820
Romania	2,225
Russia	1,680,000
Serbia	1,700
Slovakia	500
Tajikistan	200
Turkmenistan	100,000
Ukraine	39,000
Uzbekistan	65,000
Total Eastern Europe and FSU	2,026,753

Middle East

Country	bcf
Abu Dhabi	198,500
Bahrain	3,250
Dubai	4,000
Iran	974,000
Iraq	112,000
Israel	1,275
Jordan	213
Kuwait	54,500
Neutral Zone	1,000
Oman	30,000
Qatar	910,500
Ras al Khaimah	1,200
Saudi Arabia	239,500
Sharjah	10,700
Syria	8,500
Yemen	16,900
Total Middle East	2,566,038

Western Europe

Country	bcf
Austria	570
Denmark	2,542
France	341
Germany	9,000
Greece	35
Ireland	350
Italy	5,800
Netherlands	50,000
Norway	82,320
Spain	90
Turkey	300
UK	17,000
Total Western Europe	168,348

Africa

Country	bcf
Algeria	161,740
Angola	2,000
Benin	40
Cameroon	3,900
Chad	—
Congo (former Zaire)	35
Congo Brazzaville	3,200
Egypt	58,500
Equatorial Guinea	1,300
Ethiopia	880
Gabon	1,000
Ghana	800
Ivory Coast	1,000
Libya	52,650
Mauritania	1,000
Morocco	58
Mozambique	4,500
Namibia	2,200
Nigeria	181,900
Rwanda	2,000
Somalia	200
South Africa	—
Sudan	3,000
Tanzania	230
Tunisia	2,300
Total Africa	484,433

Asia-Pacific

Country	bcf
Afghanistan	1,750
Australia	90,370
Bangladesh	5,000
Brunei	13,800
China	80,000
China, Taiwan	297
India	37,960
Indonesia	97,786
Japan	1,400
Malaysia	75,000
Myanmar	10,000
New Zealand	900
Pakistan	28,000
Papua New Guinea	12,200
Philippines	3,480
Thailand	14,750
Viet Nam	6,800
Total Asia-Pacific	418,487

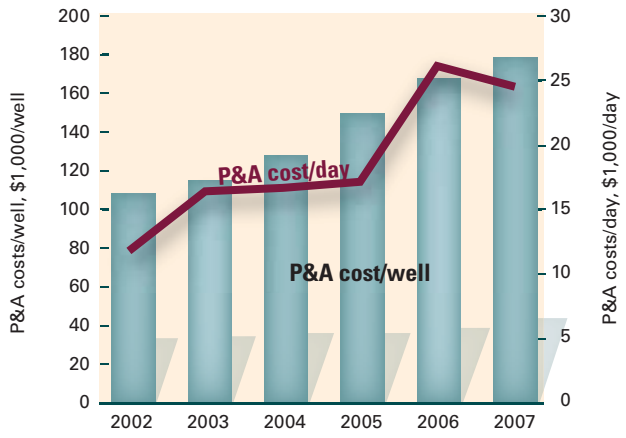
Western Hemisphere

Country	bcf
Argentina	16,090
Barbados	6
Belize	—
Bolivia	24,000
Brazil	10,820
Canada	57,946
Chile	3,460
Colombia	3,996
Cuba	2,500
Ecuador	—
Guatemala	—
Mexico	14,557
Peru	8,723
Suriname	—
Trinidad and Tobago	18,770
United States	204,385
Venezuela	152,380
Total Western Hemisphere	517,833
Total world	6,182,692
Total OPEC	3,152,358

October 2007 saw delivery of the first of eight Q-Flex LNG carriers, all with capacity to carry more than 200,000 cu m of cargo. Delivered first to owner Overseas Shipholding Group, the Al Gattara can carry 210,200 cu m in five insulated compartments. The vessel was built by Hyundai at its Ulsan, South Korea, yard. Among the new features it has in common with the seven other Q-Flex vessels due to enter service by first-quarter 2009 are Al Gattara's diesel engines driving twin propellers and an onboard reliquefaction plant to return boil-off gas to the cargo compartments. (Photograph from OSG.)

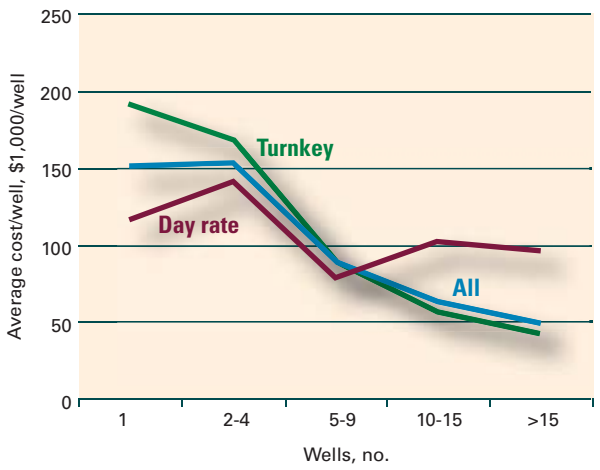
AVERAGE, EQUIVALENT P&A COSTS

Fig. 7



IMPACT ON AVERAGE COST BY CONTRACT TYPE

Fig. 8



operations is generally larger and of greater significance the farther offshore the activity occurs.

• *Water depth.* Water depth is often a primary variable in offshore construction and drilling activities because water depth determines the size and technical specifications of the service vessel and rig.

In water depths 400 ft (120 m) or shallower, depth is not expected to be a significant factor because this category is relatively homogeneous in type of rig required. For deepwater wells, water depth will likely play a greater role in the cost of the operation.

• *Age.* The equipment and components of a well will deteriorate over time from corrosion, wear, and normal operating conditions that may affect the ability of the work crew to perform P&A functions. In old wells, it is not uncommon to find downhole obstructions in the production tubing, leaks, and corrosion.

Not all components of a well have the same age, however, and therefore age comparisons need to be made with caution. A well completed 25 years ago, for example, could have a new tubing string installed from a recent workover. Without detailed knowledge of the maintenance history of each well, such information remains inaccessible, and age may be an unreliable indicator.

• *Preparation.* The availability of good records is essential to planning and execution. If good records are unavailable or do not match the well configuration, planning success may be affected.

In old wells, records may not exist and, if they do, often provide incomplete or inaccurate data to indicate downhole conditions. The long time between well completion and P&A means that operations are often performed after the value of the reservoir is exhausted. Ideally, operators should develop an abandonment plan before the well is drilled, which should be updated each time the well's mechanical configuration is changed.

• *Problem wells.* Problems may arise in P&A activities that delay the operation. When an obstruction prevents pumping, wireline typically recovers the obstruction or moves it to a point where pumping can be conducted.

Differences in fluid densities of the cement plug and wellbore fluids can contribute to plug failures, and inconsistencies may cause the cement to move down through the well fluid and become contaminated. Instability is also influenced by wellbore angle, workstring or hole diameter, and wellbore-fluid geologies.

Such unexpected configurations or wellbore conditions as holes in casing can also slow the abandonment operation and contribute to cost overruns.

• *Fluid type, severity.* Wells with sour fluids will have accelerated corrosion rates and stress cracking that, depending on the age and wellbore construction, may impair a company's ability to perform P&A functions. Components that feature corrosion-resistant alloys can mitigate the effects of sour fluids to some extent.

• *Well access.* In normal operations, P&A activity takes place from a platform or workboat, and procedures and tools are designed for vertical access. For structures destroyed in a hurricane, the wellbores lie horizontally on the seabed, requiring special equipment and procedures.

The loss of a platform can be compensated by the use of a lift boat or mobile drilling unit. To allow vertical access to wellbores, divers must cut conductors. Diver cuts are significantly more hazardous and expensive than mechanical cutting, and limited access and poor visibility often slow progress and expose personnel to more risk than normal conditions.

• *Technology.* Application and use of advanced technology vary with service provider and job specification. Tradeoffs exist between the cost-saving potential associated with new technology vs. the start-up cost of learning; e.g., multifunction fishing techniques can reduce

the number of trips required to cut and recover casing and the wellhead assembly in deepwater operations but are also more expensive and difficult to apply. The impact of technology and advanced diagnostic tools on specific operations is usually difficult to quantify.

• *Construction practices.* Well-construction practices used in drilling and completions and decisions the operator makes during the well's production life can affect P&A requirements. If annuli are properly isolated with no uncontaminated cement during completion and if the well is kept in good mechanical condition with regular workovers, abandonment is usually relatively straightforward to perform.

• *Rig vs. "rigless" method.* P&A operations can be performed with either rig or rigless methods. The method chosen is dictated by engineering requirements, contractor preference, and equipment availability. Both methods are popular in the Gulf of Mexico.

The traditional approach involves using a rig with a derrick, drawworks, and surface equipment, and precedes much like a normal workover. A liftboat may be moved to the job site or platform equipment may be available. Most subsea wellheads require a rig-based method.

In the rigless approach, a crane pulls pipe, and coiled tubing and wireline units assist with the placement of cement plugs. Coiled-tubing units can enter and exit wells faster and are normally less expensive than the rig method.

• *Exogenous conditions.* Weather conditions, mechanical problems, and logistics can significantly affect the scope of offshore operations and in most instances are unpredictable. Weather is a factor in all offshore operations and weather extremes reduce labor productivity and increase downtime. Mechanical problems and logistics can be mitigated to some extent through preparation and proper contingency planning.

Regression model results—I*

Table 4

Parameter	TC = α_0 + α_1NW					
	Day rate		Turnkey		All	
	α_0 = 0	α_0 ≠0	α_0 = 0	α_0 ≠0	α_0 = 0	α_0 ≠0
α_0		59.5 (1.5)		173.2 (3.0)		149.6 (4.4)
α_1	102.6 (13.5)	91.6 (8.8)	65.7 (14.3)	55.9 (10.1)	69.3 (18.9)	59.0 (13.9)
R^2	0.61	0.40	0.59	0.42	0.58	0.43
n	116.0	116.0	140.0	140.0	256.0	256.0

*The t-statistics of the regression models are presented in parenthesis.

Regression model results—II*

Table 5

Parameter	TC = α_0 + α_1ND + α_2NW					
	Day rate		Turnkey		All	
	α_0 = 0	α_0 ≠0	α_0 = 0	α_0 ≠0	α_0 = 0	α_0 ≠0
α_0	—	51.7 (1.4)	—	–65.2 (–1.9)	—	–10.6 (†)
α_1	5.5 (3.9)	5.4 (3.9)	18.4 (18.5)	19.2 (17.9)	12.6 (15.7)	12.7 (14.6)
α_2	56.8 (4.2)	48.1 (3.2)	9.6 (24)	10.8 (2.8)	24.4 (6.3)	24.6 (6.3)
R^2	0.65	0.46	0.88	0.83	0.79	0.69
n	116.0	116.0	140.0	140.0	256.0	256.0

*The t-statistics of the regression models are presented in parenthesis. (†) denotes t-statistics < 1.

Descriptive statistics

The database for analysis was compiled from jobs performed by Tetra Applied Technologies in the gulf 2002-07. The sample set consisted of 256 jobs and 1,156 wells performed across a wide cross-section of operators, representing 15-50% of all wellbores plugged annually. At the time of the analysis, the sample set for 2007 was incomplete; conclusions based on the 2007 data are therefore not definitive.

Cost and operational data were collected by review of invoice and job reports for all offshore operations performed by Tetra Applied Technologies. Job reports describe the day-to-day (actually, hour-to-hour) operations and include information on contract type, operational activities, and use of liftboats and workboats.

Water depth was available for only a portion of the sample, and job type was described for fewer than half the wells. Contract type was specified. Jobs mainly involved platform wells, and although several wells were performed with rigless techniques, most the jobs used rigs. All of the jobs were in water depth less than 400 ft on dry trees. No subsea wellheads were abandoned.

For turnkey contracts, we employed the total cost of the operation rather than the revenue received (the contract bid). The majority of the sample set represented standalone P&A jobs, but we also included a dozen or so jobs performed as part of a total decommissioning operation in which the P&A cost data were clearly delineated. Costs are reported as current (nominal) dollars and are not adjusted for inflation.

An accompanying box describes variable notation.

• *Contract cost.* In 2002-07, day-rate contracts consisted of 116 jobs and 300 wellbores, and turnkey contracts 140 jobs and 856 wellbores. Contract type is an important determinant of the cost of the operation. The average P&A cost for a day-rate contract was significantly smaller than the average turnkey cost, ranging anywhere from 50-65% less expensive (Table 1). In 2006-07, a dramatic reversal occurred, with average day-rate contracts exceeding the turnkey variety by four times in 2006 and almost double in 2007 (Table 2).

A composite average P&A cost that aggregates day-rate and turnkey contracts exhibits more regularity over time because it averages across all jobs (Fig. 5). Fig. 6 shows the annual increase in the composite P&A cost: In 2002-07, the increase in the composite average P&A cost was 11.3%/year.

IMPACT OF SCALE ON AVERAGE P&A COST

Table 6

Contract type	Parameter (unit)	1 well	2-4 wells	5-9 wells	10-15 wells	>15 wells
ALL	Avg_cost_well, $1,000/well	152	154	88	64	48
	SD_Acw	14	14	12	11	11
	Number_jobs	116	77	36	15	12
	Number_wells	116	236	289	181	334
DR	Avg_cost_well, $1,000/well	116	141	79	103	96
	SD_Acw	121	132	50	51	—
	Number_jobs	63	42	8	2	1
	Number_wells	63	135	59	26	17
TK	Avg_cost_well, $1,000/well	194	169	90	58	44
	SD_Acw	168	101	74	41	40
	Number_jobs	53	35	28	13	11
	Number_wells	53	101	230	155	317

A structural shift in cost appears between 2002-05 and 2006-07. This change in cost is due to the influence of three factors: scale economies, the level of competition for services in the aftermath of the 2005 hurricanes, and job type performed.

Turnkey contracts averaged 3.4 wells/job in 2002, 4.3 wells/job in 2003, 4.7 wells/job in 2004, and 5.9 wells/job in 2005. During this same period, between 1.2-2.5 wells/job were plugged under day-rate contracts.

In 2006, because of devastation from Hurricanes Katrina and Rita, damaged structures required more wells to be abandoned. It appears that turnkey operations were a favored contract for this activity. Well owners preferentially select turnkey contracts for large well inventories, old wells, or complex operations.

The total number of jobs did not increase significantly from previous years, but the number of wells per job increased substantially (averaging 15.6 wells/job). Scale effects appear to be important when five or more wells/job are plugged.

Cost increases observed in 2006-07 are also due to the high level of competition for services. After the 2005 storms, competition for labor, equipment, and vessels in the gulf rose dramatically, increasing vessel day rates two or three times historic levels. The same competitive pressures hitting day-rate contracts also affect turnkey jobs, but scale economies for turnkey jobs appear to serve as a moderating lever.

The third factor contributing to cost differences between contract types is related to the type of job performed, whether the operation was a temporary abandonment or a permanent abandonment.

Temporary abandonment is easier and cheaper to perform than permanent abandonment, and a significant number of P&A operations performed in 2006 were temporary abandonments. Those jobs performed under a turnkey contract will accentuate cost differences and contribute to a lower relative value, for all other things equal.

• *Daily cost.* Fig. 7 shows the average cost to plug and abandon a well expressed on an equivalent day-rate basis. The two numerical values are closely, but not perfectly correlated, across time. In 2002-05, the average cost to perform P&A activity ranged from $5,600-13,000/day for day-rate contracts, $15,800-22,300/day for turnkey contracts, and $11,800-17,200/day for the composite category (Table 1).

In 2006, the average cost increased significantly across both contract types, to $28,000/day for day-rate contracts and $23,200/day for turnkey contracts (Table 2). The composite category averaged $26,100/day in 2006.

High day rates have continued into the 2007 season, reflecting the continued strong demand for labor and service vessels in the gulf, but shows signs of returning to more moderate prehurricane levels. Steady, moderate inflationary pressures on daily cost in 2002-05 appeared, while the hurricane destruction and its impact on the service market made 2006 exceptional. Moderation in the daily rates is evident in 2007 and is likely to continue in the future in the absence of destructive weather events.

• *Average number of days.* The number of days to plug and abandon a well has been relatively stable over the past 5 years, averaging about 10 days/well, except in 2006, when many wells were plugged under turnkey contracts at an average of 2.4 days/well (Table 1). That many of the wells plugged in 2006 were temporary abandonments at least partially explains the favorable performance.

• *Composite statistics.* The average cost to plug and abandon a well under a turnkey contract over 2002-07 is slightly greater than under a day-rate contract, but as we have previously shown the composite statistics—because of the aggregation process—mask important trends that have

Variable notations

Plug and abandonment jobs are classified according to day rate (DR) and turnkey (TK) contract type and in a category that aggregates both contract types (ALL).

The data are described by average cost per well, Avg_cost_well (Acw); average cost per day, Avg_cost_day (Acd); and average days per well, Avg_days_well (Adw).

The standard deviations of Avg_cost_well, Avg_cost_day, and Avg_days_well are denoted as SD_Acw, SD_Acd, and SD_Adw. The number of jobs and number of wells per category are denoted as Number_jobs and Number_wells. The ratio Number_wells/Number_jobs indicates the average number of wells serviced per job.

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Cost relations

In Table 4, total cost is correlated with the number of wells (NW) per job:

- Day-rate contracts: Total_cost = 102.6 NW
- Turnkey contracts : Total_cost = 65.7 NW
- All contracts: Total_cost = 69.3 NW

In Table 5, total cost is correlated against the number of wells per job and the number of days (ND) to perform the service:

- Day-rate contracts: Total_cost = 5.5 ND + 56.8 NW
- Turnkey contracts : Total_cost = 18.4 ND + 9.6 NW
- All contracts: Total_cost = 12.6 ND + 24.4 NW

occurred over the past 5 years.

The 5-year average cost to plug and abandon wells is $17,900/day, and it takes about 9 days/well to perform the operation (Table 3). Turnkey contracts that Tetra writes serve about twice as many wells than day-rate contracts (6.1 vs. 2.6 wells/job).

• *Total cost.* The total cost of P&A operations depends on several observable and unobservable factors. Methods to predict the total cost of a job based on a subset of recorded variables are subject to significant limitations and are only reliable "on average" when a large number of jobs are considered.

One of the simplest ways to forecast the cost of a P&A operation is to correlate the total cost of the activity with the number of wells per job. If one could accurately estimate the number of days to perform the operation, this additional information would improve the forecast if the conjecture were accurate. Because the number of days to perform the activity is unknown and uncertain, however, we run the risk of introducing additional uncertainty into the problem.

Tables 4 and 5 depict regression models for total cost, using the number of wells per job and the number of days as the descriptive variables. We estimate the model with and without a fixed-term coefficient and aggregate the data according to contract type. The correlations are based upon the complete data set with no inflation adjustments. The output statistic is measured in terms of $1,000. (An accompanying box presents cost relations.)

Both factors are highly significant, as expected, and as number of days is incorporated in the model, the model fits improve substantially. Models without a fixed term are also more robust in all the formulations.

Scale economies

Scale economies may arise from technical efficiency arising from the size of the job and from discounts contractors offer on multiple well packages.

P&A jobs are usually performed at one site. In some cases, contracts may be let on a field or area-wide basis. As

Limitations of analysis

The P&A job data consist of a large and diverse sample, but because the data are from a single contractor, the analysis may not be representative of the industry as a whole. We believe the benefits of using a consistent and homogeneous data set outweigh the drawbacks from potential contractor bias.

All the jobs were performed on dry-trees in water less than 400 ft deep. Because deepwater wells and subsea wells are more complex to plug and abandon and in some cases significantly more complex, extrapolation of the summary statistics outside this categorization is not valid.

The reported data did not allow us to differentiate between the type of operation performed under turnkey and day-rate contracts. In normal years, turnkey contracts are often used on complex wellbores or uncertain operations. During the aftermath of the 2005 hurricane season, turnkey contracts were the preferred mechanism to help operators reduce their financial exposure and operational risk associated with cleanup operations.

Job requirements for temporary abandonment are not as rigorous as permanent abandonment. For all things equal, therefore, the average cost of a typical temporary abandonment would be expected to be less than a normal permanent abandonment. Unfortunately, the two operations cannot be distinguished from the data entries; we therefore cannot distinguish the impact of this factor on the cost data.

It would be desirable to correlate P&A costs with the characteristics of the wellbore, job and contract type, and the technical aspects of the operation, but such a correspondence is difficult to realize in practice due to the complexity and uncertainty of the operation and lack of reliable data. Even if downhole conditions could be modeled accurately, the degree of uncertainty due to topside factors can only be reduced, not eliminated. P&A cost estimation, like most other aspects of decommissioning operations, will always exhibit a high degree of uncertainty.

the number of wells per job increases, unit costs typically decline. If learning effects are present for multiple well operations, the contractor may become more efficient, and this should be reflected in the cost trends.

Another reason scale economies may be observed in P&A activity has to do with discounts that contractors offer operators on multiple well packages. In this case, the discount offered by the contractor to acquire the job, rather than any inherent learning, would be responsible for the cost reduction. The job data were analyzed by contract type according to the number of wells per job, for 1 well job, 2-4, 5-10, 11-15, and more than 15 well jobs. (Table 6).

For day-rate contracts, the average cost per well exhibits no well-defined trend, but we observe that the average cost per well for jobs with 1-4 wells is somewhat greater than the larger well-count categories.

For turnkey contracts, the results exhibit a clearer trend. As the number of wells per job increases in turnkey contracts, the average cost per well decreases significantly. The average cost per well for jobs with less than 5 wells is $177,000/well. For jobs with 5-10 wells/job, the average cost decreases to $90,000/well, a 50% decrease in unit cost from the 1-4 well job category.

As the number of wells per job increases further, the unit cost continues to decrease, from $58,000/well (11-15 wells) to $44,000/well (more than 15 wells).

(A final box presents the limits of this analysis.) ✦

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Reed Hycalog: Rig building persists while NA fleet use drops

Robust pricing for oil and gas continue to drive North American fleet growth in the drilling market, and the number of land and marine drilling rigs continues to increase worldwide, according to Grant Prideco's 54th annual ReedHycalog rig census.

The census data represent activity during 45 days, May 2- June 15, 2007. A rig is counted as being active if it has "turned to the right" at any time during the 45-day period.

North American rig fleet utilization has decreased over the past year.

The US fleet rose to 2,817 rigs, up 23% from 2006, but utilization dropped to 85%, down 11% from a year earlier. The increase in the fleet resulted from 614 additional rigs, of which 349 were newly constructed; the remainder reactivated or refurbished (189), built from components (71), or moved in from another country (5). Rigs were also taken from the US fleet; 77 were removed from service (cold-stacked), 14 were moved out of the country, and 4 were destroyed.

The total number of US rig owners increased to 310, up 53 from 2006, as more companies entered the drilling market (Fig. 1). This number is building back up from a low in 2002 and has reached about the same level as 1995.

The Canadian fleet reached a record high of 871 rigs, up 9% (net 73 rigs) from 2006, but utilization fell to 43%, down from 84% utilization in 2006. All the rigs added to the Canadian fleet were either newly constructed (86) or assembled from components (2). Sixteen rigs left the fleet; 10 were moved out of Canada and 6 were retired or used for parts.

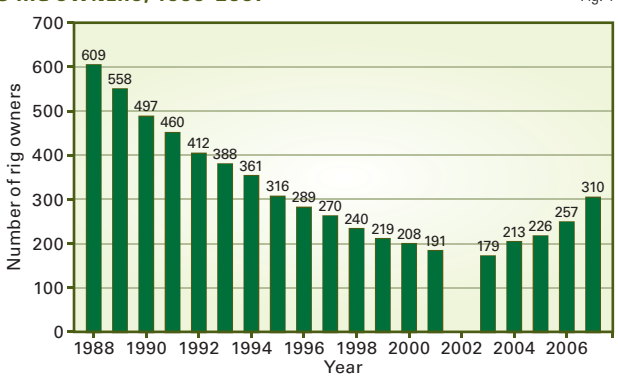
This is the third year that the census has tracked international land rig activity, with coverage increasing each year. Overall international utilization was 94% for 2007, down from 95% in 2006. Rig utilization in Africa showed the largest drop, to 86% in 2007 from 99% in 2006, attributed to a drop in shallow barge drilling in Nigeria.

ODS Petrodata provides data on mobile offshore drilling units to the census. The global MODU fleet remained about the same, with a net drop of 4 units, but utilization rose to 88%, up from 85% in 2006. Fleet additions include 11 newbuilds and 11 reactivated rigs. Another 26 rigs were reclassified as retired, having not worked in more than 5 years.

ReedHycalog Pres. John Deane presented the results of the rig census and drilling contractor survey on Nov. 2 at the International Assoc. of Drilling Contractors' 2007 annual meeting, in Galveston, Tex. A summary of the data is available at www.grantprideco.com/rhrigcensus/2007censushistory.xls. ✦

US RIG OWNERS, 1988-2007

Fig. 1



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Method relates diesel cetane, octane ratings

William Morris
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Wilmington, Del.

A method tested on various diesel blends of known cetane numbers showed a good correlation with the fuel's octane numbers.

Spontaneous ignition results in knock in a spark-ignition engine, whereas spontaneous ignition is required in a diesel engine. In effect, octane number and cetane numbers are opposite measurements of the same phenomenon. Low octane number implies high cetane number.

It is advantageous to test diesel fuels in octane test engines that are much more widely available than cetane test engines. To investigate this possibility, we tested 50-50 blends of diesel fuels with iso-octane in a motor octane engine under standard operating conditions. The motor octane test is run at a high temperature, which should favor operability with diesel fuel blends.

Correlations

We carried out the tests with six diesel fuels of known cetane number, resulting in a good correlation. The correlation, however, did not work well for blends containing a cetane improver. Motor octane test results underpredicted the effect of cetane improver on ASTM D613 cetane engine results.

The correlation for diesel fuels without cetane improvers using the motor octane blending value is:

Cetane number = 58.4 – 0.54 × Motor octane blending value.

Subsequently, we performed a more detailed study including diesel fuels from seven different refineries within six different companies. Diesel reference fuels were included, and the diesel fuel from one refinery was tested with 0.1% and 0.2% cetane improver.

Table 1 shows the results.

As in the preliminary study, the effect of cetane improver on cetane number was underpredicted.

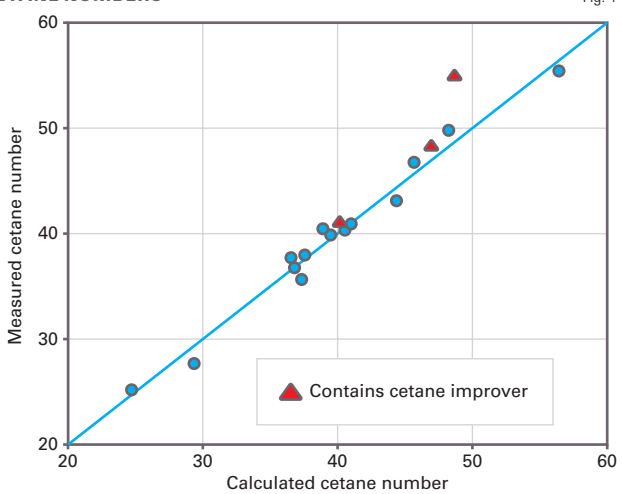
The correlation based on fuels without cetane improver using the motor octane for a 50-50 blend of diesel and iso-octane is:

Cetane number = 105.9 – 0.94 × Motor octane for 50-50 blend.

Fig. 1 shows the close agreement

CETANE NUMBERS

Fig. 1



CETANE CORRELATION WITH MOTOR OCTANE

Table 1

Sample	Motor octane number, 50-50 blend with iso-octane	Cetane		
		Calculated[1]	Measured[2]	Difference
Group I[3]				
ASTM 49.9 check	61.4	48.1	49.1 (49.9)	+1.8
ASTM 38.0 check	72.7	37.5	38.7 (38.0)	+0.5
Refinery A	73.7	36.6	37.9	+1.3
Refinery B	72.8	37.4	35.7	–1.7
Refinery C	63.8	45.9	46.5	+0.6
Group II				
Refinery D	70.7	39.4	39.9	+0.5
Refinery E	81.0	29.7	27.6	–2.1
Refinery F	71.1	39.0	40.4	+1.4
Refinery G	69.6	40.4	40.2	–0.2
75% Refinery C, 25% LCO[4]	73.5	36.8	36.9	+0.1
75% Refinery C, 25% LCO, 0.2% CI[5]	70.0	40.1	40.7	+0.6
Group III				
Refinery C	65.4	44.4	43.0	–1.4
25.4 reference	86.3	24.7	26.0 (25.4)	+0.7
40.7 reference	69.2	40.8	40.8 (40.7)	–0.1
55.4 reference	52.4	56.6.	57.0 (55.4)	–1.2
Group IV				
Refinery C + 0.1% CI	62.4	47.2	48.0	+0.8
Group V				
Refinery C + 0.2% CI	60.8	48.7	54.9	+6.2

[1]Calculated cetane = 105.87 – 0.94 x motor octane number. [2]Correlation uses standard values in parentheses and excludes cetane improver blends. [3]Groups tested at different times. [4]LCO = light cycle oil. [5]CI = cetane improver (2-ethyl hexyl nitrate).

between calculated and measured cetane number for diesel fuels without a cetane improver.

The standard error, which is only 1.29 cetane numbers, can be explained by the variability of the cetane and motor octane tests. The lack of fit must be small.

Converting the above equation to the blending value form yields the improved equation:

Cetane number = 58.9 – 0.47 × Motor octane blending value.

The improved equation is similar to that obtained in the preliminary work, but this equation gives predictions about three cetane numbers higher. The industry may wish to consider this test procedure as an alternate to cetane engine test, ignition delay tests, and the cetane index.

Use of the correlation

The blending-value form of the equation is useful because it facilitates evaluation of alternate constituents of diesel fuel.

For example, consider balancing the use of 325°+ F. reformer feed vs. its use to maximize reformate value. This might be done by taking the cut after hydrotreating as a premium component for low-sulfur diesel. Otherwise, the cut point before hydrotreating could be changed to include the 325°+ F. portion in diesel fuel.

In either case, one can estimate the cetane number by assuming that the motor octane blending value will be reasonably close to the motor octane rating of the cut. Based on gas chromatograph data for a reformer feed, the motor octane of the 325°+ F. portion will be about 45. On that basis, the cetane number will be about 38, quite suitable for diesel fuel:

Cetane number = 58.9 – 0.47 (45) = 37.7

Balanced against the increase in diesel fuel volume would be the loss of reformate quantity and quality. When reforming to a 92 (R + M)/2 full boiling reformate, the 325°+ F. reformate cut will be about 100 (R + M)/2.[1]

Despite this large disadvantage, such a change could be worthwhile under unusual marketing and refining conditions.

Further development

The under-prediction of cetane improver effects could be due to the high surface temperature of the mixture heater with this method. Intake air temperature was 100° F. and the air-fuel mixture is 300° F.

A preliminary test with the mixture heater turned down or off might provide an answer. The fuels would be 50-50 iso-octane blends of high-cetane reference fuel, low-cetane reference fuel, and low-cetane reference fuel with

NELSON-FARRAR COST INDEXES

Refinery construction (1946 Basis)

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

	1962	1980	2004	2005	2006	Aug. 2006	July 2007	Aug. 2007
Pumps, compressors, etc.	222.5	777.3	1,581.5	1,685.5	1,758.2	1,758.6	1,846.5	1,850.3
Electrical machinery	189.5	394.7	516.9	513.6	520.2	524.6	517.3	514.6
Internal-comb. engines	183.4	512.6	919.4	931.1	959.7	965.7	974.5	980.8
Instruments	214.8	587.3	1,087.6	1,108.0	1,166.0	1,178.1	1,272.4	1,272.4
Heat exchangers	183.6	618.7	863.8	1,072.3	1,162.7	1,179.4	1,374.7	1,374.7
Misc. equip. average	198.8	578.1	993.8	1,062.1	1,113.3	1,121.3	1,197.1	1,198.6
Materials component	205.9	629.2	1,112.7	1,179.8	1,273.5	1,301.9	1,368.2	1,356.9
Labor component	258.8	951.9	2,314.2	2,411.6	2,497.8	2,482.1	2,596.4	2,615.7
Refinery (Inflation) Index	237.6	822.8	1,833.6	1,918.8	2,008.1	2,010.0	2,105.1	2,112.2

Refinery operating (1956 Basis)

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

	1962	1980	2004	2005	2006	Aug. 2006	July 2007	Aug. 2007
Fuel cost	100.9	810.5	971.9	1,360.2	1,569.0	1,652.4	1,537.9	1,381.5
Labor cost	93.9	200.5	191.8	201.9	204.2	192.6	207.1	203.8
Wages	123.9	439.9	984.0	1,007.4	1,015.4	977.7	1,025.8	1,006.5
Productivity	131.8	226.3	513.3	501.1	497.5	507.8	495.2	493.9
Invest., maint., etc.	121.7	324.8	686.7	716.0	743.7	744.5	776.8	779.4
Chemical costs	96.7	229.2	268.2	310.5	365.4	380.5	396.2	381.6
Operating indexes								
Refinery	103.7	312.7	486.7	542.1	579.0	583.7	594.6	579.1
*Process units**	103.6	457.5	638.1	787.2	870.7	896.7	872.3	817.5

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

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

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

0.2% cetane improver added.

If the results of preliminary tests are promising, it might be feasible to increase the intake air temperature so that a 300° F. mixture temperature could be achieved with a lower temperature mixture heater.

Acknowledgment

The data reported here were obtained at the DuPont Co. Petroleum Laboratory under the supervision of W.S. Vilda. ✦

Reference

1. www.gasolineblendingplus.com.

The author

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CORROSION MODELING—Conclusion

Field inputs guide internal pitting corrosion model

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Laboratory experiments and observation of pit growth rates in six operating fields have led to development of a model to predict internal pitting corrosion of oil and gas pipelines. The inputs required to use the model (construction and operational) are readily available from the field.

The model accounts for the statistical nature of pitting corrosion, predicts the growth of internal corrosion pits, considers the variation of pitting corrosion rate, and determines any error in the prediction.

The first part of a two article series (OGJ, Nov. 26, 2007, p. 68) examined the pitting corrosion mechanism as well as problems in predicting internal pitting corrosion of oil and gas pipelines, before beginning an assessment of the parameters influencing internal pitting corrosion.

This second, concluding article continues the assessment of parameters begun in Part 1 and discusses both the predicting model and its validating observations.

Operational parameters

• *Pressure.* Higher pressure (or partial pressure of a particular species) induces higher corrosion if it increases the dissolution of metal and decreases the pitting corrosion rate if it facilitates the formation of intact surface layers.

Table 1 shows the experimentally determined variation in pit growth rates with pressure.

PRESSURE EFFECT Table 1

Pressure, psi	μm/year
<100	100
100-500	50
>500	35

• *H_2S partial pressure.* The acid formed by the dissolution of H_2S is about three times weaker than that formed by the dissolution of CO_2 (i.e., carbonic acid), but H_2S is about three times more soluble than CO_2 gas, resulting in similar contributions of CO_2 and H_2S partial pressures to lower pH.

H_2S EFFECT Table 2

Partial pressure H_2S, psi	μm/year
<2.5	85
<10	50
<50	45
≥50	40

The formation and stability of iron sulfides determine the effect of H_2S on the pitting corrosion rate. Iron sulfides are generally good electronic conductors and have low overpotential for hydrogen evolution, noble electrode potentials, and defect structures.

Table 2 shows the experimentally determined variation in pit growth rates with H_2S partial pressure.

• *Sulfate ion.* Anions such as sulfate inhibit pitting by raising the pitting potential. Sulfate might therefore raise the critical pitting temperature below which no stable pitting occurs at any electric potential.

Sulfate's effect then centers on the ability of metastable pits to become repassivated. Stabilization is tied to the sulfate layer that develops over the metastable pit. Sulfate ion's effect is predominant only in the presence of H_2S. Sulfate ion had no effect on corrosion rate in experiments.

Table 3 shows the experimentally determined variation in pit growth rates with sulfate pressure.

SULFATE EFFECT Table 3

Sulfate concentration, ppm	μm/year
<750	75
<1,000	50
<1,500	25
<2,500	15
≥2,500	10

• *CO_2 partial pressure.* Dissolution of gaseous CO_2 in solution leads to formation of carbonic acid. This weak acid reacts with iron to form iron carbonate. The formation and stability of iron carbonates determine CO_2's effect on pitting corrosion rate.

Table 4 shows the experimentally determined variation in pit growth rates with CO_2 partial pressure. Increasing the partial pressure of CO_2 causes the surface layers to become compact, leading the pitting corrosion rate to decrease with CO_2 partial pressure.

CO_2 EFFECT Table 4

Partial pressure CO_2, psi	μm/year
<2.5	100
<10	65
<30	50
<100	20
≥100	15

• *Bicarbonate ion.* Bicarbonate ion

Bicarbonate effect

Table 5

Bicarbonate concentration, ppm	µm/year
<500	90
<1,000	70
<2,000	50
<4,000	40
≥4,000	20

Chloride effect

Table 6

Chloride concentration, ppm	µm/year
<10,000	5
<20,000	25
<40,000	30
<60,000	50
<80,000	55
<100,000	60
<120,000	95
≥120,000	100

Experimental conditions

Table 7

Parameter	Minimum condition	Maximum condition	Units
Solid production	No solids present	Solids are present	n/a
Temperature	5	125	°C.
Total pressure	0	750	psi
H_2S partial pressure	0	50	psi
CO_2 partial pressure	0	100	psi
Bicarbonate concentration	0	4,000	ppm
Sulfate concentration	0	2,500	ppm
Chloride concentration	0	120,000	ppm
Flow	0	5	m/sec

effect becomes prominent only in the presence of CO_2. Carbon dioxide dissolved in water readily combines with water to form carbonic acid. The carbonic acid then dissociates into the hydrogen ion and bicarbonate ion. The excess bicarbonate shifts the equilibrium to the left, decreasing the rate of CO_2 corrosion.

Bicarbonate also acts as a buffer. A bicarbonate buffer can absorb H^+ ions and neutralize the acids produced by CO_2 dissolution. This buffer contains a weak acid, carbonic acid, H_2CO_3, and a bicarbonate anion, HCO_3.

Table 5 shows the experimentally determined variation in pit growth rates with bicarbonate concentration.

- *Chloride ion.* Chloride ions are the most common cause of pitting. Like other halides, chloride ion acts as a very potent agent in destroying otherwise protective passive surface layers. In the case of chloride-induced pitting, the corrosion mechanism also involves strong chloride concentrating effects in a growing pit, accelerating the rate of pit development in an autocatalytic growth process.

Table 6 shows the experimentally determined variation in pit growth rates with chloride ions.

Computable parameters

Computable parameters are extensively used in understanding corrosion and include pH, wall-shear stress, and flow regime. Either the values of the operational parameters[1,2] or field measurements can provide the basis computing these parameters.

Predicting corrosion

The three construction parameters required for predicting internal pitting corrosion of oil and gas pipelines are inclination of the pipe, ID, and OD (or WT). Carbon steel is predominantly used for construction of oil and gas pipelines. Minor variations in the

Field pipe pit-growth rates

Table 8

Feature position, m	Depth, %	Clock position	Feature position, m	Depth	Depth (pit gauge) %	Clock position
15.776	31.5	6:00:00	825.455	69.3	54.5	5:30:00
17.408	34.4	7:30:00	826.133	33		5:30:00
18.095	34.4	7:00:00	826.688	44.5		5:30:00
25.459	30	5:30:00	826.702	38.4		4:30:00
26.951	33	5:30:00	826.912	30		5:30:00
27.777	34.4	5:30:00	827.03	38.4		5:30:00
28.353	47.8	5:30:00	827.117	48.9		5:30:00
40.72	30	5:30:00	827.25	43.3		5:30:00
43.412	34.4	5:30:00	827.604	40.9		5:30:00
43.655	34.4	5:30:00	837.104	30		5:30:00
57.29	30	5:00:00	837.421	30		5:30:00
61.197	45.6	4:30:00	837.52	31.5		5:30:00
172.622	31.5	6:30:00	852.347	33		5:00:00
173.29	37.1	6:30:00	859.024	30		5:00:00
175.387	31.5	6:30:00	859.114	33		5:00:00
188.705	33	7:30:00	865.927	30		5:00:00
189.966	31.5	7:30:00	897.86	31.5		5:30:00
190.03	30	7:30:00	901.777	38.4		5:30:00
196.69	30	6:30:00	901.817	33		5:30:00
202.824	30	7:00:00	902.242	52		5:00:00
206.047	33	6:30:00	902.296	30		5:00:00
232.159	31.5	6:30:00	904.457	31.5		5:00:00
238.527	37.1	6:30:00	904.511	31.5		6:00:00
253.498	30	6:30:00	904.523	47.8		5:00:00
274.322	38.4	6:30:00	904.546	34.4		5:00:00
276.058	39.7	6:30:00	906.27	58.8		3:30:00
291.704	31.5	6:00:00	934.479	31.5		4:00:00
363.705	30	5:30:00	937.565	54		4:30:00
364.675	31.5	5:30:00	941.758	34.4		4:00:00
463.143	30	5:30:00	942.521	34.4		4:00:00
467.962	33	4:30:00	950.364	38.4		3:30:00
469.485	31.5	5:00:00	964.45	33		4:00:00
469.523	30	5:00:00	964.584	72.5		4:00:00
470.016	31.5	5:30:00	964.584	30		5:30:00
470.226	31.5	5:30:00	964.596	35.8		2:30:00
470.831	31.5	5:30:00	964.601	65.9		4:00:00
478.372	33	5:30:00	965.453	37.1		11:00:00
492.054	30	5:00:00	968.43	39.7		5:30:00
494.665	34.4	5:00:00	968.555	39.7		5:30:00
495.149	30	6:00:00	968.567	34.4		6:30:00
497.493	33	5:00:00	979.598	42.2		6:30:00
498.15	31.5	5:00:00	1008.598	52.1	52.1	5:30:00
571.128	31.5	5:30:00	1018.939	30		7:00:00
571.759	33	5:30:00	1018.949	30		7:30:00
578.622	31.5	5:00:00	1018.972	30		7:30:00
584.404	30	5:00:00	1019.437	44.5	50	6:00:00
612.042	31.5	4:30:00	1020.403	31.5		6:00:00
641.795	31.5	4:30:00	1020.571	72.5	74.8	7:00:00
641.878	30	5:00:00	1020.696	51	50	7:00:00
654.651	44.5	6:00:00	1020.71	31.5		7:30:00
698.299	30	5:30:00	1021.251	38.4		7:00:00
736.084	48.9	5:30:00	1021.371	53.1		7:00:00
738.84	30	5:00:00	1021.387	48.9		6:00:00
738.851	35,8	6:00:00	1021.387	31.5		7:30:00
756.76	30	5:30:00	1026.544	30		8:30:00
758.001	34.4	5:30:00				
770.269	31.5	5:30:00				
774.342	30	4:00:00				
774.994	30	5:30:00				
778.077	31.5	4:30:00				

composition of carbon steel are not considered.

The nine operational parameters required are production rates of oil, water, gas, and solid, total pressure, partial pressures of CO_2 and H_2S, temperature, and concentration of chloride ions. Each of the operational parameters individually can alter pitting corrosion rates. Concentration of bicarbonate ion alters the pitting corrosion rate only in the presence of CO_2. Similarly, concentration of sulphate ion alters pitting corrosion rate only in the presence of H_2S. The ultimate rate at which pits will propagate depends on the combined effect of all operational parameters.

While prediction of the individual effect of each parameter can happen deterministically, the combined effect of these variables needs application of statistical principles.

Several methods have predicted the probability of the system pitting corrosion rate based on short-duration measurements. These methods include extreme value statistics,[3] Weibull distribution function,[4] Gumble distribution function,[3] corrosion damage function,[5] stochastic process,[6] Markov process,[4] and artificial neural network.[4]

All approaches accept that pitting corrosion's driving force is a distributed parameter, while varying in their treatment of driving force and pattern of distribution.

This article assumes that each operational variable produces an individual pit growth rate (resulting in nine different pitting corrosion rates) and that pit growth rate stemming from the variables not considered (e.g., acetic acid effect) is the mean value of the nine pit growth rates. The tenth parameter does not affect the predicted pitting corrosion rate but does increase the uncertainty of the prediction.

The actual pit growth rate occurring in the oil and gas pipeline is the distributed function, consisting of the mean value of the 10 pit growth rates. The resultant pit growth rate is the rate at which the pits will start to grow in the localized anodic region where the surface layers are removed.

Except for one operational variable (water), removal or control of one or more operational variables will change the pit growth rate, but not prevent pit growth. The absence of water in a location, however, prevents pitting corrosion regardless of the other variables.

Various reasons, including partial reformation of surface layers, local solution saturation, change of corrosion potential, and local increase of pH prevent pits from growing continuously at the same rate at which they start. Pit growth rate diminishes parabolically as a function of time.

The assumptions made in obtaining pit growth rates render the overall pit growth rate probabilistic in nature. The accuracy of this prediction lies within the standard deviation of the pit growth-rate prediction.

Laboratory experiments conducted at pipeline operating conditions, field experiments conducted over 4 years in six operating fields, and assumptions made on the probabilistic nature of the pitting corrosion yield the pitting corrosion rate of oil and gas pipelines expressed by Equation 1 (in accompanying equation box).

Development of this model used the following assumptions:

- Type of pipeline steel used will not affect corrosion rate.
- Volume and type of solid production is irrelevant.
- H_2S concentration is not zero, otherwise sulfate concentration is irrelevant.
- CO_2 concentration is not zero, otherwise bicarbonate concentration is irrelevant.
- Unless the actual emulsion type is determined at or above 30% water, the emulsion is oil-in-water.[7 8]

The simplified pitting corrosion rate formula given above cannot account for several situations. Chief among these is when H_2S or CO_2 partial pressure is zero. The sulfate ion effect depends upon the presence of H_2S and the bicarbonate ion effect depends on the presence of CO_2.

The absence of H_2S requires modification of the simplified pitting corrosion rate formula, removing the PH_2S and $C_{sulfate}$ terms, replacing them with a value of 85, and reducing the denominator by 1. The absence of CO_2 requires modification of the simplified pitting corrosion rate formula, removing the P_{CO2} and $C_{bicarbonate}$ terms, replacing them with a value of 100, and reducing the denominator by 1.

In the absence of both H_2S and CO_2, Equation 2 can predict the simplified pitting corrosion rate.

Within constrains of the assumptions made and range of conditions in which the experiments were conducted (Table 7), Equation 2 can predict the internal pitting corrosion of sour and sweet pipelines.

Statistical functions drive the pitting corrosion rates of oil and gas pipelines,

FIELD CONDITIONS Table 9

Oil production rate, cu m/day	27
Water production rate, cu m/day	50
Gas production rate, cu m/day	n/a
Sand production	Yes
Temperature, °C.	13
Pressure, psi	300
OD, mm	168.3
ID, mm	161.94
Chloride ion concentration, ppm	6,000
Sulfate ion concentration, ppm	<1
Bicarbonate ion concentration, ppm	2,330
H_2S partial pressure, psi	60
CO_2 partial pressure, psi	6

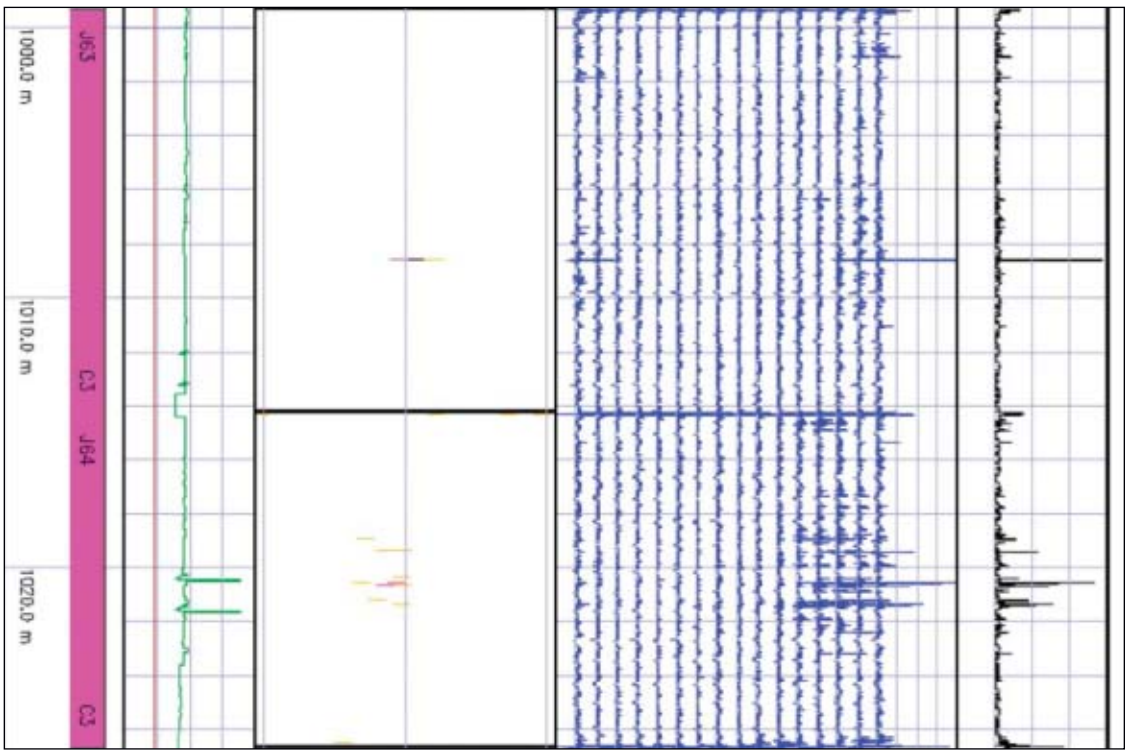
OPERATING PIPELINE ACTUAL PITTING CORROSION RATES Table 10

Months	50% wall loss* mm/year	50% wall loss* µin./year	75% wall loss* mm/year	75% wall loss* µin./year
23	0.830	32.67	1.24	48.82
24	0.795	31.30	1.19	46.85

*Note: Initial WT = 3.18 mm, 125.2 µm.

PITTING CORROSION RATE COMPARISON Table 11

	Low flow µin./year	Low flow mm/year	High flow µin./year	High flow mm/year
Predicted	47±24	1.2±0.6	53±29	1.3±0.7
Actual	46.85–48.82	1.19–1.24	46.85–48.82	1.19–1.24



Analysis of this magnetic flux leakage readout showed pits penetrating as much as 72% of WT, prompting the company to shut down the pipeline and replace the damaged section (Fig. 1).

making the predicted pitting corrosion rate probabilistic. The standard deviation of Equation 1 and Equation 2 determined the error in the prediction. Gumble's probability chart could also distribute the driving forces.

Validation

As part of its integrity management program the company examined the pipeline using magnetic flux leakage. The analysis showed pits penetrating up to 72% of WT (Fig. 1). In order to avoid a leak, and the resulting environmental damage, the company shut down the pipe and replaced the damaged section. Subsequent depth-gauge measurements of the damaged sections of pipe showed that 74.8% of the wall had been penetrated in one section.

Table 8 shows pit depths and their locations along the pipe.

This 1-km pipe section first started receiving water flood in January 2004. Shutdown and repair occurred in November 2005. This pipeline operated without the use of inhibition. Pitting corrosion, therefore, can be reasonably assumed to have occurred over 23 and 24 months.

The majority of the pits discovered in the pipe section penetrated less then 50% of the 3.18 mm WT. Pitting corrosion took place at a calculated rate of 1.19 to 1.24 mm/year, depending on whether the pipe was in service for 23 or 24 months.

Tables 9 and 10 show operating conditions of the pipeline and detailed pitting corrosion rate calculations, respectively.

These field data validated the pitting corrosion model. Among the data required to use the model, the only data missing were the gas production rate, the emulsion inversion point, and the wettability of the oil. Emulsion inver-

EQUATIONS

$$\text{Pitting corrosion rate } (\mu\text{in./year}) = \{[\Sigma\ (-0.33\theta + 55) + (0.51W + 12.13) + (0.19W_{ss} + 64) + (50 + 25R_{solid}) + (0.57T + 20) + (-0.081P_{total} + 88) + (-0.54P_{H2S} + 67) + (-0.013C_{sulfate} + 57) + (-0.63P_{CO2} + 74) + (-0.014C_{bicarbonate} + 81) + (0.0007C_{chloride} + 9.2) + C.R._{general})]/12\} \times 1/t \quad (1)$$

Where:

θ	=	the contact angle of oil in a water environment
W	=	(100 × total water production/total water + total oil production)
W_{ss}	=	wall shear stress
R_{solid}	=	1 if there is a production rate of solids for the pipe or 0 if there is no production rate of solids for the pipe
T	=	temperature, °C.
P_{total}	=	total pressure, psi
P_{H2S}	=	partial pressure, H_2S, psi
P_{CO2}	=	partial pressure, CO_2, psi
$C_{sulfate}$	=	concentration sulfate, ppm
$C_{bicarbonate}$	=	concentration bicarbonate, ppm
$C_{chloride}$	=	concentration chloride, ppm
$C.R._{general}$	=	the average pit growth rates of oil, water, flow, solid, temperature, total pressure, partial pressures of H_2S and CO_2, and chloride
t	=	a constant depending on the time

$$\text{Pitting corrosion rate } (\mu\text{in.py}) = \{[\Sigma\ (-0.33\theta + 55) + (0.51W + 12.13) + (0.19W_{ss} + 64) + (50 + 25\text{Rsolid}) + (0.57T + 20) + (-0.081P_{total} + 88) + (0.0007C_{chloride} + 9.2) + 185 + C.R._{general})]/10\} \times 1/t \quad (2)$$

sion point and oil wettability require experimental determination. Absent the results of these experiments, this article assumes the pipeline was operating under water-wet conditions carrying oil-in-water emulsion.

Production of the gas through casing venting complicated determination of the gas production rate. Absent the actual gas production rate, this article simulated both low flow and high flow regimes by calculating the pitting corrosion rate for both conditions.

Table 11 shows predicted pitting corrosion rates of 0.6-1.8 mm/year for the low flow regime and 0.6-2.0 mm/year for the high flow regime. This compares quite favorably to the observed corrosion rate of 1.19-1.24 mm/year. ✦

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Two new tools for E&P operations

A new quad full high-definition monitor for ultrarefined geoscience visualization and analysis and a new data-compression appliance are suited for exploration and production uses.

The new Landmark M5600 monitor features a 56-in. quad full high-definition screen that the firm says is four times the size and twice the pixel count of current high resolution 30-in. screens. The monitor offers a resolution of 3,840 by 2,160.

When the monitor is paired with one of the firm's recommended visualization servers and high-performance work stations from Dell, HP, Sun, and Verari, it makes high-end visualization capabilities affordable and easy to deploy, both in individual work areas and in team rooms, the company notes.

The monitor's resolution, when coupled with its expansive viewing area, allows users to view large volumes of detailed data in full context. The monitor also allows users to view multiple data sources together. The company says this capability enables geoscientists to digitally revisit the days when they would put big sheets of paper on the wall side-by-side. The M5600 allows users to do the same thing they used to do with paper, only in high-resolution digital format.

Data-compression appliance. The device, known as the Storwize STN 6000, is capable of tripling E&P data-storage capacities through real-time storage compression—a feature that the firm says efficiently and effectively improves storage space without the purchase of additional storage devices. Installation of the STN 6000 does not require any changes to existing infrastructure. The compression operations are invisible to users, while application and storage performance increase as a result of the device.

The appliance is produced by Storwize Inc., San Jose, Calif. The STN 6000 is designed to work with any network attached storage array.

It delivers real-time, lossless, data compression and decompression at speeds that make it transparent to users.

The technology uses patent-pending algorithms that can reduce operating expenses associated with a customer's current storage units. For example, the technology can delay migrations to additional storage units and also lower costs associated with power, air conditioning, and available floor space. Because the appliance compresses large volumes of data before backup, it can reduce downtime and shorten backup and restore cycles, the company says. In addition, it can reduce the amount of data sent over wide-area networks for remote backup.

Source: **Landmark Div., Halliburton,** 5 Houston Center, Houston, TX 77010.

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Offshore

Imports of crude and products

	Districts 1-4		District 5		Total US		
	11-16 2007	11-9 2007	11-16 2007	11-9 2007	11-16 2007	11-9 2007	*11-17 2006
	1,000 b/d						
Total motor gasoline	1,060	960	64	54	1,124	1,014	1,198
Mo. gas. blending comp.	692	558	22	54	714	612	649
Distillate	263	209	4	1	267	210	205
Residual	304	239	—	—	304	239	343
Jet fuel-kerosine	75	38	121	114	196	152	127
Propane-propylene	213	107	20	26	233	133	150
Other	648	752	39	48	687	800	522
Total products	**3,255**	**2,863**	**270**	**297**	**3,525**	**3,160**	**3,194**
Total crude	**8,664**	**9,368**	**1,156**	**1,119**	**9,820**	**10,487**	**10,490**
Total imports	**11,919**	**12,231**	**1,426**	**1,416**	**13,345**	**13,647**	**13,684**

*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.

OIL&GAS JOURNAL online research center

OGJ crack spread

	*11-16-07	*11-17-06	Change	Change, %
	$/bbl			
SPOT PRICES				
Product value	103.02	66.76	36.26	54.3
Brent crude	91.46	57.79	33.67	58.3
Crack spread	11.57	8.98	2.59	28.8
FUTURES MARKET PRICES				
One month				
Product value	102.57	67.30	35.27	52.4
Light sweet crude	93.68	57.54	36.14	62.8
Crack spread	8.89	9.76	–0.88	–9.0
Six month				
Product value	103.58	75.56	28.02	37.1
Light sweet crude	89.17	63.82	25.35	39.7
Crack spread	14.41	11.74	2.67	22.8

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

Purvin & Gertz LNG netbacks—Nov. 23, 2007

Receiving terminal	Liquefaction plant					
	Algeria	Malaysia	Nigeria	Austr. NW Shelf	Qatar	Trinidad
	$/MMbtu					
Barcelona	7.30	5.05	6.39	4.93	5.71	6.36
Everett	6.22	4.22	5.79	4.28	4.74	6.55
Isle of Grain	9.68	7.96	9.14	7.86	8.15	9.01
Lake Charles	4.99	3.13	4.77	3.32	3.66	5.67
Sodegaura	5.73	7.45	5.92	7.77	7.02	5.10
Zeebrugge	6.79	4.88	6.10	4.78	5.29	6.13

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	16,445	49,393	23,320	9,760	60,360	13,820	5,226
PADD 2	62,638	47,377	15,495	7,051	25,948	1,225	22,648
PADD 3	163,065	64,629	28,825	12,246	30,707	17,667	30,834
PADD 4	15,861	5,161	1,514	512	2,367	309	[1]2,915
PADD 5	55,596	28,630	21,250	9,261	11,623	6,076	—
Nov. 16, 2007	**313,605**	**195,190**	**90,674**	**38,830**	**131,005**	**39,097**	**61,623**
Nov. 9, 2007	**314,676**	**195,027**	**90,647**	**40,933**	**133,412**	**39,294**	**61,609**
Nov. 17, 2006[2]	**341,134**	**201,658**	**91,227**	**39,053**	**133,820**	**42,727**	**70,896**

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

Refinery report—Nov. 16, 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	1,616	1,624	1,706	86	495	106	79
PADD 2	3,042	3,014	1,981	197	927	37	191
PADD 3	7,290	7,099	3,385	659	2,052	327	701
PADD 4	526	522	259	22	167	10	[1]139
PADD 5	2,706	2,638	1,633	406	539	205	—
Nov. 16, 2007	**15,180**	**14,897**	**8,964**	**1,370**	**4,180**	**685**	**1,110**
Nov. 9, 2007	**15,295**	**15,048**	**8,895**	**1,439**	**4,217**	**671**	**1,068**
Nov. 17, 2006[2]	**15,143**	**14,992**	**8,699**	**1,401**	**4,081**	**593**	**1,066**
	17,448 operable capacity		**87.0% 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 11-21-07	Pump price* 11-21-07	Pump price 11-22-06
	¢/gal		
(Approx. prices for self-service unleaded gasoline)			
Atlanta	273.2	312.9	215.4
Baltimore	261.9	303.8	215.7
Boston	259.8	301.7	217.1
Buffalo	265.3	325.4	241.3
Miami	276.7	327.0	238.4
Newark	259.3	292.2	207.4
New York	247.9	308.0	231.1
Norfolk	258.3	295.9	209.9
Philadelphia	261.0	311.7	233.8
Pittsburgh	260.1	310.8	222.0
Wash., DC	270.7	309.1	226.0
PAD I avg.	263.1	309.0	223.4
Chicago	293.1	344.0	260.8
Cleveland	268.3	314.7	220.6
Des Moines	262.6	303.0	208.6
Detroit	275.5	324.7	226.8
Indianapolis	268.2	313.2	223.5
Kansas City	263.9	299.9	209.9
Louisville	270.5	307.4	218.5
Memphis	265.1	304.9	210.2
Milwaukee	254.0	315.3	234.4
Minn.-St. Paul	266.0	306.4	220.9
Oklahoma City	271.1	306.5	207.9
Omaha	257.9	304.3	223.8
St. Louis	268.5	304.5	214.9
Tulsa	263.1	298.5	209.7
Wichita	256.3	299.7	216.8
PAD II avg.	267.6	309.8	220.5
Albuquerque	271.6	308.0	217.0
Birmingham	266.1	304.8	213.8
Dallas-Fort Worth	261.2	299.6	213.6
Houston	253.7	292.1	207.0
Little Rock	264.4	304.6	212.0
New Orleans	258.6	297.0	213.0
San Antonio	254.6	293.0	209.0
PAD III avg.	261.4	299.9	212.2
Cheyenne	267.3	299.7	215.4
Denver	268.4	308.8	210.8
Salt Lake City	260.2	303.1	226.3
PAD IV avg.	265.3	303.9	217.5
Los Angeles	274.6	333.1	243.1
Phoenix	257.6	295.0	220.5
Portland	274.0	317.3	243.9
San Diego	284.6	343.1	247.9
San Francisco	301.5	360.0	264.0
Seattle	278.8	331.2	254.6
PAD V avg.	278.5	330.0	245.7
Week's avg.	**266.8**	**310.4**	**223.3**
Oct. avg.	**237.3**	**280.9**	**228.0**
Sept. avg.	**236.3**	**280.4**	**253.3**
2007 to date	**232.5**	**276.1**	—
2006 to date	**215.3**	**258.9**	—

*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

	11-16-07 ¢/gal		11-16-07 ¢/gal
Spot market product prices			
Motor gasoline (Conventional-regular)		Heating oil No. 2	
New York Harbor	243.30	New York Harbor	257.63
Gulf Coast	236.30	Gulf Coast	256.00
Los Angeles	255.00	Gas oil	
Amsterdam-Rotterdam-Antwerp (ARA)	230.87	ARA	264.42
Singapore	236.07	Singapore	247.62
Motor gasoline (Reformulated-regular)		Residual fuel oil	
New York Harbor	241.55	New York Harbor	167.57
Gulf Coast	239.75	Gulf Coast	174.40
Los Angeles	257.00	Los Angeles	197.88
		ARA	173.04
		Singapore	181.13

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

BAKER HUGHES RIG COUNT

	11-23-07	11-24-06
Alabama	4	4
Alaska	11	6
Arkansas	50	34
California	40	36
Land	38	32
Offshore	2	4
Colorado	110	87
Florida	0	0
Illinois	0	0
Indiana	2	0
Kansas	16	13
Kentucky	1	2
Louisiana	165	195
N. Land	60	56
S. Inland waters	25	21
S. Land	29	47
Offshore	51	71
Maryland	1	0
Michigan	1	2
Mississippi	6	17
Montana	11	17
Nebraska	0	0
New Mexico	73	101
New York	2	11
North Dakota	48	35
Ohio	13	8
Oklahoma	199	181
Pennsylvania	17	15
South Dakota	0	1
Texas	859	767
Offshore	10	9
Inland waters	2	4
Dist. 1	22	14
Dist. 2	36	23
Dist. 3	67	59
Dist. 4	82	92
Dist. 5	181	143
Dist. 6	113	119
Dist. 7B	39	39
Dist. 7C	64	41
Dist. 8	119	103
Dist. 8A	21	26
Dist. 9	40	33
Dist. 10	63	62
Utah	43	46
West Virginia	24	19
Wyoming	67	94
Others—NV-3; TN-6; VA-1	10	6
Total US	**1,773**	**1,697**
Total Canada	**391**	**453**
Grand total	**2,164**	**2,150**
Oil rigs	343	297
Gas rigs	1,424	1,395
Total offshore	65	85
Total cum. avg. YTD	**1,763**	**1,642**

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	11-23-07 Percent footage*	Rig count	11-17-06 Percent footage*
0-2,500	55	5.4	51	1.9
2,501-5,000	109	59.6	100	45.0
5,001-7,500	222	26.5	228	19.2
7,501-10,000	451	1.1	426	2.8
10,001-12,500	444	3.6	434	1.8
12,501-15,000	288	—	246	0.4
15,001-17,500	116	—	121	—
17,501-20,000	64	—	75	—
20,001-over	34	—	33	—
Total	**1,783**	**8.3**	**1,714**	**6.4**
INLAND	38		37	
LAND	1,694		1,617	
OFFSHORE	51		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]11-23-07	[2]11-24-06
	1,000 b/d	
(Crude oil and lease condensate)		
Alabama	14	20
Alaska	649	655
California	640	681
Colorado	50	63
Florida	6	6
Illinois	30	28
Kansas	95	100
Louisiana	1,370	1,373
Michigan	15	15
Mississippi	50	47
Montana	96	98
New Mexico	173	165
North Dakota	108	115
Oklahoma	169	172
Texas	1,360	1,348
Utah	45	50
Wyoming	143	146
All others	60	67
Total	**5,073**	**5,149**

[1]OGJ estimate. [2]Revised.

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

US CRUDE PRICES

$/bbl*	11-23-07
Alaska-North Slope 27°	71.17
South Louisiana Sweet	98.25
California-Kern River 13°	85.90
Lost Hills 30°	93.90
Southwest Wyoming Sweet	90.18
East Texas Sweet	94.25
West Texas Sour 34°	88.25
West Texas Intermediate	94.75
Oklahoma Sweet	94.75
Texas Upper Gulf Coast	91.25
Michigan Sour	87.75
Kansas Common	93.75
North Dakota Sweet	86.50

*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]	11-16-07
United Kingdom-Brent 38°	90.77
Russia-Urals 32°	87.74
Saudi Light 34°	87.86
Dubai Fateh 32°	85.83
Algeria Saharan 44°	92.21
Nigeria-Bonny Light 37°	92.14
Indonesia-Minas 34°	91.83
Venezuela-Tia Juana Light 31°	87.38
Mexico-Isthmus 33°	87.27
OPEC basket	89.22
Total OPEC[2]	88.29
Total non-OPEC[2]	87.18
Total world[2]	87.79
US imports[3]	85.21

[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]

	11-16-07	11-9-07	11-16-06	Change, %
	bcf			
Producing region	1,071	1,063	1,015	5.5
Consuming region east	1,991	2,002	1,964	1.4
Consuming region west	478	471	470	1.7
Total US	**3,540**	**3,536**	**3,449**	**2.6**
	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.

PACE REFINING MARGINS

	Sept. 2007	Oct. 2007	Nov. 2007	Nov. 2006	Change 2007 vs. 2006	Change, % 2007 vs. 2006
	$/bbl					
US Gulf Coast						
West Texas Sour	13.31	11.27	13.13	12.21	0.93	7.6
Composite US Gulf Refinery	13.31	10.44	13.24	11.28	1.96	17.4
Arabian Light	11.08	7.68	11.33	11.99	–0.66	–5.5
Bonny Light	7.23	5.04	7.68	3.96	3.63	92.0
US PADD II						
Chicago (WTI)	15.87	9.26	11.59	11.10	0.49	4.5
US East Coast						
NY Harbor (Arab Med)	5.87	4.62	7.79	10.81	–3.02	–28.0
East Coast Comp-RFG	9.87	8.15	10.46	13.01	–2.55	–19.6
US West Coast						
Los Angeles (ANS)	9.46	12.48	14.17	18.62	–4.44	–23.9
NW Europe						
Rotterdam (Brent)	3.67	3.04	6.77	1.73	5.04	290.5
Mediterranean						
Italy (Urals)	9.78	8.95	11.45	7.47	3.98	53.2
Far East						
Singapore (Dubai)	4.68	6.30	7.51	(0.34)	7.84	2341.6

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

US NATURAL GAS BALANCE DEMAND/SUPPLY SCOREBOARD

	Aug. 2007	July 2007	Aug. 2006	Aug. 2007-2006 change	Total YTD 2007	Total YTD 2006	YTD 2007-2006 change
	bcf						
DEMAND							
Consumption	1,801	1,658	1,761	40	15,465	14,728	737
Addition to storage	294	397	302	–8	2,228	2,026	202
Exports	57	60	55	2	492	471	21
Canada	25	29	17	8	278	196	82
Mexico	28	28	32	–4	181	230	–49
LNG	4	3	6	–2	33	45	–12
Total demand	**2,152**	**2,115**	**2,118**	**34**	**18,185**	**17,225**	**960**
SUPPLY							
Production (dry gas)	1,625	1,626	1,620	5	12,536	12,296	240
Supplemental gas	5	5	6	–1	40	41	–1
Storage withdrawal	168	84	113	55	2,284	1,692	592
Imports	390	414	365	25	3,103	2,797	306
Canada	303	311	313	–10	2,435	2,385	50
Mexico	0	5	0	0	18	3	15
LNG	87	98	52	35	650	409	241
Total supply	**2,188**	**2,129**	**2,104**	**84**	**17,963**	**16,826**	**1,137**

NATURAL GAS IN UNDERGROUND STORAGE

	Aug. 2007	July 2007	June 2007	Aug. 2006	Change
	bcf				
Base gas	4,226	4,229	4,230	4,213	13
Working gas	3,017	2,894	2,580	2,969	48
Total gas	**7,243**	**7,123**	**6,810**	**7,182**	**61**

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

WORLDWIDE NGL PRODUCTION

	Aug. 2007	July 2007	8 month average Production 2007	8 month average Production 2006	Change vs. previous year Volume	Change vs. previous year %
	1,000 b/d					
Brazil	88	79	84	86	–2	–2.2
Canada	674	659	701	679	21	3.2
Mexico	378	401	408	440	–32	–7.3
United States	1,755	1,778	1,748	1,726	23	1.3
Venezuela	200	200	200	200	—	—
Other Western Hemisphere	199	199	204	215	–11	–5.1
Western Hemisphere	**3,293**	**3,316**	**3,345**	**3,346**	**–1**	**—**
Norway	270	279	287	287	—	—
United Kingdom	87	121	142	150	–8	–5.6
Other Western Europe	11	11	10	11	–	–1.5
Western Europe	**368**	**411**	**439**	**448**	**–9**	**–1.9**
Russia	428	425	426	414	12	3.0
Other FSU	160	160	160	160	—	—
Other Eastern Europe	15	14	15	17	–2	–13.3
Eastern Europe	**603**	**599**	**601**	**591**	**10**	**1.7**
Algeria	340	340	340	303	38	12.4
Egypt	70	70	70	73	–3	–4.1
Libya	80	80	80	86	–6	–7.0
Other Africa	189	182	186	190	–4	–1.9
Africa	**679**	**672**	**676**	**651**	**25**	**3.8**
Saudi Arabia	1,427	1,427	1,427	1,427	—	—
United Arab Emirates	250	250	250	250	—	—
Other Middle East	871	871	870	903	–32	–3.6
Middle East	**2,548**	**2,548**	**2,547**	**2,580**	**–32**	**–1.3**
Australia	79	80	75	81	–6	–7.9
China	180	180	180	180	—	—
India	—	—	5	42	–37	–88.7
Other Asia-Pacific	173	174	178	186	–8	–4.4
Asia-Pacific	**432**	**433**	**437**	**489**	**–52**	**–10.6**
TOTAL WORLD	**7,922**	**7,980**	**8,046**	**8,105**	**–58**	**–0.7**

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

OXYGENATES

	Aug. 2007	July 2007	Change	YTD 2007	YTD 2006	Change
	1,000 bbl					
Fuel ethanol						
Production	13,458	13,051	407	97,659	74,002	23,657
Stocks	10,309	9,696	613	10,309	9,160	1,149
MTBE						
Production	1,985	2,088	–103	15,624	23,659	–58,378
Stocks	1,382	1,480	–98	1,382	1,759	–377

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

US HEATING DEGREE-DAYS

	Oct. 2007	Oct. 2006	Normal	2007 % change from normal	Total degree days July 1 through Oct. 31 2007	2006	Normal	% change from normal
New England	301	461	467	–35.5	470	666	657	–28.5
Middle Atlantic	197	385	399	–50.6	271	496	526	–48.5
East North Central	268	500	424	–36.8	382	679	580	–34.1
West North Central	334	520	424	–21.2	460	711	607	–24.2
South Atlantic	83	185	164	–49.4	97	216	189	–48.7
East South Central	136	249	213	–36.2	146	293	246	–40.7
West South Central	82	97	83	–1.2	83	106	92	–9.8
Mountain	308	372	360	–14.4	406	537	543	–25.2
Pacific	189	184	186	1.6	280	236	294	–4.8
US average*	**191**	**307**	**282**	**–32.3**	**261**	**403**	**383**	**–31.9**

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

rethinking
RECOVERY METHODS

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AUCTION

IN THE UNITED STATES BANKRUPTCY COURT
FOR THE WESTERN DISTRICT OF MICHIGAN

In re:	:	Chapter 11
JORDAN RIVER RESOURCES, INC., et al.,	:	Case Nos. 07-01747, 07-02139, 07-01750, and 07-01786
Debtors.	:	(Jointly Administered)

NOTICE OF UNIFORM BIDDING PROCEDURES IN CONNECTION WITH THE SALE OF SUBSTANTIALLY ALL OIL AND GAS-RELATED ASSETS OF DEBTORS AND THEIR RELATED ENTITIES

TO ALL INTERESTED PERSONS:

The following procedures will govern the conduct of a sale of substantially all of the oil and gas related assets of the Debtors, Jordan River Resources, Inc., ("Jordan River"), Apple Tree Resources, Inc. ("Apple Tree"), Superior Petroleum Corporation ("Superior"), and Redstone Energy Corporation ("Redstone") (collectively, the "Debtors"), together with the sale of substantially all of the oil and gas-related assets of the Debtors' Related Entities (as defined in the Asset Purchase Agreement and Sale Motion), pursuant to 11 U.S.C. §§ 363, 365, and 105. The sale contemplated herein and in the Sale Motion filed herewith includes the sale of Debtor's interests in the Assets and the interests of the Subsidiaries and the Related Entities in the Assets. Liquidating Agent consents to the sale of the interests of the Subsidiaries and Related Entities in the Assets. Trustee consents to the Liquidating Agent being the primary contact person for any and all Qualified Bids that may be made for the Assets:

A. The **Sale Hearing** shall be held no later than December 12, 2007, at 1:30 p.m. (EST) in Federal Building and United States Courthouse in Lansing, Michigan before the Honorable Scott Dales, United States Bankruptcy Judge for the Western District of Michigan; and,
B. If, as provided below, an auction for consideration of Qualified Bids that may be presented to the Liquidating Agent (the "**Auction**") becomes necessary, it shall commence on December 10, 2007, at 10:00 a.m. (EST), at the offices of Clark Hill PLC 212 East Grand River, Lansing, MI 48906, or such other location as the Liquidating Agent may designate.

Further instructions regarding bidding can be obtained by contacting:

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Gasoline price sting not what politicians say

The sting of rising gasoline prices is a handy political cudgel, whatever its severity.

"For the nearly 7 years of the Bush administration," House Speaker Nancy Pelosi (D-Calif.) said recently, "the rising cost of gas and home heating oil has been a major economic stress on millions of American families" (OGJ, Nov. 12, 2007, p. 36).

Yet a report by the Federal Reserve Bank of Dallas notes that US expenditures on gasoline as a share of American budgets remain well below levels of the early 1980s.

"At today's higher incomes, gasoline expenditures claim less than 4% of US after-tax personal income," write Stephen P.A. Brown, director of energy economics and microeconomic policy, and Raghav Virmani, economic analyst, in the Dallas Fed's October Economic Letter. "The comparable figure for 1981 was more than 6%."

Early in the Bush presidency, the gasoline claim on after-tax income was 3% or below. It has risen steadily since 2002, partly because of increases in driving but mostly because of rising gasoline prices, Brown and Virmani say.

To blame Bush for gasoline price increases is to overlook market events such as hurricanes, strains on crude supplies, and relentlessly growing demand—about which presidents can't do much.

Brown and Virmani have developed a model showing how the US spot gasoline price tracks the spot price of West Texas Intermediate crude. Using just those factors, the model shows spot gasoline prices eventually rise by 2.8¢/gal for every $1/bbl increase in spot WTI.

Refined to account for seasonality and other factors, the model explains more than 99% of past US gasoline prices.

Its forecast? At crude prices indicated by October futures contracts, spot gasoline prices will rise by 20¢/gal in the next few months then decline by 35¢/gal over the next 3 years, with seasonal variations each year of about 27¢/gal.

Stress? Yes. But it won't be historic, as politicians are sure to portray it.

"At today's incomes," Brown and Vermani say, "retail gasoline prices would have to reach about $5.50/gal before they took the same share of US household budgets as they did in 1981."

(Online Nov. 23, 2007; author's e-mail: bobt@ogjonline.com)

The Editor's Perspective

by Bob Tippee, Editor

Market Journal

by Sam Fletcher, Senior Writer

Marching to $100/bbl oil

When the front-month crude futures contract fell $3.45 to $91.17/bbl Nov. 13—the lowest level in nearly 2 weeks on the New York Mercantile Exchange—after the International Energy Agency reduced estimates of global oil demand for the fourth quarter through 2008, many analysts declared the march to $100/bbl oil had finally fizzled. Imagine their surprise when the January crude contract jumped $3.39 to a record closing of $98.03/bbl Nov. 20, climbing as high as the Nov. 7 record of $98.62/bbl in intraday trading. The price continued climbing to $99.29/bbl in early electronic trading Nov. 21 before closing at $97.29/bbl, down 74¢ for the day on NYMEX. But the push for $100/bbl oil may not be over.

The volume of crude traded Nov. 19 on the New York market was "the lowest level of the last 55 trading days," said Olivier Jakob, managing director of Petromatrix GMBH, Zug, Switzerland, in a Nov. 21 report. In a low-volume, preholiday market, a large pension fund buying oil assets with the weaker dollar could trigger a rally.

Analysts in the Houston office of Raymond James & Associates Inc. blamed the record-low weakness of the US dollar for driving up crude prices. "Credit spreads widened following the Federal Reserve's cut in its growth outlook for next year to a growth of only 1.8-2.5%. This, coupled with the US 10-year Treasury yield falling below 4% for the first time since 2005, sunk the dollar to a new record low [of] $1.4850 vs. the euro," they said.

Moreover, Raymond James said, "Oil was trading up premarket on expectations of colder weather in the Northeast and supply setbacks in Canada and Mexico." Fire damaged a 155,000 b/d oil sands upgrader at Royal Dutch Shell PLC's Scotford refining complex near Edmonton, Alta., on Nov. 18. The upgrader and Shell's adjacent 98,000 b/d refinery were operating at reduced rates Nov. 20. Oil produced by the upgrader is processed through the refinery.

Dollar value

However, analysts at Barclays Capital Research, a division of Barclays Bank PLC, London, claim the weakness of the dollar against other currencies has limited effect on oil markets. "A widespread misconception is that the value of the dollar and the price of oil are linked by a clear indirect relationship. This belief has grown stronger over the past 3 months fueled by the simultaneous acceleration in the fall of the greenback and the move up in oil prices. In our view, the relationship between the two is far more tenuous that many might think. Firstly, there is no evidence that periods of dollar weakness are associated with higher oil prices, and, historically, a wide range of behavior has been displayed," they reported Nov. 21.

"Arguably, a weaker dollar makes oil cheaper for nondollar consumers, whereas it squeezes profits for non-US producers, which should prove supportive for prices over time," said Barclays analysts. "While the magnitude of the effect is far from clear, its transmission would involve substantial time lags. Refiners are often insulated from fluctuations in the value of the dollar as both their inputs and outputs are denominated in the same currency, and any knock-on effect induced by higher-end user demand would likely be in the region of quarters and years rather than days. On these grounds we see very little substance to those explanations which base the latest move-up in oil prices on the deterioration of the dollar, and by contrast we see the tightening of the physical market balance as having a far better explanatory power."

They predicted, "Severe constraints on the supply side and limited room for maneuver by the Organization of Petroleum Exporting Countries in the short term will keep prices vulnerable to supply disruptions and a faster-than-expected erosion of the inventory cover."

OPEC's summit meeting Nov. 17-18 in Riyadh was only the third meeting of member heads of state in the group's 47 years. At that meeting, President Hugo Chavez of Venezuela and President Mahmoud Ahmadinejad of Iran urged that the cartel quit pricing its oil in US dollars in favor of a basket of stronger currencies. Saudi Arabia opposed that move.

Analysts at Barclays Capital Research see little chance for such a change. "It would necessitate a major overhaul of the existing pricing system, given that OPEC crudes are currently priced in terms of dollar adjustments from dollar-denominated benchmarks. The absence of non-US dollar alternatives (the only exception being the yen-denominated contracts traded on the Tokyo Commodity Exchange) would therefore require moving away from current market mechanisms and setting up a brand new pricing system, which we believe is unfeasible," they said.

(Online Nov. 26, 2007; author's e-mail: samf@ogjonline.com)